2010 Long Term Resource Plan

Terasen Gas

July 15, 2010

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EXECUTIVE SUMMARY

1) Introduction

Energy services that integrate low and no-carbon fuel technologies with conventional energy supply provide solutions to some of B.C.'s most pressing challenges: increasing demand for energy, increasing energy costs, carbon emissions, job creation and economic stability to name a few. Efficiency improvements, conservation and reduction of carbon emissions are today's top priorities, creating immense challenges amidst an ever growing population demanding more energy at low cost. In 2010, Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW"), collectively referred to as the "Terasen Utilities" or "the Utilities", began integrating a range of alternative energy solutions and services into their core natural gas transportation and delivery business, while at the same time significantly increasing expenditures on energy efficiency and conservation programs. This Long Term Resource Plan ("LTRP") builds on those initial steps to transform the Terasen Utilities into a complete, integrated energy provider of alternative energy solutions incorporating the reliability of conventional energy services.

Together, the Terasen Utilities provide natural gas service to more than 935,000 residential, commercial, and industrial customers throughout British Columbia. Table ES-1 summarizes the customer and natural gas consumption characteristics of each service area.

Table ES-1: 2009 Service Statistics for the Terasen Utilities

	TGI Lower Mainland	TGI Interior	TGVI	TGW	Alternative Energy Services**
Number of Customers	582,199	253,480	97,705	2,580	748†
Annual Demand (TJ)	86,409	27,865	11,651	663	--
Peak Day Demand (TJ/d)	918	331	110	7	--
Length of Transmission Pipeline (km)	256	2,063	671	--	--
Length of Distribution Pipeline (km)*	11,030	8,237	3,435	95	--

* Includes both low and intermediate pressure pipelines

** Statistics from a forth company - Terasen Energy Services - which served all alternative energy customers prior to 2010. TES is not the subject of this Long Term Resource Plan. Information provided for context only.

† Data is a combination of individual customers and units served by a common alternative energy system - data to 2nd quarter 2010

The Terasen Utilities are owned by Terasen Inc., which itself is a subsidiary of Fortis Inc., the largest investor-owned utility company in Canada. Together with the B.C. based electric utility subsidiary, FortisBC, Fortis utilities deliver energy to more than one million customers in 135 communities across the province.

The resource planning process explores the social, regulatory and market landscapes in which the Terasen Utilities must continue to operate over the planning horizon. The 2010 LTRP examines future demand and supply resource conditions over the next 20 years and recommends actions needed during the next four years to ensure customers' energy needs are met over the long term. The Terasen Utilities' LTRP is submitted every two years, providing a snap shot in time of this ongoing planning process, including information and analysis updates and a revised four year action plan. These timelines allow Terasen Utilities to continuously improve its energy delivery strategies and ensure that system and regional resources with long lead times are being developed when needed.

2) Resource Planning Objectives

One of the first steps in this process is establishing an appropriate set of planning objectives to guide the resource planning strategy. Meeting customer needs and achieving the proper balance between multiple objectives is the key challenge in making resource decisions. Terasen Utilities' resource planning objectives are:

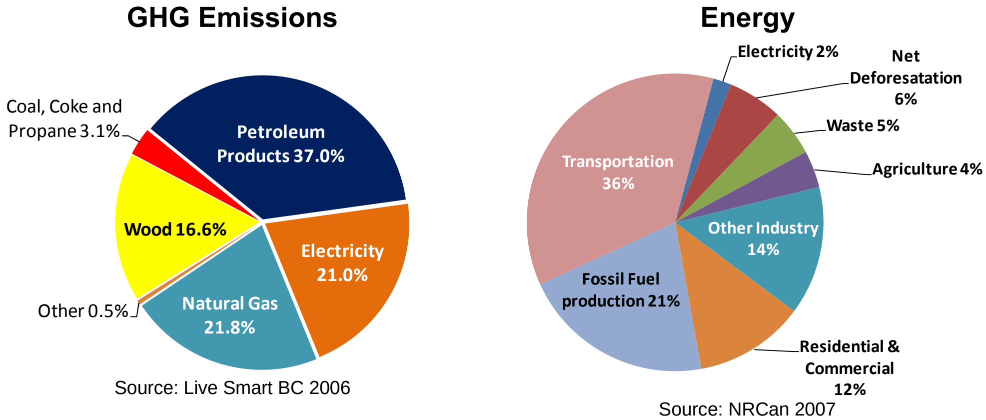
- ensuring safe, reliable and secure energy services;
- providing innovative and cost effective energy solutions;
- expanding energy efficiency and conservation initiatives;
- acting on social and environmental priorities; and
- contributing to climate change solutions.

3) Planning Environment

An ever-increasing factor affecting the planning environment today is the requirement to continually reduce the carbon footprint of the province's and Pacific Northwest ("PNW") region's energy systems over time, thus contributing to climate change solutions in an economically responsible way. This one factor is driving government policy, social attitudes, environmental responsibilities and the competitive nature of the energy business throughout the region. As part of the PNW, B.C.'s interconnection with its neighbours' energy transmission grids allows market trading of energy resources throughout the region, emissions resulting from energy choices made in any one jurisdiction have a global impact, unencumbered by provincial or national boundaries.

The most common forms of energy used in B.C. and throughout the PNW are natural gas, electricity and petroleum based fuels. Historically, the economic alternatives to these energy types have been higher carbon and/or pollutant emitting fuels such as coal, fuel oil and wood. Today, both the demand for and costs of energy continue to rise steadily along with our population growth. Due to the large hydro generation base in B.C., there is a belief that electricity represents the best low carbon choice to meet energy needs. However, B.C.'s electricity grid cannot physically or economically meet all of these requirements. Figure ES-1 shows both the current end-use energy sources for B.C. and the most significant opportunities for reducing Greenhouse Gas ("GHG") emissions. Looking forward, renewable and low carbon end-use energy alternatives have a prominent role to play in meeting the growing need for energy.

Figure ES-1: Energy Use and GHG Reduction Opportunities in B.C.



B.C.'s government continues to pass energy and GHG emissions related policies and legislation aimed at shifting energy use to reduce emissions. The 2007 Energy Plan, Carbon Tax Act, GHG Emission Reduction Acts, Green Building Codes, the Act, Climate Action Secretariat and Western Climate Initiative are some of the many initiatives implemented by the Province. The major focus of many of these initiatives is the role that B.C. electricity can play to shift energy demand and impact GHG emissions, while natural gas objectives contained in the Energy Plan focus on development of B.C.'s vast gas reserves for the economic benefit of the province.

Most recently, B.C.'s Clean Energy Act ("CEA") entrenches aggressive goals for GHG emissions reductions within B.C. The CEA also paves the way for clean electricity exports from B.C., giving the Province an important role in reducing regional GHG emissions. While the CEA has a significant focus on electricity based solutions, it does recognize the importance of integrating other alternatives and does not preclude using natural gas in end use applications where appropriate. All energy utilities are encouraged to increase energy efficiency and conservation programs and help develop innovative energy technologies. Natural gas is viewed along with electricity and hydrogen as an important clean transportation fuel for the Province. Increasing the utilization of waste heat and other waste resources such as biomass and production of biogas from waste organics are objectives of the CEA. Communities are also encouraged to innovate in their quest to become carbon neutral by 2012.

Many other regional energy issues also provide a backdrop for the development of future energy resources. In B.C. and the PNW, as we progress towards a low carbon economy, natural gas is expected to act as the transition fuel for both electricity generation and direct use applications. This view results from the fact that natural gas is the cleanest and lowest carbon fossil fuel, and from the relative lack of regional renewable electricity generation resources outside of B.C. The development of economic technologies to access vast quantities of shale gas in northern B.C., the U.S. Rockies and many other areas throughout North America has resulted in a favourable supply picture for the foreseeable future and has the potential to alter the trading patterns and flow of natural gas throughout the continent. At the same time, the British Columbia Hydro and Power Authority's ("BC Hydro") most recent Service Plan expects electricity rate increases of approximately 9%, 13% and 5% in each of the next 3 years as electricity self sufficiency, renewable resource development and replacement of aging infrastructure are top agenda items. A key consideration in developing sustainable energy plans is affordability, and as electricity prices increase, customers will continue to look for energy solutions that fit their needs and budgets.

4) Low Carbon Energy Supply Initiatives

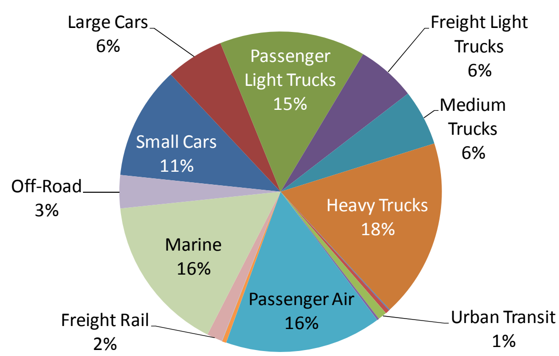
Alternative energy systems that integrate renewable, thermal end-use energy solutions such as geo-exchange, waste heat recovery and solar-thermal technologies supplemented as required by conventional natural gas and electric services for homes, businesses and communities are a key part of the Terasen Utilities' evolving low-carbon energy strategy. These technologies can serve individual, single-use buildings from single family homes to high-rise apartments or mixed use commercial buildings as discrete energy systems. Incorporated into more complex district energy systems, these technologies can be combined in different ways to take advantage of local available resources to meet the thermal energy needs of customers across entire mixed use communities. Terasen Utilities is incorporating an integrated approach to energy delivery for the ultimate benefit of all our customers, who are seeking integrated solutions to improve their energy efficiency and reduce carbon emissions.

The British Columbia Utilities Commission ("the Commission") approved this initiative as part of a Negotiated Settlement Agreement with respect to TGI's 2010-11 Revenue Requirement Application, allowing TGI to pursue and develop alternative energy projects with the proviso that all associated costs are paid by alternative energy customers and not by TGI's natural gas customers. TGI continues to pursue alternative energy projects in B.C. and is currently in the proposal and development stages of numerous projects. TGI intends to continue expanding its alternative energy business by offering these services to new and existing customers and developing the necessary infrastructure and operating capacity. As cost effective new renewable and low carbon technologies emerge, TGI will examine their practicality and compatibility for incorporation into integrated energy systems.

The Terasen Utilities are also uniquely positioned to affect a reduction in GHG emissions from B.C.'s largest emitting sector – **transportation** (see Figure ES-1). This opportunity will help customers in two ways. First, the added throughput will benefit existing customer by utilizing the existing natural gas infrastructure, which will have a positive impact on distribution rates. Secondly, it will help new customers meet their GHG goals in an economically manner by implementing proven technology. These customers are making significant investments in low carbon vehicle equipment and are looking to the Terasen Utilities as a trusted partner to deliver the energy solutions they need for years to come.

With tariffs in place, we can deliver both liquefied natural gas ("LNG") and compressed natural gas ("CNG") fuel solutions to a large portion of the transportation sector. Our low carbon fuel strategy targets return-to-base fleet vehicles for CNG solutions where fueling infrastructure economics make sense and vehicle ranges can match fuel capacity. Transport industry fleets with large engines present LNG solution opportunities where larger fuel capacities are needed for heavy duty or longer haul operations. Marine and rail fleets offer future LNG fueling opportunities. The transportation markets we are targeting (light, medium and heavy duty trucks, transit, marine fleets and potentially rail) emit almost 50% of transportation related emissions in B.C. (Figure ES-2). The Utilities plan to submit an application to the Commission in the summer of 2010 to outline the business plan and provide a comprehensive solution for customers.

Figure ES-2: GHG Emissions form B.C.'s Transportation Sector



Source: NRCan 2007

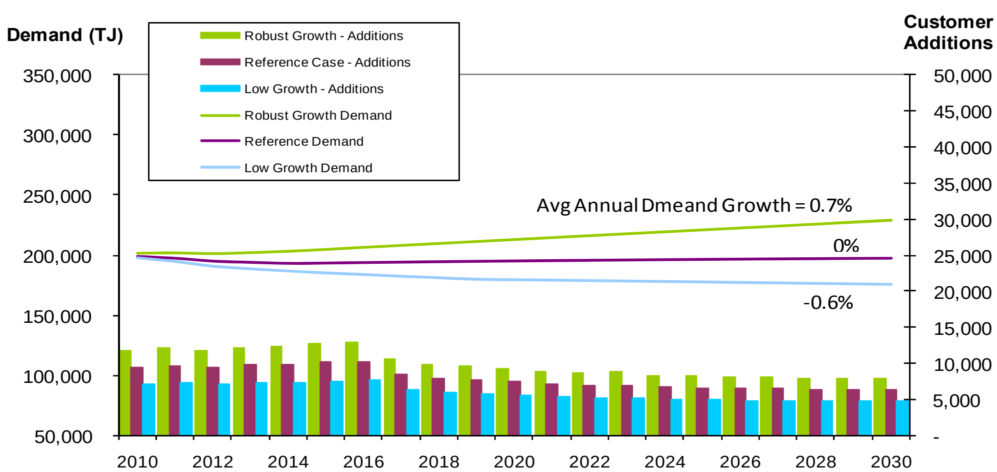
Market research completed in 2010 suggests that our customers have a strong desire to purchase renewable, clean energy from the Utilities. TGI is pursuing the acquisition of **biogas supplies** from prospective B.C. producers. Biogas, containing mostly methane and carbon dioxide, is produced from waste organic materials through anaerobic digestion in landfills, sewage treatment plants and on farms. When upgraded to pipeline quality biomethane, this carbon neutral source of gas is interchangeable with natural gas. A comprehensive biomethane supply and sales tariff application was submitted to the Commission in June, 2010 to allow expansion of our biomethane supplies and program offerings. TGI estimates growth in supply over the next 10 years can reach approximately 3,600 terajoules ("TJ"), and believes that demand will surpass supply throughout this period.

5) Energy Market Trends and Demand Forecasts

Current demand forecasting methodologies are critical inputs to planning for our core natural gas services. The Utilities must also develop new methodologies for forecasting demand for integrated, alternative energy solutions. While the impact of integrating renewable thermal energy solutions with conventional energy systems on forecasting results is expected to be small over the next 5 to 7 years, growth in such systems will follow from the development efforts and strategies being implemented today. This growth will begin to have a marked impact in longer term energy and GHG emissions forecasting. The Terasen Utilities continue to perform traditional natural gas demand forecasting and are developing revised methodologies to examine this impact under a range of future conditions.

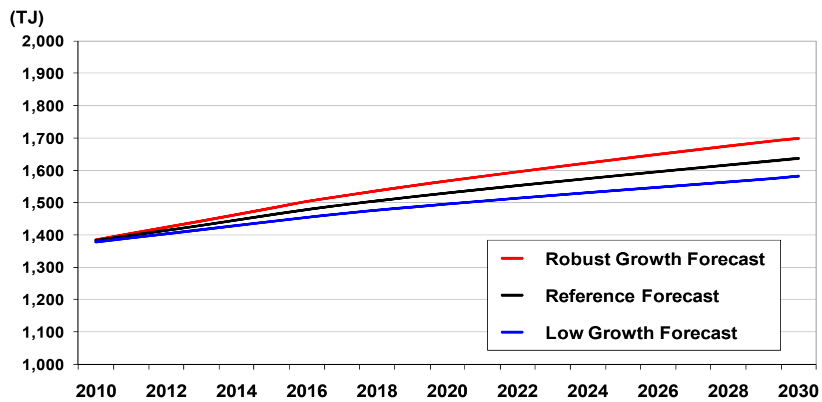
Under the current gas demand forecasting methodology, the housing market, driven by population growth, and the related household formations forecast developed by B.C. Stats, continues to be the largest factor expected to impact demand over the long-term. The Terasen Utilities use this information along with recently observed trends to forecast customer additions. The recent economic downturn impacted the housing market and thus customer additions, causing the Utilities to reduce expectations for new additions from that presented in the 2008 Resource Plan. Figure ES-3 shows the customer additions forecast for each of the reference case, robust growth and low growth demand forecast scenarios. The high customer additions scenario results from a robust economic recovery and growth future in which natural gas prices remain low making it a preferred fuel for space and water heating and in commercial, industrial and institutional applications. The low customer additions scenario results from a slower economic recovery, higher gas costs and an ongoing shift in societal values away from all fossil fuels including natural gas.

Figure ES-3: Customer Additions and Annual Demand Forecast – All Utilities



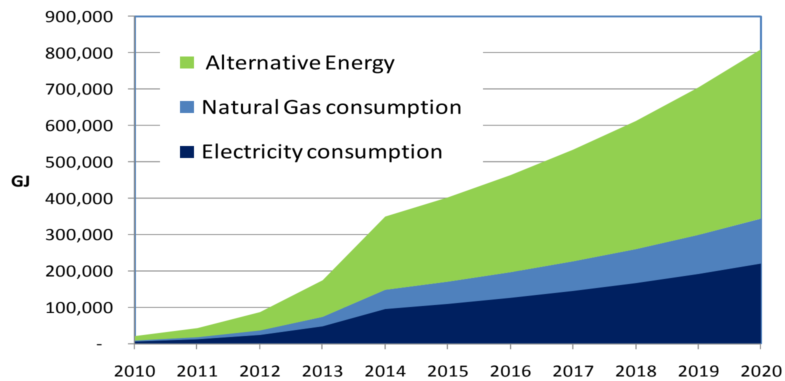
The annual natural gas demand forecast is also shown in Figure ES-3. A shift to higher efficiency furnace installations as well as a general shift in the housing market toward smaller, multi-family housing units continues to put downward pressure on average annual use per customer rates and thus annual demand. In 2010, the Utilities increased spending on energy efficiency and conservation programs for 2010/11. This funding is putting downward pressure on annual demand, particularly within the TGI customer base, which has a substantial inventory of older furnaces and a higher proportion of high density housing under development. Within the TGVI and TGW service areas this trend is countered by other factors such as fuel switching from heating oil and propane to natural gas; therefore, average use per customer is expected to remain stable. Over all the Terasen Utilities, the current forecast methodology results in a reference case annual demand forecast that is relatively flat, with declines in average use per customer in the TGI service areas offsetting growth in demand from customer additions across all of the Utilities. Modest growth in peak day demand - the amount of daily demand expected on the coldest day planned for – is forecast for each of the utilities under each of the forecast scenarios (Figure ES-4) since even the most efficient natural gas heating system will be working hardest during extreme cold weather periods.

Figure ES-4: Peak Day Demand Growth – All Utilities



The current methodology used to forecast annual and peak day demand does not include the impact of expected growth in adoption of integrated, alternative energy solutions by either existing or future customers; or the potential expansion of energy efficiency and conservation programs beyond 2011. The Terasen Utilities' forecasting activities are evolving to capture the changes that are underway in our customers' energy demand patterns. While these changes will not have a marked impact in the short term on natural gas demand, we need to be developing new methodologies in forecasting now to better understand the implications over the long run. Figure ES-5 shows the results of an example forecast scenario indicating how the Terasen Utilities' integrated energy solutions can help to meet energy efficiency and GHG reduction targets. While the utilities expect to continue adding new natural gas customers as these changes occur, the nature of the demand may well become peakier as natural gas back stops the peaking needs of integrated, renewable thermal energy solutions during extreme cold weather.

Figure ES-5: Potential Growth in Energy Demand for Multi-unit Buildings



Note: Alternative Energy Demand represents the amount of conventional natural gas and electricity expected to be displaced by renewable thermal end-use solutions such as geo-exchange, waste heat recovery and solar thermal technologies in a Lower Mainland example.

More work needs to be done to gather the necessary information to prepare this type of forecast outlook for all customer categories throughout the province and to use that information as a utility planning tool. The Terasen Utilities are also working with other utilities to explore the potential to prepare a cooperative, all-energy base-line forecast for the province's thermal energy needs against which to measure the potential impact of renewable thermal, integrated energy solutions.

6) Energy Efficiency and Conservation (Demand Side Resources)

In order to help customer manage their energy bills and support the Province's energy efficiency and carbon reduction targets, approved Energy Efficiency and Conservation ("EEC") program spending by utilities needs to be substantial enough and long-term to truly impact customer decisions and behaviour across all customer groups. Future certainty is also critical in order to make these behavioural shifts permanent and to engage partners such as trades and equipment suppliers in the activities needed to implement change. The Terasen Utilities are implementing a significant increase in EEC activity for 2010 and 2011. Over the long term, the Utilities need to secure long term EEC funding.

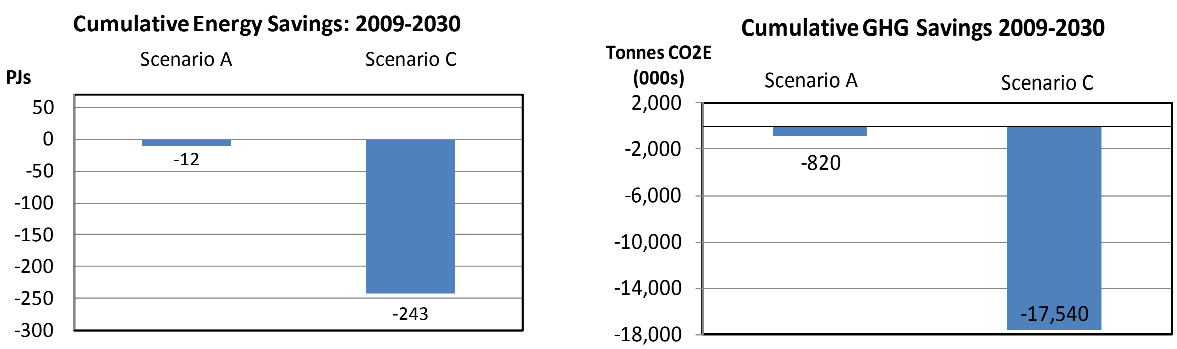
The total available funding for EEC programs and initiatives in 2010 and 2011 is $72.3 million as shown by program type in Table ES-2. This level of funding allows the Terasen Utilities to employ a holistic approach to energy efficiency including a range of incentive and upgrade programs to improve residential and commercial equipment efficiency, education programs to promote energy efficient behaviour, programming for low income and rental housing and the development of performance-based building codes. Industrial programs for transport customers and innovative technology programs are still in development and are expected to allow for some customization of EEC activity to target the specific needs of individual customers and respond to innovative technology opportunities in these areas.

Table ES-2: Total Approved EEC Funding for 2010-2011

($000s)	TGI		TGVI	
	2010	2011	2010	2011
Residential and Commercial Programs	23,075	23,075	4,726	4,726
Affordable Housing	2,400	2,400	600	600
Industrial Interruptible	435	1,875	-	-
Innovative Technologies	2,300	4,669	478	956
Total	**28,210**	**32,019**	**5,804**	**6,282**

Without approval for funding beyond 2011, however, the savings identified in Table ES-3 will not grow to their optimal potential and will stabilize at or below the level of implementation achieved during the three-year period 2009 - 2011. Further, cost / benefit criteria for approval of EEC funding do not adequately consider the implications of carbon reduction targets. The Terasen Utilities examined both energy savings and GHG emissions reductions for different potential EEC funding scenarios, ranging from current approved funding only, to an ongoing increase in funding set at 5% of gross annual revenues (~$80 million annually) for the next 10 years. This higher level of funding, at preliminary estimates, has the potential to contribute 16,000,000 tonnes of GHG reductions toward the B.C. Government's 2050 emissions reduction target of 80% below 2007 levels. Table ES-3 compares these two scenarios.

Table ES-3: Estimated Savings Comparison of EEC Funding Alternatives



The Terasen Utilities intend to pursue expanded and ongoing EEC funding toward these goals. A planned Conservation Potential Review ("CPR") and further investigation of potential transportation sector savings are important next steps.

7) On-system Natural Gas Infrastructure Planning

To determine if pipeline systems and facilities are sufficient to meet demand growth, the Utilities examine the ability of pipeline, compression, and on-system storage resources to manage the physical capacity of delivery systems. We also examine the ability of energy efficiency programs to reduce demand during peak periods. Completion of natural gas service to Whistler has alleviated capacity constraints for TGW. Completion of the Mt. Hayes natural gas storage facility in 2011 will alleviate the transmission constraints affecting TGVI and TGI's Lower Mainland service regions.

On the TGI Interior Transmission System, however, service through the Okanagan Valley to meet peak demand is expected to become constrained by 2017 under the reference case forecast. Alternative solutions include expanding the pipeline capacity through looping (adding a second, parallel pipeline) north of Penticton, pipeline looping east of Kamloops or adding a storage facility in the north Okanagan area. Addition of a large new industrial load could advance the need for this capacity expansion. For example, FortisBC has also identified growing electric system capacity constraints in the Okanagan. A new natural gas fired peaking generator is one of the resource options being considered to provide a firming resource for a range of potential renewable resources and to avoid extensive new transmission requirements.

TGI is also facing a period in which substantial portions (25 to 35%) of its existing infrastructure will be reaching the end of its expected service life within the next ten years. While the Terasen Utilities have been and continue providing safe, reliable, environmentally responsible and cost effective natural gas service to customers, this wave of aging infrastructure creates additional challenges for current asset management practices. In order to meet these challenges, the Terasen Utilities have been taking steps to design and implement enhancements to existing asset management programs.

The objective is a holistic asset management approach that considers complete business and asset life cycle parameters to strike a balance between asset performance, business risk and economics with system safety and reliability at its heart. The end result will be a Long Term System Sustainment Plan that allows the Utilities to identify and prioritize transmission and distribution system asset sustainment projects and programs with appropriate lead times for asset renewal. The benefits to customers will be the levelling of asset replacement costs over time, while system safety and reliability are maintained. Longer term benefits arise from system sustainment cost and efficiency improvements and continuous asset management process improvement.

TGI also has the challenge of adding new assets to support its low carbon, integrated energy strategy. Alternative energy infrastructure, fueling and interconnection infrastructure to serve the transportation sector and biogas upgrading and interconnection equipment will all be required as we pursue these important initiatives.

8) Responding to Regional Gas Supply Trends

Upstream from the Terasen Utilities' transmission systems are a network of pipelines and storage facilities that move gas from production and trading areas to distribution utilities, industrial users and electricity generating stations. Increasing competition in the PNW region for these resources, the need to maintain diverse and hence secure supplies, and the development of new, North American supply basins are factors affecting planning for utilities throughout the region. We need to respond to these factors through gas supply planning practices and infrastructure improvements to protect the interests of our customers. We also have opportunities to develop new infrastructure that will increase the region's capacity to deliver natural gas when it is needed most by optimizing the region's existing natural gas infrastructure.

Technology advancements are leading to the development of vast new gas reserves in northern B.C. Similar developments are occurring in supply basins located in the U.S. Rockies and in southern and eastern U.S. This trend is has resulted in a favourable North America gas supply picture for the foreseeable future and creating a potential shift in natural gas flows on transmission pipelines serving British Columbia and the PNW as producers vie to bring these new reserves to market.

With the ability to supply markets throughout North America, the Alberta gas trading hub is one of the continent's most open marketplaces. Demand for natural gas from Alberta oil sands production is also expected to grow. Natural gas producers and shippers are therefore developing pipelines that will take gas from B.C. west into Alberta. Our analysis shows that by 2015, almost twice as much (3.5 billion cubic feet ("Bcf") – per day) capacity could be built to flow natural gas west into Alberta and off shore to global markets than is expected to be produced (1.9 Bcf per day) in B.C. This increased competition for B.C. supply could ultimately lead to higher prices and increased price volatility for gas flowing south through B.C. where the Terasen Utilities currently purchase the majority of our customer's supply.

A number of natural gas transmission pipeline projects are proposed in the PNW to address a looming capacity constraint, improve supply diversity and gain access to new supplies in the U.S. Rockies or northern B.C for some of the region's largest gas utilities. Some of these proposals avoid the transmission pipeline that flows south through B.C., potentially exacerbating the B.C. market price and volatility issue for our customers. The Terasen Utilities are exploring opportunities to mitigate this risk and are working with Spectra to provide transportation service alternatives across the combined systems of both Utilities including TGI's Southern Crossing Pipeline. This service provides Spectra's shippers access to both the Huntingdon/Sumas market serving B.C and the PNW and the California and Alberta markets while keeping gas flowing south through B.C. Shippers who contract for this service can take advantage of seasonal and temporary price differentials between the two markets to soften the impact of such price volatility. TGI is exploring the possibility of expanding its pipeline between Kingsvale and Oliver, B.C. to provide greater capacity for this service should the pilot be successful. In addition to this expansion, construction of additional on-system natural gas storage could help to alleviate the competition for regional resources during short term periods of price volatility.

9) Stakeholder Consultation

Stakeholder needs and concerns are critical to resource planning. More than simply facilitating open communication, effective stakeholder consultation provides the utility with insights that can impact the entire planning process, from trends that influence demand forecasting and Demand Side Management ("DSM") analysis to the development of an action plan for implementing preferred planning solutions. Terasen Utilities consultation activities include EEC Advisory Group engagement, stakeholder workshops, presentations to municipalities throughout the province, web site communications and focussed meetings with select stakeholders seeking input on a range of regional and provincial energy issues and system expansion needs. Additional stakeholder consultation associated with TGI and TGVI Revenue Requirement Applications in 2009 also informed the Resource Planning Process. Following the filing of this Resource Plan, the Terasen Utilities will continue discussions with stakeholders regarding its recommendations, and intend to establish a Resource Planning Advisory Group to provide additional, regular engagement with our stakeholders.

10) Action Plan

The actions that Terasen Utilities intends to pursue over the next four years based on the information and evaluation provided in this Resource Plan are:

- Pursue and secure funding solutions for expanded and ongoing EEC beyond 2011 and explore program acceleration options, including a review of cost / benefit criteria.
    - Complete a CPR to determine potential for energy and GHG emissions savings from residential, commercial and industrial customers.
- Continue development of new energy forecast approaches including additional end-use and customer research to examine energy choice implications.
- Continue working with other utilities to explore the development of a base-line forecast for thermal energy demand in B.C. against which to assess energy choice impacts.
- Pursue integrated energy and carbon reducing customer solutions through:
    - Expanding TGI's alternative energy service and exploring emerging low carbon and renewable energy technologies.
    - Applying to the Commission for approval to invest in fueling infrastructure to deliver the clean, low carbon benefits of natural gas to the transportation industry.
    - Increasing supply and sales of carbon neutral biomethane through purchase agreements and infrastructure investment subject to Commission approval of the June 2010 Biogas Application.
- Enhance the Terasen Utilities' comprehensive asset management strategy and develop a Long Term System Sustainment Plan for approval by the Commission.

- Plan for and prepare Certificate of Public Convenience and Necessity ("CPCN") applications for near-term distribution system requirements identified in the Terasen Utilities 5-year Capital Plans.

- Continue monitoring and evaluating system expansion needs in the Okanagan area, including working with FortisBC to determine potential requirements and timing for providing natural gas service for a new gas fired peaking facility.

- Protecting and promoting the needs of our customers to secure long term gas supply while minimizing costs by monitoring developments in regional gas supply issues, working with Spectra Energy on B.C. based market solutions, studying the feasibility of expanding the Terasen Utilities' transmission system and strengthening relationships with gas producers and shippers. .

- Liaise with provincial, regional and national energy and climate related policy makers to lend the Terasen Utilities' expertise in energy issues and planning to the development of policy that will impact B.C.'s energy customers.

This Action Plan continues the Utilities evolution and builds on the work to date to transform the Terasen Utilities into a complete, integrated energy provider of alternative energy solutions incorporating the reliability of conventional energy services.

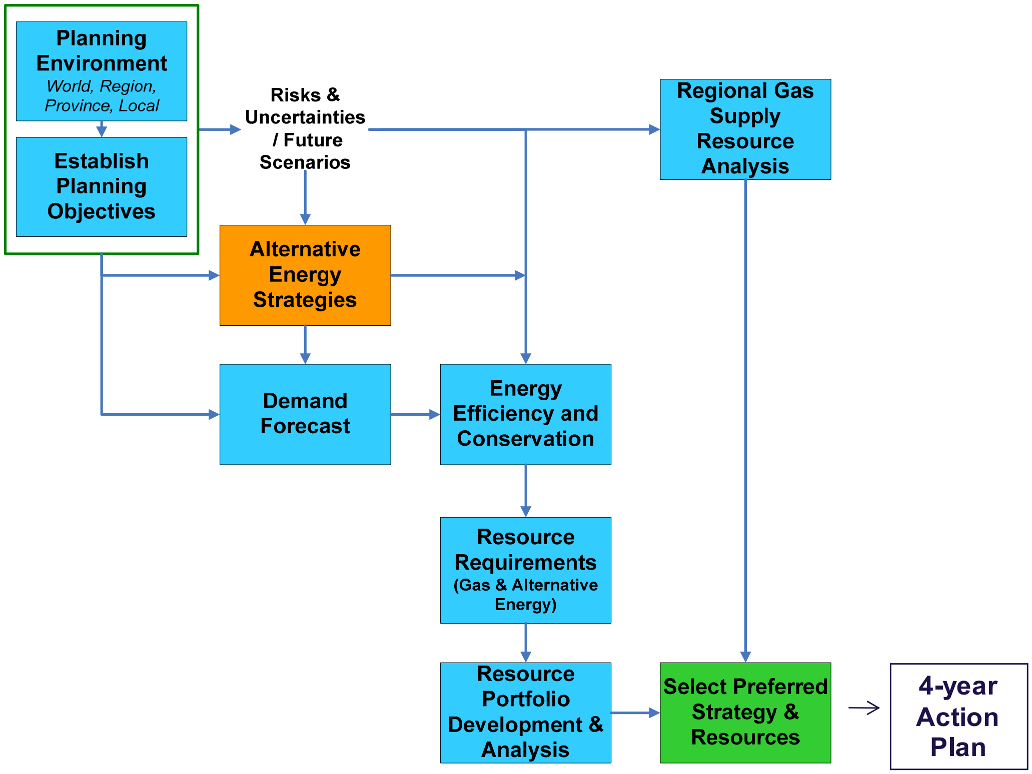
1 INTRODUCTION

Energy utilities in the PNW[1] have an opportunity to help provide solutions to some of the region's most pressing challenges: increasing demand for energy, increasing energy costs, carbon emissions, job creation and economic stability to name a few. Efficiency improvements, conservation and reduction of GHG emissions are today's top priorities, creating immense challenges amidst an ever growing population demanding more energy at a reasonable cost. No single form of delivered energy can solve all of these problems. Rather, a corner stone to delivering cost effective services to all of B.C. for years to come will be the development of diverse energy sources, technologies and delivery infrastructure as well as providing complete information to customers so that the right energy solutions are installed for the right end uses.

This document presents the 2010 LTRP for the Terasen Utilities[2]. The resource planning process begins by closely examining the planning environment the utilities operate in, and identifying expectations for future customer and demand growth. The demand and supply side resource alternatives for meeting that future demand are then assessed, and actions are recommended for ensuring the proper resources are in place to deliver the preferred energy solutions and meet future customer needs. Figure 1-1 outlines the resource planning process for Terasen Utilities. Although the process is iterative rather than linear, the final stage of this process is the development of a four-year action plan that implements the recommendations of the plan and ensures the ongoing assessment of resource requirements and alternatives.

1 The Pacific Northwest is most commonly considered to include B.C., Idaho, Washington and Oregon
2 In keeping with the approved service sharing agreements between them, the term "Terasen Utilities" in the context of this LTRP may also refer broadly to the resources used to undertake activities for one or more of the utilities.

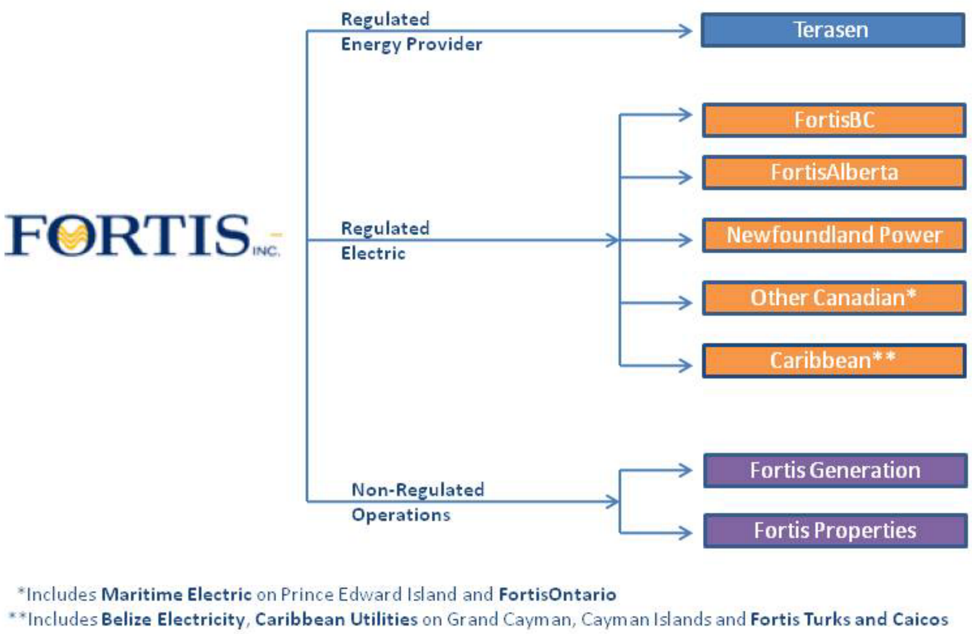
Figure 1-1: Terasen Utilities Resource Planning Flow Chart



1.1 Introduction to the Terasen Utilities

The Terasen Utilities are subsidiaries of Terasen Inc., which since May, 2007 has been owned by Fortis Inc., the largest public investor-owned utility company in Canada. The B.C. based electric utility FortisBC is also a Fortis Inc. subsidiary and sister company to Terasen Utilities. Figure 1-2 shows the relationship of Terasen Utilities to other Fortis Inc. Companies.

Figure 1-2: Corporate Structure of Fortis Inc. Business Units



The activities of a forth company, Terasen Energy Services ("TES"), also provide an important backdrop in planning for the future of Terasen Utilities. Although this LTRP does not set out a strategic action plan for TES, beginning in 2010 the types of activities undertaken by this forth company are now being undertaken by TGI in relation to new projects. These activities include the development, construction and operation of alternative energy systems and the setting of rates and cost recovery for those systems. In the context of this LTRP, alternative energy systems are those low and no carbon technologies that provide renewable thermal energy solutions for the end user such as geo-exchange, waste heat recovery, solar thermal and combined heat and power as well the combination of any of these types of technologies with conventional energy services in discrete[3] and district[4] energy systems.

The Terasen Utilities provide natural gas services to more than 935,000 residential, commercial, and industrial customers in more than 125 communities throughout B.C. These statistics put the combined utilities of Terasen Gas among the largest gas utilities in Canada and make it the largest in the PNW. Table 1-1 provides a summary of customer, demand and pipeline characteristics for each of the Terasen Gas Utilities, with TGI broken out into Interior and Lower Mainland service areas. Figure 1-3 shows the transmission pipelines and service area locations.

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3 Serving a single building
4 Serving multiple buildings within a community

Table 1-1: 2009 Statistics for the Terasen Utilities

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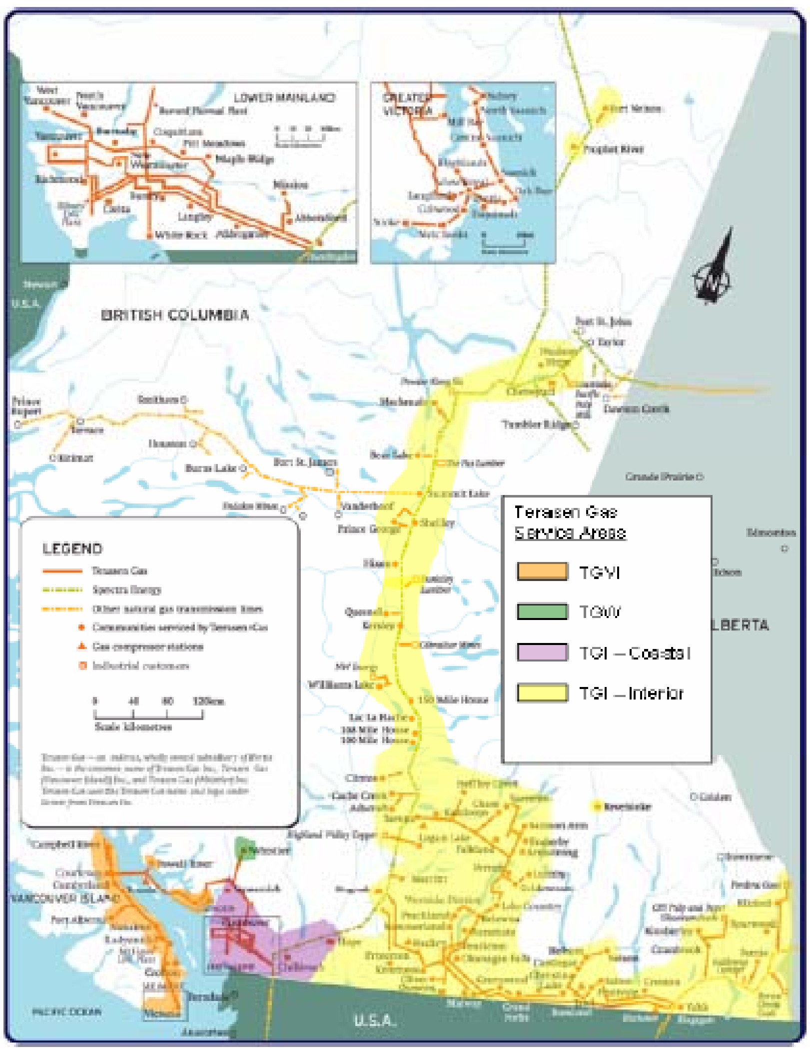
* Includes both low and intermediate pressure pipelines

** Statistics from a forth company - Terasen Energy Services - which served all alternative energy customers prior to 2010. TES is not the subject of this Long Term Resource Plan. Information provided for context only.

† Data is a combination of individual customers and units served by a common alternative energy system - data to 2nd quarter 2010

Figure 1-3: Map of the Terasen Utilities Transmission Pipelines and Service Areas



1.2 Regulatory Context for Long Term Resource Planning

In B.C., like many other regulatory jurisdictions in the region, Integrated Resource Planning[5] ("IRP") is the primary tool for identifying long-range infrastructure requirements and resource acquisition strategies, and for sharing this information with stakeholders. Under the *Utilities Commission Act*, (the "Act"), the Commission has the authority to regulate utilities in the province and to require utilities to, among other things, submit resource plans. In 2003, the BCUC issued its resource planning guidelines which continue to guide BCUC in the preparation of resource plans.

The Act includes Section 44.1, "Long-term Resource and Conservation Planning". Resource planning is more than simply a requirement of the BCUC and the Act, it is also a valued strategic planning activity that Terasen Utilities has carried out for many years. The key activities which encompass the resource planning process are embedded in the overall planning processes which the Utilities undertake in providing service to our customers. In keeping with the Provincial Government's 2007 Energy Policy, effective resource planning requires that consumers have access to the information needed to make the best choices among all available energy sources. The Utilities continue to engage customers and stakeholders as a critical part of the LTRP process.

In conducting its own resource planning process, Terasen Utilities believes it is also important to understand the planning issues, competitive environment and resource requirements for other utilities in the PNW region because of the common infrastructure to serve both electricity and natural gas demand. As such, Terasen Utilities actively participates as a stakeholder in the resource planning efforts of other gas and electric utilities in the region including BC Hydro, FortisBC and Puget Sound Energy. To facilitate its understanding and response to regional resource issues, Terasen Utilities also participates in planning and resource assessment activities and events conducted by regional organizations including the Northwest Gas Association ("NWGA"), the Northwest Power and Conservation Council ("NWPCC") and the Pacific Northwest Economic Region ("PNWER"). The regional outlooks provided by these organizations inform the analyses and recommendations in this LTRP.

1.3 Long-Term Resource Plan Objectives

Terasen Utilities' resource planning objectives form the basis for evaluating all potential resources in the Plan including major infrastructure projects, gas supply alternatives, integrated energy solutions and demand side programs. The objectives reflect the Utilities' commitment to providing the highest level of quality energy services to its customers. Terasen Utilities' five key resource planning objectives are outlined below.

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[5] The terms Integrated Resource Planning, Long Term Resource Planning and Resource planning can be used interchangeably

- **Ensure Safe, Reliable and Secure Supply**

A secure energy supply is essential for all of Terasen Utilities customers. Ensuring a sufficient supply of gas and the capacity to deliver gas to customers during anticipated peak demand periods is an ongoing objective for the Utilities. Acquiring resources that improve the reliability and security of supply will also help to reduce rate volatility.

- **Provide Innovative and Cost Effective Energy Solutions to Customers**

Customers and regulators expect the Utility to procure and deliver energy in the most cost-effective and efficient manner possible. The most desirable resource options will provide cost effective service solutions and help to manage rate volatility both in the near term and into the future. DSM strategies which are cost effective can add value to customers through more effective use of the gas delivery infrastructure and more efficient use at the burner tip. Integrating alternative energy services with conventional energy supply, low carbon fuel strategy for the transportation sector and and the development of carbon neutral biogas are examples of innovative solutions Terasen Utilities is involved with to deliver energy in a efficient and cost effective manner.

- **Expand Energy Efficiency and Conservation Initiatives**

EEC is one of the key themes identified in the B.C. clean energy act to meet carbon reduction targets. In today's world of volatile energy prices, increasing demand for energy and need for additional new energy resources, efficiency and conservation remain among the lowest cost alternatives. To acquire these savings, EEC program spending by utilities needs to be substantial enough and long-term to truly impact customer decisions and behaviour across all customer groups. For this reason, Terasen Utilities have made EEC one its key objectives for the 2010 LTRP.

- **Acting On Social and Environmental Priorities**

It is important to incorporate environmental and socio-economic considerations into the selection process for demand and supply resources by examining the impact of resource selection alternatives on land-use, air emissions, the local economy, and First Nations and B.C. communities served.

- **Contributing to Climate Change Solutions**

It is important for the Terasen Utilities to provide solutions that help customers reduce their GHG emissions. The Terasen Utilities have an important role to play in helping customers understand how their energy consumption contributes to climate change and identify solutions that can help achieve their desired result.

1.4 Status of 2008 LTRP Action Plan

In its previous Resource Plans, Terasen Utilities presented a list of actions to implement the recommendations outlined throughout the Plans. Table 1-2 provides an update on the 4-year action plan described in the previous Resource Plans for the Terasen Utilities.

Table 1-2: TGI 2008 Resource Plan Action Items

	Action Item	Status
1	Implement new energy efficiency and conservation (EEC) programs and continue research and planning for future EEC programming.	Final design and implementation of the approved demand side management[6] (DSM) programs for 2009 and 2010 are underway. Additional funding approved for industrial DSM program development and innovative technologies. Planning for updated Conservation Potential Review is underway
2	Participate in FortisBC and BC Hydro resource planning processes	Terasen Utilities provided input into both FortisBC and BC Hydro resource planning processes. Terasen Utilities' participation in the BC Hydro LTAP resulted in a decision to undertake to participate in an "Electric Load Avoidance" demand side study – the decision was later over turned by the Province. FortisBC's recommended future electricity generation resources include renewables backed up by natural gas fuelled generation during peak demand periods.

[6] http://en.wikipedia.org/wiki/Energy_demand_management

	Action Item	Status
3	Influence provincial and regional energy and climate-related policy development.	Terasen Utilities works with policy makers and energy planners to communicate the benefits and importance of using natural gas in the regional and provincial energy mix to reduce greenhouse gas emissions[7] and keep energy rates low. Examples include: • the Canadian Gas Association's "smart gas strategy" , (link to Vision of B.C. energy future PDF) • Input into the development of B.C.'s carbon credit system, advocating for renewable, end-use energy systems such as geoexchange[8] and solar thermal technology combined with natural gas[9]. • Provincial support for TGI's biogas initiative.
4	Continue monitoring and evaluating system expansion needs in the Okanagan area.	Terasen Utilities continues to monitor FortisBC's Integrated Resource Plan[10] and their potential need for natural gas generation as a back-up to renewable electricity production during peak electric demand periods.
5	Plan for near-term distribution system requirements – Coquitlam Compressor Station and South Arm, Fraser River Crossing	Terasen Utlities received approval for a Certificate of Public Convenience and Necessity (CPCN) application, permitting the upgrade of the Fraser River South Arm Crossing[11] in March 2009. Work on the project is underway. Further investigation into the Coquitlam compressor units determined that replacement of only specific components within the units are required. A number of other projects outlined in the 2008 Terasen Utilities Resource Plan were undertaken.

7 http://en.wikipedia.org/wiki/Greenhouse_gas
8 http://www.terasen.com/EnergyServices/GeoexchangeSystems/default.htm
9 http://www.terasengas.com/_AboutNaturalGas/default.htm
10 http://www.fortisbc.com/about_fortisbc/planning/resource_planning.html
11 http://www.terasengas.com/_AboutUs/NewAndOngoingProjects/FraserRiver/default.htm

	Action Item	Status
6	Investigate regional pipeline and storage infrastructure alternatives	This is an ongoing activity. The 2010 Northwest Gas Association (NWGA) Outlook Study identified that while regional gas supply infrastructure is being used very efficiently and currently meets the regions' capacity needs, growing demand for both residential use and electricity generation is causing increasing capacity constraints in the existing infrastructure. Terasen Utilities is monitoring opportunities to participate in or influence regional infrastructure projects that will best help to meet the needs of B.C. natural gas users. The 2010 LTRP describes emerging gas supply issues in the region upon which the Utilities must act to promote and protect the interests of their customers
7	Pursue clean energy initiatives	Project initiatives underway include developing biogas[12] as an alternative supply, using natural gas for vehicles[13] as a transportation fuel for trucks, large fleets and other transportation industry needs, and development of alternative energy systems like geoexchange, solar thermal and district energy systems[14] in conjunction with natural gas for residential and commercial heating solutions.

1.5 Structure and Key Messages of the LTRP

The remaining sections and key messages are summarized as follows:

- **Section 2 – Planning Environment**

The energy planning environment in B.C. continues to change rapidly. The opportunities, risks and uncertainties within which the Utilities must plan are discussed, as are the implications of the competitive market place and changing government policy and legislation.

- **Section 3 – Low Carbon Initiatives and Projects**

The utilities are embarking on a low carbon strategy in which a number of initiatives are underway, including integrated energy systems that utilize renewable thermal energy solutions supplemented by conventional energy, new natural gas fuelled transportation initiatives and the

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12 http://www.terasengas.com/_AboutUs/NewAndOngoingProjects/BiogasProductionRFEOI/default.htm
13 http://www.terasengas.com/_AboutNaturalGas/NaturalGasVehicles/default.htm
14 http://www.terasen.com/EnergyServices/DistrictEnergySystems/default.htm

acquisition of carbon neutral biogas supplies for delivery to customers seeking to reduce their carbon footprint.

- **Section 4 – Market Trends and Energy Forecasting Activities**

Traditional natural gas forecasts show that annual demand growth appears to be levelling, with declining use rates being offset by growth in customer numbers. With continuing customer growth adding heat sensitive load, design day demand continues to grow. With the changing nature of energy choices and customer behaviours, the Utilities are exploring a number of new forecasting activities.

- **Section 5 – Energy Efficiency and Conservation**

The Utilities have implemented a host of new Energy Efficiency and Conservation programs that will customers manage their energy costs and GHG emissions. Current funding for these programs is short term; however, and to truly have a long term impact on energy conservation and GHG reductions, the Utilities need to seek additional, ongoing funding approvals.

- **Section 6 – Gas Supply Resources**

The majority of transmission infrastructure on the Utilities' gas network has sufficient capacity to meet customer demand for many years; however, there is an approaching transmission system constraint in the Okanagan area. The Utilities will need to add new infrastructure to implement their biomethane and new NGV initiatives, as well as upgrade and maintain their distribution and support systems across their service regions. A substantial portion of existing infrastructure is approaching its planned age of retirement, and the Utilities are enhancing their asset management processes to both manage this wave of necessary capital investment and develop continuous improvement in their asset decision making processes.

The nature of the natural gas supply markets that the Utilities rely on is also changing, with competition for supply increasing. The utilities need to plan and act to promote and protect the interests of its customers of the long term. Ongoing price risk management, monitoring and participation in regional infrastructure issues and the development of new supply services and infrastructure are all keys to securing cost effective natural gas supplies for years to come.

- **Section 7 – Stakeholder Consultation**

Stakeholder Feedback is a critical part of the LTRP process. Stakeholders are taking a growing interest in the planning activities of the Utilities and provided valuable feedback during a number of stakeholder events. Resource Planning is and ongoing process and the Utilities intend to continue engaging stakeholders on an ongoing basis.

- **Section 8 – Action Plan**

Sets out the actions the Terasen Utilities intend to take over the next 4 years to implement the recommendations identified in this LTRP.

2 PLANNING ENVIRONMENT

The opportunities, risks and uncertainties within which Terasen Utilities must plan for the future extend well beyond a review of typical energy commodity markets, rates and competitiveness. This LTRP is being submitted during a time of rapid change in energy technology, market forces, public opinion and related government policy around energy use. Energy consumers are faced with a myriad of energy services and equipment choices and often conflicting information with which to make decisions that may impact their energy consumption for years to come. Terasen Utilities' LTRP must consider all of these factors, inform its stakeholders with an accurate and easily understood account of the planning environment, and make recommendations that provide the best path forward for meeting customer energy needs.

In view of the rapidly changing environment the traditional view of electric and gas utilities providing the energy needs for homes and businesses in fairly defined categories will not be the same going forward. Because of the many influences it will only be possible to assess the competitive position of a fuel or energy source relative to alternatives with any certainty after the fact. Forecast energy prices, the future price of carbon, how energy costs get reflected in customers rates, government energy policies, customer perceptions and actions, capital costs of equipment, and type of technology being installed make it difficult to predict with any degree of certainty on how these factors may influence a fuel or energy source competitive position against another.

This section provides an overview of the planning environment within which the 2010 LTRP has been developed. It begins with a discussion of both conventional and new alternative energy supply and pricing for solutions that can serve the needs of consumers and the competitive environment for these energy solutions. The implications of current and evolving energy and climate change policy at the federal, provincial and local levels are also discussed. Energy diversity, using the right fuel most effectively for the right use, optimizing existing infrastructure and developing energy services that customers want are key guiding principles that are informed by the information contained in this section.

2.1 Energy Supplies and Pricing

There will be enough energy for many years to come to heat our homes, businesses and communities, and fuel the movement of people and cargo throughout the region. The evolution towards more sustainable energy systems and greater use of renewable forms of energy will serve to further extend the life of conventional fuel resources. But where will that energy come from and how much will it cost compared to what we are used to paying and how will conventional sources of energy compare with new alternatives? The answers to these questions are uncertain as the energy industry continues to move through a changing environment.

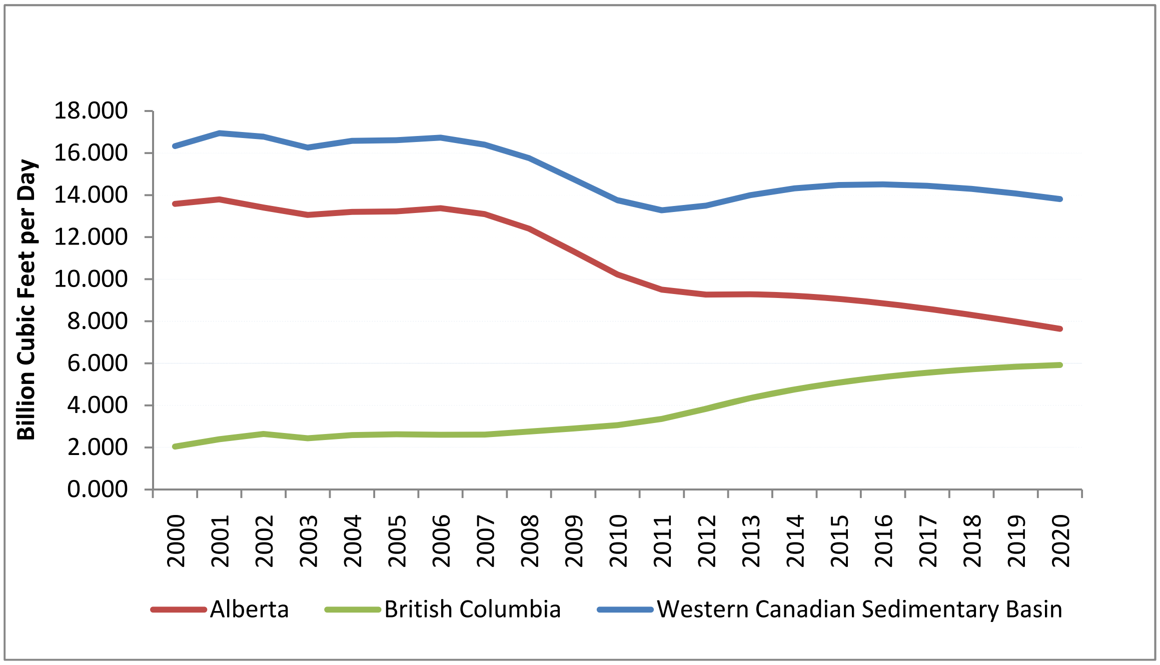
The following discussion explores natural gas supplies, natural gas commodity prices, electricity markets and prices, alternative thermal energy solutions and the price of carbon.

2.1.1 NATURAL GAS SUPPLIES

The North American natural gas resource industry is currently undergoing a major structural shift driven by the development of unconventional supply sources. Recent technological advances in drilling and well completion techniques have allowed producers to access tight sands and shale formations which previously were assessed to be too difficult and uneconomic to produce. The current reserves estimates suggest that there is sufficient supply potential to meet North American requirements for more than one hundred years. However the long term energy outlook shows that these new developments will only serve to offset the decline in conventional resources production rates while overall North American production rates are not expected to increase for several years. Nevertheless, this is a significant shift from previous expectations that North America would face a growing reliance on LNG imports to meet the gap between supply and demand.

In the Western Canadian Sedimentary Basin ("WCSB"), the significant unconventional gas findings in Northeast B.C.'s Horn River and Montney fields are expected to significantly increase B.C. production which will offset declines in conventional production from Alberta as illustrated in Figure 2-1. The WCSB has historically served as the supply source for domestic consumption in B.C. and Alberta, and for export markets accessed by the Spectra ("Westcoast") pipeline, the Alliance pipeline and the three TransCanada Pipelines ("TCPL") systems including the Canadian Mainline, Northern Border and the B.C. Foothills & Gas Transmission Northwest ("GTN") systems.

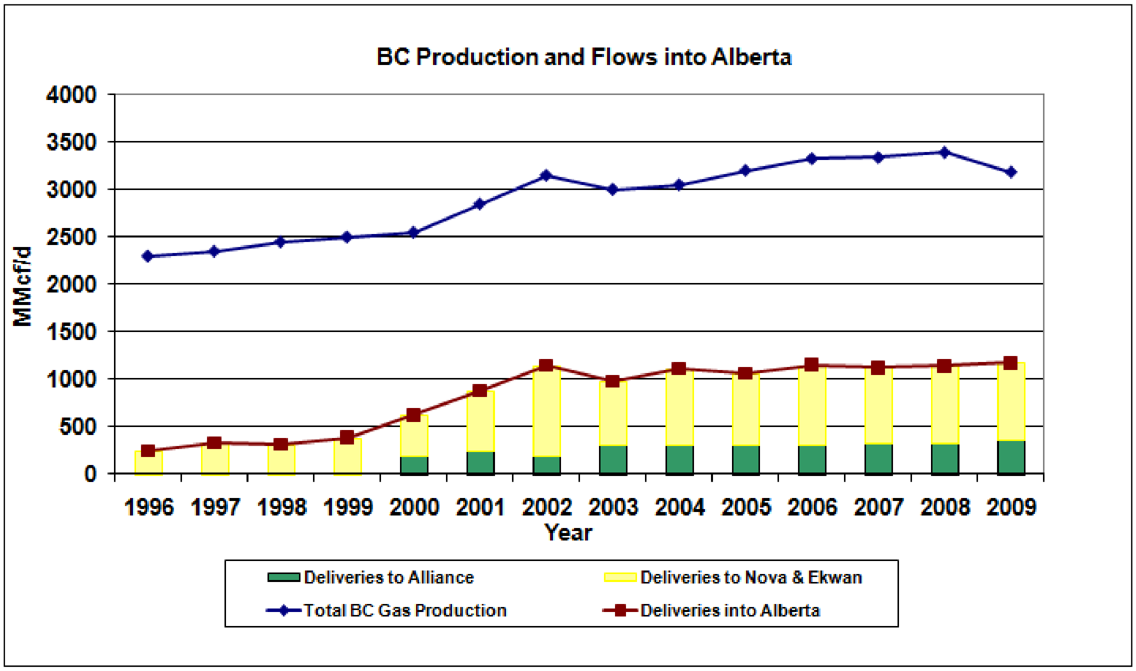
Figure 2-1: WCSB Gas Production History and Outlook



Over the past several years there has been a significant amount of B.C. production flowing east to serve the more liquid Alberta markets and the three interconnecting TCPL pipelines. Since 2001, more than one third of B.C. production has flowed into Alberta as shown in Figure 2-.

In terms of access to B.C. unconventional gas supply for markets served by the Utilities, we will need to compete for access to this supply with other markets including consumers in Alberta where natural gas demand growth is being driven to fuel the oilsands development. The Alberta oil sands currently consume around 1.0 Bcf/d of natural gas and this amount is forecast to more than double by 2017. A portion of the new supply will connect to Spectra's Westcoast system which in turn connects to the Terasen Utilities and PNW markets, however a number of new pipeline projects are being developed which will allow B.C. producers to connect directly to TransCanada's Alberta system, the Alliance Pipeline and other markets (discussed further in Section 6.2). It should be recognized that new connections to markets must be developed in order for the full potential of the B.C. shale gas reserves to be realized. The Utilities are working closely with other regional stakeholders to ensure that these developments will not negatively impact its ability to competitively access supply.

Figure 2-2: Increasing flow of gas from B.C. to Alberta



2.1.1.1 Natural Gas Commodity Prices

Although the supply potential for natural gas is significant, the rate of the development of these new natural gas resources and related infrastructure still depend on North American natural gas prices. Currently, market prices are depressed due to weakened industrial demand, steady production levels and healthy U.S. storage balances. It is generally felt that current pricing levels are too low to sustain long term development of the unconventional gas reserves and continue to offset production declines elsewhere. For example, given the growing gap between natural gas and oil prices, a growing number of natural gas companies now appear to be shifting investment and resources back to oil production, in part motivated by the ability to apply the same technology advances developed in the new gas fields. In addition, future economic recovery, and environmental policies that support coal to gas switching for electricity generation is expected to result in higher demand. As supply and demand come back into balance it is expected that prices will strengthen. Nevertheless the new supply potential within North America has indeed had a moderating impact on long term price forecasts.

Trends in energy costs, particularly in natural gas and electricity prices, influence consumers buying decisions on energy system equipment and fuel choices. Despite the recent focus on renewable energy sources, natural gas and electricity remain the two primary energy choices for consumers in B.C. This section presents a discussion of natural gas price forecasts prepared by independent sources, and then compares the natural gas price outlook with the forecasts for other fossil fuels.

2.1.1.1.1 Natural Gas Price Forecasts

The Terasen Utilities generally utilize price forecasts generated by other industry experts when analyzing the possible future gas market conditions. The short term future prices of natural gas also influence the Utilities' rates that it sets quarterly and annually for the commodity and midstream components of its rate structure. This section provides a long term view to 2035 of natural gas prices as forecasted by independent sources.

GLJ Petroleum Consultants Ltd. ("GLJ") is a private petroleum industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis. GLJ prepares commodity price and market forecasts after a comprehensive review of information available to the reported quarter.

Another external source, the U.S. Energy Information Administration ("EIA"), also prepares a range of gas price forecasts using the last 30 years of data including normal weather and storage inventories to generate the price forecasts. The 2010 Annual Energy Outlook ("AEO"), which was released on May 11, 2010, presents long-term projections of energy supply, demand, and prices through 2035. The AEO reference case price forecast is based on an assumption of moderate growth in energy consumption and projects strong growth in renewable electricity generation and use of natural gas in the transportation sector.

Figure 2-3 below, presents natural gas price forecasts from GLJ, EIA Reference case, EIA High Growth case and EIA Low Growth case. It should be noted, however, that these forecasts are based on long term market fundamentals and do not necessarily reflect short term supply and demand imbalance situations which could cause natural gas prices to vary significantly relative to average forecast price levels due to the unpredictability of these imbalance events.

Figure 2-3: Third Party Long-Range Gas Price Forecasts – Henry Hub[15]

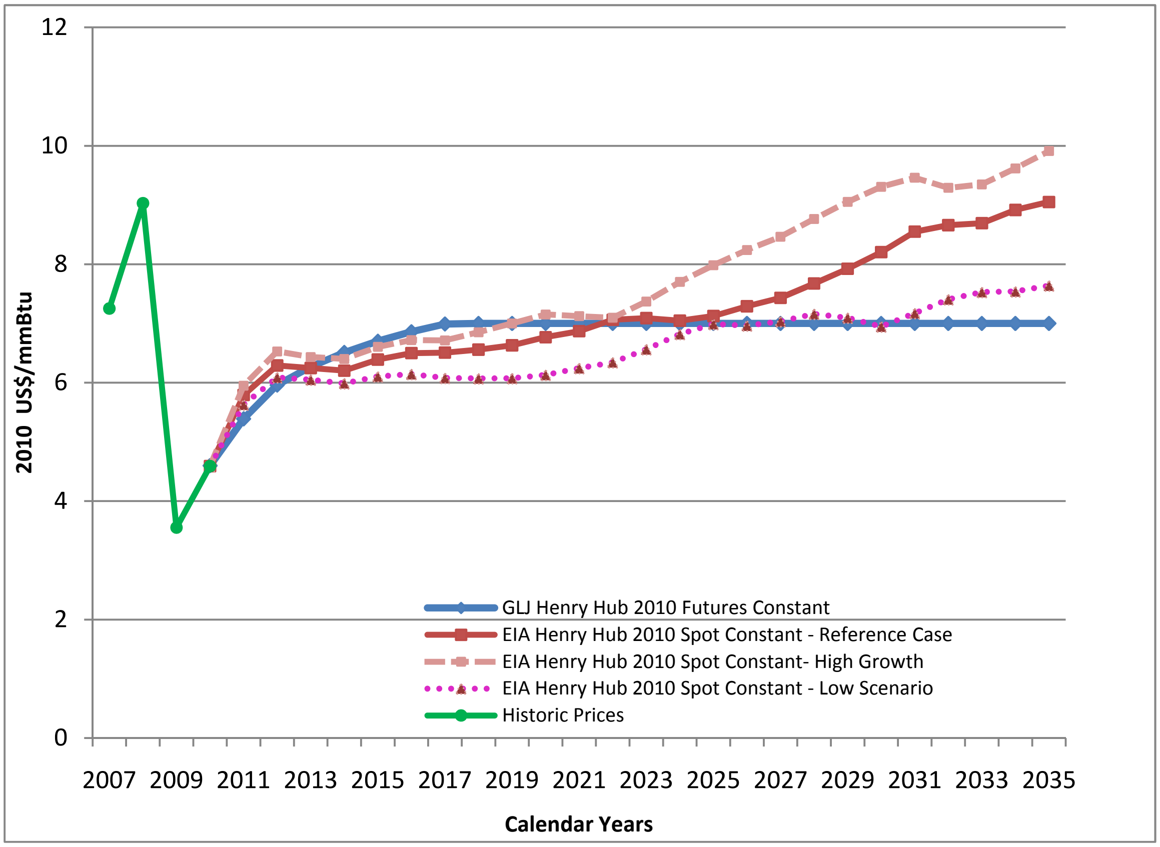
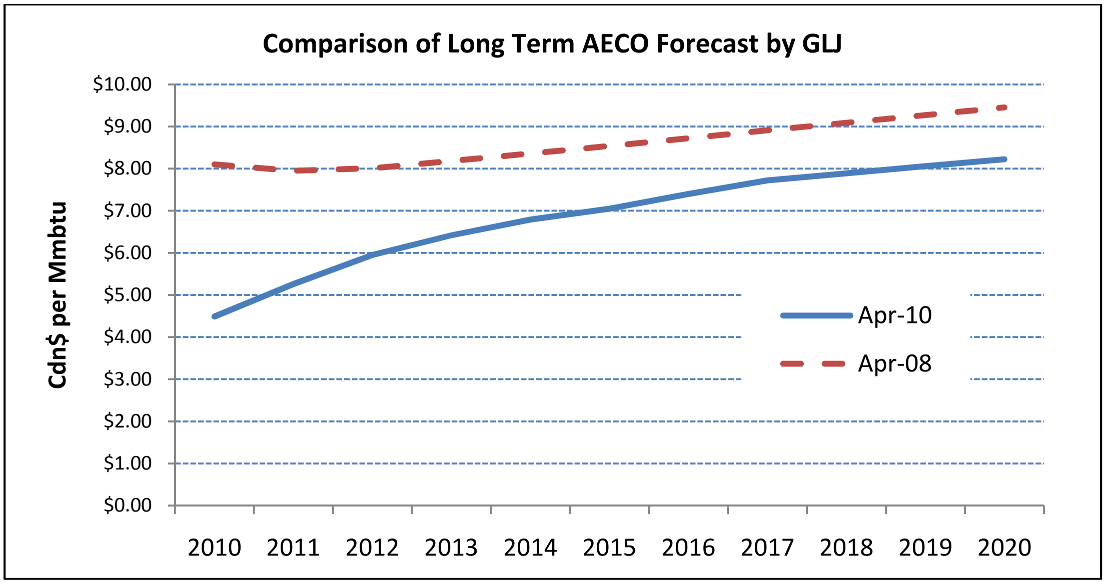


Figure 2-4 which follows, presents the GLJ long term AECO forecast to 2020 and compares that to the same GLJ forecast prepared in April 2008 when the 2008 Resource Plan was being prepared. The comparison reflects the current market expectation that although prices will strengthen as supply and demand come back into balance, recent developments in unconventional gas production and the associated reserve potential has helped to moderate the view of long term prices.

15 The Henry Hub is a benchmark pricing point for natural gas in North America. Natural gas prices in B.C. are priced in some relationship to this pricing point; therefore, the Henry Hub is a proxy for what consumers in B.C. might pay for natural gas over time.

Figure 2-4: Comparison of 2010 and 2008 Long Term Forecasts[16]

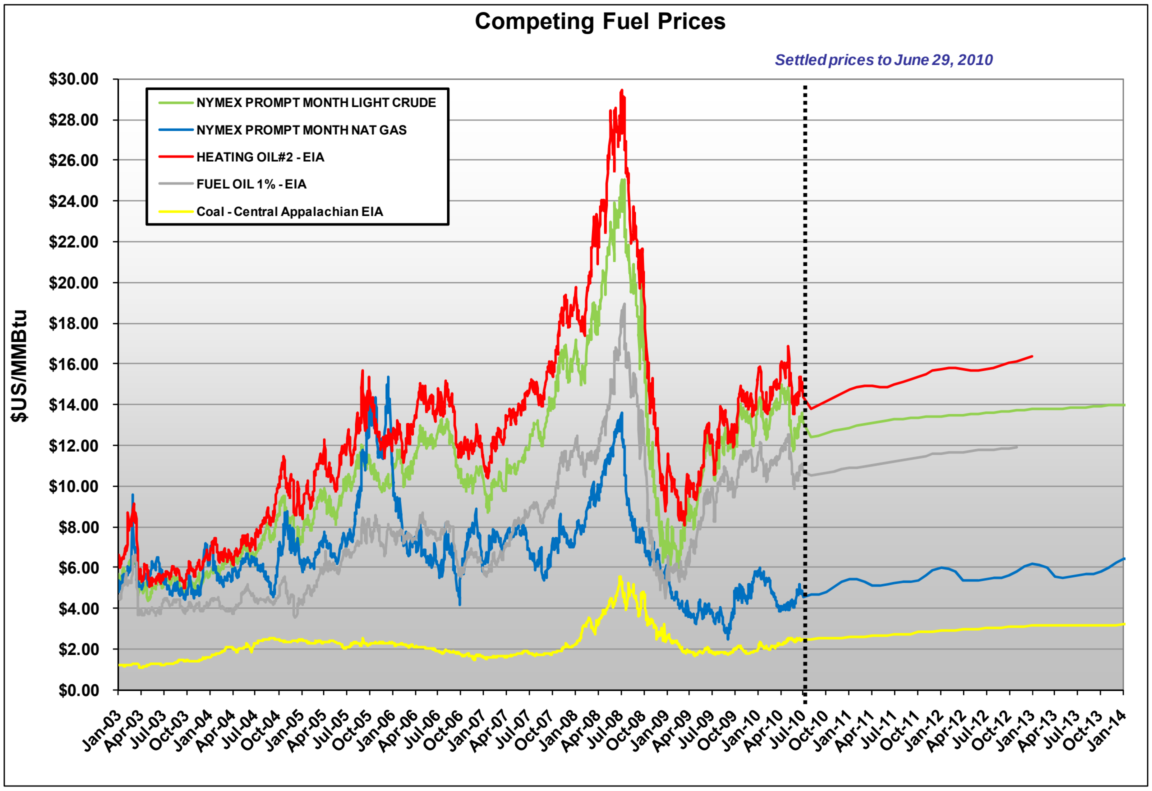


2.1.1.1.2 Natural Gas Prices Compared with Competing Fuel Prices

Historically natural gas prices have been heavily influenced by oil prices due to the short term substitutability of crude oil products with natural gas for industrial and commercial processes and electricity generation. As illustrated in Figure 2-4, price fluctuations in crude oil prices can have major impacts on natural gas prices regardless of the fundamental supply and demand factors that underpin gas prices. This was observed during mid-2008 when crude oil rallied to over $145 US per barrel by July, pulling up natural gas prices to almost $14 US/MMBtu. Oil prices then collapsed to nearly $30 US per barrel by the end of 2008, pulling natural gas prices down with it. Since that time, however oil prices have rallied significantly while North American natural gas prices have remained at lower levels due to poorer shorter term fundamentals. Consequently, the price of coal is becoming increasingly relevant by acting as the floor for natural gas prices due to significant capacity to switch between coal and gas fired electric generation. With stricter environmental regulations placed on coal-fired generation going forward, it is anticipated that this gas-for-coal substitution may occur at higher price levels than in the past.

[16] The Henry Hub is a benchmark pricing point for natural gas in North America. Natural gas prices in B.C. are priced in some relationship to this pricing point; therefore, the Henry Hub is a proxy for what consumers in B.C. might pay for natural gas over time.

Figure 2-5: Historic and Settled Future Commodity Prices – Oil and Natural Gas

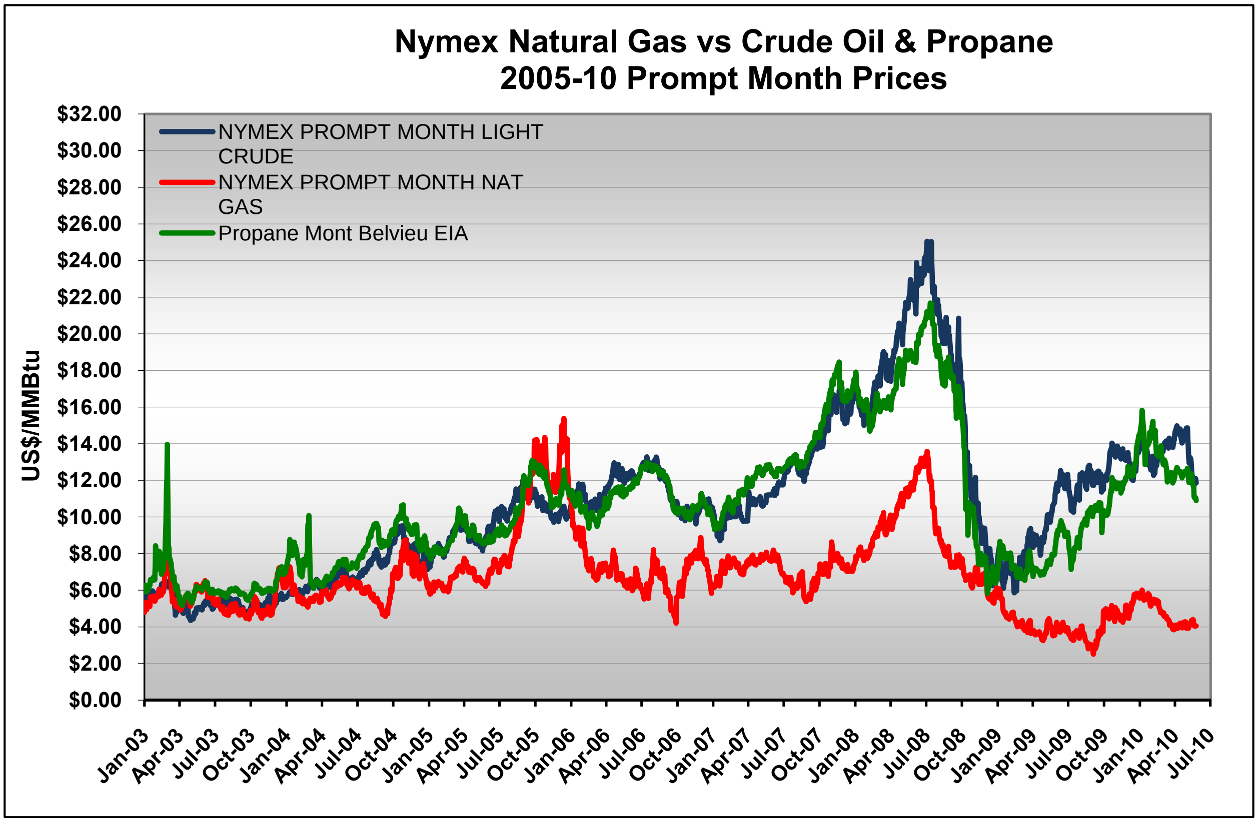


2.1.1.1.3 Natural Gas Prices Compared to Propane Prices

A portion of the Terasen Utilities' customers, primarily in Revelstoke, are served by piped propane distribution systems. Previously, customers in Whistler were served by a propane system. In 2009, the Whistler Pipeline and Conversion Project converted Whistler municipality from a propane system to natural gas.

Historically, propane prices have diverged from natural gas prices and the trend indicates that propane prices tend to follow the higher of oil and natural gas prices. Figure 2-5 shows that this divergence has continued and propane is currently priced higher than natural gas. Based on the tendency for propane to track the higher of oil or natural gas prices the differential between propane and natural gas would be expected to persist in keeping with oil – gas differentials forecast in Figure 2-4.

Figure 2-6: Historic Natural Gas Prices versus Propane and Crude Oil

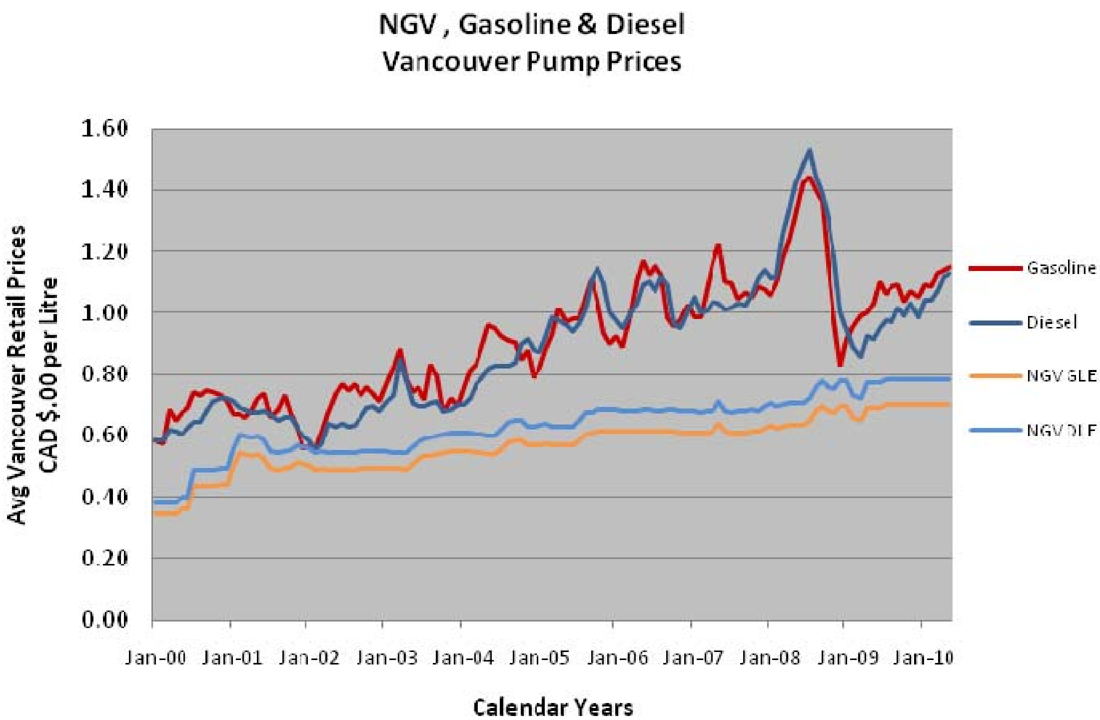


2.1.1.1.4 Natural Gas Price Compared to Diesel and Gasoline

Natural gas usage in the transportation sector is gaining traction in North America, given the abundance of natural gas, its favourable pricing in comparison to oil, which drives diesel and gasoline pricing, and its ability to produce environmental benefits such as lower GHG emissions.

A price comparison of natural gas, diesel, and gasoline for the Vancouver marketplace are outline in Figure 2-7 below.

Figure 2-7: NGV Fuel has a Price Advantage against Diesel and Gasoline



Note: Average pump prices for NGV, regular unleaded gasoline & low sulphur diesel in Vancouver include all applicable taxes. NGV prices include GST.
Source: MJ Ervin & Associates

The key points to note from this comparison are:

- With a brief exception in the 2001-2002 timeframe Natural Gas Vehicles ("NGV") has been consistently priced at a level significantly below both diesel and gasoline for the entire decade
- Pricing of NGV in B.C. has been far less volatile than both diesel and gasoline
- NGV presently has a price advantage of approximately $0.35/litre relative to diesel fuel.
- NGV presently has a price advantage of approximately $0.45/litre relative to gasoline

2.1.1.2 B.C. and Regional Electricity Issues

Electricity and natural gas are competing energy sources in a number of consumer end uses such as space and water heating. Electricity is also the energy source for many other end uses such as powering lights and appliances for which natural gas is not an effective alternative. Because of its importance in many aspects of the economy the electricity sector is frequently the focus of public policy initiatives.

In B.C. the provincial government has recently enacted the CEA as a new piece of legislation affecting the energy industry in the province with a primary focus on the electricity sector. The stated objectives of the Province in establishing the CEA are to achieve B.C.'s potential as a green energy powerhouse, to create a framework to achieve electricity self-sufficiency within B.C., to promote economic growth and jobs within B.C., and to facilitate the export of B.C.'s green electricity to other jurisdictions while maximizing the benefits of exported electricity for all British Columbians[17].

The likelihood of B.C. achieving success in these objectives is highly affected by policy in the neighbouring jurisdictions in which B.C.'s exported power is likely to be sold. The electricity industry in each jurisdiction is strongly influenced by energy, environmental and economic government policy at state (or provincial) and federal levels. There are also a number of regional organizations such as, for example, the Western Climate Initiative ("WCI") that are influencing policy and action in the various jurisdictions. The policy context in the western North America jurisdictions is fragmented and that makes it difficult to predict how the various initiatives will unfold and how each jurisdiction will be affected by the evolving areas of energy and climate change policy.

One area that illustrates the policy fragmentation in the west is Renewable Portfolio Standards ("RPS"). Most but not all jurisdictions in the Western Interconnection have an RPS, a requirement whereby the electric utilities within the jurisdictions must acquire a certain percentage of their electricity supply from renewable sources by a certain date. There are differences from jurisdiction to jurisdiction in what resources will qualify as RPS-compliant and whether (and on what basis) renewable resources from other jurisdictions will be considered acceptable. A key issue in this regard for electricity exports from British Columbia to California is that much of B.C.'s hydro-power potential does not qualify under California's current RPS rules. Like B.C., other jurisdictions have drivers other than simply achieving environmental benefits in establishing an RPS. Factors such as fostering economic development within the state or achieving improved energy security and reliability may be of similar or higher importance than attaining environmental benefits.

British Columbia has been recognized as having a large potential in the area of renewable electricity generation. For instance the Western Renewable Energy Zones ("WREZ") Phase 1 Report identifies a large potential in B.C. particularly in the areas of wind generation and hydro generation[18]. However, the WREZ Phase 1 Report also identifies large renewable power generation potential in a number of other western jurisdictions as well. The southwest states of

[17] Clean Energy Act, See Appendix A-1
[18] WREZ Phase 1 Report, June 2009, Renewable Energy Generation Summary, page 24

Arizona, California, Nevada and New Mexico have large potential in solar thermal generation. States such as Colorado, Montana, Wyoming and New Mexico have large potential in wind generation. The diversity and magnitude of renewable generation potential in the west suggests that there will be competition amongst jurisdictions and resource types to supply the overall renewable requirements in the region.

As discussed further in Section 2.1.1.4 electricity rates in British Columbia are currently among the lowest in North America. However, electricity rates for consumers in British Columbia are forecast to increase over the next number of years. For example, B.C. Hydro issued a ten-year outlook for electricity rate increases as part of its 2008 LTAP proceeding,[19] which indicated estimated rate increases well above general inflation. Among the factors contributing to these rate increases are the need to acquire new supply resources to meet growing load and comply with the provincial self-sufficiency requirements and increased levels of capital spending required sustain the aging system and accommodate load growth. FortisBC has not issued a similar outlook for future rate increases but is facing similar cost pressures and load growth as BC Hydro is. At the same time as electricity rates are forecast to increase the B.C. government has included in the *Clean Energy Act* the objective "to ensure the authority's [BC Hydro's] rates remain among the most competitive of rates charged by public utilities in North America." How the outlook for significant rate increases and the objective to keep rates among the most competitive in North America will ultimately play out in terms of electricity rates in B.C. is very difficult to predict. Rate structures, such as BC Hydro's Residential Inclining Block ("RIB") rate also affect consumers' perceptions of energy prices. How future general rate increases or increases in the marginal cost of new power supply will be incorporated in the Step 1 and Step 2 rates of the RIB rate structure (or other conservation rate structures) is also uncertain at this point in time.

2.1.1.2.1 Electricity Generation

Electricity provides approximately the same share in B.C. of the end use energy market as natural gas[20]. B.C.'s electricity supply is predominantly a hydroelectric generation system, with over 90 percent of electricity generation being from renewable, low or no carbon sources[21]. The provincial government's commitment to maintain this high level of electrical generation from clean and renewable resources in B.C. has been reiterated most recently in the *Clean Energy Act* where the objective "to generate at least 93% of the electricity in British Columbia from clean or renewable resources" has been set out.

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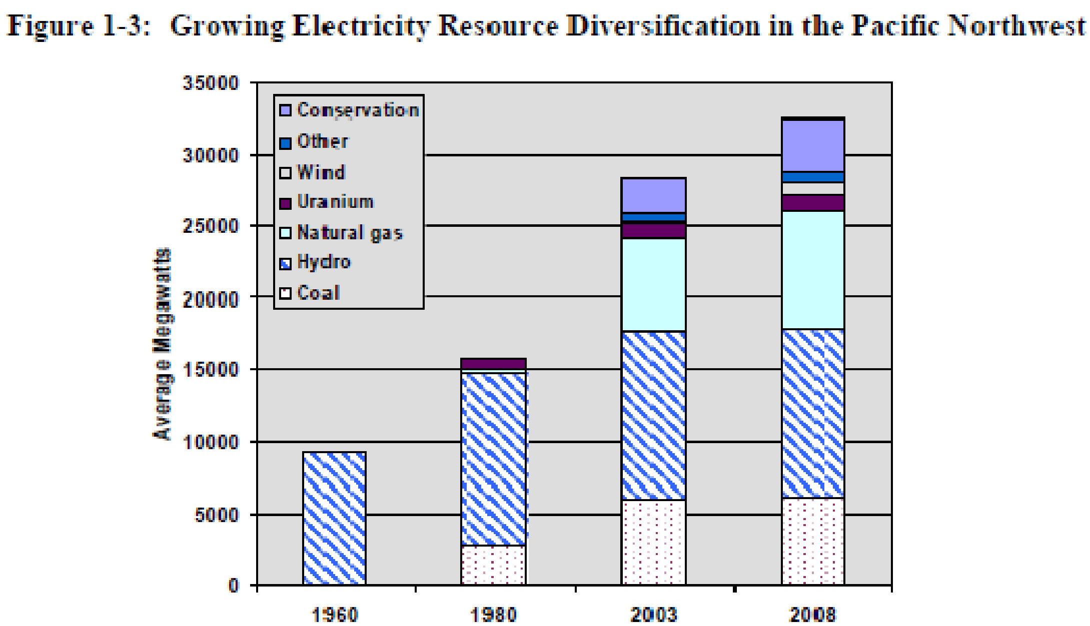
[19] BC Hydro 2008 LTAP, Exhibit B-3, BCUC IR 1.7.1, Attachment 1. A three-year projection of rate increases is also found in BC Hydro's most recent annual Service Plan which confirms expected increases of similar magnitude in the shorter term.

[20] NRCan Comprehensive Energy Use Database

[21] Ministry of Energy, Mines and Petroleum Resources. "Electric Generation and Supply". Retrieved from http://www.empr.gov.bc.ca/EPD/Electricity/supply/Pages/default.aspx

By comparison electricity generation in other areas in the PNW region includes large portions that are generated using coal and natural gas. The following chart[22] reproduced in Figure 2-8 was taken from the NWPCC Sixth Power Plan, shows how the mix of electricity generation in the PNW has changed over time.

Figure 2-8: Mix of Electricity Generation in PNW Over Time



With continuing population and economic growth expected in the PNW, and with the expectation of increasing carbon emission costs going forward, the new resources needed to meet growing electricity needs are expected to come from conservation, renewables and natural gas-fired generation. The Sixth Power Plan estimates that 85% of future load growth in the region can be met through cost-effective conservation. Renewables, primarily in the form of wind generation, are being added to meet Renewable Portfolio Standards and to contribute to the load growth not avoided by conservation. Natural gas-fired generation is the likely resource to fill any remaining load-resource gap and to provide firming capability for the intermittent renewable resources. Pursuing these strategies will allow utilities in the Pacific Northwest to make their contribution to the achievement of public policies and GHG emissions reduction goals with natural gas included as part of the solution.

California's electricity requirements are met by generation resources that are approximately 70% of in-state and approximately 30% net imports. About three quarters of California's imported power comes from other jurisdictions in the U.S. Southwest and the balance comes from the PNW. California's Renewable Portfolio Standard of having 33% renewables by 2020 is a large driver of change in the state electricity sector. Overall demand by 2020 is expected to

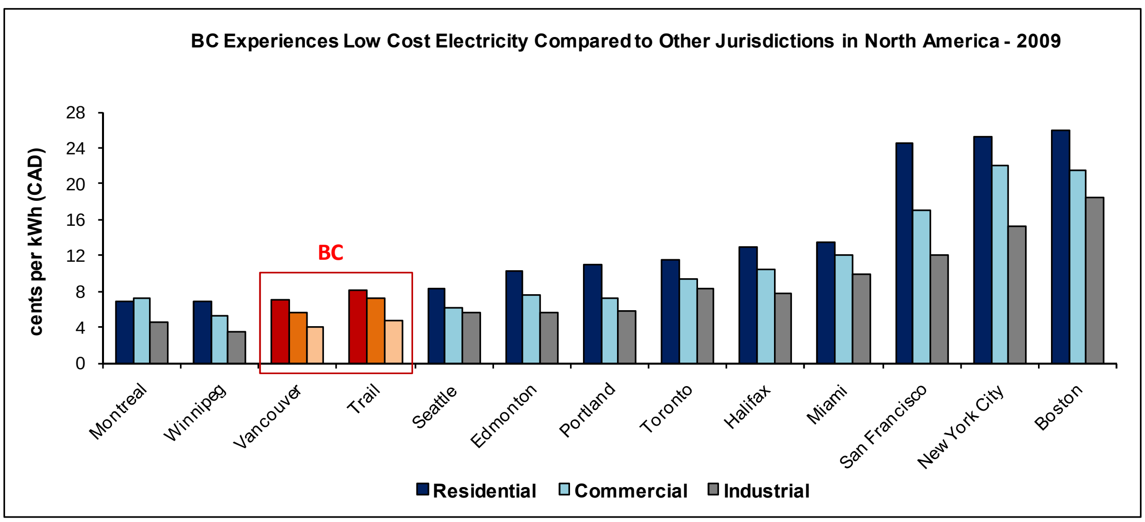
[22] NWPCC Sixth Northwest Conservation and Electric Power Plan, page 1-11

exceed 330,000 GWh suggesting RPS electricity requirements in the order of 110,000 GWh. A California RPS requirement of this large amount is in the order of one and a half to two times B.C.'s current domestic electricity demand. The magnitude of this amount has prompted interest in exports of B.C.'s clean and green electricity to meet California's renewable power requirements. Although there is strong reasons why an export arrangement from B.C. to California would be desirable there are also a number of obstacles to overcome. It is frequently noted that B.C. is a winter peaking jurisdiction while California is summer peaking so taking advantage of excess B.C. generation capability for exports in the spring and summer periods is an obvious benefit of such an arrangement. However a large expansion of electricity transmission capacity between B.C. and California would necessary to accommodate moving significant quantities of electricity. A second obstacle lies in California's current definition of qualifying RPS resources. Much of B.C.'s clean and renewable potential, such as many run-of-river projects are not RPS eligible in California as things currently stand. B.C.'s *Clean Energy Act* has as one of its objectives to open the way for expanded exports of B.C. electricity. Much effort has already gone into studying the export potential and the required transmission expansion but there is still a lot of uncertainty as to how and when all these arrangements will come to fruition.

2.1.1.3 B.C. Electricity and Gas Rates

Electricity rates in British Columbia have historically been among the lowest in North America. Figure 2-9 presents electricity rate comparison information from the most recent version of a study prepared annually by Hydro Quebec. Rates in Trail, B.C. have been added in to represent FortisBC's service territory.

Figure 2-9: Electricity Rate Comparisons



Notes:

- Rates based on Hydro-Quebec's "Comparison of Electricity Prices in Major North American Cities" Effective April 2009
- Trail rates are based on FortisBC electric rates effective January 1, 2010

The B.C. government has made public commitments to keep BC Hydro's rates among the lowest in North America. This has been expressed most recently in the *Clean Energy Act* where one of British Columbia's energy objectives is "to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America". The low electricity rates in B.C. have posed a stronger competitive challenge for natural gas relative to the situation in other jurisdictions. Low electricity rates also create a competitive challenge for the development of alternative energy solutions which tend to be more capital intensive than traditional forms of energy.

2.1.1.3.1 Natural Gas and Electricity Comparison

Figure 2-10 below provides a historical and projected comparison of natural gas bills with the comparable electricity bills. The natural gas bills are based on 95 GJ/year and an assumption of 90% efficiency, while the electricity bills assume 100% efficiency.

In March 2010, BC Hydro requested approval from the BCUC for a general rate increase of 6.11 per cent effective April 1, 2010. BC Hydro's F2011 Revenue Requirement Application ("RRA") is currently under review by the Commission and a decision is expected by the year end.

Figure 2-10: Residential Natural Gas and Electricity Bill Comparison

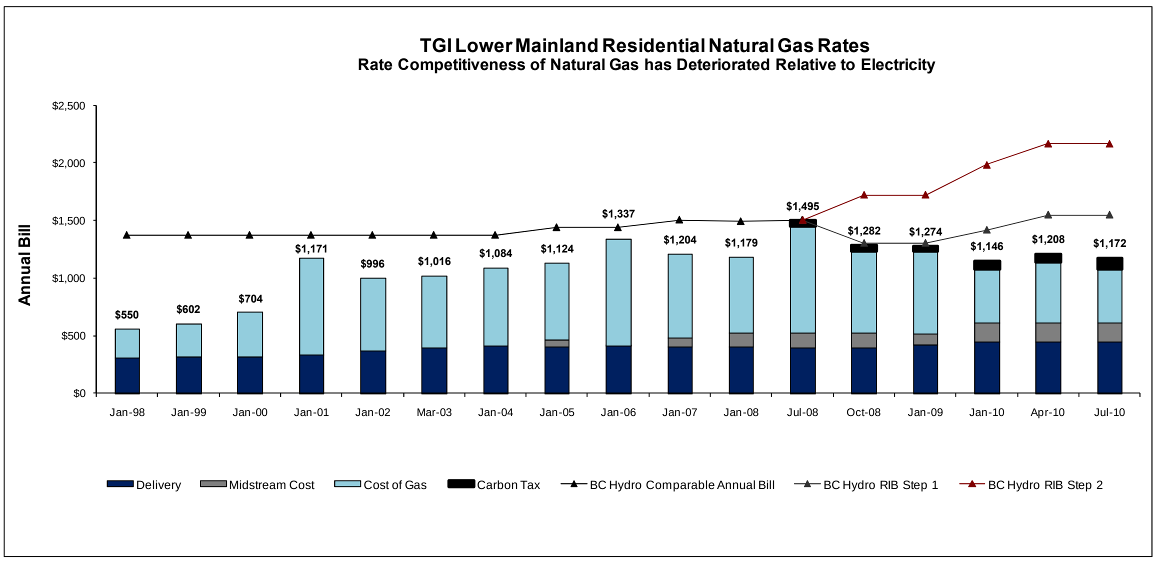


Figure 2-10 demonstrates that while the historical natural gas cost advantage has experienced erosion, natural gas continues to have a modest operating cost advantage relative to electricity. However, the Utilities believe that other factors, such as higher upfront capital costs of a natural gas installation relative to electrical installations and greater rate volatility also figure prominently in the overall competitive position of natural gas relative to electricity. Figure 2-11 demonstrates that natural gas rates need to be lower than electricity rates by approximately $10/GJ to pay back the higher capital costs of a natural gas installation relative to electric baseboards. Also, public perceptions of natural gas as a fossil fuel-based energy source and more restrictive policies driven by climate change concerns (such as possible increases in B.C. Carbon Tax in the future) add uncertainty to the future competitiveness of natural gas going forward.

Figure 2-11: Payback on Incremental Capital Costs for a Natural Gas Heated Home

Payback of Capital Costs (New Construction)	
Space Heating Requirement Only	
New Construction - Home in Lower Mainland (2500 square feet in size)	
Capital Costs for High Efficiency Furnace (90%) and Ducting / Installation	**$ 7,000**
Less: Capital Costs for Electric Baseboards	**(2,500)**
Difference in Upfront Capital Costs	**$ 4,500**
Discount Rate (Cost of Capital)	**6%**
Measurable Life of Furnace	**18**
Amount that has to be recovered annually in operating costs to payoff difference in capital cost	**$415.60**
Add: Furnace maintence costs per year	**100.00**
	$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**

2.1.1.4 Demand Side Management and Renewable Thermal Energy

As part of its climate action plan to reduce GHG emissions, the Province of British Columbia introduced *The British Columbia Climate Action Charter* involving the Province, the Union of British Colombia Municipalities ("UBCM") and Signatory Local Governments. In support of the Provincial Climate Action plan, the Utilities have implemented a suite of EEC (DSM) programs that help our residential, commercial and industrial customers reduce their natural gas consumption and their GHG emissions. The Utilities' EEC programs promote energy conservation through a variety of programs that focus on the replacement of older low efficiency appliances, conservation efforts through education and outreach programs and implementing renewable energy solutions.

Along with the Terasen Utilities' efforts to promote conservation, the Province's Climate Action plan will bring about changes to building codes, energy policies and other actions that will produce lower thermal energy demands throughout the province as well as substituting traditional energy sources with renewable thermal energy technologies. The Utilities recognize a new forecasting methodology is required to forecast future energy demands in its traditional gas markets as well as new alternative energy developments.

It is important for the Utilities to forecast natural gas demands accurately; and also important to recognize the impact that alternative energy technologies, building design and fuel switching will have upon the overall energy mix and energy demands within British Columbia in the future.

The ability to forecast the thermal energy demand in B.C. through a variety of scenarios will help the Utilities, the Province and other utilities understand the future energy picture. This forecasting will also allow the Utilities to help the Province to understand the effects that potential energy polices will have upon all energy delivery systems.

The province of British Columbia has been in the enviable position of being among the lowest cost electricity jurisdictions in North America. This is a function of the province having a rich endowment of hydro-based electricity generation much of which was developed thirty or more years ago (referred to as the Heritage Resources). Since electricity rates in B.C. are cost based and the low cost Heritage Resources make up the majority of the overall electricity resource portfolio it is reasonable to expect that the cost advantage for B.C. electricity rates relative to other jurisdictions will persist for some time. As discussed above British Columbia also has a very large endowment of cost-effective natural gas resources. However, natural gas is traded in a continental marketplace and the commodity rates that natural gas customers pay are market based. Market influences happening elsewhere such as hurricanes causing production to be shut in on the U.S. Gulf Coast or a cold winter causing abnormal depletion of gas storage inventories affect commodity prices for natural gas consumers in B.C. Although the Utilities continues to believe that natural gas is competitively challenged relative to electricity in B.C. the pricing of natural gas and the benefits of natural gas service have been favourable enough in the past for it to be the energy source chosen for the thermal energy needs of many consumers in the province.

The low cost of electricity and conventional energy in B.C. in turn creates a hurdle for alternative energy developments which tend to be more costly (or at least may appear to be so). Alternative energy developments also tend to be more technically complex than meeting energy demands with traditional energy sources. The Utilities believe that significant growth is needed in alternative energy developments in order for the provincial energy and climate change mitigation objectives to be achieved. Alternative energy developments must form an important component of the energy future along with EEC programs, building codes and appliance efficiency standards if these provincial objectives are to be met. Ingenuity and resources must be brought to the table by all parties - government, utilities, the development community, and energy consumers in order to overcome any cost and technical challenges, and to achieve the desired GHG emissions reductions.

There are many indications of new and expanded activity happening on various fronts in the energy and utility sector. Improving energy efficiency and reducing GHG emissions in thermal applications for the residential, commercial and municipal sectors are being approached from many angles. Expanded utility DSM programs, government incentive programs, building code changes and the expansion of alternative and integrated energy solutions are all examples of approaches being taken to achieve targets in these objectives. Terasen Utilities' own programs include a large increase in EEC programs and expansion into integrated and alternative energy solutions.

Recently there has been a large increase in interest in B.C. in exploring integrated and alternative energy solutions to achieve the energy and climate change goals that have been established in the province. In keeping with their commitments under the B.C. Climate Action Charter municipalities across B.C. are increasingly exploring the viability of establishing district energy systems as a means of reducing greenhouse gas emissions, achieving energy efficiency and reducing waste. Non-government organizations such as the Community Energy Association and Quest (Quality Urban Energy Systems of Tomorrow) are acting as catalysts to spur interest in district energy systems. The province of B.C. has expressed support for the development of district energy systems in a number of ways. For example the province has developed a promotional factsheet entitled the "District Energy Sector in British Columbia"[23], which identifies district energy systems as an efficient way to heat and cool buildings and reduce greenhouse gas emissions. Also the recently established RuralBC website, which provides an easy reference point for communities to access resources and program funding in various areas, notes that funding is available to study the viability of district energy systems in communities across the province and to assist in implementing them[24]. BC Hydro has also recently launched its Power Smart Sustainable Communities Program[25] to support communities in these areas.

2.1.1.5 Carbon Pricing

The future cost of carbon and GHG emissions is another important element in the energy planning environment for this LTRP. While Section 2.3 discusses climate change mitigation policies and legislation in detail a few issues are discussed here with respect to carbon pricing as it will affect energy pricing going forward. The province of B.C. implemented a carbon tax effective July 1, 2008 initially based on $10/tonne of CO_2e and increasing by $5/tonne each July 1 until reaching $30/tonne of CO_2e on July 1, 2012. At the July 1, 2012 level the B.C. Carbon Tax will add $1.49/GJ to the price of natural gas, 6.67 cents per litre to the price of gasoline and 7.67 cents per litre to the price of diesel fuel[26] .

The level of the B.C. Carbon Tax is known with certainty until July 2012 but some parties are suggesting that it is necessary to increase it to a much higher level in order to drive consumer behaviour towards the much lower levels of fossil fuel use necessary to achieve legislated GHG reductions. The outcome of other policy initiatives at the U.S. and Canadian federal level could lead to the introduction of GHG emission cap-and-trade systems or carbon taxes imposed by other levels of government. Overall carbon taxes or cap-and-trade systems will lead to higher costs for fossil fuel consumption. The potential for a much higher cost of carbon in the future

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23 See link to document at www.empr.gov.bc.ca/MACR/investors/Pages/English.aspx. The document lists eighteen district energy systems in BC either operating currently or under development. Terasen Gas is aware of a number of other district energy proposals, not included in the eighteen that are also under active development presently. Currently, new district energy system proposals are coming to light on a regular basis.

24 See link to program at www.ruralbc.gov.bc.ca/power_smart.htm

25 See http://www.bchydro.com/powersmart/ps_communities.html

26 Gasoline and diesel carbon tax rates were reduced by 5% effective Jan. 1, 2010 as a result of the Renewable and Low Carbon Fuel Standard (see BC Ministry of Finance September Tax Schedule "Carbon Tax Rates by Fuel Type – From January 1, 2010").

adds another level of uncertainty to the selection of energy solutions going forward with the likely outcome unfavourable to natural gas.

2.1.1.6 Conclusion

A simple rate or economic comparison between different energy alternatives may have been appropriate in the past to assess the competitiveness of the various energy forms. Increasingly the future of different energy forms is being strongly influenced by government policy aimed at climate change mitigation and by shifting public opinion caused by environmental concern. The shift towards integrated alternative energy solutions and a heightened focus on energy efficiency and conservation are indicators of these changes. Economics are not the only or even the main driver of consumers' energy decisions. There is a great deal of uncertainty about how these influences will ultimately unfold but it is fair to expect that the place of natural gas will be different in the future thermal energy landscape.

2.1.2 TRANSPORTATION ENERGY

Terasen Utilities believe there are several reasons why looking at the transportation sector is an important area to consider in the development of its LTRP. The transportation sector is the largest source of GHG emissions in B.C., contributing about 36% of the province's total emissions. If British Columbia is to achieve its legislated targets for GHG emission reductions it is clear that reductions from the transportation sector must make a large contribution to these goals. The use of natural gas as a fuel source for vehicles offers the opportunity to displace higher GHG emitting fuels such as diesel and gasoline. The use of natural gas in vehicles also offers the opportunity to develop a local market for a B.C.-produced resource. This local economic development opportunity will displace fuels that are largely imported from outside British Columbia. Thirdly, the development of a larger NGV market in B.C. offers the opportunity to offset natural gas demand decreases in other customer segments such as the residential and commercial sectors. Increasing NGV load also offers benefit to the natural gas system as NGV load tends to be more year-round in nature than low load factor space heating which is the dominant contributor to demand in the residential and commercial customer segments.

The Terasen Utilities believe the best near-term opportunities for widespread adoption of NGV solutions is in the return-to-home, fleet vehicle market, rather than the personal vehicle market. The specific target market for natural gas as a transportation fuel is described further in Section 4.3.

Electric Vehicles ("EVs") are increasingly viewed as a promising low carbon solution for the passenger vehicle market, which is a small portion of the overall transportation fuel market. Currently, EVs are not available in the B.C. marketplace and have limited range for fleet and heavy duty vehicle use. Strong growth in this sector could pose significant challenges for the province's electricity grid. Over the long term; however, the utilities believe that both NGVs and EVs can play an important role in B.C.'s transportation future. It is likely that the market share for Hybrids will continue to grow in the passenger vehicle market and may emerge to take a significant share of the market as battery technologies improve and cost premiums decline. Hybrid vehicles have seen limited introduction into certain heavy duty truck fleet applications and transit bus markets.

The market for biofuels in B.C. is also expected to continue growing, but that penetration will be limited by the economics of biofuel production and emerging awareness of certain limitations with respect to the life cycle impact of biofuels. Emerging issues include the widely differing GHG impact of biofuels depending on the source of feedstock and the land use impact of using agricultural resources (land) for fuel production rather than food production.

This section sets out the market background for the transportation sector in B.C. to set the context for NGV growth opportunities in portions of the market. Additional discussion of the NGV marketplace can be found in both Sections 3 and 4.

- **B.C. Motor Fuels Market Overview**

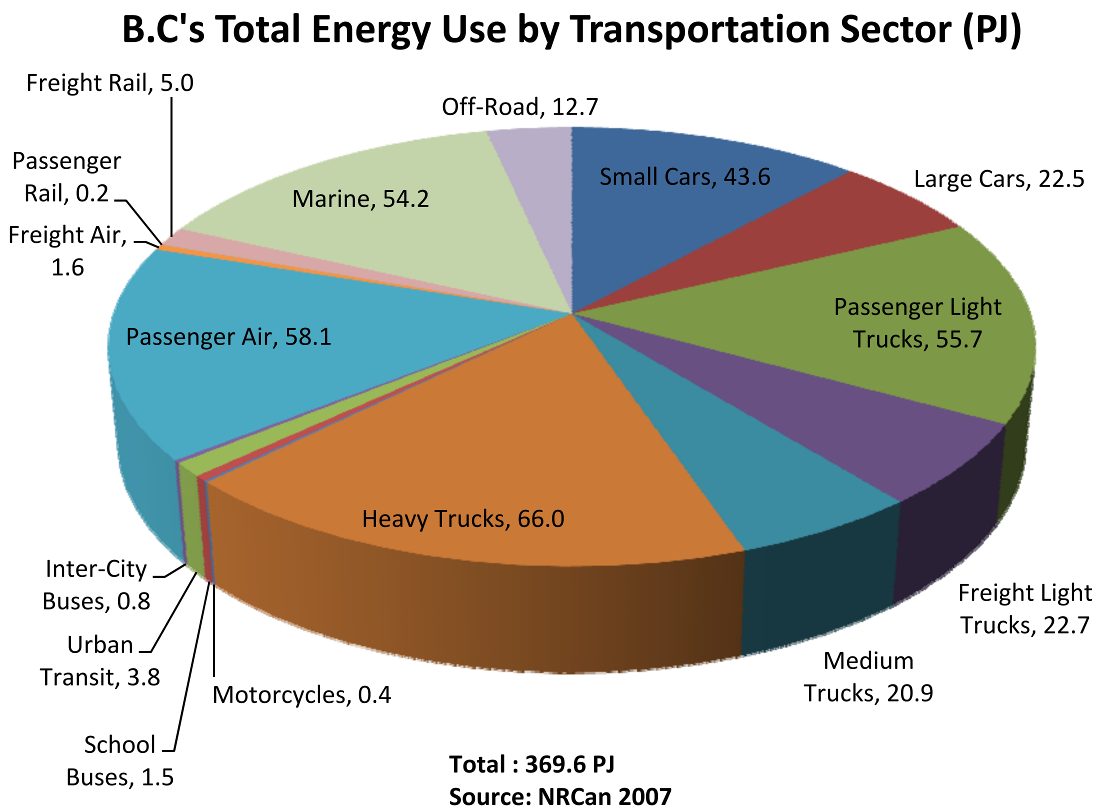
The analysis presented below is based on publicly available data from the Natural Resources Canada Office of Energy Efficiency ("NRCan"). Detailed information on transportation energy use, fuel type, and GHG emissions are given for the years from 1990 through 2007.[27]

- **Energy Use**

The total energy use from B.C.'s transportation sector was 370 PJ in 2007. The figure below shows total energy used by each transportation segment.

[27] Natural Resources Canada, Office of Energy Efficiency, 2007: http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/trends_tran_bct.cfm

Figure 2-12: B.C.'s Transportation Sector Total Energy Use 370 PJ in 2007

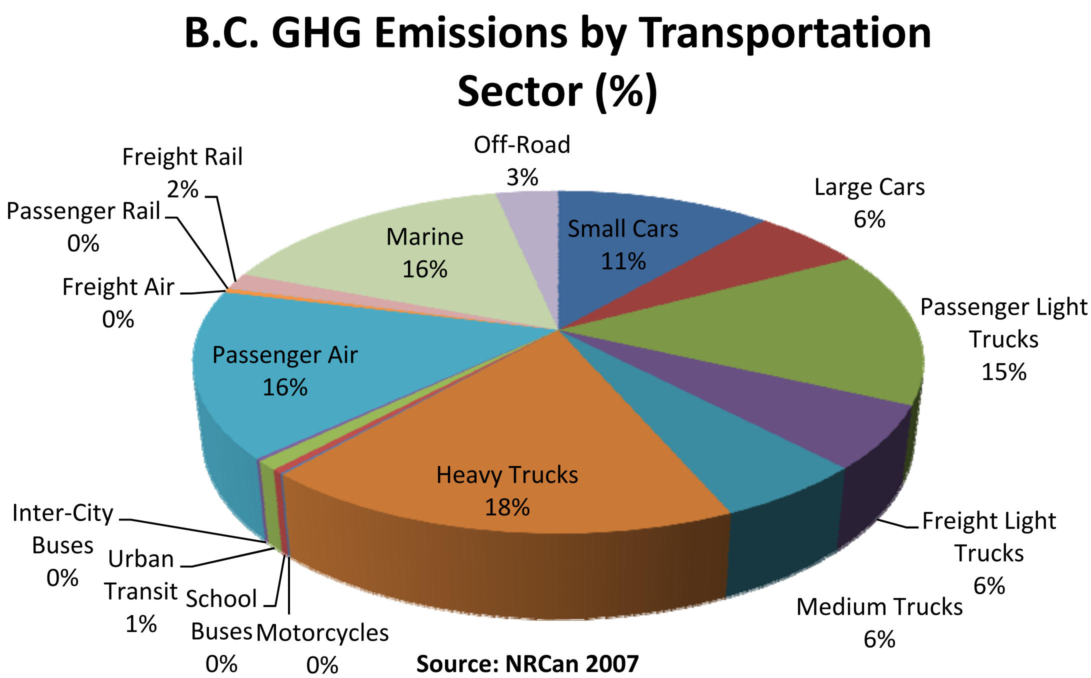


<u>Greenhouse Gas Emissions from the Transportation Sector</u>

B.C.'s transportation sector produced over 25 million tonnes ("Mt") of carbon dioxide equivalents in 2007.[28] The following graph breaks down the GHG emissions by each segment.

[28] NRCan 2007

Figure 2-13: B.C.'s Transportation GHG Emissions by Segment



The Figure 2-13 above illustrates that the trucking (light trucks, medium truck and heavy trucks) segment makes up approximately 44% (or 11.4 Mt) of the total emissions profile. Passenger cars (small and large) represent approximately 17% (4.4 Mt), and marine consists of 16% (4.1 Mt). Data from NRCan indicates heavy-duty NGVs emit 15%-30% less GHG emissions than their diesel counterparts[29]. These sectors represent an important opportunity for the Utilities to use natural gas as a transportation fuel in these high emission sectors to help meet B.C.'s legislated GHG reduction targets.

2.1.3 ENERGY EXPORTS FROM B.C.

The energy sector is one of B.C.'s largest categories of exports, accounting for 27 percent of exports[30]. The province's exports are expected to increase at "a double-digit pace" in the next couple of years as commodity prices rebound and demand from the U.S. recovers. The energy sector in particular is forecast to see a 20 percent growth in 2010 and 17 percent in 2011, a major rebound after a decline of more than 30 percent in 2009[31]. This growth in the dollar value of energy exports is mainly due to increased natural gas prices, forecast to be as much as 40

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[29] For more detail, please see Section xxx
[30] Export Development Canada. "Global Export Forecast: Spring 2010". Retrieved from http://www.edc.ca/english/docs/GEF_e.pdf
[31] Export Development Canada. "Global Export Forecast: Spring 2010". Retrieved from http://www.edc.ca/english/docs/GEF_e.pdf

percent higher than 2009) as well the Horn River Basin shale gas formation, and coal production[32]. With anticipated high demand for natural gas, it continues to be B.C.'s most important energy export. In the long term, the construction of a pipeline from the Montney shale gas formation as well as the possibility of an LNG liquefaction terminal in Kitimat will further increase the province's export capacity[33]. B.C.'s significant role in energy markets will be further strengthened by the B.C. government policies and initiatives, such as the *Clean Energy Act*, promoting the development of an electricity export market. Moreover, as mandated by the B.C. Energy Plan, the Net Profit Royalty Program stimulates development of natural gas and oil resources that are not economic under previous royalty programs by sharing the capital risk of successful developments and recognizing the long-lead times associated with these developments.

2.2 Energy and Climate Change Policy and Legislation

Energy policy at all levels of government is increasingly focused on energy conservation and efficiency, clean energy production, and energy consumption behavior aimed at reducing GHG emissions as a means to address challenges imposed by climate change. In recent years, B.C.'s provincial government and municipalities have taken steps to develop targets and action plans to support reductions in GHG emissions. The actions of Canada's federal government, while not (yet) reflected in formal policy or legislation, reinforce this focus on cutting GHG emissions through reducing consumption of carbon based fuels. In the U.S., the change in the federal government resulted in a renewed commitment to clean energy and GHG emissions reductions[34]. Thus, all levels of government across North America recognize that GHG emissions reduction is a pressing need, which gives rise to an increased focus on energy policy and energy issues.

Government energy policies and legislation have a great influence on the direction of how energy will be produced and on the energy choices that customers make now and into the future. This section explores how federal policy in Canada and the U.S., state policy in the PNW, and B.C. provincial government policy and initiatives are all focusing on energy consumers with the common goal of GHG emissions reduction.

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32 Export Development Canada. "Global Export Forecast: Spring 2010". Retrieved from http://www.edc.ca/english/docs/GEF_e.pdf

33 Export Development Canada. "Global Export Forecast: Spring 2010". Retrieved from http://www.edc.ca/english/docs/GEF_e.pdf

34 There are currently two bills being reviewed by the U.S. Congress, the American Clean Energy and Security Act (the Waxman-Markey bill) and the American Power Act (the Kerry-Lieberman bill), at this time it is not clear which one, or if either, will be signed into law.

2.2.1 FEDERAL APPROACHES TO CLIMATE CHANGE IN CANADA AND THE U.S.

At a federal level both Canada and the U.S. have similar views on climate change policy and GHG emissions reduction objectives. With respect to transportation fuel efficiency standards, Canada and U.S. appear to agree on the path forward.

2.2.1.1 Canada

The Canadian federal government has demonstrated its commitment to participate in international efforts to mitigate climate change by setting energy and environmental policies which, although not legally binding, focus on reducing GHG emissions. The government of Canada's commitment to addressing climate change and its harmonization with the U.S. policies indicate the direction in which the federal government wants to move.

The Canadian federal government has actively sought to align its clean energy and climate change policies with those of the U.S. government. On January 30, 2010, Canada set a new goal to reduce GHG emissions in this country by 17 per cent below the 2005 level by 2020. This new target is a slight change from its earlier goal of reducing GHG emissions by 20 per cent below 2006 levels by 2020, which aligned with the U.S. targets[35].

In addition to setting GHG emissions reduction targets similar to those of the U.S., the Canadian government addresses GHG emissions within the transportation sector on a "continental basis" with the U.S. given that "we occupy the same economic space, the same environmental space, and the same energy marketplace"[36]. The government of Canada has announced its intention to take action on each of the major sources of GHG emissions starting with the transportation sector, the biggest source of GHG emissions in the country, accounting for 25% of Canada's total GHG emissions[37]. For the transportation sector, the Canadian government has put in place mandatory national emissions standards, referred to as *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations* under the *Canadian Environmental Protection Act.* These standards are similar to U.S. regulations, effective 2011, requiring that new passenger cars and trucks must be fuel efficient and should produce lower GHG emissions. Furthermore, NRCan has initiated public consultation and formed a roundtable to develop of a roadmap for natural gas use in the transportation sector[38]. As a result, natural gas and electricity will likely play a bigger role in providing energy for transportation in the future.

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[35] Climate change policy and GHG reduction targets are currently fragmented between federal and provincial levels. Government of Canada. "Canada's Action on Climate Change". May 6, 2010. Retrieved from http://www.climatechange.gc.ca/default.asp?lang=En&n=72F16A84-1

[36] National Post. "Canada Lowers Climate Change Target: Critics". January 30, 2010. Retrieved from http://www.nationalpost.com/news/story.html?id=2505931

[37] Environment Canada. "Government of Canada to Reduce Greenhouse Gas Emissions from Vehicles". April 1, 2009. Retrieved from: http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=29FDD9F6-489A-4C5C-9115-193686D1C2B5

[38] Natural Resources Canada. "Public Consultation Activities". Retrieved from http://www.nrcan-rncan.gc.ca/com/consultation/concon-eng.php

In order to achieve its GHG emissions reduction targets, Canada is continuously developing policies that regulate emissions[39], enhance energy efficiency, and increase the share of renewable energy in the overall energy mix[40]. However, the federal government faces a significant challenge since domestic oil and natural gas production are contributors of economic benefits to Canada. The question becomes how does Canada reduce GHG emissions while maintaining the economic benefits that are generated from these resources? Although there has been a lack of leadership on developing a comprehensive federal plan to reduce GHG emissions, some provinces have been active in moving forward with their own plans and policies. Over time, this could lead to set of overlapping and potentially contradicting policies across Canada and the region as the Federal government evolves its energy and GHG policies forward.

2.2.1.2 United States

In recent years, the U.S. government has proposed aggressive energy policy reform, including the need for a reduction of GHG emissions (using a cap and trade program), which would encourage more clean renewable, sustainable energy development. On January 29, 2010, the U.S. federal government announced that it will reduce its own GHG emissions by 28 percent by 2020 and GHG emission reductions can be achieved by measuring current energy and fuel use, being more energy efficient and moving to clean energy sources such as solar, wind and geothermal [41]. The U.S. government and the Obama administration are also looking to the "green economy", in particular green energy, with more attention to the development of clean and renewable energy, to stimulate the economy, build local market capacity, foster innovation in clean energy industries, and increase jobs[42].

The U.S. is also focused on energy self sufficiency and energy independence in order to reduce its imported energy supply, increase domestic energy supply, and use of natural gas in sectors such as transportation or electricity generation to reduce the impact of GHG emissions and dependency on imported oil, and improve its energy security[43]:

- On May 15, 2009, the *American Clean Energy and Security Act* (the "ACESA") was introduced in the U.S. by U.S. House Energy and Commerce Committee Chairman

[39] In June 2010, Government of Canada announced its intent to regulate emissions from electricity sector, noting that thirteen per cent of Canada's total GHG emissions come from coal-fired electricity generation.

[40] Government of Canada. "Canada's Action on Climate Change". February 1, 2010. Retrieved from http://www.climatechange.gc.ca/default.asp?lang=En&n=D43918F1-1

[41] The White House Office of the Press Secretary. "President Obama Sets Greenhouse Gas Emissions Reduction Target for Federal Operations". January 29, 2010. Retrieved from http://www.whitehouse.gov/the-press-office/president-obama-sets-greenhouse-gas-emissions-reduction-target-federal-operations.

[42] The White House. "Energy & Environment". Retrieved from http://www.whitehouse.gov/issues/energy-and-environment

[43] The White House Office of the Press Secretary. "Remarks by the President on the Economy at Carnegie Mellon University". June 2, 2010. Retrieved from http://www.whitehouse.gov/the-press-office/remarks-president-economy-carnegie-mellon-university

Henry Waxman and House Energy and Environment Subcommittee Chairman Edward Markey (hence also referred to as the Waxman-Markey bill). The *ACESA* is a comprehensive national climate and energy bill aimed to establish an economy-wide, GHG cap-and-trade system to help address climate change and build a clean energy economy.

- On July 8, 2009 ,the *New Advanced Transportation to Give Americans Solutions Act* (the "NAT GAS Act") was introduced in the U.S. Senate by Senator Robert Menendez and co-sponsored U.S. Senate Majority Leader Harry Reid and Senator Orrin Hatch, which aims to extend and increase tax credits for NGV's and refueling. The NAT GAS Act will provide incentives for consumers, commercial truckers, and state and local governments to aggressively move from using vehicles burning polluting, imported gasoline and diesel, to vehicles running on clean, domestic natural gas.[44]

- On May 12, 2010, Senators John Kerry and Joe Lieberman introduced the *American Power Act* (the Kerry-Lieberman bill) to the Senate of the U.S., which has been deemed to reduce GHG emissions, provide incentives for the domestic production of clean energy technology, reduce dependence on foreign oil, create clean energy jobs, and secure the energy future of the U.S.[45] The new bill promotes domestic clean energy development, renewable energy and energy efficiency, clean transportation, and the capture and sequestration of carbons. This bill includes specific incentives for the conversion to clean, natural gas vehicles. The *American Power Act* is a further testament to the fact that GHG emissions reductions cannot be achieved without economic sustainability.

These bills are currently being reviewed by the Senate in the U.S. Congress and it is not clear which one, or if either, will be signed into law.

Both Canada and U.S. are increasingly focused on reducing GHG emissions and both countries are moving forward to a low carbon economy, promoting the development of alternative and renewable energy; however, there are distinct regional characteristics in both Canada and the U.S. that identify different energy requirements and solutions to meet their GHG emissions reduction objectives. For example, there are different challenges for reducing GHG emissions in provinces and states that have fossil fuel production driving their economy. This is further complicated by the changing mix in electricity generation fuels between jurisdictions. More specifically, some jurisdictions have much higher carbon intensity in these sectors than other jurisdictions. The regional context for B.C. is discussed next.

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[44] NGV Global News. "New US NAT GAS Act of 2009 Introduced on 'Energy Independence Day'". July 8, 2009. Retrieved from http://www.ngvglobal.com/new-us-nat-gas-act-of-2009-introduced-on-energy-independence-day-0708

[45] The *American Power Act*. Retrieved from http://kerry.senate.gov/work/issues/issue/?id=7f6b4d4a-da4a-409e-a5e7-15567cc9e95c

2.2.2 PACIFIC NORTHWEST REGIONAL CONTEXT

Although GHG emission reductions cannot be addressed solely within the boundaries of any single political jurisdiction, GHG emission sources can be unique to each jurisdiction and therefore policies, regulations, initiatives, and solutions to reduce GHG emissions may be different based on how such emissions are produced in each jurisdiction.

The PNW refers most commonly to three northwestern states in the U.S. (Washington, Oregon, Idaho) and B.C. in Canada[46]. With the exception of B.C., where electricity supply is predominantly from hydroelectric generation, and currently over 90 per cent of electricity generation is renewable low or no carbon electricity[47], political leaders and utilities in the PNW region, generally consider natural gas to be a solution to their climate change goals both in electricity generation and direct use applications[48]. This is mainly due to the fact that the greatest source of GHG emissions for northwest U.S. comes from coal-fired electricity generation and so policies are developed to move away from coal-based electricity generation to natural gas or renewables combined with natural gas in order to significantly reduce GHG emissions output in this sector[49]. In B.C., however, electricity supply is predominantly from hydroelectric generation, with currently over 90 per cent of generation from renewable low or no carbon electricity[50], resulting in the development of policies that are unique among PNW jurisdictions with regard to the role of natural gas and electricity in meeting energy demands from customers and businesses.

Since using natural gas for space heating and other appliances in the home is more efficient than using natural gas to generate electricity (the marginal resource in the PNW)[51] for use in these same applications, direct use of natural gas is the preferred choice for both the customer and the utility, over electricity. Lower GHG emissions and downward pressure on overall energy costs contribute to the case for direct use of natural gas where it can be used at high efficiencies. For example, utilities such as Puget Sound Energy ("PSE") and Avista Utilities, both combined electric and natural gas utilities, promote the direct use of natural gas as away to avoid new electricity demand, even in service territories where another utility provides the natural gas, and thus realizes the increased demand from such programs. Further, these jurisdictions see that natural gas generation has a role to play in firming intermittent renewable electricity generation. These utilities see natural gas as an important solution to the region's

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46 In some contexts, references to the Pacific Northwest can also include the State of Montana, the Province of Alberta and occasionally the State of Alaska.

47 British Columbia Ministry of Energy, Mines and Petroleum Resources. "Electric Generation and Supply". Retrieved from http://www.empr.gov.bc.ca/EPD/Electricity/supply/Pages/default.aspx

48 Direct use of natural gas in home heating, water heating, cooking, and clothes drying.

49 Discussion Paper – Energy Planning and Climate Change Issues in the Pacific Northwest Region. Included in the Terasen Gas 2008 Resource Plan, Appendix B: Regional Policy Issues.

50 British Columbia Ministry of Energy, Mines and Petroleum Resources. "Electric Generation and Supply". Retrieved from http://www.empr.gov.bc.ca/EPD/Electricity/supply/Pages/default.aspx

51 Northwest Power and Conservation Council. February 2010. 6th Northwest Power Plan, Appendix D, page D-2.

climate change challenges and for reducing their own GHG emissions or meeting state-mandated renewable portfolio standards, while still managing cost impacts for customers[52].

For example, PSE, which serves the Puget Sound region of the northwest U.S., recommends using natural gas directly for home space and water heating when available and encourages customers to switch their heating from electricity to natural gas. Some of the customer benefits that PSE indicates with a conversion to natural gas are lower energy costs, environmental benefits, higher efficiencies and lower cost to maintain natural gas furnaces, increased home value, and versatility[53].

The NWGA advocates climate change policies, promoting the right energy source for the right use. "For instance, high-efficiency end-use natural gas applications such as residential furnaces, tank and instantaneous tankless water heaters, commercial boilers, industrial furnaces and combined heat and power systems are all applications where natural gas is more energy efficient than equivalent electric systems"[54].

The NPCC currently uses the following policy in promoting the direct use of natural gas for space and water heating in the region:

> *The Council recognizes that there are applications in which it is more energy efficient to use natural gas directly than to generate electricity from natural gas and then use the electricity in the end-use application. The Council also recognizes that in many cases the direct use of natural gas can be more economically efficient. These potentially cost-effective reductions in electricity use, while not defined as conservation in the sense the Council uses the term, are nevertheless alternatives to be considered in planning for future electricity requirements.*
>
> *The changing nature of energy markets, the substantial benefits that can accrue from healthy competition among natural gas, electricity, and other fuels, and the desire to preserve individual energy source choices all support the Council taking a market-oriented approach to encouraging efficient fuel decisions in the region[55].*
>
> *Furthermore, natural gas is viewed as a pillar of the region's electricity resource strategy to reduce the use of coal fired generation and allows the integration of a growing fleet of*

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52 Electric power generation is from different sources, coal-fired power plants (36%), hydroelectric (41%), natural gas (20%) and the remaining sources include nuclear, biomass, landfill gas, petroleum, waste and wind. Puget Sound Energy. "Energy Supply: Electricity- Power Supply Profile". Retrieved from http://www.pse.com/energyEnvironment/energysupply/Pages/EnergySupply-Electricity-PowerSupplyProfile.aspx

53 Puget Sound Energy. "Choosing Natural Gas". Retrieved from http://www.pse.com/solutions/foryourhome/pages/ChoosingNatGas.aspx?tab=1&chapter=1

54 NWGA. "Natural Gas and Climate Change in the Pacific Northwest", p. 3. See Appendix A-2.

55 Northwest Power and Conservation Council. Sixth Northwest Conservation and Electric Power Plan. February 2010. Page 8-2. http://www.nwcouncil.org/energy/powerplan/6/Default.htm

> *intermittent renewable resources[56]. In most jurisdictions in the PNW, new large hydro projects are not permitted due to their impact on the environment' eliminating the potential development of such resources to accompany the intermittency of renewables.*
>
> *The use of natural gas as a transportation fuel alternative to gasoline and diesel, using Compressed Natural Gas ("CNG") or Liquefied Natural Gas ("LNG"), is being explored in the PNW region, where it is a low-cost, low-emissions fuel used for passenger vehicles, buses, delivery vans, taxis, postal vehicles, ferries, port applications, and so forth[57].*

Thus, natural gas plays an important role in reducing GHG emissions in Washington, Oregon and Idaho, reducing demands on foreign petroleum, and diversity of transportation fuel in the PNW region. Given that these jurisdictions can use natural gas in direct use application and to produce electricity to reduce their GHG emissions, they do not have the pressing need to utilize natural gas in combination with geothermal or solar in order to reduce the carbon intensity of the energy consumed in thermal applications. Instead, more emphasis has been placed on the role of alternative energy, such as wind for electric generation in the Pacific Northwest.

2.2.2.1 Pacific Northwest: Summary

Given that the PNW views natural gas as a critical component for reducing GHG emissions, along with increased efficiency, adding renewable generation resources and improving infrastructure[58] there is an anticipated increase in regional demand for natural gas. Pricing of carbon will inevitably result in an increase in gas fired generators and thus most of the increase in demand for natural gas[59]. The PNW region needs to retain and secure access to abundant and diverse sources of supply and must ensure associated transmission, storage, and distribution infrastructure can grow as necessary[60]. Since B.C. is part of the PNW region, the anticipated increase in demand of natural gas within the region will provide B.C. an opportunity to leverage its new natural gas supply resources to fulfill this anticipated market demand.

2.2.3 B.C. PROVINCIAL GOVERNMENT AND MUNICIPALITIES

The B.C. provincial government along with many municipalities within the province, are all aggressively encouraging the reduction of GHG emissions, by having a focus on lowering energy consumption and improving energy efficiency and conservation, and are keen in their search for and developing of alternative (and renewable) energy sources.

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56 Northwest Power and Conservation Council. Sixth Northwest Conservation and Electric Power Plan. February 2010. Page 10-2.
57 NWGA. "Natural Gas and Climate Change in the Pacific Northwest". See Appendix A-2.
58 Northwest Power and Conservation Council. February 2010. "Sixth Northwest Conservation and Electric Power Plan". Ch 10, p. 1&2.
59 CERI presentation. Climate Change & Natural Gas. April 2010. Presented by David C. McColl.
60 NWGA. "Natural Gas and Climate Change in the Pacific Northwest". See Appendix A-2.

The role of natural gas and electricity is the energy mix is different in B.C. compared to other jurisdictions in the PNW due to the fact that B.C.'s electricity supply is predominantly from hydroelectric generation, with over 90 per cent of generation currently from renewable low or no carbon electricity[61]. The B.C. government has been an active leader in clean energy policies and initiatives, encouraging the switch from higher to lower emission energy sources. However, as a GHG emitting energy source natural gas for home heating and other direct use applications is facing challenges in B.C.'s policy environment given that the electricity produced in the Province is viewed as clean and renewable. Also, there is less emphasis placed on use of natural gas for electricity generation in B.C., as opposed to other regions in the PNW, due to the large capability of the heritage assets within BC Hydro supply resources and also the considerable potential for renewable resource development in the Province. This preference of the electricity use over natural gas influences public perception regarding energy production and consumption, particularly in the role that natural gas can play as part of the solution in climate change initiatives.

If implementation of B.C. government policies was to result in substantial electrification in sectors currently served by gas, the Province would face substantial electricity supply and capacity concerns in the future. Given this reality, alternative energy solutions will likely play a bigger role in the future supported by natural gas. As more and more energy and climate change policies are implemented and refined, government, utilities, and stakeholders must continue their efforts to make sure public policy is clear and understood by all so that solutions can be found to achieve the established goals.

The implications of these policies for utilities are profound, and utilities are compelled to respond. Given these external realities, the Terasen Utilities have introduced new service offerings to augment the Utilities' natural gas business as a response to the challenges and opportunities presented by climate change policies. These new service offerings include alternative energy solutions, such as geothermal, solar and district energy systems. A summary of the key B.C. government legislative developments are discussed below.

2.2.3.1 Clean Energy Act

On April 28, 2010, the B.C. government announced the CEA (Bill 17), which aims to ensure electricity self-sufficiency at low electricity rates by 2016, to harness B.C.'s clean power potential to create jobs, and to strengthen environmental stewardship and reduce GHG emissions. It focuses almost exclusively on electricity, and sets conditions for the development of an electricity export market. A copy of the CEA is provided in Appendix A-1. Section 2 sets out B.C.'s new energy objectives,[62] almost all of these objectives have implications for energy

[61] British Columbia Ministry of Energy, Mines and Petroleum Resources. "Electric Generation and Supply". Retrieved from http://www.empr.gov.bc.ca/EPD/Electricity/supply/Pages/default.aspx

[62] Some of these objectives build on existing policies and previously publicized objectives, such as those contained in the 2007 BC Energy Policy.

efficiency and optimization, and carbon reduction solutions that the Terasen Utilities can provide as part of its vision and action plan for the future.

The *CEA* focuses on the ideals of electricity self sufficiency within the Province and becoming a net electricity exporter. Two significant actions that cement the Province's strategy for achieving these conditions are dictated by the CEA: BC Hydro and BCTC are to be recombined and a significant reduction in the BCUC oversight of BC Hydro and BCTC will be implemented. Approval of over $10 billion in new capital projects (such as Site C and the Smart Metering initiative) will thus be outside the BCUC's purview. In addition, BC Hydro no longer has to file long term resource plans with the BCUC, but rather the recombined BC Hydro must fine an integrated resource plan with the government. The *CEA* mandates conservation targets for BC Hydro, whereby BC Hydro must acquire 66% of load growth to 2020 through demand side measures, up from 50% previously specified and requires (subject to ministerial regulation) that smart meters are installed at all BC Hydro customer premises by the end of 2012.

The *CEA* encourages the use of natural gas, electricity, and hydrogen for vehicles as alternatives to high GHG emitting fuels like gasoline and diesel. It is also supportive of alternative energy and biogas. The *Clean Energy Act's* new definition for "demand side measure" excludes electricity-to-gas fuel switching as an option, which could likely change customer's and public's perception of natural gas as a clean and efficient fuel to be encouraged. While this act does not promote the use of natural gas over electricity for thermal uses; neither does it preclude the use of natural gas over electricity, recognizing the important role that both energy types play in meeting B.C.'s energy and resource needs. With the current focus by the provincial government and media placed on electricity in B.C. being a renewable energy source there may be confusion about the role of natural gas among customers and stakeholders.

The *CEA* seeks to address a number of impediments in the existing legislative and regulatory framework to achieving the Province's goal of becoming a green energy powerhouse. However, much of what is expressed in the *CEA* is an extension of previously stated or referenced government priorities, many of which are discussed through the remainder of this section. The *CEA* also leaves open quite a number of areas for future determination through the issuance of regulations by the Minister or the Lieutenant Governor in Council.

2.2.3.2 Energy Plan 2007: A Vision for Clean Energy Leadership

On February 27, 2007, the B.C. government released a new Energy Plan: A Vision for Clean Energy Leadership, which continues to build on the policies that were outlines in the Energy Plan of 2002. The introduction of the Energy Plan in 2007 marked a significant change in the energy policy landscape in B.C. whereby the government demonstrated its commitment to the production of clean energy and reduction of GHG emissions in the province, by leveraging the province's key natural strengths and competitive advantages involving clean and renewable sources of energy. The Energy Plan of 2007 has the following goals and objectives:

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

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

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

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

e) Implement Energy Efficiency Standards for Buildings by 2010.

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

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

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

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

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.

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

Furthermore, in the Energy Plan, the government indicates its commitment to reducing GHG emissions from the transportation sector. The transportation sector is the largest source of GHG emissions in the province accounting for approximately 39% of the Province's emissions. Diesel and gasoline are the primary fuels used in the transportation sector and as such account for a significant portion of the GHG emissions as well as contribute to a reduction in air-quality in Metro Vancouver. Vehicle retrofit technology is available to convert vehicles to cleaner fuel sources. The Energy Plan highlights that "natural gas burns cleaner than either gasoline or propane, resulting in less air pollution,[63]" implying that the adoption of NGVs can play a role in helping the province reduce GHG emissions in the transportation sector.

[63] 2007 BC Energy Plan – A Vision for Clean Energy Leadership, p. 19

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.

2.2.3.3 Greenhouse Gas Reduction Targets Act and Offset Emissions Regulation

As part of the B.C. Throne Speech delivered on February 13, 2007, the government first announced targets for provincial GHG reductions. Effective January 1, 2008, the *Greenhouse Gas Reductions Targets Act* enshrines in law the provincial government's commitment to becoming carbon neutral, and sets province wide targets for GHG emissions reductions of:

- 33% from the 2007 level by 2020, and
- 80% from the 2007 level by 2050

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

- 6% below 2007 levels by 2012, and
- 16% below the 2007 levels by 2016

The *Greenhouse Gas Reductions Targets Act* made B.C. the first jurisdiction in North America to make a legally binding commitment to carbon neutral operations.

The Pacific Carbon Trust, acting on behalf of the Province of B.C., acquires GHG offsets from projects that are located in B.C. and that meet provincial eligibility criteria as defined by the Offset Emissions Regulation. The Emission Offsets Regulation received royal assent on December 3, 2008, under the provisions of the *Greenhouse Gas Reduction Targets Act.* The emission offsets 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 a carbon-neutral public sector. Offsets represent emission reductions or removals through projects such as renewable energy generation and energy efficiency initiatives.

2.2.3.4 Carbon Tax Act

In July 2008, B.C. government became the first jurisdiction in North America to introduce a consumer–based carbon tax. Through the use of price signals the carbon tax is intended to encourage consumers to reduce their use of fossil fuels and related emissions, thus influencing individuals and businesses to make more environmentally responsible choices. The *Carbon Tax Act* was introduced as creating a revenue-neutral carbon tax, and requiring the Minister of Finance to return carbon tax revenues to taxpayers through income tax cuts. The carbon tax is intended to apply to the retail purchase or use in B.C. of fossil fuels, including gasoline, diesel fuel, natural gas, home heating fuel, propane and coal. The initial tax rate was based on $10 per tonne of carbon dioxide-equivalent emissions released from burning the fuel, with increases by $5 per tonne over the following four years reaching $30 per tonne as of July 1, 2012. This Act added $0.50 per gigajoule ("GJ") to the cost of natural gas in the first year, rising to $1.50/GJ after 4 years from the date of implementation. It is projected that the tax will generate revenues of about $1.85 billion over the first three years. The carbon tax gives consumers in B.C. 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 GHG emissions reductions by 2020.

Potential for carbon tax increases and the level of tax beyond 2012 remain uncertain at the present time. However, in its report entitled "Meeting British Columbia's Targets: A report from the B.C. Climate Action Team", the Climate Action Team recommends the following:

> *"After 2012, if required to achieve the emissions targets, increase the British Columbia carbon tax in a manner that aligns with the policies of other jurisdictions and key economic facts"*[64].

There are some reports that indicate carbon taxes may need to go up to $300 per tonne in order to have a meaningful impact on consumer behavior and therefore reduce GHG emissions[65].

2.2.3.5 2008 Amendments to the Utilities Commission Act and DSM Regulation

In 2008, the B.C. government 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

64 Meeting British Columbia's Targets, A Report from the B.C. Climate Action Team, July 28, 2008, page 3

65 J & C Nyboer and Associates, Inc. A Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: A sectoral and regional analysis, dated August 22, 2008, prepared for National Round Table on the Environment and the Economy.

- to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation.

The Commission is required to consider government's energy objectives in the context of long-term plans, applications for a CPCN, applications for approval of expenditure schedules and energy purchase contracts.

A further regulation that is administered by the BCUC is the Demand-Side Measures Regulation. These regulations were approved by Order-in-Council No. M271/2008 on November 6, 2008. Key changes introduced by the regulation are:

1. A public utility's DSM 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;
    - 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.
    - An education program for students enrolled in schools in the public utility's service area
    - If the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area
2. The Commission considers a number of items in cost effectiveness of a public utility's DSM plan portfolio, including:
    - Cost effectiveness of a DSM proposed in an expenditure portfolio or a plan portfolio may compare the costs and benefits of the DSM individually, the DSM and other DSMs in the portfolio, of the portfolio as a whole.
    - The Total Resource Cost ("TRC") test must be used in determining cost effectiveness of DSM for low income households and in using the TRC test, the benefit of DSM to be 130% of its value.
    - Cost effectiveness of a specified DSM proposed in a plan portfolio or an expenditure portfolio must be determined by cost effectiveness of the portfolio as a whole.
    - Cost effectiveness of a public awareness program must be determined by the cost effectiveness of the DSM portfolio as a whole.

- The Ratepayer Impact Measure ("RIM") test cannot be used as basis for finding a program not to be cost-effective.

TGI and TGVI have been involved in EEC activities for some time and these programs have been successful in the past in promoting the efficient use of natural gas, encouraging the adoption of low carbon energy alternatives, reducing energy costs for customers, and supporting government policy by reducing GHG emissions. TGI and TGVI will continue to explore new area's of opportunity within this field as we have done recently with the 2008 EEC Application, which secured increased funding for EEC activities and programs, allowing for a broader set of programs to be rolled out to customers.

2.2.3.6 B.C. Climate Action Charter and Municipal Government Commitments

Under the *Greenhouse Gas Reduction Targets Act*, the B.C. government has made a legally binding commitment to become carbon neutral by 2012. Not only has the province of B.C. shown leadership in establishing challenging energy and climate change objectives, local governments from across B.C. have joined with the Province and the Union of B.C. Municipalities by committing to the British Columbia Climate Action Charter pledging to significantly cut GHG emissions by 2012 through carbon neutrality. Carbon neutrality will mean having no net emissions of GHGs, generally achieved through reducing GHG emissions where possible, by investing in projects that eliminate GHGs, and capturing and containing GHG emissions. As of January 20, 2010 - 177 local governments and the Islands Trust have now signed the Charter and these signatories commit to carbon neutrality in internal operations by 2012, measuring and reporting on community GHG emissions profile, and creating complete, compact, more energy efficient communities.

As a result of new policies and efforts to address global warming, municipalities are being compelled to reduce their carbon footprint and this sector's actions will further impact B.C.'s efforts in becoming a low carbon economy. However, there is a cost to these municipalities for reducing their carbon footprint and a lack of clarity as to what carbon neutrality means. In the absence of specific guidance as to how they should interpret it, many municipalities are facing struggles in achieving what they have signed up for. For example, the municipalities around Trail have committed to have their operations carbon-neutral by 2012, either by doing things internally or by purchasing offsets. However, there are outstanding questions about how this will be achieved, such as whether the city must also consider emissions by its contractors[66]. Furthermore, there are discrepancies between what the federal and provincial governments consider as carbon sequestering, including whether planting a tree counts towards reducing GHG emissions.

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[66] Trail Daily Times, "Carbon plans moving slowly". May 19, 2010. Retrieved from http://www.trailtimes.ca/article/20100519/TRAIL0101/305199958/carbon-plans-moving-slowly

The two largest municipalities in B.C. — Vancouver and Surrey — are examined to see how they are achieving carbon neutrality and their long term goals on reducing carbon footprint.

- **City of Vancouver: Green Capital**

The City of Vancouver has an action plan for becoming the world's greenest city by 2020. In order to progress toward an environmentally sustainable future, the City of Vancouver is developing plans—for the green economy, energy-efficient buildings, clean transportation, urban forest management, and so forth. The City's goal is to position Vancouver as a Green Capital – a hotbed of green commerce and innovation. The action plan focuses on three areas: 1) green economy and green jobs, 2) greener communities, and 3) human health. The following are the goals set in the City's action plan related to the green economy, green jobs, and greener communities:

1. Green Economy Capital: Secure Vancouver's international reputation as a mecca of green enterprise
    - 2020 Target: Create 20,000 new green jobs
2. Climate Leadership: Eliminate Vancouver's dependence on fossil fuels
    - 2020 Target: Reduce greenhouse gas emissions 33 per cent from 2007 levels
3. Green Buildings: Lead the world in green building design and construction
    - 2020 Targets: All new construction carbon neutral; improve efficiency of existing buildings by 20 per cent
4. Green Mobility: Make walking, cycling, and public transit preferred transportation options
    - 2020 Target: Make the majority of trips (over 50 per cent) on foot, bicycle, and public transit
5. Zero Waste: Create zero waste
    - 2020 Target: Reduce solid waste per capita going to landfill or incinerator by 40 per cent
6. Easy Access To Nature: Provide incomparable access to green spaces, including the world's most spectacular urban forest
    - 2020 Targets: Every person lives within a five-minute walk of a park, beach, greenway, or other natural space; plant 150,000 additional trees in the city

7. Lighter Footprint: Achieve a one-planet ecological footprint

    - 2020 Target: Reduce per capita ecological footprint by 33 per cent

The City of Vancouver's general strategy to achieve carbon neutrality from its own operations is to use best practices to reduce emissions from civic buildings, fleet, and solid waste and to offset remaining emissions by developing incremental, verifiable GHG reduction projects and programs in the local community.

The City of Vancouver is taking actions to become the greenest city by 2020. In following Vancouver's lead as the world's new Green Capital, other municipalities in British Columbia and elsewhere will adopt similar initiatives following in Vancouver's footsteps and leverage on opportunities that the City of Vancouver creates.

- **City of Surrey: Advancing Sustainability**

The City of Surrey, as one of the fastest growing municipalities in B.C., continues to work on becoming a greener and more sustainable city, positioning itself as a premier investment location and leader in the sustainability sector, specifically by becoming an appealing location choice for clean technology companies.

Surrey's Sustainability Charter is the first document of its kind in the Lower Mainland and is designed to guide the City's approach to social, cultural, environmental and economic sustainability.

The Sustainability Charter outlines specific goals for achieving the vision for and commitment to sustainability. As part of its sustainability initiatives, the city of "Surrey incorporates "Triple Bottom Line Accounting" into its operations, incorporates and encourages alternative energy sources, and strives for carbon neutrality and no net impact from waste". The City will seek ways to reduce the use of fossil fuels and to be carbon neutral, through a wide range of alternative energy sources that focus on renewable energy. These may include district heating systems, wind, active and passive solar, biomass, waste to energy and geo-exchange heating and cooling. Most resources will be produced locally, recycled or reused.

The increasing efforts of various municipalities to achieve carbon neutrality and to meet long term goals on reducing carbon footprint indicate that customers expectations on way of life are changing and thus companies, such as the Terasen Utilities, play an important role in bringing out the best practices and offering low carbon solutions and services for customers to meet the climate change objectives.

2.2.3.7 B.C. Bioenergy Strategy

On January 31, 2009, the B.C. Bioenergy Strategy was released by the Province (see Appendix A-3 for a copy of this strategy). In this document, the Province is focused on developing bioenergy resources in B.C. to enhance both the environmental and economic benefits for the people who live in B.C.[67] Bioenergy includes waste from landfills, water treatment plants and agriculture. TGI is moving forward in making these goals a reality with our recent biomethane application, which was filed with the BCUC on June 8, 2010. See Sections 3 and 6 for more details on this application.

2.2.3.8 B.C. Speech from the Throne (2010)

The February 10, 2010, B.C. Speech from the Throne re-emphasized clean energy as a cornerstone of B.C.'s Climate Action Plan to reduce GHG emissions[68]. It also highlighted that the government is pursuing clean modes of transportation, such as using vehicles powered by CNG and LNG.

2.2.3.9 B.C. Provincial Government and Municipalities: Summary

Public policies and government initiatives in B.C. have focused on encouraging clean energy to a large extend in response to the achieve GHG emissions reduction goals. These policies and initiatives emphasize lowering energy consumption and improving energy efficiency and conservation, and are keen in their search for and developing of alternative (and renewable) energy sources. However, the policy environment in B.C. could be interpreted by some stakeholders or customer s to favor the use of electricity over natural gas, a low carbon energy source that can be used in direct use application, electricity generation, and transportation sector. As more and more energy and climate change policies are implemented and refined, government, utilities, and stakeholders must continue their efforts to make sure public policy is clear and understood by all so that solutions can be found to achieve the established goals.

2.2.4 ENERGY AND CLIMATE CHANGE POLICY AND LEGISLATION: SUMMARY

Energy policy at all levels of government is increasingly focused on addressing climate change and the reduction of GHG emissions. Given that the climate is a concern across all jurisdictions and the energy sector has broader social, economic, and environmental impacts, which go beyond political boundaries within the region, energy planning and policies should be considered within a North American regional context.

Natural gas is expected to "act as the transition fuel towards a low carbon economy"[69] in North America and has an important role in long-term sustainability due to the advantages inherent in

[67] BC Bioenergy Strategy: Growing Our Natural Energy Advantage, page 5. See Appendix A-3.
[68] Legislative Assembly of British Columbia. Speech from the Throne. February 9, 2010. Retrieved from http://www.leg.bc.ca/39th2nd/4-8-39-2.htm
[69] CERI presentation. Climate Change & Natural Gas. April 2010. Presented by David C. McColl.

its physical properties (i.e. lowest emissions of the fossil fuels, no/low particulate matter, etc.)[70]. Elsewhere in North America, where energy needs are frequently met through burning coal or refined petroleum products, natural gas is recognized as a cleanest fossil fuel and consumers are encouraged to use gas in place of electricity. In B.C., by contrast, there is an abundance of renewable sources of hydro-electric generation. We must overcome the perception that electricity 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. Natural gas is also complementary to many of the renewable and alternative energy sources, such as geothermal and solar, that provide carbon intensity-reducing solutions for energy consumption. There are more sustainable solutions than using electricity alone, which result in lower net emissions and reduced energy use. These will be achieved by continuously seeking to employ each energy form in its highest and best uses across interconnected energy grids regardless of jurisdictional borders.

Natural gas is a clean, efficient, and abundant source of energy that plays an important role in the energy portfolio, whether it is used for direct application, electricity generation, transportation, or as a supplementary source for renewable and alternative energy. Recognizing this, the Terasen Utilities continue to evolve its customer offerings and integrating natural gas in its energy solutions to customers. These solutions promote the efficient use of energy and help customers reduce their carbon intensity. First, we have secured expanded funding to provide further EEC programs to our customers. Second, we have secured approval from the BCUC and customers to undertake integrated energy solutions (such as geothermal, solar and other technologies), in combination with natural gas within the regulated entity of Terasen Utilities. This ultimately will lead to a broader set of energy solutions for customers. Third, on June 8, 2010, TGI filed with the BCUC an end to end business model for the development and sales of Biomethane to our customers. This application, if approved, will provide our customers with lower carbon solutions. Fourth, as discussed in Section 3, we are working towards transportation solutions to provide CNG and LNG to customers.

Given that natural gas is a fuel of choice for a low carbon economy that can be used efficiently in direct applications for thermal energy, electricity generation, transportation, and as an integral source in alternative energy applications, we expect to see a growing demand for it and will therefore require the necessary infrastructure and resources to meet the demand. When energy 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. In this way, carbon reduction may be enhanced through appropriate energy choice.

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[70] Natural gas is widely referred to as transition fuel as it is the lowest emitting fossil fuel and an abundant flexible source of energy to support the move to a low carbon economy, because it can be used in direct use applications, to produce electricity, and in the transportation sector. This flexibility helps to reduce GHG emissions in an economic way by displacing higher carbon fuels.

3 LOW AND NO-CARBON INITIATIVES

3.1 Low Carbon Initiatives and Projects

Integrated, end-use energy solutions displace conventional fuels with low or no-carbon energy sources or systems. Terasen Utilities are pursuing integrated energy solutions in three important ways: renewable and low-carbon thermal technologies for homes, businesses and institutional facilities (the built environment); natural gas as a low carbon transportation fuel alternative to diesel and gasoline; and the development of carbon neutral biogas to displace conventional natural gas for homes, businesses and potentially in vehicles.

We believe it is in the best interest of existing and new customers that TGI provide both gas and integrated energy solutions. As such we believe that the requests set forth in this section should be approved to facilitate that development.

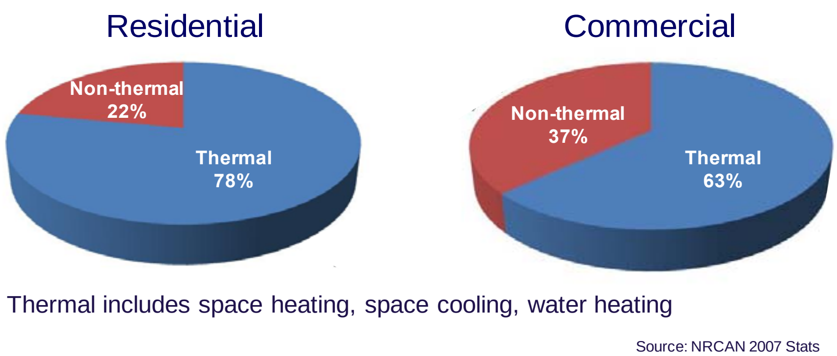
3.1.1 INTEGRATED ENERGY SYSTEMS FOR BUILDINGS AND COMMUNITIES

Geo-exchange, waste heat recovery, biomass and solar thermal energy systems are examples of integrated energy solutions that utilize thermal heating and cooling energy from the environment to replace or supplement traditional natural 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. The Terasen Utilities are now offering a full range of these types of efficient, low carbon intensity energy alternatives. We expect the amount of energy demand from these services to be small at first, but to grow substantially over time as more and more customers seek solutions from the utility to help reduce and manage the carbon footprint of the energy they use.

This section describes these renewable, thermal energy systems, how they meet the needs of our customers and our LTRP objectives, and the steps that the Utilities continue to take in developing the service offerings. The activities and resources described here have previously been introduced to customers, stakeholders and the Commission through the TGI and TGVI 2010-2011 RRA. Under the terms of the TGI and TGVI RRA negotiated settlement agreements, the costs of developing these systems will be recovered from integrated energy customers through future regulatory and rate setting proceedings specific to these services. As an important part of the Utilities' strategy to become an integrated provider of thermal energy services, these activities and resource needs form an integral part of the LTRP.

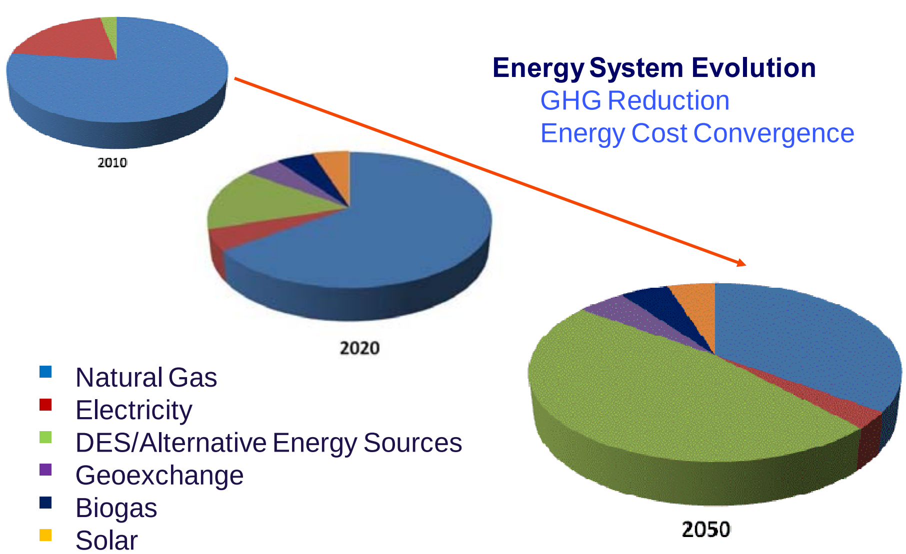
Geo-exchange and solar thermal energy systems are similar in that they utilize thermal heating and cooling energy from the environment to replace or supplement space heating and cooling and water heating served by traditional gas and electrical energy systems. District energy systems use a variety of energy sources, including traditional heating sources such as gas and non traditional sources like geo-exchange, heat recovery from industrial processes and waste management systems, biomass and solar thermal systems to deliver both heating and cooling to the end use customer. As indicated by Figure 3-1, since the bulk of energy supplied to large groups of our customers serve thermal uses, these systems have the potential to provide large portions of the province's energy needs.

Figure 3-1: Thermal vs. Non-thermal Energy Demand in B.C.



Integrated energy systems are a key part of the Terasen Utilities low carbon strategy to help existing and future customers alike cost effectively reduce the carbon footprint for their energy needs, and help meet B.C.'s overall GHG emission reduction targets. Figure 3-2 conceptually shows the important role that integrated energy will play in meeting the thermal energy and GHG reduction needs of our customers.

Figure 3-2: Transformation of Thermal Energy Delivery in B.C.

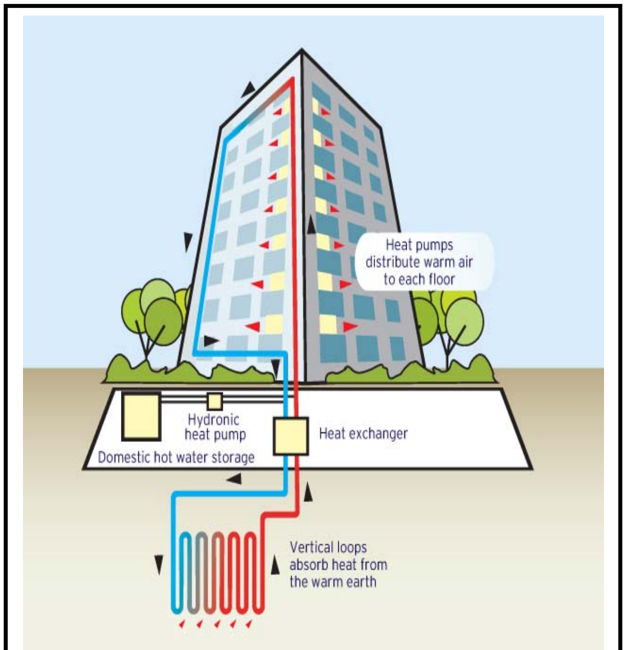


3.1.1.1 Description of Typical Integrated Energy Systems and Infrastructure

Renewable, thermal energy systems employ energy sources in variety of combinations, almost always relying on conventional energy systems to provide back-up and peaking energy service. Designing an integrated energy system that can provide 100% of peak thermal energy requirements presents both technical and economic challenges. Often, a single renewable energy source such as geo-exchange will be combined with conventional natural gas service. Multiple renewable systems can also be employed in combination with the conventional energy. For example, geo-exchange systems can provide space heating and cooling while a solar-thermal installation can provide a portion of the domestic hot water needs to the same multi-family or multi-use building. District energy systems can employ multiple energy sources and systems to balance the heating and cooling needs for a community with many end use needs. While geo-exchange and solar-thermal systems can be designed to serve single family homes, the Utilities are focusing our initiatives on larger multi-unit and district energy systems. The following descriptions of some of the systems provides an understanding of the types of equipment or infrastructure involved.

- **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[71]. 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.



[71] Typically geo-exchange systems are designed to provide 50-80% of the heat with the remaining heat provided for by a gas boiler

➢ Solar-Thermal

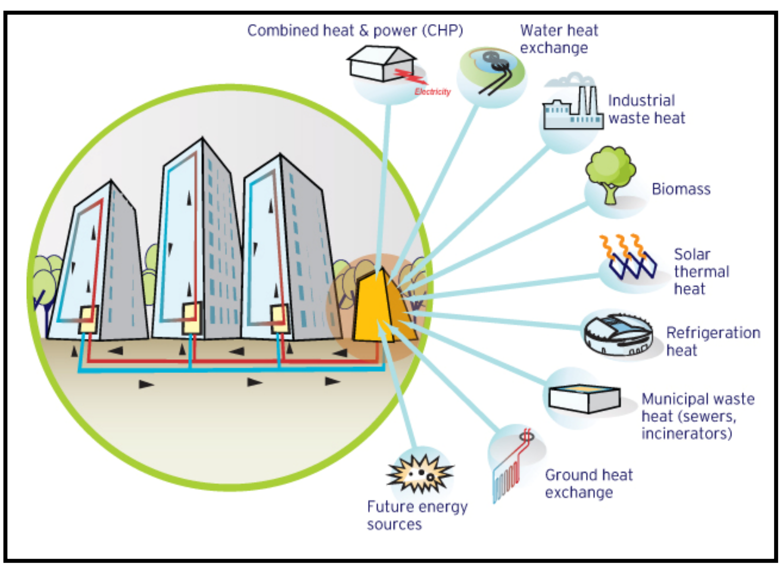
Solar-thermal water heating systems, also called solar hybrid water heating systems, are more typically used to supplement traditional gas and electric energy systems that supply domestic hot water, improving the efficiency and lowering the carbon intensity of the traditional systems. A system of solar 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.

➢ 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.

3.1.1.2 Target Market

- **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, multifamily 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.

- **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.

> **Quesnel Community Energy System: First of its Kind in North America**
>
> As of July 2010, letters of intent has been signed for the Quesnel Community Energy System, a biomass system that will generate ***both heat and power*** by capturing waste heat and left-over residues from an existing sawmill.
>
> **Participants**
>
> - Terasen Gas Inc.
> - The City of Quesnel
> - West Fraser Mills Ltd.
> - BC Hydro
>
> **Costs**
>
> Approximately $14 million in capital costs
>
> **Benefits**
>
> Based on 1.7MW of power production and heat service to 14 buildings initially, the QCES will:
>
> - Reduce greenhouse gas emissions by 6,000 tonnes per year.
> - Produce 81,000 gigajoules per year of carbon-neutral heat.
> - Generate 14.2 gigawatt hours per year of clean electricity.

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.

3.1.1.3 TGI's Next Steps in Delivering Integrated Energy Services

TGI will continue to provide integrated energy products for our customers. In order to achieve this TGI will:

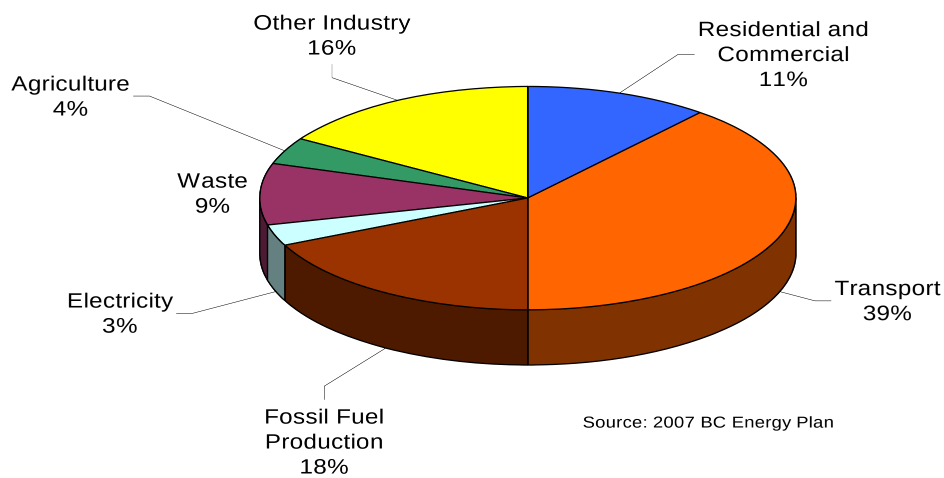
- continue to work with customers in defining and developing their integrated energy needs;
- develop business, regulatory and operational models in which to deliver integrated energy to our customers; and
- submit an application to the Commission which will seek approval of an overall business and regulatory model and seek CPCN approval of specific projects.

3.1.2 NEW NATURAL GAS VEHICLE SOLUTIONS

The Terasen Utilities' customers are seeking integrated, low carbon energy solutions that can help them to manage their energy costs and minimize their carbon footprint. New and complete natural gas vehicle solutions are a vital opportunity for the Utilities to serve these needs and help reach the impressive GHG reduction targets legislated by the Province. This section provides background on NGV technology in B.C., identifies the need and availability of incentive funding for vehicle purchases to spur development NGV solutions, describes the strategy behind new solutions being developed by TGI and presents TGI's intention to bring forward a an application to the Commission for more complete transportation fuel service offerings.

The Utilities see the development of new NGV services, programs and markets as a key part of its low carbon strategy to help meet both the changing needs of our customers and the GHG reduction targets legislated by the Province. The transportation sector is responsible for more energy use and carbon emissions than any other sector (Figure 3-3). As such, it provides B.C.'s biggest opportunity to contribute to a global reduction of carbon emissions and other pollutants over the next 20 years. TGI is developing new NGV solutions that will capture this opportunity for emission reductions, as well as provide an important source of load growth on the Terasen Utilities systems to help optimize system throughput for the benefit of all customers.

Figure 3-3: B.C. Greenhouse Gas Emissions by Sector



Natural gas is a lower carbon alternative to conventional diesel and gasoline and can therefore play a much greater role in this sector than it has historically, improving emissions, reducing reliance on oil and supporting technology development in B.C. Using natural gas instead of conventional fuels reduces GHG and other emissions, such as oxides of nitrogen, sulphur oxides, carbon monoxide and particulate matter. Furthermore, using natural gas for transportation application significantly reduces the customers fuel cost. To capture this benefit, customers must make significant investments in vehicles and equipment that can use natural gas. Given the financial risks, customers are looking to the Terasen Utilities as a trusted partner that can be depended upon to deliver the energy they need for years to come. We believe that the greatest near-term potential to deliver these solutions is in the return-to-base, fleet vehicle market.

As described in Section 2, natural gas is well positioned to compete against conventional fuels which dominate the market for transportation. Low carbon transportation fuel requirements have been legislated, the fuel price advantage for natural gas over conventional diesel and gasoline has improved further, all levels of government are increasing their focus on reducing transportation related emissions and proven technology ready for commercial use is readily available. The Utilities believe that NGVs have a viable and important role to play in the B.C. transportation fuels.

➢ **Natural Gas Vehicles**

NGVs look like any other vehicle. The difference is NGVs operate on natural gas rather than the fuel we typically pump into our vehicles' tanks. Clean Energy Fuel Corp. offers the following summary:

"NGVs typically use one of two varieties of natural gas: Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG). CNG is the preferred fueling method for light to medium NGVs, Heavy-duty NGVs with weight and range requirements typically fuel up on LNG, which allows them to store more fuel on board with less tank weight. L/CNG stations can service both types of NGVs by converting LNG into CNG"[72]

In general terms, the benefits of NGVs are:

- Better for the environment, with significantly lower CO2 (carbon dioxide), NOx (nitrogen oxide) and greenhouse gas emissions than the majority of existing vehicles on the road today
- Lower fuel cost - 25 to 50 per cent less than the pump price for gasoline
- Lower maintenance costs - natural gas burns cleaner so engine parts stay cleaner
- A natural resource, produced here in B.C. and elsewhere in Canada

Data from Natural Resources Canada indicates heavy-duty NGVs emit 19-29 % less GHGs than their diesel counterparts. Light-duty vehicles emit almost 30% less GHGs compared to their gasoline equivalents. NGVs also emit 50-80% less air quality contaminants such as NOx, SOx and particulate matter[73].

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72 http://www.cleanenergyfuels.com/ngvs_what.html
73 Emission comparisons cited here are available from NRCan GHGenius modeling software available at: http://www.oee.nrcan.gc.ca/transportation/tools/greenhouse-gas-info.cfm?attr=16

The methodology adopted within the provincial regulation combines measures of the base carbon intensity of the fuel with measures of the efficiency of the engine technology that is used with the fuel. This results in an effective Carbon Intensity in use. CNG has a carbon intensity approximately 38% lower than gasoline and 28% lower than diesel. LNG's carbon intensity is roughly 43% lower than gasoline and 34% lower than diesel[74].

3.1.3 BACKGROUND ON NATURAL GAS VEHICLE SOLUTIONS IN B.C.

Historically, NGV programs in B.C. were focused on the passenger vehicle market through the development of public fueling stations. In 1997 there were 51 public fueling stations in operation in B.C. NGV sales peaked in 1999 reaching 609,000 GJ. Since then, this market has declined due primarily to:

- Lack of OEM vehicle availability - OEM manufacturers exited the market in the 2000/01 time period.
- Unreliable Conversion Technology - Vehicle conversions became more complex with the introduction of electronic engine controls and more sophisticated pollution abatement technologies. After-market conversion technologies had challenges providing reliable vehicle solutions.
- Lack of Support from Fuel Vendors – NGV station providers focused efforts on development of markets in other jurisdictions such as the U.S. market.
- Passenger Vehicle Market Focus – The focus on passenger vehicle markets is more difficult to support as it relies on the development of public fueling infrastructure.
- Modest Price Advantage – In the early part of the decade the pricing advantage of CNG was more modest that it is at present.

Currently, TGI continues to offer NGV Service and modest levels of vehicle incentive grants through Rate Schedule 6. TGI also received approval for the sale of LNG under Rate Schedule 16, Interruptible Liquefied Natural Gas and Dispensing Service[75], effective June 15th, 2009. This rate schedule provides assurance of supply and cost certainty to fleet vehicle and LNG refueling station owner-operators, initiating the development of a new NGV market. LNG sales originate from the Tilbury LNG storage facility in Delta, complementing its existing usage.

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74 Low Carbon Fuel Requirements Regulation Intentions Paper for Consultation http://www.empr.gov.bc.ca/EEC/Strategy/BCECE/Documents/LCFRR%20Intentions%20Paper%20Final.pdf

75 BCUC Order No. G-65-09

➢ **New Incentive Funding**

Vehicle funding to help offset the incremental capital cost of NGVs is a critical driver that motivates customers to adopt natural gas as a transportation fuel. The Terasen Utilities received approval for $2.3 million in 2010 and $4.7 million in 2011 for Innovative Technologies to advance emerging technologies. Since the Innovative Technologies portfolio was formulated, TGI has made progress with some of the technologies, particularly to support implementation of NGV technology. For more information on the Utilities' Innovative Technologies portfolio, see Section 5.

Terasen's Environmental Leadership in Action: NGV Fleets

Terasen has incorporated using NGVs for company's fleet vehicles as NGVs, such that fuel savings and the most optimal emissions profile for the company is attained.

Terasen leases or purchases vehicles equipped to operate on natural gas fuel by the original equipment manufacturer if available. Otherwise, Terasen converts units to operate and run on natural gas using aftermarket conversion kits.

TGI has initiated a pilot incentive program to encourage operators of heavy duty fleets such as garbage trucks and waste haulers to switch to natural gas from higher-carbon diesel. TGI has received expressions of interest from the City of Vancouver, City of Surrey, City of Port Coquitlam, and other third party partner. to use the EEC funding to purchase new natural gas vehicles for garbage collection and transfer operations. Under the provisions of the pilot program, the fleet operators would be reimbursed for the incremental cost of the NGVs over conventional vehicles. TGI expects to assist with funding the adoption of 16 and 32 heavy duty diesel trucks in 2010 and 2011 respectively.

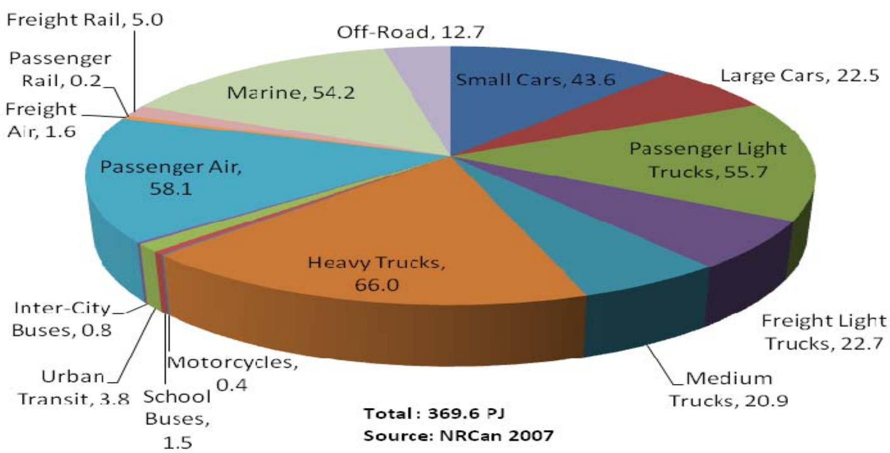
This penetration is based on current cost estimates, allocated funding levels and expression of interest from prospective customers. It should be noted that in the absence of such funding, these operators were not able to commit to NGVs. The higher initial capital cost of NGVs is a significant barrier to adoption in transportation markets but once this is overcome the operator will receive the benefits of lower operating costs and reduced emissions. The success of the initial offering of this program demonstrates there is a strong correlation between incentives and adoption and awareness for emerging technologies. Terasen Utilities believes that the need for such incentives will decline as NGVs gain greater share of the market and the capital cost premium for NGVs declines with volume.

3.1.4 TERASEN UTILITIES NGV STRATEGY

➢ **Target Market**

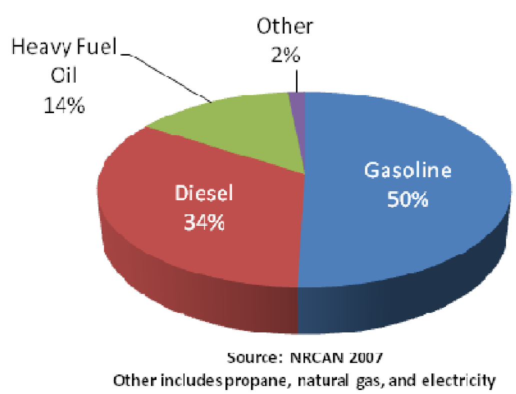
The Terasen Utilities believe the near-term opportunities for natural gas in the transportation sector in B.C. are in the return-to-home applications where commercial fueling technology exists for industrial use vehicles such as light, medium and heavy trucks, waste haulers, as well as bus fleets. Long-term opportunities may exist in marine passenger vessels and in new light-duty passenger vehicle technology. The total transportation sector fuel usage was 370 PJ in 2007 as shown by category in Figure 3-4. Of this total, the target markets that TGI has identified make up 290 PJ. TGI expects natural gas demand from its new NGV solutions to grow to 30 PJ or 6.5% of this total market by 2030. NGV target market segments and demand scenarios are discussed further in Section 4.3.

Figure 3-4: Total B.C. Transportation Market Sector Energy Use by Category (PJ)



The target market can also be broken down by fuel type as shown in Figure 3-5. Gasoline represents 50% of the target market and is consumed primarily in the passenger car and light duty truck segments. Diesel fuel is consumed primarily in the heavy duty and vocational trucking segments. Nearly two-thirds of TGI's NGV growth targets are focused on the high mileage, heavy duty truck segment, where diesel fuel occupies 100% of the market.

Figure 3-5: Terasen Utilities NGV Target Market by Fuel Type



➢ Vehicle Availability

Heavy duty, vocational fleets (ie. garbage trucks), and transit buses can be serviced and supported through an existing dealer network. OEM product offerings exist in the heavy duty segment from manufacturers such as Kenworth and Peterbilt, in the transit segment from New

Flyer, and in the vocational truck market from Crane Carrier, Autocar, Freightliner, and Mack. The light duty and medium truck segments are more challenging. At present the approach being utilized within the TGI fleet is to purchase OEM equipment that is factory prepared and certified to be "NGV Ready" for subsequent conversion by qualified aftermarket conversion suppliers. This approach is presently offered by Ford on a variety of truck and van models. General Motors has also announced a return to providing OEM Natural Gas ready vehicles.[76] Additionally, the marine segment has OEM manufacturer availability from Rolls Royce and Wartsilla.

Focus on Commercial and Fleet Vehicles

TGI aims to concentrate on commercial and fleet vehicles that operate out of a single location, or between a limited number of points. A constrained service area makes the refueling investment more manageable. The medium and heavy duty truck segments, as well as transit buses consume high amounts of fuel. Specific consumption level expectations are described in Section 4.3.

The business strategy should focus on fleet vehicles that can be economically served by a minimal number of fueling stations. This implies a focus on "return home" fleet vehicles and vehicles that operate between a limited number of destinations (e.g. ferries or long haul trucks that travel from point to point.

Fueling – A Complete Offering

A successful development strategy will need to provide a complete offering to the fleet customer. TGI's strategy will require extension of the service offering to provide fueling station assets and services. For CNG applications, a compression, storage and dispensing service needs to be added. For LNG applications, a local storage and dispensing service needs to be added. TGI has been exploring this market place for some time now and to date, no other businesses are stepping forward to fulfil this role in B.C..

The task of establishing fueling infrastructure is not trivial and requires experience and expertise with respect to compressed gas facilities and/or cryogenic fuels facilities. The provision of these services is consistent with TGI's role as a trusted supplier of energy products and services and should be part of our service offering.

As discussed above, provision of fueling services is a key element of TGI's new NGV strategy. We propose the addition of services for both CNG and LNG fueling stations.

- CNG - Compression, high pressure storage, dispensing and metering assets
- LNG - Cryogenic storage, dispensing and metering

[76] Oilweek magazine June 2010: http://www.oilweek.com/articles.asp?ID=732

The assets provided for each station are different but the service and proposed rate model are the same.

By providing commercial fleet customers with an offering that is readily comparable to their existing fuel products (ie. gasoline, diesel), the benefits of NGVs may be easier for customers to understand. For commercial fleet customers, this means providing a single bill from a single vendor which includes all service up to the point where fuel is delivered into the tank.

TGI is presently exploring project proposals with the City of Port Coquitlam and another third party interest. These projects involve heavy duty vocational trucks that run on CNG. The aforementioned parties communicated to TGI that trucks would use approximately 1100 GJ/unit/year over an average total distance of 40,000 kilometers per vehicle per year.

In 2009, TGI, Westport Innovations, and IMW Industries combined with Wastech Services Ltd. for a pilot project where solid waste was transported using heavy duty LNG garbage trucks, from Greater Vancouver to the Cache Creek landfill[77]. The results of the study concluded that the NGV trucks would consume up to 9,500 GJ/unit/year over an average total distance of 389,000 kilometers per vehicle per year. TGI is also exploring a potential project with the City of Vancouver's fleet of waste transfer vehicles. These vehicles consume approximately 1,500 GJ per year operating approximately 80,000 kms per year. It is expected that fleets with high mileage are more likely to convert to LNG operation as the operating cost savings will be greater for these fleets. Given the range of potential fuel consumption and the propensity for LNG customers to be high mileage applications, TGI believes that 2,500 GJ/truck/year is a reasonable estimate for average heavy duty vehicle fuel consumption.

3.1.5 CONCLUSIONS AND NEXT STEPS FOR NEW NGV SOLUTIONS

TGI's new NGV initiatives can provide substantial GHG and other emission reductions from the largest emitting sector in B.C. The transportation markets we are targeting (light, medium and heavy duty trucks, transit, marine fleets and potentially rail) emit almost 50% of transportation related emissions in B.C. These initiatives can help our customers manage their costs and carbon footprints, and help meet the Province's emission reduction targets. Our low carbon fuel strategy targets return-to-base fleet vehicles for CNG solutions where fueling infrastructure economics make sense and vehicle ranges can match fuel capacity. Transport industry fleets with large engines present LNG solution opportunities where larger fuel capacities are needed for heavy duty or longer haul operations. Marine and rail fleets offer future LNG fueling opportunities.

The Terasen Utilities have a role to play in removing the barriers that will enable the development of an NGV industry in B.C., which will help new customers reduce their GHG emissions in a cost effective manner, while providing benefits to existing customers by

77 http://www.wastech.ca/uploads/media%20material/090507_Wastech_LNG_mediapkg.pdf

improving the utilization of the existing natural gas infrastructure. The Utilities expect to grow demand in its NGV target market to 30 PJ annually by 2030. NGV solutions must be complete solutions, however, and provide the customer with service that allows them to directly fuel their vehicles and equipment without the need for them to supplement a portion of the service, or risk the unwillingness to participate in this important opportunity.

TGI intends to bring forward an application to the Commission in the summer of 2010 for approval of more complete transportation fuel service offerings. That application will include the requirement for and appropriate treatment of CNG and LNG fueling infrastructure being sought from the Utilities by existing and potential future customers. Extension of a more complete NGV service to the TGVI and TGW service territories is contemplated at a later date pending future unbundling of gas delivery rates for these utilities.

More Opportunities for Compressed Natural Gas:
Napa Valley Wine Train Example

The Napa Valley Wine Train started a program for the experimental conversion of a Napa Valley Wine Train Alco locomotive to 60% natural gas and 40% diesel fuel mixture. In 1999 the conversion became permanent. A total conversion of locomotive 73 was completed and it was put into service using 100% Compressed Natural Gas on in 2008.

Source: http://winetrain.com/about/our-train

3.1.6 CARBON NEUTRAL BIOMETHANE OFFERING

Biogas is a readily available supply of renewable gas from landfills, sewage treatment plants, food waste, and agricultural operations. Established technology exists that can be used to upgrade biogas to biomethane, which has characteristics that make biomethane a reliable and safe substitute for natural gas. Moreover, biomethane is a renewable fuel. The production and consumption of biomethane is considered carbon neutral. The use of this carbon neutral fuel in place of a carbon positive fuel such as natural gas results in a net reduction of GHG emissions as well as other environmental and economic benefits for potential biogas producers throughout the province. This offering to customers promotes government's energy policy objectives favoring the use of renewable energy, the efficient use of energy and reducing GHG emissions. More importantly this product offering and business model meets the needs of our customers. TGI's biogas initiative also helps create green jobs and industry within B.C. and can help improve the sustainability of waste management practices in many of the provinces regions and industries.

In its 2008 Resource Plan, Terasen Utilities identified the development of biogas supply and sales as an important initiative and action plan item. Today, two separate supply projects are under way, and a TGI application to the BCUC for approval of a comprehensive, flexible, end to end biogas supply and sales tariff program is now in a regulatory review process[78]. TGI intends to continue developing biogas supply resources and extending its green gas offering to more customers as supply and demand growth allows.

Market research completed in 2010 suggests that our customers have a strong desire to purchase renewable clean energy from the Utilities. TGI's biogas projects and low carbon fuel (or "Green Gas) offering is a way to align our service offerings in order to fulfill our customers' desire to be part of the solution in meeting changing environmental issues. The data collected by the Utilities shows that large numbers of residential and commercial customers want to use biomethane, far more customers than TGI believes it can serve during the initial stages of its biogas initiative. The development of biogas supply and a Green Gas offering to customers will help us meet the demands and expectations of customers.

The development of renewable energy is more advanced in the electricity industry in B.C. than it is in the natural gas industry, in terms of both the quantity of supply developed and the business models and contractual arrangements supporting the industry. The heavy policy focus in B.C. on developing renewable electricity resources combined with the existing extensive hydro-based Heritage electricity resources create the public impression that B.C. electricity is the only "green" and environmentally-preferred energy source. In these circumstances it is becoming more difficult for natural gas to compete on an environmental basis.

In response, TGI plans a measured, phased, flexible and scalable that balances supply and demand for biomethane through a Green Gas offering. TGI believes that offering a renewable energy product will help meet customer demand for environmentally friendly options. Further, it will help to establish a path forward for complying with any future mandatory requirements for including renewables in a utility's energy mix, if and when renewable portfolio standard or similar regulation may be established for natural gas utilities in B.C..

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[78] TGI's Application for Approval of a Biomethane Service Offering and Supporting Business Model, for the Approval of the Salmon Arm Biomethane Project and for the Approval the Catalyst Biomethane Project was submitted to the BCUC on June 8th, 2010.

3.1.6.1 Three Types of Voluntary Green Pricing Programs

The term "green pricing" is used in reference to utility programs in which utility customers pay a premium to have a portion of their energy come from a renewable energy source. Utilities use these funds to invest in renewable energy development or purchase carbon offsets on behalf of their customers to offset GHG emissions associated with their energy use. In recent years, a number of different models have been developed by public utilities in Canada and the U.S. to deliver green products and pricing to customers. In this section, TGI provides an overview of the types of voluntary[79] green business models or programs that have been employed in North America, discusses participation rates in North American voluntary programs based on certain green pricing premiums, and reviews a few specific examples of green pricing programs in North America. This discussion provides the context and background for the Utilities' proposed demand-side business model discussed later in this section.

There are three main types of programs that are being offered in the voluntary renewable energy market: contribution programs, energy-based programs, and offset programs.

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

- **Energy-based Programs:** The second and most successful are the energy-based programs. This type of program allows customers to choose a selected amount of energy to be supplied from renewable sources for a premium. Typically green pricing programs are structured so that customers can either purchase green power for a certain percentage of their energy use (often called "percent-of-use products") or in discrete amounts or blocks at a fixed price ("block products"), such as a 100 kWh block of electricity.

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

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

Biogas projects, wind projects, and/or solar projects within their jurisdiction or service territory.

Utility green pricing programs in the U.S. have grown significantly over the past decade. A 2007 Chartwell report indicated that 58% of utilities surveyed had some kind of green pricing program[80]. The National Renewable Energy Laboratory (NREL) reports that more than 850 utilities in the U.S. have some sort of green pricing program[81]. The vast majority of programs offered are for renewable electricity programs, however, gas utilities are now entering the arena as a way to respond to consumer demand to reduce their carbon footprint. TGI has concluded that, among the three voluntary green pricing models in use in North America, and supported by the primary research (see following section), a renewable energy-based program is appropriate for its customers at this time.

3.1.6.2 Demand in B.C.

TGI commissioned TNS Canadian Facts[82], one of Canada's largest marketing and social research firms, to conduct a primary market research study to validate and evaluate the potential customer demand for a biogas program in B.C., its market drivers, and factors affecting different price points. Two comprehensive studies (herein after referred to collectively as the "Study") were conducted (between November 2009 and January 2010) of B.C. households and businesses to understand consumer demand specific to biogas and aid in the development of a Green Gas program. Detailed findings of the Study can be found in Appendix B-9 (Biogas Market Summary Report). A summary of the results of this Study that assisted TGI in coming to the following determinations on the framework for a Green Gas offering are discussed below.

3.1.6.2.1 Demand in B.C. Terasen Utilities' Conclusions Regarding Program Design

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

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

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80 Chartwell, Helping Customers Live a Sustainable Lifestyle, May 2007
81 NREL, Green Power: Marketing in the United States: A Status Report (2008 Data)
82 TNS Canadian Facts is one of Canada's largest marketing and social research firms. TNS was established as Canadian Facts in 1932 as the country's first survey research organization. Today, they have offices in Toronto, Montreal, Ottawa and Vancouver, with 170 full-time members of staff.

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

Targeting residential customers in the initial rollout is reasonable, since residential customers indicate a higher participation potential (16% vs 10% for commercial) and have greater certainty around use rates in order to better manage supply and demand imbalances. TGI proposes to expand the Green Gas offering to the commercial market once Biogas supply is further established and experience has been gained with the program in the residential market.

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

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

In summary, TGI believes that the market research that has been done demonstrates that customers are very supportive of Terasen Utilities developing biogas supply resources and providing a renewable product offering.

3.1.6.3 Key Elements of Proposed Green Gas Business Model

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

- TGI proposes creating a new Biomethane Tariff, similar to TGI's Standard Rate, to allow eligible customers to either remain on the standard commodity rate or to select the TGI's Biomethane Tariff which will be a specific blend of biomethane and conventional natural gas (for Phase 1, TGI proposes a blend of 10% Biomethane and 90% conventional natural gas).

- Gas Marketer rules and functionality that are part of the Customer Choice program will remain unchanged as the customer will continue to have choice of commodity supplier between a Gas Marketer's fixed rate and the TGI variable rate.

- The number of customers eligible to participate in the Customer Choice program will not be impacted and the Gas Marketer base load requirements will be calculated based on the same methodology that exists today. This methodology is defined as the Monthly Supply Requirement or MSR.

- By electing to remain with TGI as the commodity supplier, a customer may choose to remain either on the standard rate (e.g., TGI Standard Rate Schedule 1) or they may select the Biomethane option (TGI Rate Schedule 1B), which is understood to be a specific blend of Biomethane (eg. 10% Biomethane; 90% conventional natural gas).

- Biomethane rates will typically be set on a forecasted 12 month period and the non-biomethane commodity tariff rate will remain subject to quarterly rate adjustments. The Biomethane Residential Tariff, will be an open tariff like the TGI Standard Rate Schedule 1[83]

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

3.1.6.3.1 <u>Phased Product Offering Strategy</u>

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

Phase 1 is expected to launch in Fall 2010, and is generally targeted at residential customers. The objectives of the initial roll-out of the Green Gas program will be to validate producer reliability and consumer interest. These objectives will be carried out by a flexible, simple, cost effective business model solution. The objective of market validation is addressed in Phase 1 by targeting the Green Gas offering at residential customers. TGI's research shows the highest uptake potential in the residential market; therefore, this sales model will allow for the maximum participation in a Green Gas offering while minimizing billing system impacts in the near term with one tariff. Leading with a single product (a 10% blend) will allow for tighter control over the number of enrolments and will match the limited supply in the first year. Actual residential customer use rates have a tighter range around an average than commercial customers, which will help to predict total consumption for residential customers who enrol in the program.

Phase 2 is currently anticipated to begin in the first quarter of 2012, will expand the product offering to match demand once supply has been further established and the Utilities new Customer Information System ("CIS") is in place so as to minimize unnecessary incremental costs associated with an additional tariff offering. This phase is foreseen to be launched around the first quarter of 2012. This phase will see the roll-out of a Commercial Green Gas offering to Rates 2 and 3 (called 2B and 3B), as well as higher blends from the currently

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[83] The Company's research of other green pricing programs elsewhere in North America found that the majority of green pricing programs offered by utilities have open entry and exit dates for residential customers. Source: NREL, Green Power: Marketing in the United States: A Status Report (2008 Data)

proposed 10%. There is also some support for higher-percentage blends and offerings to small commercial customers as demonstrated in the supporting documentation. In addition, larger commercial customers and industrial customers have informally voiced interest in being included in a future expanded Green Gas program.

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

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

3.1.6.4 Projected Demand

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

- Ramping up to the industry average participation rate of 2.2%[84]; and
- Ramping up to the potential market share identified in the primary research Study of 16% for residential customers and 10% for commercial customers.

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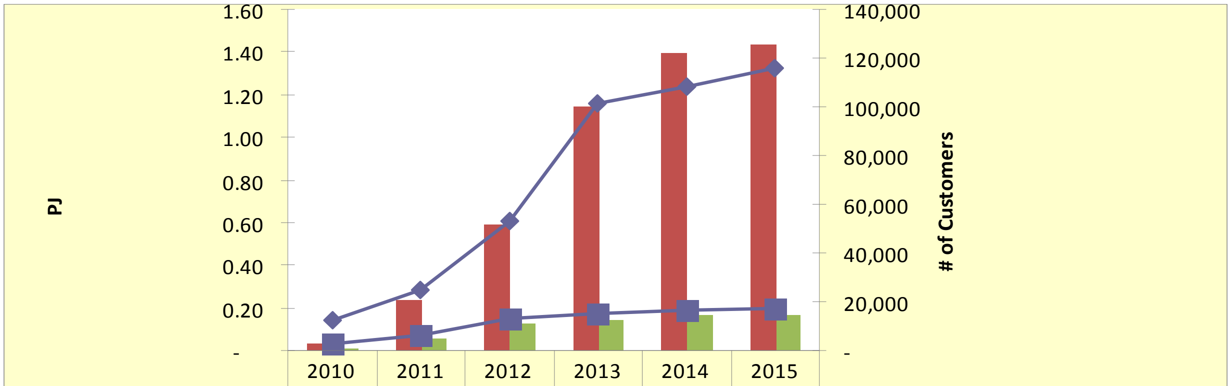
[84] NREL, Green Power: Marketing in the United States: A Status Report (2008 Data)

Figure 3-6: Low and High Demand Scenario



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

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

3.1.6.5 Low Carbon Fuel ("Green Gas") Conclusions and Recommendations

Biogas is a renewable energy source that can be upgraded to carbon neutral Biomethane. When Biomethane is injected into Terasen Utilities distribution system it offsets the use of natural gas and reduces GHG emissions. Terasen Utilities, as the major natural gas utility in British Columbia, is uniquely positioned to promote the development of Biogas upgrading in B.C. The proposed Green Gas Offering allows for a phased approach to gauge consumer demand and drive supply project initiatives that can be expanded to customer groups as supply builds. Success of the program will be monitored closely and development of additional blends and expansion to other service territories could unfold over time.

In Summary, the Green Gas offering represents a significant first step in the development of Biogas as a new source of renewable energy to meet TGI's customers' needs. This offering to customers promotes government's energy policy objectives favoring the use of renewable energy, the efficient use of energy and reducing GHG emissions. TGI has a role to play in helping develop this industry that otherwise might not develop without utility support.

3.1.7 OTHER LOW CARBON AND RENEWABLE ENERGY SOLUTIONS

The Terasen Utilities will continue to explore new technologies and test their appropriateness for inclusion as part of our low carbon initiatives. Combined heat and power, generating electricity from waste heat at our compressor stations, advanced metering and other emerging technologies continue to show promise for potential future applications within the Utilities' integrated, low and no carbon portfolio of energy solutions. Customers are looking for Terasen Utilities to provide these solutions as we transform into a complete, integrated energy provider.

Some technologies may also prove to be disruptive, rather than complimentary to the Utilities core natural gas service offerings. The Utilities research and investigations will seek to uncover these challenges as well as market opportunities to add to and improve on the secure, reliable and cost effective energy services we provide.

4 MARKET TRENDS AND ENERGY FORECASTING

4.1 Introduction

A key stage in planning the future resource requirements for the Terasen Utilities is the development of customer and energy demand forecasts that provide insight into the amount of energy we need to provide and the load characteristics that our energy systems must be designed to meet. We must be able to acquire and deliver the total quantity of energy our customers will need throughout the year, adjusting for seasonal variations and changing market conditions. The primary design factor for system infrastructure and supply resources is the need to meet short term spikes in demand that are primarily weather driven. The forecasting process looks ahead over the planning horizon so that we are acting now to ensure we can cost effectively meet our customers' energy needs in the future.

Traditionally, the Utilities forecasting efforts have been focused on natural gas customer and demand outlooks to support supply, infrastructure and financial planning. Our traditional natural gas customer and demand forecast remains a primary function and are based on long standing methodologies that have been examined by stakeholders and evaluated and accepted by the Commission through numerous regulatory review processes. These traditional, accepted methodologies continue to underpin the examination of natural gas resource needs for the Utilities. Section 4.2 describes the methodologies used to develop our traditional demand forecast and provides an update on the natural gas customer and demand outlook over the 20 year planning horizon.

The Terasen Utilities have also now embarked on a broad range of new, alternative energy solutions to help customers manage both their energy costs and the environmental footprint of their energy demand. We have therefore identified a need to develop new ways to forecast energy demand for this wide range of customer end-use alternatives. Implementing renewable thermal energy alternatives, enhanced energy efficiency and conservation programs, and low carbon transportation fuel solutions will have an impact over time on demand and required infrastructure for conventional natural gas and electricity service. These new initiatives will also have infrastructure and other resource requirements that need to be met as their market penetration and demand grows. While these initiatives are not expected to have a marked impact on conventional energies in the short term, the Utilities expect to see a growing rate of change in customer behaviour, energy choice and energy consumption. Today, the Utilities are in the process of developing new methodologies to accommodate the shifting trends we expect to see emerging.

Section 4.3 examines new forecast methodologies that we are developing to capture the changing nature of energy choices available to our customers and the trends in energy consumption that we expect to see emerging over time. A new end-use focused approach to natural gas demand forecasting is examined that we believe will allow us to better capture and analyze the impact of changing customer choice and behaviour. Preliminary methodologies for forecasting growth and development of low carbon and renewable integrated energy solutions for communities are examined using residential application scenarios. Demand scenarios for new growth in natural gas vehicle fueling are also presented as part of our new forecasting initiatives for incorporating the Utilities low carbon and renewable energy solutions.

While we have initiated the development of these new methodologies and provide examples for discussion purposes, we have also identified where new data sources, further research and other resources are required in order to fully develop, validate and implement these forecasting initiatives. We expect to continue this development work over the next few years alongside the preparation of our traditional natural gas demand forecasts.

4.2 Traditional Natural Gas Demand Forecast

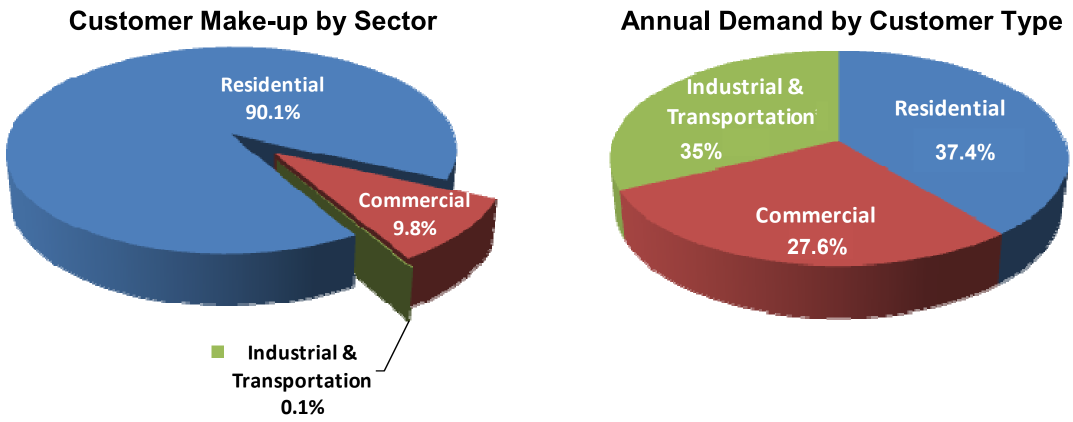
Two key elements that underpin the Terasen Utilities' resource planning activities are the traditional forecasts of annual demand and design day (also called peak day) demand for natural gas. The annual demand forecast represents the annual consumption by region and customer class and is used for gas supply contracting and rate setting purposes. The design day forecast provides an estimate of the maximum daily demand of natural gas that would be expected under extreme weather conditions, and is used for system and capacity planning as well as gas supply planning purposes. The Utilities' demand forecasts are used to ensure adequate system capacity, for the determination of gas supply resources and also to provide a base line against which to analyze the impact of proposed or potential future initiatives such as expanded energy efficiency and conservation activities or growth in natural gas sales for fueling transportation.

Inputs to the demand forecast include the analysis of historical data and trends from the Utilities' own systems, as well as many of the external factors discussed in Section 2. This section (Section 4.2) reviews the interplay of these factors in assessing future demand expectations and presents the annual and design day demand forecast results. Details regarding the demand forecast scenarios and results for each of the Terasen Utilities' service areas are provided in Appendices B-2 and B-3.

The Terasen Utilities customer base consists predominantly of residential customers who account for 90% of the overall customer base. However, on an annual demand basis, there is a relatively even split between customer groups which include residential, commercial and industrial / transportation[85] customers. The makeup of customer base and demand has implications on infrastructure requirements and conservation as discussed throughout this Resource Plan.

[85] Transportation customers in this case refer to customers who purchase their own natural gas supply and contract with the Terasen Utilities to transport that supply across our system.

Figure 4-1: Terasen Utilities' Customer and Demand Overview



4.2.1 MARKET TRENDS

Though identifying and investigating trends in historical data is an important part of forecasting the demand for natural gas, understanding the changes occurring in the marketplace and how they will impact the overall demand for energy is equally important. To that end, this section discusses market trends the Utilities have considered while developing its forecast of customer additions, average use per customer, annual demand, and also design day demand.

4.2.1.1 Population Growth

The most important trend to be considered when preparing the demand forecasts is the anticipated growth in population. Current projections from B.C. Stats estimate the province will add approximately 1.5 million new residents over the course of the next 20 years which will bring the current population of 4.5 million to 6.0 million by 2030. Population growth provides an indicator of the need for new housing and energy demand in B.C. and is one of the factors that inform provincial forecasts of household formations, housing starts and housing mix. These housing factors closely correlate to customer growth for the Terasen Utilities and thus provide key inputs into the customer forecast. The aggregate effect on the Utilities is expected to be an increase of approximately 150,000 customers over this same period, bringing the total number of customers to slightly above 1.1 million by the end of the planning period.

4.2.1.2 Residential Use Trends

Declining residential use per customer rates is a phenomenon affecting mature natural gas utilities across North America[86]. This same trend has been observed in most of the Terasen Utilities' service territories except TGW. For TGW, no discernable pattern has been identified, most likely due to the resort nature of the community and varying use patterns of land and homeowners and renters. The main drivers of this continuing decline include the renewal of

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86 Residential Natural Gas Consumption, Heading Toward an Inflection Point. September, 2009. Cambridge Energy Research Associates Inc. 12p.

existing furnace stock, changes to building codes and standards, and also a shift in housing type from single family dwellings to multifamily dwellings. Upon identifying the main drivers and assessing the corresponding impact, the Terasen Utilities' forecasting methodologies in this Resource Plan reasonably forecast future residential average use per customer. Each of the main drivers is discussed in the following sections.

➢ Renewal of Existing Furnace Stock

The most significant driver of declining residential average use per customer in B.C. is the replacement of low-efficiency natural gas furnaces with higher efficiency models. Changes to the building code in 1990 mandated mid-efficiency furnaces as the minimum requirement for homes built since that time. Changes to building code legislation stipulated that high-efficiency furnaces be required for new construction as of 2008. For retrofit activity, the same minimum efficiency requirement was put in place as at December 2009.

In 2008, the Utilities conducted a Residential End Use Study ("2008 REUS" – see Appendix B-1) where residential customers were surveyed, with the primary goal being to understand how the Utilities' residential customers use energy in their homes. The survey included questions regarding the appliances present in homes and their respective efficiency ratings, housing type, and numerous other dwelling characteristics. Table 4-1 illustrates the estimated furnace efficiency shares by region that were derived from the 2008 REUS. Standard efficiency furnaces account for the largest proportion (45%) of gas furnaces still in use, followed by mid-efficiency furnaces (39%), and high efficiency furnaces (16%).

Table 4-1: Furnace Efficiency by Region (%)

Natural Gas or Piped Propane, 2008 REUS

Furnace Efficiency	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base*	297	513	231	72	113	1226	923	942
Standard efficiency (less than 78% AFUE)	52.1	38.0	19.0	20.7	29.2	45.0	47.0	54.5
Mid-efficiency (78% to 85% AFUE)	34.0	44.2	56.5	42.8	49.5	39.0	37.7	28.9
High efficiency (90% AFUE or higher)	13.9	17.7	24.5	36.5	21.2	16.0	15.3	16.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

* Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Table 4-2 summarizes the age profile for furnaces in use in the Terasen Utilities' five regions. Average furnace age varied from 10.1 years to 15.4 years depending upon the region. The average age of furnaces owned by our customers is 14 years. These types of characteristics, especially when monitored over time, provide a solid basis from which to estimate the impact of retrofit activity on natural gas appliances.

Table 4-2: Age of Furnace by Region

Natural Gas or Piped Propane, 2008 REUS

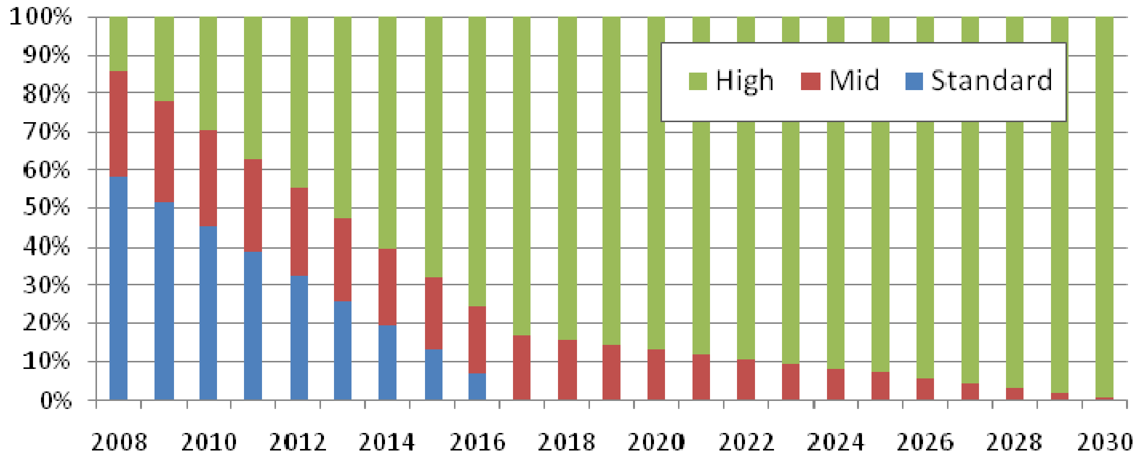
Age of Gas Furnace (years)	LM	INT	TGVI	TGW	FN	2008 TG	2008 TGI	2002 TGI
Unweighted base	350	590	274	87	121	1422	1061	1500
Median	12.0	10.0	10.0	10.0	7.0	10.0	10.0	n/a
Mean	15.4	12.5	10.5	10.2	10.1	14.0	14.3	13.4
Standard deviation	21.0	8.7	3.8	0.9	1.6	12.0	13.8	n/a

This analysis of furnace age indicates a large portion of the standard efficiency furnaces will be retiring and be replaced with high efficiency furnaces in the coming years. This will have a significant impact on the Utilities' residential average use per customer, particularly in the Lower Mainland which has the largest customer base and the oldest stock of heating equipment among the Utilities service areas. Depending on the housing type and region, we estimate that a typical standard efficiency furnace consumes approximately 17 to 20 GJ[87] more per year than higher efficiency furnaces. A shift in the existing mix of furnaces from standard efficiency (currently the largest portion) to high efficiency will lead to a significant decrease in residential average use per customer.

Figure 4-2 illustrates the anticipated changes in furnace efficiency shares for single family dwellings in the Lower Mainland region[88]. Once standard efficiency furnaces are phased out from the Utilities' existing residential customer base, the rate of decline is expected to become more gradual. Based on the 2008 REUS, we estimate that standard efficiency furnaces will be completely phased out from its existing customer base sometime between 2017 and 2020 depending on the region. The Utilities estimate the decline in overall residential average use per customer from shifting furnace efficiency to be an approximate 2% per year for the next 3 to 5 years.

[87] Based on analysis from 2008 REUS.
[88] Based on the 2008 REUS assuming a maximum life of 30 years for standard efficient furnaces

Figure 4-2: Furnace Efficiency Share in Single Family Dwelling-LML

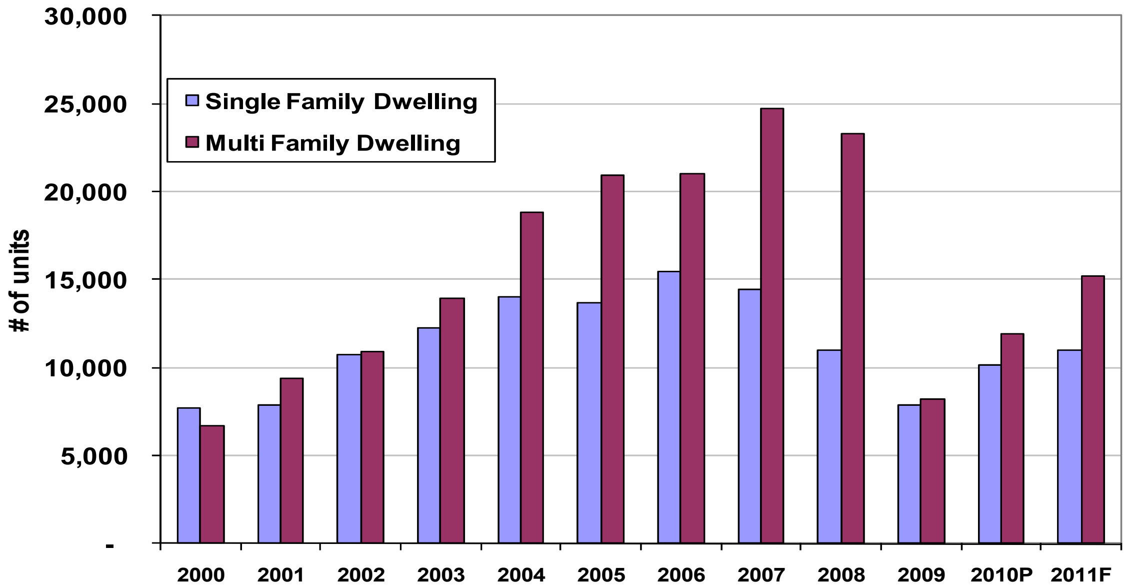


The Utilities anticipate that the last of the standard-efficiency furnaces will come out of service by 2017 for single family dwellings in this region based on replacement at the expected end of useful life of the asset. Although some customers may choose to increase maintenance costs for old equipment to avoid replacement costs, it is not unreasonable to assume that by 2030 all of the standard and mid-efficient furnaces in single family dwellings located in this region will have been replaced by high-efficiency technology. This type of analysis has been incorporated while estimating use per customer forecast for the 20 year planning period.

- **Shift in Housing Type**

Housing type is another factor impacting residential use per customer rates. Figure 4-3 shows the shift that has occurred over the past decade in the predominant housing type, from single family to multi-family dwellings. This continuing shift toward the multi-family housing type in B.C. is driven by affordability and limited availability of land for single family home construction. Canadian Mortgage and Housing Corporation ("CMHC") forecasts that the trend is expected to continue for 2010 and 2011. It is not unreasonable to assume that this pattern in housing type will continue for the foreseeable future.

Figure 4-3: B.C. Housing Starts – Mix of Housing Types



Source: CMHC

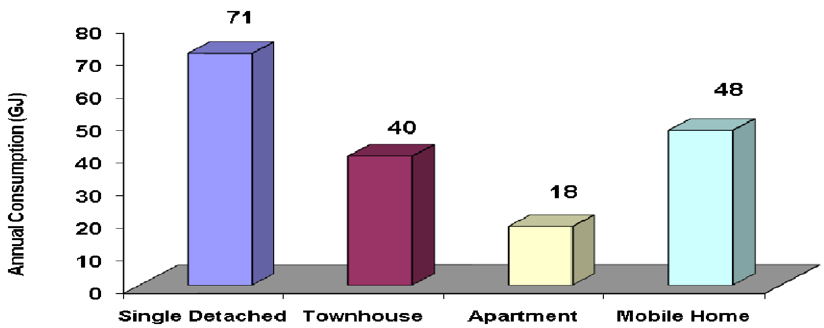
An analysis of 2009 customer data indicates that the Utilities were successful in bringing natural gas service to approximately 80%[89] of completed residential units (all types) reported by CMHC within the Utilities' service territories.

As a percentage of CMHC completions, the Utilities estimate that the vast majority (approx. 95%+) of SFDs installed natural gas service while 60 to 70% of MFD units completed were attached in some form; either with natural gas being piped to the individual units or serving some common application that benefits all residents of the housing complex. The challenge in assessing the level of penetration into the MFD markets lies in the fact that approximately 80% of the estimated attached MFD units are served by a single common meter. Situations where a common meter provides natural gas to an entire MFD building makes it difficult to determine how much of that consumption is attributable to individual suites as opposed to serving common loads.

This shift in new housing type has important implications for overall residential average use per customer. As illustrated in Figure 4-4 below, the average annual consumption for space heating purposes, regardless of energy type, is significantly lower for multifamily dwellings than for single family dwellings.

[89] Based on analysis from the Terasen Utilities' customer information system and validated with 2008 REUS results.

Figure 4-4: Space Heating Consumption – All Energy Types

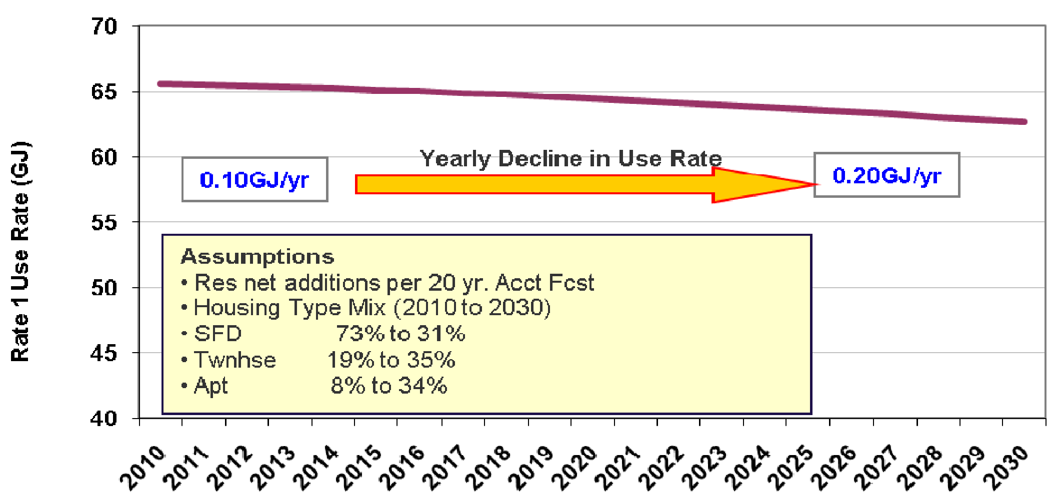


Source: NRCan

The impact of the continued dominance of multifamily dwellings in the housing market is an estimated decline in residential average use per customer by approximately 0.1 to 0.2 GJ per year. Figure 4-5 illustrates the estimated impact by gradually changing the mix of housing type while holding the typical average annual consumption per housing type and also annual customer additions constant.

It is important to note the values in this analysis are not meant to reflect forecasted values, but are chosen to gauge the independent impact a shift of housing types within the housing market has on the overall residential annual demand. Though not insignificant, the results suggest that housing type plays a considerably smaller role in declining residential usage rate than does the replacement of low-efficiency furnaces.

Figure 4-5: Impact of Shifting Housing Type on Use Rate for Space heating



4.2.2 NATURAL GAS COMPETITIVENESS

Section 2 discusses the competitive position of natural gas relative to other fuels and energy systems for home heating. That discussion includes consideration of natural gas rates (including the provincial Carbon Tax) compared to electricity (the main alternative to natural gas for this purpose in B.C.), furnace oil, propane and alternative energy systems. While rates are an important aspect of competitiveness, it should be recognized that other factors also play a role in energy choice, such as comfort and attitudes toward different fuel types.

Although much focus is placed on electricity in B.C. being a renewable energy source, opposition to the development of new infrastructure to meet growing electricity demand also continues to grab headlines. The Province's new Clean Energy Act does not promote the use of natural gas over electricity for thermal uses; neither does it preclude the use of natural gas over electricity, recognizing the important role that both energy types play in meeting B.C.'s energy and resource needs. The Utilties' initiative to acquire biogas resources and spur the growth of this new industry will also be seen in a favourable light and among energy consumers. This initiative may sway future decisions in favour of natural gas as supplies of this renewable energy source grow. Future attitudes to one of these energy types over the other remain uncertain, as both have important roles to play in a low carbon energy future.

The review of energy alternatives for space heating finds that natural gas remains at a similar level of competitiveness with respect to electricity as it has in recent years when factoring in the increases in carbon tax costs and the difference in upfront capital costs between electricity and natural gas heated homes. The competitive position of natural gas has improved, however against other carbon-based fuels. Recent technology developments that have made available unconventional sources of natural gas across North America previously thought to be economically unrecoverable, have resulted in a much more favourable outlook for the long term supply potential. For at least the short to medium term this is expected to support the natural gas competitive position of natural gas relative to other carbon based fuels.

On Vancouver Island, where many homes still use furnace oil, the advantage of natural gas has increased, making the case for conversions to natural gas more attractive. In the TGVI service area particularly, EEC programs are designed to incent customers to convert from oil to natural gas high efficiency furnaces. Similarly, the rate advantage for natural gas over propane has also grown, reinforcing the benefit of system conversion to natural gas for TGW customers. This advantage may also encourage the remaining propane users in proximity to gas lines in rural areas of the Province to convert. The position of natural gas against other carbon based fuels is also observed for vehicle transportation fuels (diesel and gasoline) as discussed in Section 2.1. The competitive position of natural gas against these carbon-based fuel alternatives is expected to help maintain growth in the demand for natural gas as a heating fuel in each of the Utilities' service areas, and support TGI's new natural gas vehicle initiatives[90].

The integrated, alternative energy solutions for thermal energy demand being implemented by the Terasen Utilities are expected to have only a small impact on natural gas demand initially, growing to a more substantial impact over the longer term. For these customers, costs are not the only consideration in making energy choices. More and more, customers with the means to do so are choosing more expensive installations for their thermal energy needs due to the perceived environmental benefits. These solutions are expected to be more widely adopted initially in district energy and larger multi-unit developments. The impact on natural gas demand of customers choosing alternative energy solutions is discussed further in Section 4.3.2

Natural gas is also expected to remain the preferred supplementary fuel for alternative energy systems due in part to the impact that this supplementary peak period demand would have on electricity infrastructure capacity needs and costs. The upfront capital costs for these systems are likely to remain prohibitive for many single family residential customers, moderating any early impact of individual alternative energy solutions on natural gas demand. The Terasen Utilities will continue to monitor the impact of alternative energy solutions on natural gas demand and adjust demand expectations accordingly.

4.2.3 COMMERCIAL USE RATE

Unlike the residential customer class, historic normalized use rates have been relatively stable across all commercial customer classes. The Utilities expect use rates to decline moderately in the short run but hold relatively constant in the long term. Going forward, as more customers engage in efficiency improvements and adopt alternative energy solutions, we expect use rates to trend downward. Until the point when additional data becomes available on the impact that expanded EEC programs and implementation of alternative energy systems have on future commercial use rates, the Utilities traditional forecasting methodologies in this LTRP are considered to reasonably forecast future commercial average use per customer.

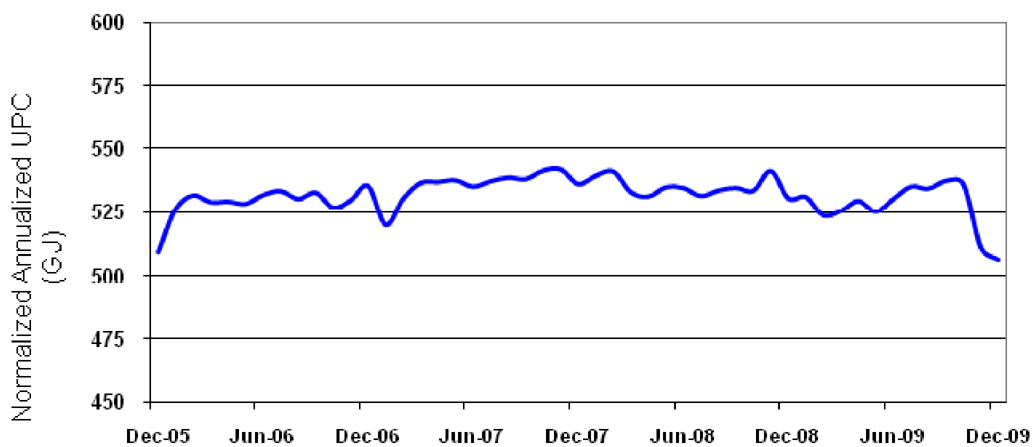
For TGI, an added a level of rigor was included by identifying the top five consuming sectors within its commercial customer classes, and analyzing those sectors individually as part of the demand forecast. By analyzing historical consumption patterns on a sector by sector basis, and incorporating the latest available economic information, TGI is able to prepare a demand forecast that is consistent with the approach outlined in the 2009 Revenue Requirement Application (RRA). Reasonable assumptions with respect to future average use per customer were developed for each sector by analyzing historical trends in consumption and considering expected efficiency improvements based on currently planned Commercial EEC programs. This ultimately led to the development of the commercial average use per customer forecast.

[90] Demand from TGI's new natural gas vehicle initiatives is not included in the traditional demand forecast – this demand is discussed separately in Section 4.3.3.

A detailed sector analysis for each small commercial (Rate Schedule 2), large commercial (Rate Schedule 3) and commercial transportation (Rate Schedule 23) as presented in the 2009 TGI RRA was carried out for this year's LTRP. The Utilities have demonstrated the analysis here by exemplifying the Apartment/Condo sector within the small commercial customer class.

Figure 4-6 illustrates the normalized annualized average use per customer over the period December 2005 through December 2009 for TGI's small commercial customers within the apartment/condo sector. This customer segment represents multi-family dwellings, and also smaller apartment or condominium buildings. The historical trend in average use per customer has been relatively stable with a slight decline in 2009. Given the recent approval and development of commercial EEC programs, there are opportunities for efficiency improvements and TGI is expecting a moderate decline in average use per customer over the longer range period.

Figure 4-6: Normalized Annual Use Rate for Apartment / Condominium Customers



In considering the trends seen in the various sectors as illustrated above, TGI is projecting the demand to increase slightly in the short term and expected to stabilize in the longer term. This is because the declines in short term use per customer are offset by anticipated increases in customer additions. In the absence of industrial sector code for TGVI and TGW customers, a forecast was developed by analyzing historical information and trends in the market.

4.2.4 INDUSTRIAL AND TRANSPORTATION CUSTOMER DEMAND

Given the relatively small number of TGI industrial customers[91], a different approach in forecasting demand is favoured over the approach taken for both residential and commercial customers. The methodology behind forecasting industrial demand is typically derived from the

91 Industrial customer forecast is limited to TGI, as TGVI and TGW have no industrial customer classes.

following two sources, an annual customer information survey and sector analyses of historical consumption.

- **Customer Information Survey**

Typically, the primary source of information for the industrial energy forecast is the industrial customer survey, which historically has been conducted over the period May through July on an annual basis. However, in 2010 the survey will be conducted in the fall of 2010 to allow for more recent data to be incorporated into the Utilities next Revenue Requirement Applications, and therefore the survey results will be used as a secondary source of information to validate the sector analysis as described below.

- **Sector Analyses**

Consistent with the 2010/2011Revenue Requirement Application (RRA) and prior years, the historical consumption patterns of the customers in each of the top seven consuming 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 results from the sector analysis were then amalgamated to arrive at an estimate of future demand by each industrial customer class.

Table 4-3 provides the 2009 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.

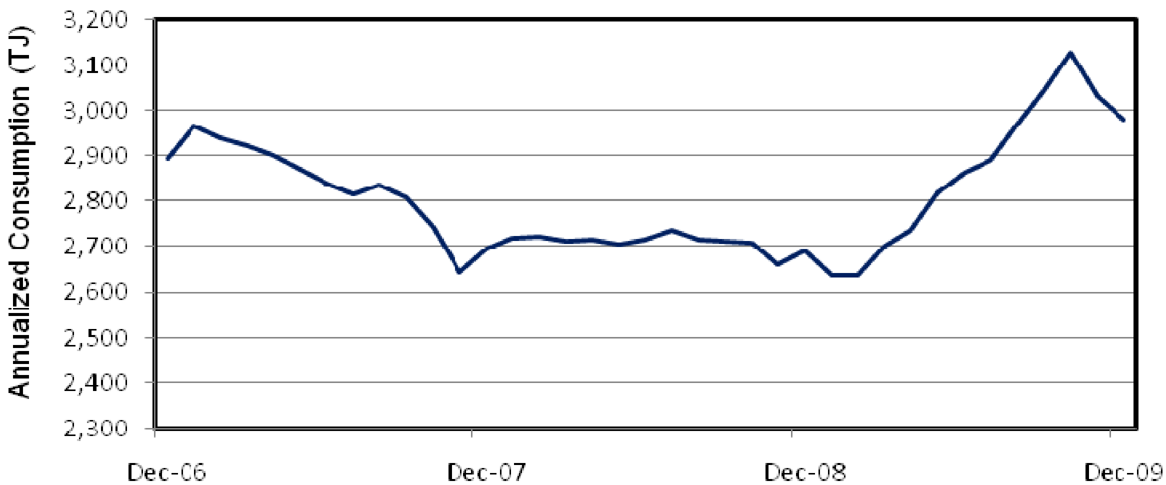
Table 4-3: Industrial Customers Top Energy Consuming Sectors

	PJ's	%
Pulp & Paper	12.4	24%
Wood Products	4.5	9%
Greenhouses	3.3	6%
Mining	2.5	5%
Apartment/Condo	3.4	7%
Chemical Manufacturing	3.4	7%
Food & Beverage	4.5	9%
Other	17.3	34%
Total	51.2	100%

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 whereas customers in the wood products sector trend more closely to economic activity. Although these sector specific factors present additional challenges when developing the industrial demand forecast, incorporating them further adds to its reasonableness

A detailed sector analysis for the industrial customer class as presented in the 2010/2011 TGI RRA was carried out for this LTRP. The Utilities have demonstrated the approach taken to forecast industrial demand by taking examples from wood products and greenhouse sector.

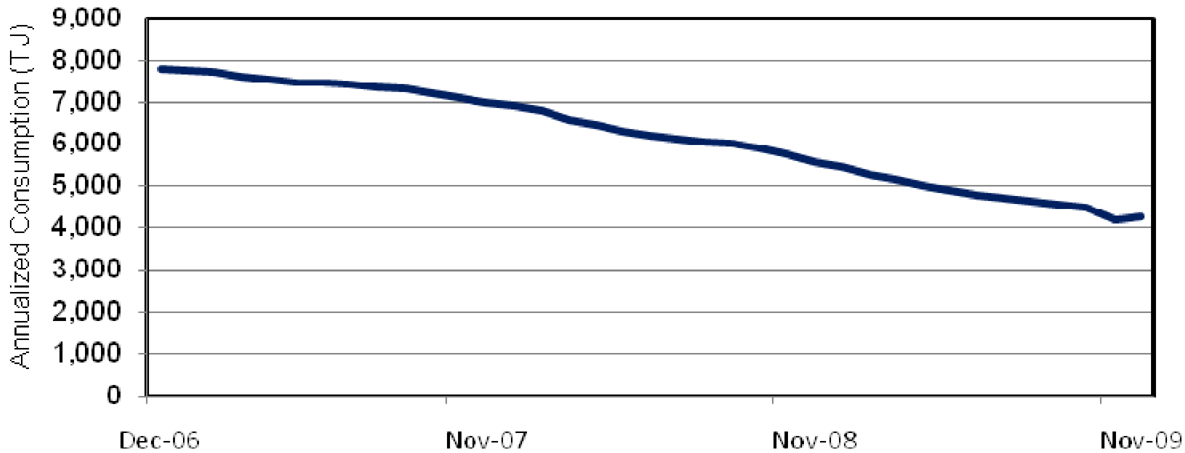
Figure 4-7: Annualized Consumption for the Greenhouse Sector



The Greenhouse sector (Figure 4-7) has seen both declines and increases in volumes since 2006. Although the more recent short-term trend is downward, there was significant growth experienced in this sector during 2008. This sector has the capability to switch between fuel sources, and therefore tends to respond to conditions in the spot market. Given that that the current development of North American shale gas has resulted in more favourable long term supply expectations relative to previous years, ', the Terasen Utilities are estimating that on average demand in this sector will remain stable throughout the forecast period.

The wood products sector, on the other hand, has been experiencing steadily declining volumes since early 2006. Figure 4-8 below illustrates this trend, and given the high level of dependence this sector has on the U.S. housing market, the Utilities anticipate a continued decline over the next few years, but stabilizing over the long-term.

Figure 4-8: Annualized Consumption for the Wood Products Sector



Through considering the trends seen in the various industrial sectors, as illustrated above, we are projecting a decline in overall demand over the forecast period based on best available information at this time.

- **Natural Gas Demand in B.C. for Electricity Generation and Vancouver Island Mills**

The discussion of annual and design day demand in this section does not include demand for Burrard Thermal Generating Station, the Island Co-generation Project or additional load from a potential new generating station in the Okanagan for meeting peak period electricity demand. Also not included in this discussion is demand from the Vancouver Island Gas Joint Venture mills. For capacity planning purposes, demand from these facilities is discussed in Section 6.1.

4.2.5 ALTERNATIVE FUTURE SCENARIOS

The Terasen Utilities forecast future customer additions and use per customer based on a range of possible future scenarios. As the forecast period increases, so do the levels of uncertainty which is why we vary the input assumptions from the reference case forecast to develop future scenarios. Two scenarios have been developed that illustrate the upper and lower range annual demand that would be expected to occur over the planning period based on a set of reasonable assumptions.

The scenarios described below for the traditional demand forecast do not incorporate the impact of new energy initiatives being undertaken by the Terasen Utilities. The potential impact of these initiatives is discussed in Section 4.3.2.

4.2.5.1 Robust Growth

The Robust Growth scenario is developed to illustrate the magnitude of additional consumption that could occur above the level set by the Reference Case, and also identifies the likely drivers that would lead to higher demand for natural gas. Although there are numerous factors that can affect consumption levels, the following items occurring concurrently are viewed as the main drivers in this scenario.

The province continues to recover from the economic downturn with growth beyond what is currently expected by the provincial Government and economists. Population migration from other provinces and immigration from other countries are greater than currently forecast, leading to greater population growth in the province. This increase in population growth is captured in higher rates of customer additions compared to the Reference forecast. The natural gas price advantage also improves with respect to electricity due to larger than expected increases in electricity rates while natural gas costs remain stable. Recognition by governments and society of the important role that natural gas can play in direct use applications to allow clean electricity exports to offset coal and natural gas fired generation in other jurisdictions could also put upward pressure on natural gas demand.

Though the forces affecting residential average use per customer are not expected to disappear under any scenario, the Robust Growth scenario envisions a situation where uses per customer rates stabilize sooner. This combined with stronger growth in population and improved capture rates in MFDs for residential customers, will support robust growth where the overall demand grows at a greater rate than for the reference case demand scenario.

For industrial customers the robust growth scenario is based upon a quicker than anticipated economic recovery in the sectors for the first two years followed by a period of stability. For example should the U.S. and world economies come out of recession sooner than expected, exports dependent sector such as the wood products, mining, chemical manufacturing and pulp and paper sectors could see higher demand than currently anticipated. At the same time, strong growth in provincial economy translates into higher demand for sectors such as apartments / condominiums and food and beverage manufacturing. The above factors have been taken into consideration while preparing the robust growth industrial demand scenario.

4.2.5.2 Low Growth

The Low Growth future scenario is developed to depict the lower bound in consumption with respect to the Reference case that could reasonably occur. The likely drivers that would lead to a lower demand for natural gas are identified and described in the following.

The province experiences weaker than expected economic growth driven by a U.S. economy that fails to recover from its recent economic downturn and in turn causes other closely linked economies, such as that in B.C. to slow. This would then manifest itself in terms of a slower rate of customer additions.

Technology advances and increasing efficiency improvements due to government regulations accelerate conservation efforts faster than what is currently anticipated. Natural gas heating equipment with standard efficiency for both space and water heating is replaced at an accelerated pace, and alternative technologies (e.g. solar thermal domestic hot water heating) begin to see broader acceptance in the market. These conditions would accelerate the decline in residential average use per customer.

As people seek to reduce the use of fossil fuels in order to minimize carbon emissions, the potential exists that the Utilities' existing customers may shift some or all of their heating loads to electricity in absence of end use policies that recognize the upward pressures that such activity will place on electricity infrastructure and regional GHG emissions. Customers with standard efficiency natural gas equipment, particularly might tend to make this switch. Though not necessarily achieving the desired outcome on a regional or global basis, confusion in the general population on how best to lower carbon emission could lead to both decreased use per customer rates and lower customer additions.

The next sections describe the main components of the Annual Demand forecast common to all three Terasen Utilities as well as additional trends that are impacting these forecast components. Details regarding the specific forecasts and scenarios for each of the Utilities are included in Appendix B-3.

4.2.5.3 Customer Additions

The customer additions forecast is derived from long-term provincial forecasts of household formations at the community level and validated against CMHC's nearer term forecasts in order to reflect the most current market situation. The forecast of customer additions is applied to both residential and commercial rate classes while no growth is assumed for industrial customers. The latest available economic analyses from the B.C. Government, major banks and other organizations are reviewed for consistency with the overall trend in household formations. For the forecast produced in support of the 2010 LTRP, the B.C. Statistics 2009 Household Formation Forecast (based on P.E.O.P.L.E. 34) was used to determine customer additions by area over the forecast period.

Commercial customer additions tend to reflect the same long-term growth patterns as those for residential customers, since growth in the business sector generally stems from growth in the population. This trend is captured in our forecast of commercial customer additions.

4.2.5.4 Use per Customer Rates Summary

The average usage, on a per customer basis, is one of the key components in estimating annual demand. The Utilities have developed a forecast of use per customer rates that forms a key input for use in long-term resource planning. The methodology to determine average use per customer for a given region and customer class as based on the following:

- Historical normalized consumption data
- Any known customer migration between rate classes
- Appliance retrofit activities and market trends
- Building codes and standards

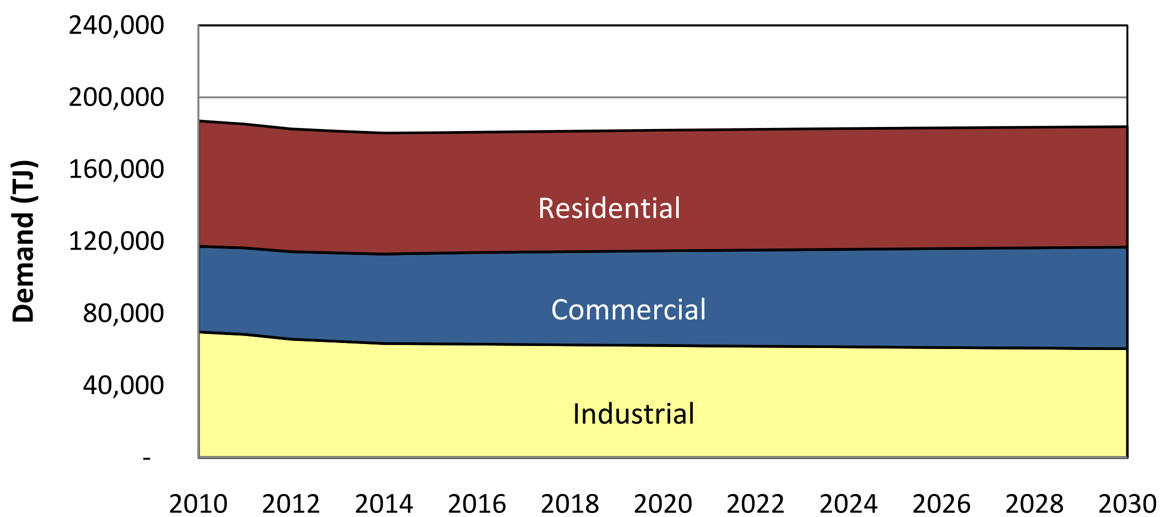
As discussed earlier, residential average use per customer for mature utilities, such as TGI have been experiencing declines since the early 1990s. A similar trend has been observed in TGVI in the last three years, while no discernable pattern has been identified for TGW. Based on recent analysis, the Utilities anticipate more rapid changes than what has been previously estimated. Declines of approximately 2% per year in residential average use per customer are now being forecast for the next 3 to 5 years, followed by more gradual declines over the planning period. The declines observed in the most recent historical normalized consumption data, expanded EEC programs coupled with various government regulations largely explain these declines in average use per customer. Other factors include current building codes mandating high efficiency furnaces for both new construction and retrofit hot water regulation with minimum efficiency of 0.6, the shift towards more multi-family dwellings in the housing mix, better insulated new homes and also the upgrading of existing homes.

4.2.6 ANNUAL DEMAND FORECAST RESULTS – ALL UTILITIES

4.2.6.1 Reference Case

On an aggregate basis across all utilities, overall consumption is forecast to remain relatively stable over the forecast period (Figure 4-9).

Figure 4-9: Reference Case Annual Demand Forecast 2010 - 2030 – All Utilities



The net increase in customer additions over the planning period is offset by a forecast decline in use per customer. Factors such as furnace replacement, building codes and standards, expanded EEC programs, and also the shift towards more multi-family homes in the housing mix work to drive down consumption on an individual basis, while the only factor contributing towards growth is an increase in the overall number of customers connected to the system. Commercial demand is expected to remain relatively stable while industrial demand is expected to stabilize within a few years.

4.2.6.2 Impact of EEC Programs on the Demand Forecast

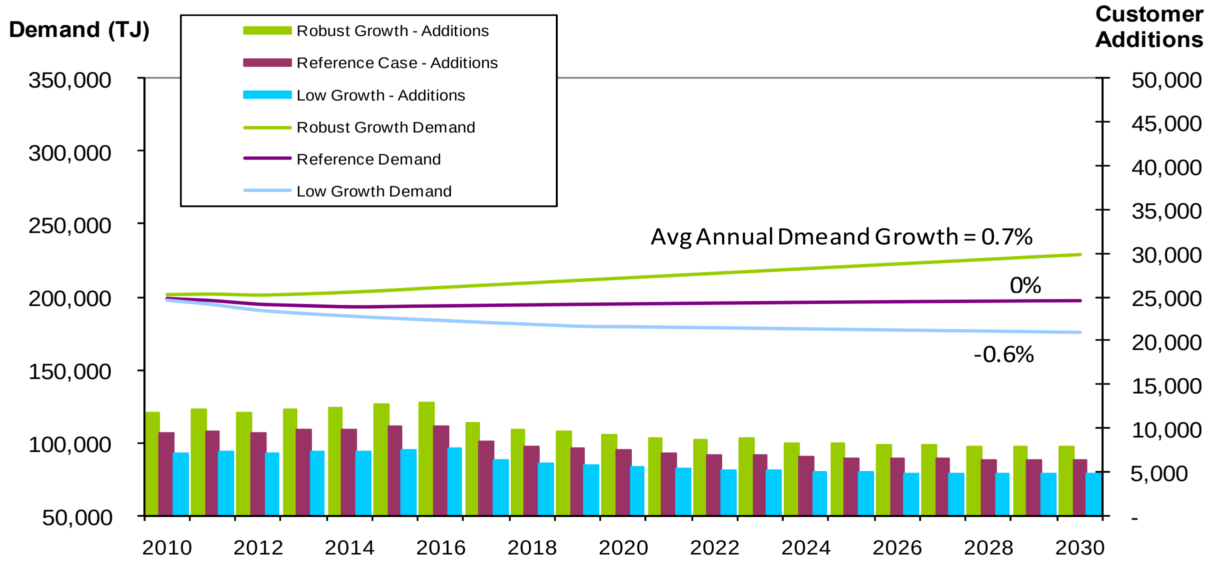
In June 2009, TGI and TGVI filed their 2010-2011 Revenue Requirements Applications, requesting approval from the Commission for an allocation of funding to be directed to new programs. The Commission approved the resulting Negotiated Settlement Agreement, which brings the total funding for EEC programs and initiatives to $72.3 million in 2010 and 2011. As the EEC funding will have a material impact on consumer behaviours further affecting demand, the current level of EEC funding is incorporated as part of building the reference demand forecast.

Section 5 discusses the potential impact on demand and GHG emissions involving different levels of future funding for EEC programs. These impacts are not incorporated here as those initiatives are still in planning stages. Once the Utilities receive approval for additional funding, and when CPR results become available, we would at that point incorporate the results into future demand forecasts.

4.2.6.3 Annual Demand – Robust Growth and Low Growth Scenarios

Figure 4-10 illustrates the Utilities' combined annual demand forecast for all three future scenarios. Appendix B-2 provides the annual demand details for each company separately.

Figure 4-10: Annual Demand and Customer Additions - All Utiliites



Under the robust growth forecast, it is anticipated that natural gas consumption could increase by approximately 0.7% per year, on average, to 220 PJ by 2030. Under this scenario, the province's population grows at a faster than anticipated rate and price signals result in customers switching heating loads more towards the direct use of natural gas in an effort to mitigate growth in electrical demand. It is important to note that increases in natural gas consumption would likely offset demand for other energy sources such as heating oil and electricity produced from fossil fuels.

A slight decline in annual demand materializes in the Low Growth scenario. This decline is contingent upon a markedly lower growth in population combined with aggressive conservation efforts and a shift towards other energy options for loads that have been traditionally served by natural gas. Under the Low Scenario, annual demand would decrease by approximately 0.5% per year, on average, to 170 PJ by 2030.

In summary, through analyzing the factors impacting demand for natural gas, incorporating the best available information when preparing the forecast, and by developing a number of scenarios, we have developed a long-term demand forecast that is both reasonable and appropriate for use in long-term resource planning.

4.2.7 DESIGN DAY DEMAND

Design day demand differs from annual demand in that it estimates the maximum daily consumption expected to occur during an unusually cold weather event. The forecast of design day demand is a crucial input into the Utilities' key activities of securing an adequate supply of natural gas and ensuring that the infrastructure is capable of delivering that natural gas where and when needed.

The determination of design day demand for the various regions is arrived at through a separate process than is the forecast of annual demand. The design day demand forecast is based upon two key inputs:

- The design day temperature; and
- The relationship between consumption and weather.

The design day temperature represents the coldest daily temperature that would be expected to occur once every twenty years. The relationship between consumption and weather is determined through regression analysis of historical daily consumption and historical daily temperature experienced over the past three years. Once this relationship is determined, the design day temperature is applied to it with the resulting design day demand per customer grossed up to reflect current customer counts. The methodology used to forecast design day demand is discussed in more detail in Appendix B-4 and remains consistent with previous years. In response to stakeholder feedback, the Utilities have undertaken a review of the regression models used to estimate the relationship between weather and consumption. The details of this review process are also described in Appendix B-4.

The design day demand forecasts for each of the Terasen Utilities is provided in Figures 4-11, 4-12 and 4-13 below. A modest growth in design day demand for each of the utilities is estimated for the current planning period which stems from modest growth in customer additions.

Figure 4-11: TGI Design Day Demand

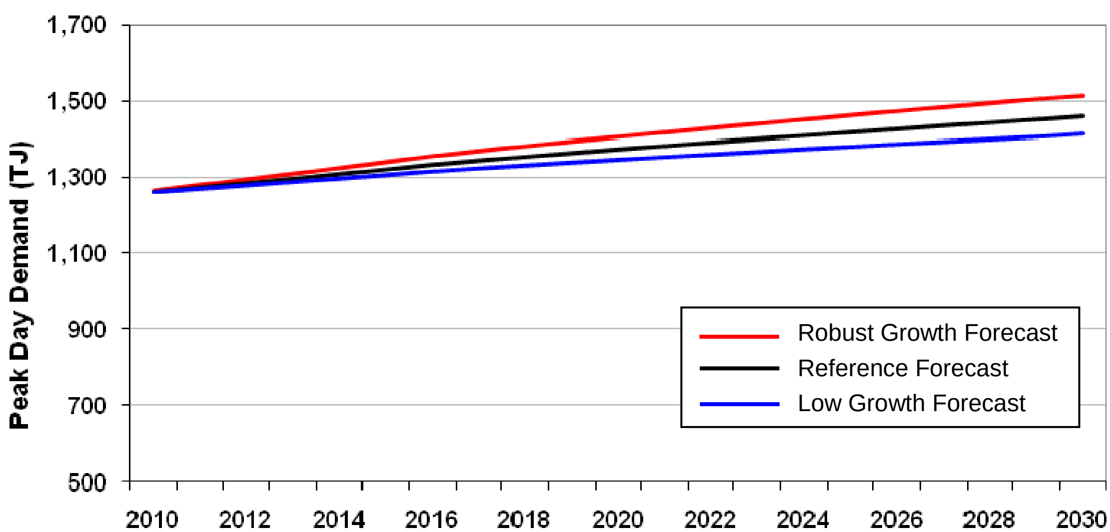


Figure 4-12: TGVI Design Day Demand

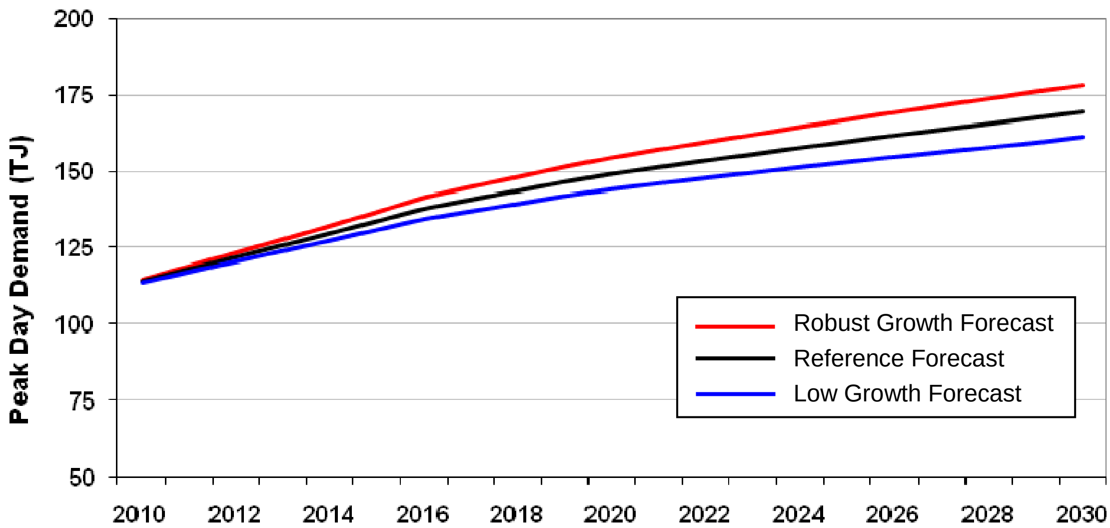
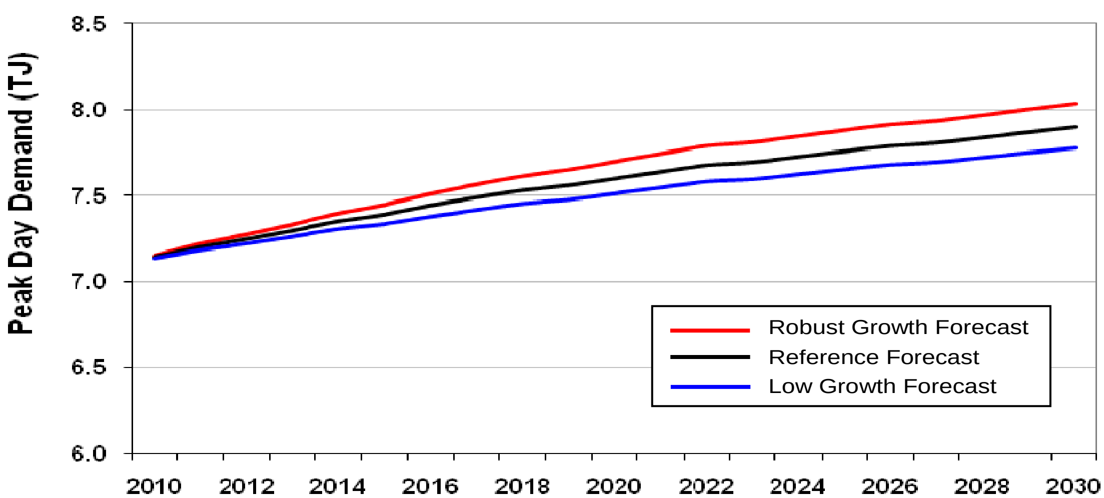


Figure 4-13: TGW Design Day Demand



The forecast of design day demand must be developed to meet expected customer demand during extreme cold weather. The consequences of under-forecasting could result in customers experiencing service interruptions at the most critical time. For this reason, and also considering that design day use per customer has remained relatively stable in recent years, design day use per customer is assumed to remain constant over the forecast period. The Terasen Utilities consider three years of historical data to ensure that actual changes in customer behaviour are reflected on an ongoing basis, but also to ensure any perceived trends resulting from short-term fluctuations in consumption are not projected onto future values. Additionally, impacts of climate change are not incorporated into the design day demand forecast. Although the overall global temperature may be trending upwards over time, and is expected to continue doing so, there is no certainty regarding the likelihood and severity of extreme weather events specific to the geographical area served by the Terasen Utilities.

By extensively analyzing the factors impacting the design day demand forecast, Terasen Utilities believe that the design day demand for this LTRP is appropriate and reasonable for infrastructure planning and gas supply contracting purposes. Going forward Terasen Utilities will continue to monitor the impact on design day demand from adoption of alternative energy stems and expanded EEC programs beyond 2011 and adjust demand expectations accordingly. The potential for increased adoption of alternative energy systems to impact design day demand is discussed in Section 4.3.2, where the development of new forecasting activities that will help determine if and when these new energy initiatives will impact existing natural gas use patterns is discussed.

4.3 New Forecasting Initiatives

4.3.1 PROPOSED NEW METHODOLOGY FOR NATURAL GAS DEMAND (RESIDENTIAL)

The Terasen Utilities expect the energy use patterns of new residential customers will evolve from that of the existing customer base today. The growing pace of change in energy policy, technology options, efficiency advancements, housing mix, customer behaviour, customer attitudes and other factors need to be addressed for each of these customer groups as part of forecasting demand for both natural gas and alternative energy solutions. For these reasons, the Utilities are adopting an end-use natural gas demand forecasting methodology that complements and may in the future replace its current natural gas demand forecasting approach. This new methodology is under development and not yet ready to be used for planning purposes. Where the Terasen Utilities' current forecasting methodology examines use rates within the residential customer service classes and applies future assumptions about these use rates to existing and new customers alike, our new approach will allow better consideration of differences in behaviours and future energy decisions between new and existing customers.

Given that the existing customer base is so large, it will continue to have the most significant impact on residential energy demand. However, as new customers have a much broader range of energy type and technology choices to choose from, they will have a growing and changing impact on future natural gas demand.

The type of energy technology solutions chosen and over all energy consumption is also expected to reflect differences in housing type. While the Utilities are not shifting the methodology by which we forecast total natural gas customer additions, the proposed methodology does include a break out of existing customers and new customer additions by housing type within the analysis of future demand. At this time, this breakout is limited to single family dwellings and townhouse type multi-family dwellings.

The Terasen Utilities' proposed new approach incorporates customer end use data such as the type of appliance broken out by end uses (space heating, water heating etc), housing type and region separated by existing and new customers. This revised approach will allow for greater flexibility in determining possible outcome because inputs that are derived from studies and research can be modified and changed as customer energy solutions and behaviours evolve overtime. Appendix B-5 provides a full discussion of this new approach, using the example of new furnace and proposed water heater regulations to show how the annual demand characteristics for new customers could differ from annual demand for the existing customer base in the Lower Mainland.

The example considers that new construction, where a natural gas furnace is installed for space heating, must use a high efficiency furnace to remain in compliance with building codes and standards. These new customers will therefore all join the Utilities' customer base at a substantially different rate of use than that of the existing customer base. The existing customer base will shift use rates much more slowly as the existing stock of lower efficiency furnaces is switched out for high efficiency models over time, as existing furnaces reach the end of their service life. The results of this example are shown for space heating demand in Figure 4-14 for the existing customer group and Figure 4-15 for the new customer group.

Figure 4-14: Natural Gas Demand Forecast for Existing Residential Customer Space Heating

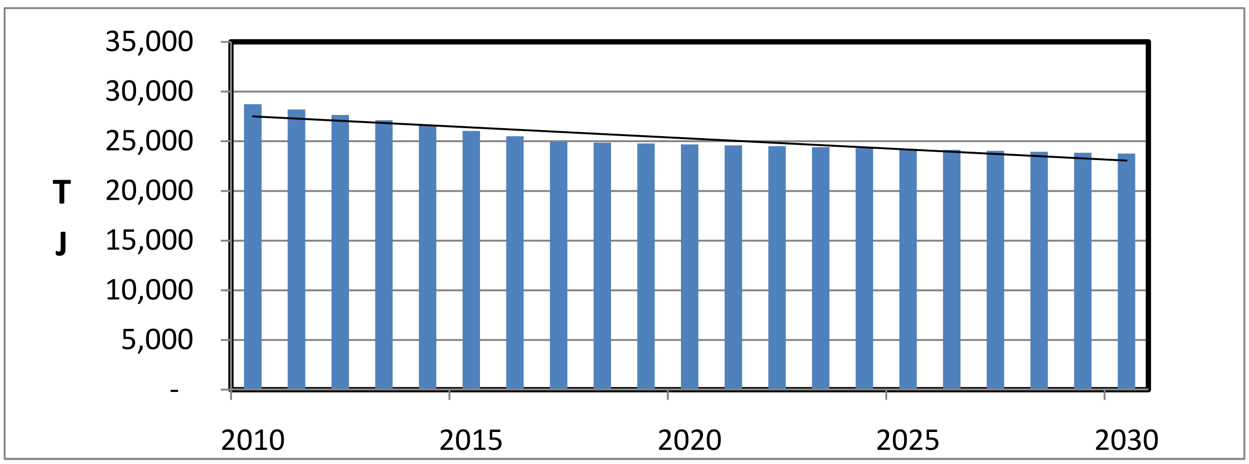
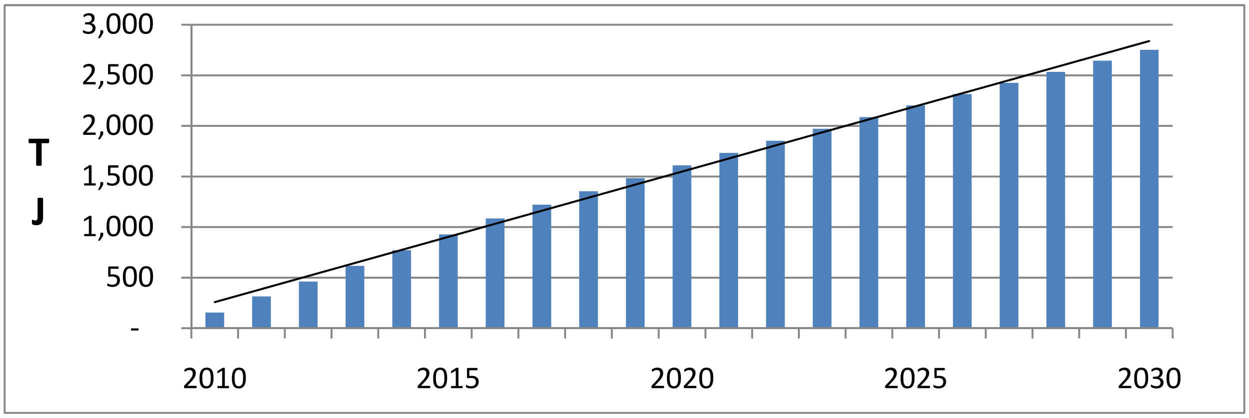


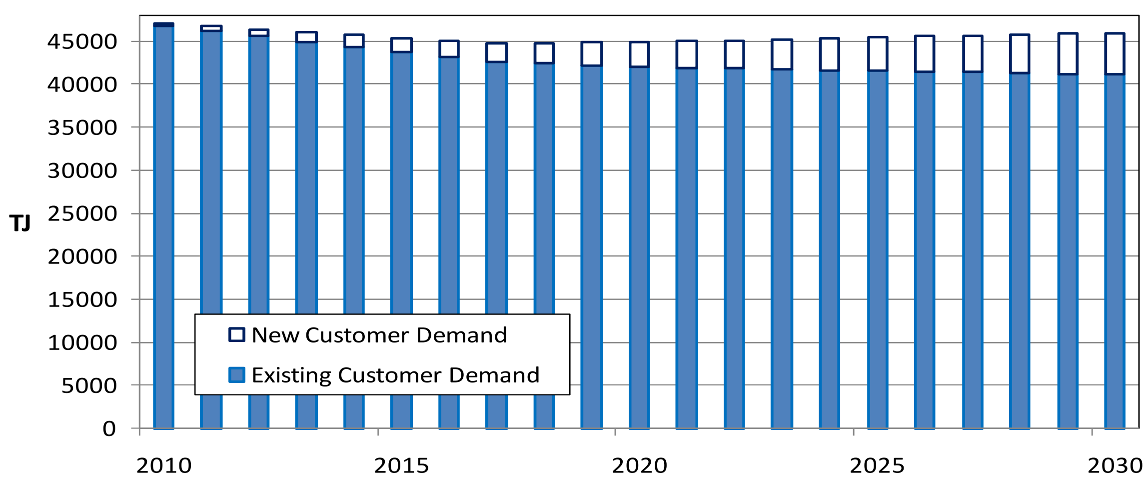
Figure 4-15: Natural Gas Demand Forecast for New Residential Customer Space Heating



Forecasting these two groups separately, and by end use will allow better consideration of the impact of new customer additions on over all annual and design day demand, and will allow the Utilities to better examine the impact, for example, of EEC programs that could speed the pace of furnace replacements among existing customers.

Figure 4-16 shows the resulting Lower Mainland Residential demand for all customers and for all end uses. While this graph shows how the above end-use analysis can get lost in the overall consumption totals, it also provides insights about where the Utilities might best focus their activities toward each of these customer groups. For example, this type of information can be used to help design energy efficiency and conservation programs.

Figure 4-16: Total Annual Natural Gas Demand Forecast for Lower Mainland Customers



Energy policy and technical ability to implement alternative, renewable thermal energy solutions are also examples of conditions that will impact new customers differently than existing customers. The current practice of multiplying average use rates by total customers within customer service classes will not permit the necessary analysis to fully examine the impacts of these conditions. An end-use approach with better consideration of new versus existing customers is needed.

Further research and analysis is required to more fully understand customers' changing behaviours, needs and energy decision making considerations, in order to employ this end use approach to demand forecasting across all service territories. While this new approach will be important for future energy planning, there remain gaps in the existing data necessary to fully apply this methodology across all customer services classes and in all service regions. The most recent REUS data has been used in developing the examples provided; however, this information needs to be supplemented with additional data and research. The Utilities will continue to refine this approach as more information about customer decisions and behaviours, as well as the performance of new technologies and EEC programs becomes available. However, for the foreseeable future, we will continue to prepare a residential customer additions and natural gas demand forecast using the traditional methodology as discussed in Section 4.2.

The Utilities have not yet explored the application of this end-use approach to forecasting of design day demand. In general, we expect to continue adding residential customers as described in Section 4.2.5, and due to the temperature sensitive nature of this demand we expect design day demand to continue growing, causing overall demand on the Terasen Utilities' systems to continue become peakier. Further, we expect the impact of the changing consumption trends among new customers to have minimal impact on overall design day demand over the next few or perhaps the next several years. Over the longer term this impact will grow; therefore, the Utilities intend to analyse the application of this end-use approach on design day demand.

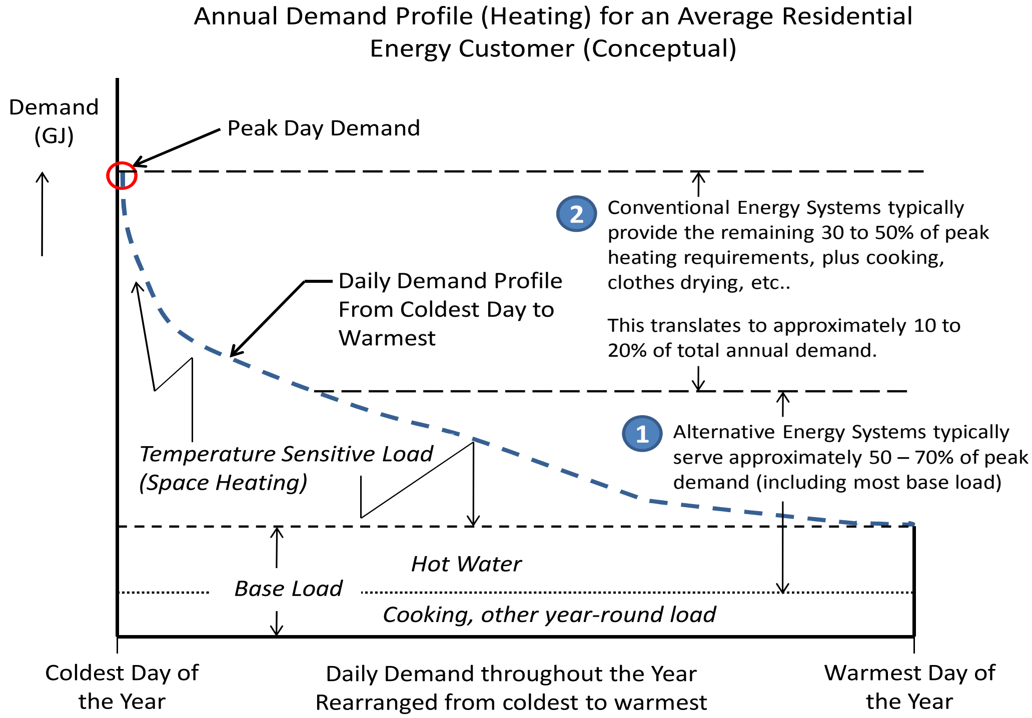
4.3.2 FORECASTING DEMAND FOR RENEWABLE THERMAL ENERGY

Delivering renewable thermal energy solutions is an important part of the Terasen Utilities low carbon energy strategy. While natural gas service will continue to form the Utilities' core business, we are growing our integrated, alternative energy solutions to better meet the needs of customers and communities. As our alternative energy services grow and evolve, the Utilities need to forecast demand for these new products and services in order to better plan for the resources we need in order to deliver them as well as to understand the impacts on our conventional natural gas demand. Forecasting demand for these services also allows us to examine the impact on carbon emissions and how best to meet this new, emerging need among our customers.

Examples of renewable, thermal energy solutions include geo-exchange, waste heat recovery and solar thermal energy systems as discussed in Section 3.1. The Utilities are improving their methodologies for forecasting demand for these solutions and, although it is not yet completely developed, the discussion below provides a conceptual demonstration of our approach. Today, the development of these new products and services remain in early stages and we expect that initial growth will be gradual, but increasing over time, allowing us to more fully develop and validate our methodologies for forecasting demand for these services over time.

Figure 4-17 illustrates how a renewable, thermal alternative energy system can impact a customer's need for conventional energy service. The graph shows thermal energy demand throughout the year for a typical residential/commercial customer[92] rearranged from the coldest day of the year to the warmest. Demand during the warmer days to the right of the graph is referred to as base load because it serves year round needs such as cooking, hot water and perhaps a small amount of space heating. As the temperature decreases (moving left along the graph) energy demand increases primarily for space heating and is highest on the coldest day of the year (peak day).

Figure 4-17: Annual Thermal Demand Profile for a Residential Energy Customer



The costs of designing a renewable thermal energy system to meet demand on every day of the year, including the coldest are extremely prohibitive. Therefore, these systems are typically designed to meet thermal energy demand for about 50 to 70% of design day, including a portion of the base load (No. 1 in Figure 4-17). This type of system can therefore serve approximately 80 to 90% of this customer's annual demand. The remainder of the demand (No. 2 in Figure 4-17) is then supplemented by conventional energy systems, which the Terasen Utilities believe is best met by natural gas where it is available.

District and discrete energy solutions are more complicated than conventional energy systems and can vary in scope and size depending on the type of solution and the individual customer

[92] For customers whose primary thermal energy need is for space heating.

needs. Very little historical data exists from which to identify potential future trends. For the purposes of explaining the concept in this LTRP, the Terasen Utilities have just considered multifamily residential condominiums and residential customers as examples for explaining the alternative energy forecasting methodology and the results of forecasting exercise example. We have discussed the impact on conventional natural gas demand and measured the impacts of these services on GHG emission reductions. The methodology for estimating demand is based on a per customer basis comparing the baseline and the alternative energy solutions to meet the same end use demand and extrapolating that for the total number of customers. At this point the total number of customers expected for each example is based on the best available information Terasen Utilities has today and is not a formalized forecast itself.

4.3.2.1 Multi-family Condominium and Apartment Buildings

One of the best opportunities to implement renewable thermal energy solutions is during the development and construction of new multi-family residential complexes and multi-unit, mixed use residential and commercial buildings. Replacing conventional energy systems in these buildings with, for example, geo-exchange, waste heat capture and solar-thermal systems in combination with conventional natural gas to meet peak demand requirements, can cost effectively improve energy efficiency and reduce GHG emissions over a greater scale than can be achieved in lower density developments[93]. Thermal energy demand in these applications includes building heating and cooling.

- **The Demand Scenario**

To demonstrate the impact of these types of systems on conventional energy demand and GHG emissions, the Utilities examined a demand scenario in which a representative 100-unit condominium building is used to model demand growth over time. The assumptions used for this analysis are provided in Appendix B-6. In the scenario, a build out of 185 such buildings is modelled over a 10 year period[94]. The energy use and emissions for the application of conventional energy systems (electricity for space heating/cooling and natural gas for water heating and make-up air) is then compared to the application of alternative renewable systems in all of the 185 buildings. The 100 unit residential building is selected as a reasonable size model to represent the market place for multi-unit buildings. The energy inputs and assumptions for the 100 unit model are provided in Appendix B-6. This scenario is set within the Lower Mainland, where a build-out of 185 such buildings over a 10 year period is a reasonable expectation[95]. A survey of builder / developer attitudes toward installing these types of energy systems (Appendix B-7) supports this expectation.

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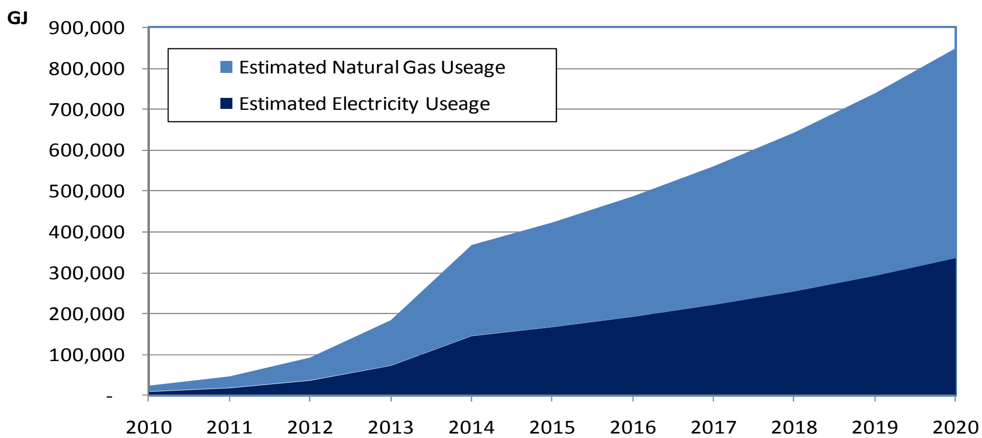
[93] When applied to a single building these integrated energy systems are referred to as discrete energy systems as compared to district energy systems that provide thermal energy to multiple buildings in a community.

[94] Since very little historic information and experience is available to inform our analyses and many uncertainties remain, we have limited our examination to a 10 year period.

[95] Extrapolating from 2008 and 2009 housing starts data, we have estimated that this build-out represents approximately 20% of the total new condominium / apartment building market over the next ten years.

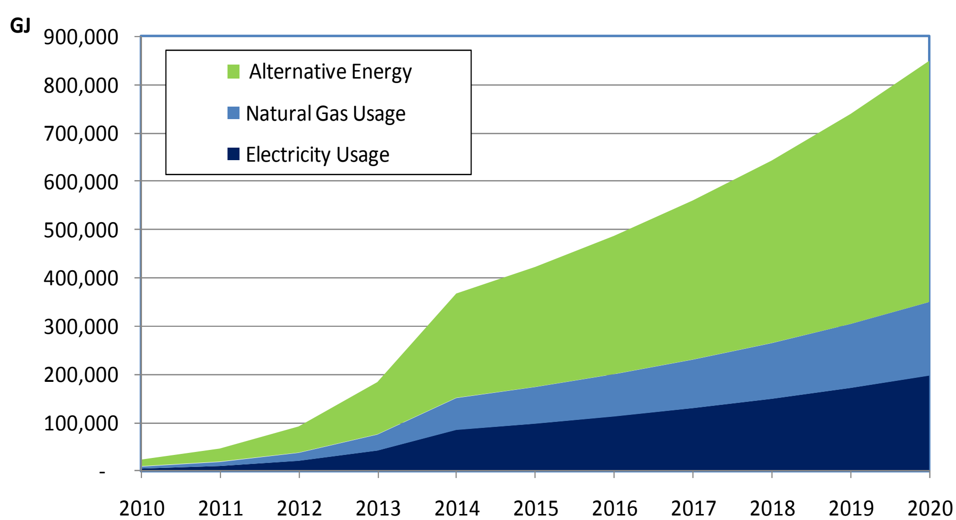
In this scenario, the number of alternative, integrated energy systems implemented in the initial years is small, but the growth rate is initially high, with the number of systems implemented doubling through the first 4 years. Beyond 4 years, growth occurs at a slower pace, resulting in a total of 185 systems at the end of the 10 year period. Figure 4-18 shows the energy delivered to heat and cool these condominium buildings through to the year 2020. The inputs into this demand curve are based on a per-customer or per-unit basis and then extrapolated for the total number of customers.

Figure 4-18: Total Annual Thermal Energy Consumption for 185 Buildings – Conventional Energy Systems



A wide variation of integrated energy systems is possible. The Utilities have modelled this scenario using a typical geo-exchange system that would serve approximately 70% of the buildings thermal energy requirements. Figure 4-19 presents the comparative electricity and natural gas usage if all 185 buildings is constructed using the integrated energy design.

Figure 4-19: Total Annual Thermal Energy Consumption for 185 Buildings - Alternative Systems



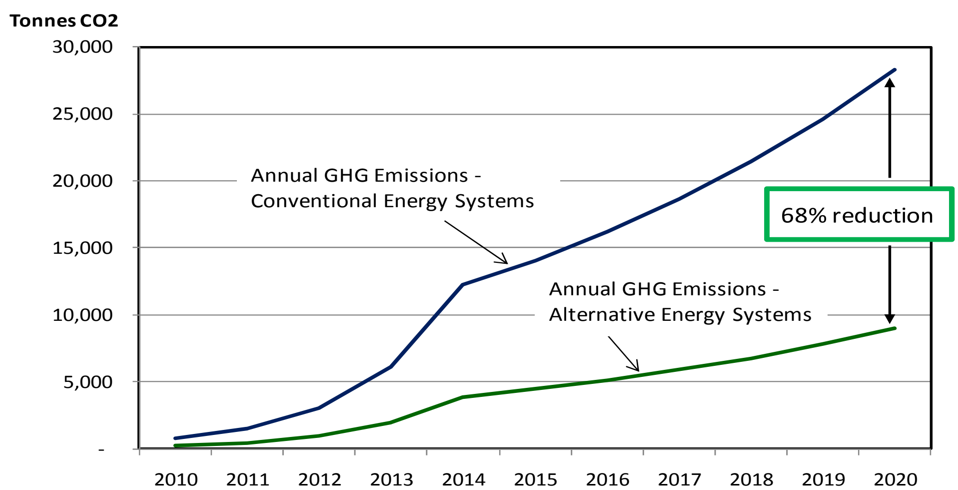
- **Natural Gas and Electricity Savings**

The implementation of renewable thermal energy systems in this scenario results in a total annual energy savings of 362,094 GJ of natural gas and 38 GWh of electricity by the year 2020. The annual natural gas savings in 2020 is approximately equivalent to removing the GHG emissions of 62,800[96] passenger cars. Cumulative natural gas and electricity savings over the ten year period are approximately 1,880,000 GJ and 199 GWh respectively.

- **GHG Savings**

The savings in both natural gas and electricity for this scenario results in the GHG reductions shown in Figure 4-20. Total cumulative GHG[97] savings over the 10 years is approximately 100,304 tonnes of CO_2e by 2020 which represents 68% reduction from the baseline emissions.

Figure 4-20: GHG Emissions Comparison for 185 Buildings – Conventional vs. Alternative energy Systems



4.3.2.2 Residential Single Family Homes and Townhouses

The Terasen Utilities conducted a similar demand scenario for lower density residential developments, again in the Lower Mainland setting. A range of alternative energy solutions exists for the single family home and townhouse type developments, including air source heat pumps, ground source heat pumps (GSHP), solar thermal and high efficiency, on demand type energy systems that use conventional energy sources. These systems can improve energy efficiency and reduce GHG emissions, and may reduce annual energy costs.

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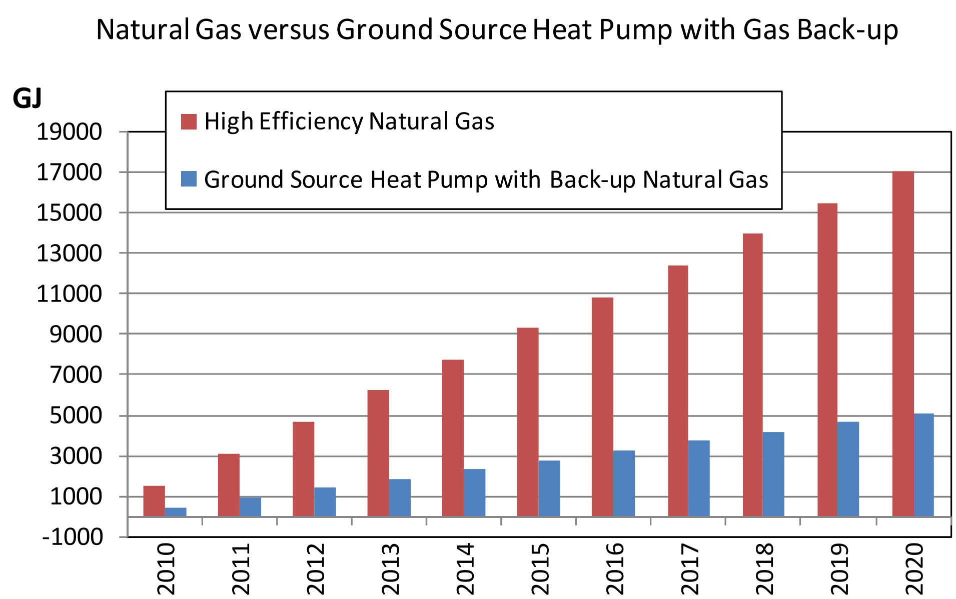
96 Number derived using the US Environmental Protection Agency, Greenhouse Gas Equivalency Calculator.
97 Based on a GHG emissions factor of 0.0510 tonnes per GJ for Gas and 0.0061 tonnes per GJ for electricity, from the Greenhouse Gas Emission Assessment Guide for British Columbia Local Governments, February 2008.

Each of these systems, however, presents implementation challenges, such as the high cost of installation and equipment and the increase in peak load for the conventional energy system used as a back-up for the alternative energy during peak demand periods. The demand scenario we have examined compares the application of a ground source heat pump with natural gas back-up to a conventional energy system using 90% or higher efficient heating equipment in new, single family homes. At this time, the comparison is limited to space heating demand. The ground source heat pump system is assumed to meet approximately 70% of the dwellings' annual space heating energy requirements.

Due to the high equipment and installation costs for ground source heat pumps, the Terasen Utilities believe implementation of this energy choice will be quite limited in spite of the energy savings and GHG reduction benefits. We estimate that the current level of energy efficiency and conservation program funding (discussed in Section 5) that is available as part of the Innovative Technologies portfolio, could support the implementation of this technology in about 33 homes per year. For this scenario, we have assumed this level of funding is available and therefore this level of implementation occurs for the next 10 years. A comparison of natural gas consumption is presented in Figure 4-21. The total number of systems implemented reaches 694 and the resulting cumulative natural gas and GHG savings are 71,600 GJ's and 3,651 tonnes of CO_2e, respectively.

Figure 4-21: Annual Space Heating Energy Comparison - Single Family Dwellings



4.3.2.3 District Energy Systems

Development of district energy systems (also called community energy systems) that combine renewable thermal energy technology with conventional, supplementary energy to serve the thermal energy needs of an entire community is an important priority initiative for the Terasen Utilities. Energy comparisons for district energy systems can be conducted using similar methods to those described above for condominium / apartment buildings and single family dwellings. Each district energy system, however, is very unique in the technology and source energy combinations employed and the wide ranging end-uses served within each community. The Utilities are continuing to examine the potential comparisons that might be made for alternative, renewable energy systems versus conventional energy technology within district energy systems in order to improve demand forecasting and scenario analysis for these types of systems. Although final results of such comparisons are not yet available for more detailed discussions, general conclusions on energy savings and GHG reductions can be made by increasing the scale of the results from the condominium / apartment and single family dwelling scenarios to that of a complete community.

4.3.2.4 Commercial and Industrial Renewable Thermal Energy

Modelling the potential demand for commercial and industrial thermal end uses is also a very complex exercise. A broad variation of commercial and industrial end uses for thermal energy exist, from basic space and water heating needs to high temperature and pressure cleaning applications to balancing thermal energy needs of sports complexes. For many of these applications, forecasting future demand is subject to market cycles and trends that are different from those impacting housing markets. Many industrial processes require higher and more consistent temperatures than can currently be achieved by the types of renewable thermal energy initiatives the Utilities are advancing.

In some cases; however, the Utilities will be delivering renewable thermal demand for commercial applications as part of their energy services to mixed use buildings and communities. As such, we will continue to explore the application of forecasting methodologies for renewable thermal, alternative energy solutions to these customer groups, including conducting additional market research on commercial and industrial needs and intentions for thermal energy.

4.3.2.5 Conclusions and Implications for Thermal Energy Demand Forecasting

The methodologies, scenarios and examples described above for forecasting thermal energy supply and resource needs are still in development. While initially, the scale of development of these alternative energy systems will be slow compared to the Utilities core natural gas business, we expect the focus on developing these services today will result in growing market penetration in future years. Therefore, the impact of implementing these solutions on natural gas demand the Utilities existing customers will be limited in the initial years. The Utilities need to be applying resources to the forecasting of demand scenarios for these services in order to better understand their impact over time on our natural gas infrastructure, annual and design day demand, system capacity needs and rate design issues. As such, we need to be acquiring additional tools, data, research and resources today that are needed to fully develop and implement these forecasting approaches. The Utilities will also continue to apply the proven and accepted traditional natural gas forecasting methodologies discussed in Section 4.2 for the foreseeable future.

The examples and observations in new methodologies developed for this LTRP are so far limited to achieving energy savings and emission reductions, and developing resources to meet the energy needs of our customers and the targets set out in government policy. The analyses become much more complex when including costs and rate impacts over time. These additional studies are, however, vital in understanding the implications of policies that government at all levels implement and the initiatives that utilities pursue. To this end, the Terasen Utilities intend to continue working with other B.C. utilities with the objective of developing a complete, base-line forecast for thermal energy demand in the province against which alternative future scenarios and energy mixes can be compared. The Utilities are also continuing to model[98] a range of energy comparisons across housing types and throughout their service regions to understand the implications of various energy initiatives that are or may be undertaken in the province such as adopting EnerGuide for Houses 80[99] as a building code compliance requirement. The results of these comparisons will be discussed in future submissions to the Commission by the Utilities.

4.3.3 DEMAND SCENARIOS FOR NATURAL GAS AS A TRANSPORTATION FUEL

In addition to the carbon reduction and air emission benefits of using natural gas as a transportation fuel, demand growth from increased adoption of NGV solutions in B.C. will help to optimize the use of the Utilities existing infrastructure, to the benefit of all of the Terasen Utilities' customers. The Utilities expect the future development of B.C.'s NGV market to be quite different than past experience (described in Section 2). Low carbon transportation fuel requirements have been legislated, the fuel price advantage for natural gas over conventional diesel and gasoline has improved further, all levels of government are increasing their focus on reducing transportation related emissions, and proven technology ready for commercial use is readily available. This changing planning environment has resulted in the development of new NGV initiatives for the Terasen Utilities and hence the examination of future NGV related demand growth scenarios outside of our traditional natural gas demand forecast.

Today, the total number of NGVs fuelled by the Terasen Utilities is approximately:

- 550 light duty vehicles; consisting of 500 passenger cars and trucks and 50 light duty Terasen Utilities fleet vehicles[100];
- 30 medium duty delivery vans; and

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[98] HOT 2XP and HOT 2000 are energy modelling software available from NRCan that the Terasen Utilities are using to model a range of energy comparisons in each of their service regions.
[99] NRCan energy rating system for homes: http://oee.nrcan.gc.ca/energuide/home.cfm
[100] Terasen fleet vehicles are scheduled for regular operations in the fall of 2010.

- 50 urban transit buses.

Looking ahead, the target market for the Utilities' NGV initiatives has changed, with return-to-base fleet operations being the most promising near-term adopters and availability of LNG as a transportation fuel increasing the number of potential NGV applications. Original equipment manufacturers have responded to the needs of this market segment and the changes in the marketplace by making a wider range of NGV equipment available in North America. This section describes the Utilities examination of potential future NGV related natural gas demand, beyond the expectations included in our current, conventional demand forecast.

Although prevailing government policy and objectives, and social attitudes have created an environment of acceptance and need for more NGV development, there are remaining challenges to more widespread implementation, such as the lack of a complete service offering including fueling infrastructure and the incremental cost of natural gas fuelled equipment over conventional diesel and gasoline equipment. Further details about the Utilities' new NGV initiatives and why we are well positioned to overcome these challenges are contained in Section 3.

The use of incentive funding through Energy Efficiency and Conservation - Innovative Technology programming (discussed in Section 5) is part of the solution to encourage increased adoption of NGV solutions. The Utilities have developed three demand scenarios for natural gas specifically as a transportation fuel by using the incentive funding as an initial market driver to increase awareness and adoption in the short term. Over the longer term, these scenarios also rely on a market transformation to wider adoption, catalyzed by the Utilities' Innovative Technology incentives and NGV initiatives.

Although new growth in NGV related demand for natural gas is expected, a number of challenges exist in developing a demand forecast. For example, historic sales of NGV medium and heavy-duty trucks sold in B.C. are negligible, providing little market data to inform future demand forecasts. The Utilities have therefore used a number of other information sources and techniques to develop a range of three alternative future demand scenarios. These scenarios are largely developed by incorporating historical NGV transportation load, potential future incentive funding as well as external factors such as market acceptance, OEM availability, government policy, government incentives, and macro-economic conditions. The scenarios allow a discussion of the benefits and implications for increasing throughput on the Utilities' natural gas system and reductions in GHG and other transportation related emissions.

The Utilities will continue to develop their methodologies for forecasting demand for these solutions. As demonstration projects and first adopters in the province show success and the remaining challenges to implementing complete solutions are solved, we expect that NGV solutions will be adopted at a faster pace as businesses seek out their environmental benefits and operational cost advantages. As that occurs, the Utilities will validate and refine the underlying assumptions on fuel consumption and market uptake, and incorporate load growth expectations from this market into its natural gas demand forecast.

4.3.3.1 Target Market segments

B.C.'s total transportation energy use in 2007 was 370 PJ from all fuel types[101]. The long term target market for the Terasen Utilities, which includes light and medium-duty trucks, heavy duty trucks, buses and marine applications, represents the majority of this demand at 292 PJ of total energy use[102]. Table 4-4 shows 2007 fuel consumption for the various transportation sectors in B.C. Capturing even a small portion of this overall market can result in a significant increase in natural gas throughput for the utilities, which benefits existing customers and can achieve large emission reductions for new customers.

Table 4-4: 2007 Transportation Fuel Consumption by Category in B.C.

Category	Fuel Type (PJ)				
	Gasoline	Diesel	Heavy Fuel Oil	Other	Total
Passenger Cars	64.1	0.6	-	1.4	66.1
Light Duty Trucks	75.8	0.3	-	2.3	78.4
Medium Duty Trucks	7.2	13.7	-	-	20.9
Heavy Duty/Vocational Trucks	-	66.0	-	-	66.0
Buses	0.2	5.3	-	0.6	6.1
Marine	-	12.2	42.1	-	54.3
Total:	147.3	98.1	42.1	4.3	291.8

Source: NRCan, 2007

Notes:
- Does not include school buses.
- Heavy duty trucks and vocational trucks are combined as both consume 100% diesel.
- Other includes propane, natural gas, and electricity

4.3.3.2 Per Vehicle Use Assumptions for NGV Demand Scenarios

The Terasen Utilities used market information acquired from pilot projects, project engineering work, industry partners, and suppliers to develop reasonable estimates on vehicle consumption for each vehicle segment in the target market. We believe industry data is more representative of the target market that is being pursued. Under all three scenarios, the NGV consumption in GJ is determined by applying a conversion factor – referred to as Diesel Litre Equivalents103 ("DLE") – to the fuel consumption data for conventional fuel vehicles. This conversion creates a comparable assessment of the energy use from diesel versus natural gas. These values are held constant for each of the scenarios. Table 4-5 shows the natural gas consumption as well as the average distance travelled for vehicles in each of the categories. Appendix B-8 describes the basis on which these vehicle consumption estimates are made.

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[101] From NRCAN 2007
[102] Target market does not include motorcycles, passenger air, freight air, passenger rail, freight rail, off-road vehicles, and school buses. These sectors represent approximately 78 PJ.
[103] The conversion is based on energy content values published in the NRCan GHGenius model. (Diesel at 38.653 MJ/litre – yields conversion factor of 25.9).

Table 4-5: Natural Gas Consumption and Average Distance Travelled for B.C. Vehicle Categories

Category	Scenario Assumptions	
	Annual Consumption per Unit (GJ)	Total Annual # of Kms
Passenger Cars	100	17,500
Light Duty Trucks	170	20,000
Medium Duty Trucks	450	20,000
Heavy Vocational Trucks	800	40,000
Heavy Duty Trucks	2,500	300,000
Buses*	1,840	70,000
Marine	92,000	65,000

* Does not include school buses

4.3.3.3 NGV Demand Scenarios

While many NGV demand scenarios are possible, the Terasen Utilities have identified a combination of factors that we believe provide a reasonable range of future demand for transportation fuel solutions. The "Favourable NGV Environment" scenario provides a most likely case compared to the others, reflecting current conditions based on the best available industry information combined with current energy and emission policies. The "Plus Passenger Vehicles" scenario examines the potential additional demand above the Favourable Environment scenario if a renewed commitment by the government and/or transportation industry toward passenger vehicle NGV solutions is made. The "Low NGV Demand Growth" scenario models a minimum likely amount of NGV demand growth, based on the momentum of recent carbon legislation and the efforts of businesses to competitively differentiate based on environmental stewardship practices.

- **Favourable NGV Environment Scenario**

The Utilities believe that the Favourable Scenario is the most likely of the three NGV demand scenarios developed, as it is based on the current positive external opportunity for increased adoption of NGV solutions as described in the introduction. This scenario is based on the best possible information available today on expected vehicle growth in the defined target segments, continued incentive funding expectations, favourable natural gas prices and availability of fueling infrastructure. The assumptions underlying this scenario are:

- Adoption of NGV solutions over the long term across all the identified target market segments except passenger cars;
- Incentive funding will continue to be a driver to reduce the initial incremental capital cost across the entire target market segments excluding passenger cars;

- In the later years, there is widespread adoption and uptake of NG vehicles from the success of the initial pilot projects;
- Public policy will continue to support the use of NG as a transportation fuel to meet climate action legislative targets;
- NG commodity prices will continue to remain favourable against other fuel types as more shale gas comes online;
- Economies of scale will help push the initial capital costs for natural gas fuelled equipment down over the longer term;
- Availability of targeted fueling infrastructure supporting the expected demand and uptake;
- Availability of OEM vehicles and improvements in conversion technology across light duty and medium duty vehicles where it is not prevalent today.

In this scenario, the Terasen Utilities forecast net cumulative transportation growth of 34,540 vehicles by 2030 which results in approximately 30 PJ. Table 4-6 shows the expected rate of adoption over the 20 year planning horizon. The total number of vehicles each year is multiplied by the per vehicle consumption across each vehicle category to estimate the total annual NGV demand.

Table 4-6: Total Number of Expected Vehicles by Category – Favourable NGV Environment Scenario

Category	Total Number of Vehicles – Favourable NGV Environment					
	2010	2011	2015	2020	2025	2030
Light Duty Trucks	550	550	1,000	5,000	10,000	20,000
Medium Duty Trucks	30	30	100	500	1,500	2,000
Heavy Vocational Trucks	-	25	200	1,000	3,000	5,000
Heavy Duty Trucks	-	9	200	1,000	3,000	6,000
Buses	50	75	250	750	1,000	1,500
Marine	-	-	1	5	20	40
Total:	630	689	1,751	8,255	18,520	34,540

Note: Passenger Car segment is not pursued by Terasen Utilities in Favourable NGV Environment Scenario

The Terasen Utilities believe that this is a reasonable estimate of future market penetration for our NGV initiatives, given the current and emerging low carbon fuel policy environment and emerging business drivers for adopting NGV solutions.

- **Plus Passenger Vehicles Scenario**

The Plus Passenger Vehicles scenario illustrates the magnitude of additional consumption that could occur above the level set by the Favourable NGV Environment Scenario if the momentum of new NGV initiatives causes renewed interest and development of NGV solutions in the passenger vehicle market category. Although there are numerous factors that can affect consumption levels, the following items occurring concurrently are viewed as the main additional drivers in this scenario:

- Increased incentive funding available from Government and from EEC programs to encourage widespread adoption of NG across all market segments including passenger cars;
- The natural gas price advantage continues to widen with respect to other fuel types;
- Public policies are formed to encourage use of NG across certain segments like heavy duty and medium duty trucks to aggressively reduce GHG's;
- Tax breaks are provided to further encourage customers to adopt NG and other low carbon vehicles;
- A renewed commitment by the government and / or fuel retailers to make fueling infrastructure for passenger vehicles publicly available; and
- Auto makers re-enter the OEM market with natural gas passenger vehicle products at competitive prices.

The Terasen Utilities forecast net cumulative transportation growth of 94,500 vehicles and total energy use of approximately 36 PJ by 2030 under the Plus Passenger Vehicles Scenario. While reachable, this scenario envisions additional government and transportation industry intervention to advance the adoption of NGV solutions in the B.C. passenger vehicle market to capture almost 6% of that market by 2030. This additional market capture is not anticipated in the near future and is not part of the Utilities new NGV initiatives, and is therefore considered less likely to occur than the Favourable NGV Environment Scenario.

- **Low NGV Demand Growth Scenario**

Given the current provincial policy environment, existing incentive funding for implementing NGV solutions, and growing industry interest in employing these incentives, the Utilities believe that at minimum, a modest level of NGV growth will occur even in a less favourable environment than outlined in the previous scenario. The Low NGV Demand Growth scenario depicts the lower bound of future consumption that could reasonably occur. The drivers that would cause this lower level of future demand for natural gas as a transportation fuel are:

- Incentive funding leads to market growth and vehicle additions but fails to stimulate wider adoption beyond the funded projects;
- Natural gas prices remain favourable versus conventional fuels but are insufficient to drive higher levels of growth;
- Public policy measures to encourage the use of NG as a transportation fuel are less aggressively pursued;
- Limited new OEM models are made available for this market in B.C., particularly in the light duty truck category.

The Terasen Utilities forecast net cumulative transportation growth of 16,280 vehicles and total energy use of approximately 13 PJ by 2030 under the Low NGV Demand Growth scenario. Due to the high level of public and government focus on reducing emissions from the transportation sector, we believe this scenario is less likely to occur than the Favourable NGV environment scenario.

4.3.3.4 Scenario Implications

Figure 4-22 shows the load growth and total number of NGVs expected in each of the three NGV demand scenarios. The Utilities have estimated[104] that in the Favourable NGV Environment Scenario, 30 PJ of natural gas demand for transportation represents about 6.5% of the total target transportation market in 2030 (Figure 4-23). Capturing 6.5% of the transportation fuel market over the next 20 years is a reasonable expectation for this low carbon alternative to conventional fuel.

[104] Estimation based on the assumption that the current target market size grows at approximately 2% per year, equal to rate of GDP growth, based on current 5 year B.C. Ministry of Finance GDP forecast.

Figure 4-22: Comparative NGV Demand Scenarios

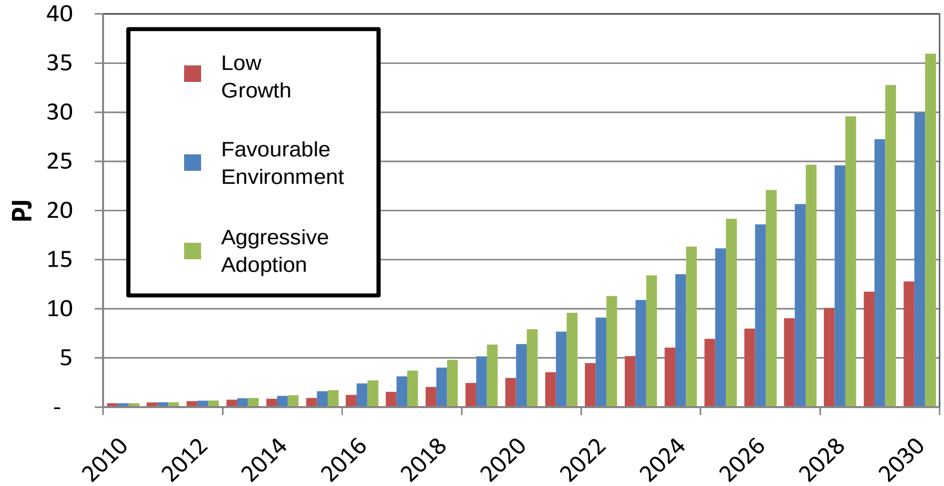
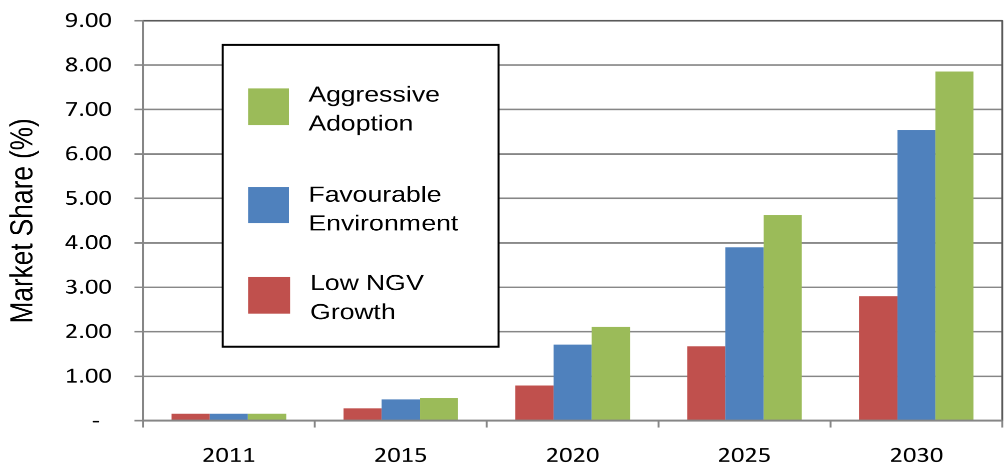


Figure 4-23: Demand Scenario NGV Share of Transportation Market



Approximately 15% of diesel demand can be replaced by natural gas in this scenario, contributing approximately 77% of the total 844,000[105] tonnes of CO_2e emissions. The amount of GHGs reduced in the Favourable Environment demand scenario is the same amount created by burning approximately 360 million litres of gasoline. Figure 4-24 shows the total cumulative GHG savings for each of the three demand scenarios at 5 year increments over the planning horizon. The Low NGV Demand scenario results in half the GHG reductions possible in the Favourable NGV Environment Scenario and falls well short of helping to meet provincial goals for carbon reduction.

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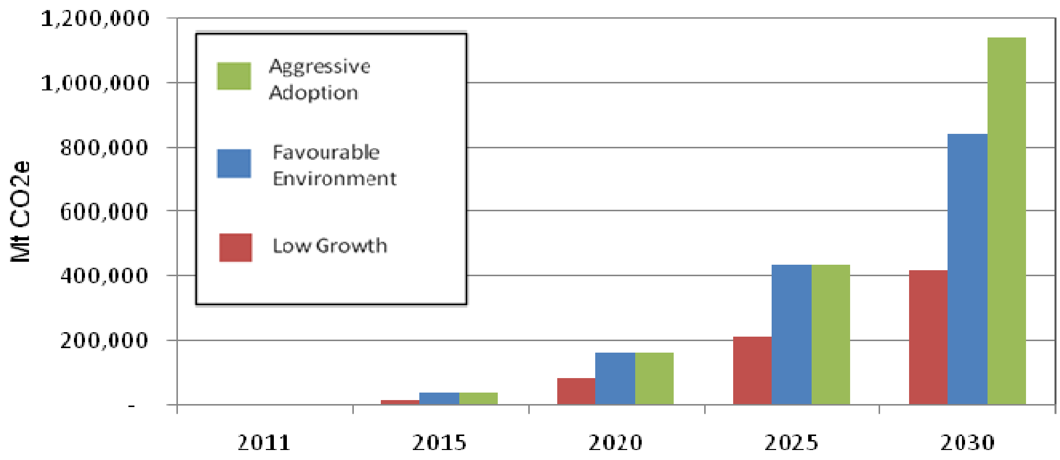
[105] Based on emissions factors of 1,433 grams per kilometre for diesel, 1,149.7 g/km for CNG and 1,035.1 g/km for LNG, published in GHGenius 3.17 software available from NRCan.

Figure 4-24: Three Scenarios - Total Cumulative GHG Reductions (Mt CO2e)



4.3.3.5 Transportation Demand Scenario Conclusions

The changing nature of market conditions for NGV solutions in B.C. has opened up an important new target customer segment for the Terasen Utilities. The Utilities believe that demand growth of 30 PJ over the next 20 years, representing just 6.5% of the overall market for transportation fuels, is a reasonable expectation for natural gas load from its new NGV initiatives. This expectation arises from the favourable market and policy environment that continues to evolve in B.C. together with the new NGV solutions that the Utilities are developing to meet the needs of the commercial, return-to-base, fleet vehicle market segment.

The addition of 30 PJ of throughput on the Utilities natural gas transmission and distribution systems will be an important offset to the levelling off of demand growth from residential and commercial customer segments as improvements in energy efficiency and adoption of alternative, renewable thermal energy solutions begins to make a marked impact in future years. This additional throughput will help to optimize use of the existing natural gas infrastructure to the benefit of all of the Utilities' customers.

4.3.4 CONCLUSIONS FOR NEW FORECASTING ACTIVITIES

The Terasen Utilities' forecasting activities are evolving to capture the changes that are underway in our customers' energy demand patterns as a result of external forces such as changing energy policy and buildings codes and standards, as well as our own initiatives to better serve the needs of our customers. While these changes will not have a marked impact in the short term on natural gas demand, we need to be developing new methodologies in forecasting now to better understand the implications over the long run. The Utilities intend engage their stakeholders in the ongoing development of these new forecasting activities, and will continue to improve our methodologies as we gain further market experience and as new information becomes available.

New, alternative energy initiatives by the Terasen Utilities, increased and ongoing EEC activities and implementation of new building codes and standards have the potential to impact growth in annual and design day demand. While the utilities expect to continue adding new natural gas customers as these changes occur, the nature of the demand may well become peakier as natural gas back stops the peaking needs of integrated, renewable thermal energy solutions (Figure 4-17 during extreme cold weather. This shift could in turn affect the natural gas system design and gas supply planning requirements as the demand characteristics of a growing proportion of new customers differs from that of existing customers.

The extent of these impacts and rate of change in demand characteristics is difficult to determine at this early stage of these new energy initiatives. The new methodologies discussed in this section, once fully developed and validated, will help the Utilities better understand the potential implications for long term resource planning and rate design.

The Utilities will also continue to develop methodologies to forecast energy demand as part of their integrated, alternative energy services and new natural gas vehicle initiatives, in order to plan for the natural gas and alternative energy resources needed to deliver these solutions. Implementation of alternative energy solutions for residential and commercial buildings and entire communities has the potential to significantly reduce conventional energy demand and carbon emissions over time. Increased adoption of new natural gas vehicle solutions can significantly reduce GHG emissions while building efficient, year-round load, countering the declines on system throughput caused be declining residential use rates. The growth in natural gas demand for transportation of 30 PJ forecasted for these new NGV initiatives by year 2030, will be important for adding baseload to the natural gas system and optimizing its use for the benefit of all the Utilities' customers.

A substantial effort will be required in the coming months to undertake these new forecasting activities, fully develop and validate the new methodologies and use them to assess the changes ahead. The tools, data, research and resources needed for these activities will also help to analyze the potential impact of future policy decisions and energy initiatives by governments, energy customers and utilities. To these end, the Terasen Utilities will continue working with other utilities and governments to understand the complete nature of thermal energy demand within the province. All of this new work will need to be done alongside our ongoing traditional forecasting processes as these will remain the primary input into our natural gas system and supply planning activities for the foreseeable future.

5 ENERGY EFFICIENCY AND CONSERVATION – DEMAND SIDE RESOURCES

5.1 The Purpose and Benefits of Energy Efficiency and Conservation

EEC programs are an integral part of the Terasen Utilities' drive to meet British Columbia's current and future energy needs and ensure the efficient use of natural gas in its service territories. Implementing EEC helps to lower energy demand, ensure the right fuel for the right use, optimize the use of and cost for energy infrastructure and reduce the carbon footprint for all our customers. Since 1992, we have been operating EEC programs and initiatives which provide incentives and support customers in reducing their consumption of natural gas. Going forward, it is important for the Utilities to secure ongoing funding to provide consistent programs to the market and thereby maximize the benefits of EEC initiatives. While the Utilities' EEC activities align with the B.C. Government's recent energy and climate actions, we believe that the current cost-benefit criteria for some programs are outdated and limit the benefits that can be delivered for emission reductions and for certain customer groups such as low income earners. Recent energy policy and legislation (see Section 2) places a high level of awareness and importance on environmental and energy use issues.

Changing building codes and equipment standards have also led to increased public awareness and interest in energy saving measures. The Terasen Utilities are committed to providing the resources to help consumers reduce energy consumption through cost effective conservation programs. This section describes our current EEC activities, and outlines a future for long-term, sustained EEC activity.

Residential Energy and Efficiency Works – REnEW

(February and March 2010)

Funded by:	Terasen Gas, FortisBC, and BC Hydro
Developed by:	John Howard Society and Vancouver ACCESS BladeRunners
Targeting:	Individuals who are overcoming employment barriers because of life challenges such as mental health issues, a history of substance abuse, poverty or homelessness
Duration:	Four weeks intensive training
Location:	Kelowna and Vancouver

Left to right:
Jan Marston (VP, Customer Care, Human Resources & Operations Governance – Terasen Gas), REnEW program participant, and John Webster (CEO and President of ACCESS)

5.2 An Overview of EEC Funding

One of the items in the 2008 RP Action Plan was to "*implement the new EEC programs and continue research and planning for future EEC programming".* The 2008 Resource Plan provided an overview of the EEC application that was submitted to the BCUC in May 2008, requesting $56.6 million over three years for EEC activities. On April 16, 2009, the Commission released its decision and Order No. G-36-09 (the "EEC Decision"), which approved funding in aggregate of $41.5 million ($34.4 million for TGI and $7.1 million for TGVI) for EEC activities to the end of 2010.

In June 2009, TGI and TGVI filed their 2010-2011 Revenue Requirements Applications, requesting the following approvals:

- An increase in EEC funding to add programs for Interruptible Industrial customers (TGI only) and Innovative Technologies.
- Reallocation of funding to Affordable Housing initiatives.
- Additional funding to implement programs until the end of 2011 and an extension of the funding approved by the Commission in the EEC Decision of April 2009.

The Commission approved the TGI and TGVI Negotiated Settlement Agreement[106], which brought the total funding for EEC activities to $72.3 million for both service territories in 2010 and 2011, as can be seen in Table 5-1. In their 2009 EEC Annual Report, the Utilities reviewed 2009 EEC activities, and outlined an action plan for 2010[107]. Results of this review showed that 2009's activity was cost-effective with a portfolio-level Total Resource ratio of 1.2, providing value to customers and British Columbia's energy system.

Table 5-1: Total Approved EEC Funding 2010-2011

($000s)	TGI		TGVI	
	2010	2011	2010	2011
Residential and Commercial Programs	23,075	23,075	4,726	4,726
Affordable Housing	2,400	2,400	600	600
Industrial Interruptible	435	1,875	-	-
Innovative Technologies	2,300	4,669	478	956
Total	**28,210**	**32,019**	**5,804**	**6,282**

EEC activities align with customer, utility and government interests, while helping to protect the environment and stimulate B.C.'s green economy. Utilities such as the Terasen Utilities are a

[106] BCUC Order Numbers G-141-09 for TGI and G-140-09 for TGVI
[107] Energy Efficiency and Conservation Programs, 2009 Annual Report: http://www.terasengas.com/_AboutUs/RatesAndRegulatory/BCUCSubmissions/default.htm

vital tool in reaching British Columbia's energy goals, because utilities have a long-established relationship with their customers, with frequent customer communications, and because customers look to their energy providers for information about managing energy consumption. Going forward, the Utilities look to secure long-term funding for EEC activities to continue supporting customers in managing their energy consumption and costs, ensuring the efficient use of natural gas, and backing British Columbia's energy needs and policy goals. Later in this section, the Utilities present a review of three future funding scenarios to help identify energy and GHG emissions savings potential and guide further analysis and discussions regarding future EEC funding.

5.3 EEC Programs Overview

The current portfolio includes our conventional EEC Residential, Commercial, and Affordable Housing programs, as well as some NGV initiatives. These programs will be implemented through 2011 and are projected to conserve over 12,000,000[108] GJs for the entire planning period, which is equivalent to heating ~126,000 homes[109] for one year (please refer to Appendix C for a full list of 2009 and 2010 programs). However, we have reason to believe that the total savings might be underestimated for two reasons. Firstly, the portfolio does not incorporate energy savings from Innovative Technologies (besides some NGV activities) or Interruptible Industrial programs. These areas are new to the EEC portfolio and new initiatives are not expected to be implemented until late 2010 and 2011; given that the Utilities have not previously had programs in these areas, and have no experience in estimating savings for these areas, we felt that a conservative approach would be appropriate. Once there are programs up and running, savings from Interruptible Industrial and Innovative Technologies programs will be incorporated into the portfolio benefit/cost analysis. Secondly, the Terasen Utilities are not only focusing on reducing energy consumption through a variety of incentive and upgrade programs, but also by inducing conservation behavioural changes through Education and Outreach. Conservation from behavioural changes, however, has not been incorporated into the Utilities' savings portfolio because of the difficulty tracking results from individual actions. Nevertheless, the Utilities believe that there is a significant potential to decrease consumption through the Education and Outreach activities. For example, turning off pilot lights in fireplaces during the summer, can reduce the energy consumption of a household by ~4 GJs[110] for the season.

Current EEC initiatives can be divided into two components: conservation activities and high carbon fuel switching activities. High carbon fuel switching programs[111] were approved by the

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108 We estimate conventional EEC programs will conserve a cumulative total of 14,000,000 GJs over the next 20 years, while conversions and adoptions of NGVs are expected to increase demand by 2,000,000 GJs in total.

109 Based on a home utilizing 95 GJs per year, the average of Terasen's current Rate 1 (Lower Mainland Residential) customers.

110 1035 BTU's/ cubic ft. X 24 hours/day X 30 days/month = 745,200 BTU's/month Because 1 GJ = 948,213 BTU's, the pilot light will use .7859 GJ's/month

111 High Carbon fuel switching programs encourage customers to convert from higher carbon fuels such as propane, diesel, and oil to natural gas.

Commission as an EEC initiative because they reduce GHG emissions, increase the efficiency of the Terasen Utilities infrastructure and lower the system cost per user which in turn reduces energy costs for customers. These activities align with the government's goal to reduce GHG emissions by 80% by 2050[112]. A prime example of high carbon fuel switching activities is incentives for NGVs, which is reviewed in Section 5.4.2.

Going forward, we propose to create programs that support a holistic approach to energy efficiency, including whole building initiatives such as labelling and the move to a performance-based building code. We will continue to develop initiatives intended to assist low-income households in reducing energy consumption, making rental accommodations more energy efficient, as well as developing programs for students in the Utilities' service areas.

5.3.1 EEC FOR CUSTOMERS IN TERASEN GAS (WHISTLER) INC.

TGW has not traditionally offered EEC programs because the customer base in the TGW service territory has historically been quite small, and recovery of EEC costs spread over the small number of customers in TGW was thought to result in unacceptably high rate impacts. While TGW did not claim any EEC program savings from the Whistler conversion, the project was instrumental in achieving carbon emission reductions through high to low carbon fuel switching and provides an improved energy platform for future EEC activity. In response to community interest in participating in EEC programs, TGW plans to include funding for EEC activity in its RRA for 2012. The CPR that we will be conducting in late 2010 will provide insight into potential programs that can be implemented in the TGW service area.

5.4 New EEC Program Areas Commencing in Late 2010

5.4.1 INTERRUPTIBLE INDUSTRIAL CUSTOMERS

TGI believes that there is significant potential for a reduction in Interruptible Industrial[113] consumption. Initiatives are currently being developed for this segment, but it is not yet clear how future load will be affected by conservation efforts. To assist TGI in determining the size and nature of EEC opportunities for this sector, an overall analysis of the industrial sector will be included in the CPR, which will be conducted in late 2010. In contrast to some of TGI's other consumer segments, special consideration must be given to mitigating the risks associated with large financial investments in energy efficiency for interruptible industrial customers and the resulting magnitude of the anticipated energy savings. The Terasen Utilities have hired an Industrial Program Manager to begin working with key stakeholders in this segment and developing programs to be implemented in 2011.

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[112] Greenhouse Gas Reductions Targets Act, 2008
[113] Interruptible industrial customers include customer classes 7, 22 and 27.

5.4.2 INNOVATIVE TECHNOLOGIES

Innovative Technologies are defined as market ready technologies that have little or no market penetration in British Columbia. The Terasen Utilities' incentives for this portfolio are designed to promote emerging technologies. The current portfolio of Innovative Technologies includes Solar Thermal Hot Water, NGV, Hydronic and Combination Heating Systems, Residential Ground Source Heat Pump ("GSHP") Systems and Commercial/Industrial GSHP Systems. We are conducting market research to determine potential programs for these technologies, and their associated savings. It should be noted that the technologies in this portfolio and the resulting impact on load are subject to change depending on market conditions, including adoption rates and introduction of new technologies.

The NGV market shows particular promise for this portfolio. As a result of potential EEC incentives, the City of Vancouver, City of Surrey, City of Port Coquitlam and other third party partner have all expressed interest in converting some of their current high carbon diesel fleet into NGVs, and purchasing new NG trucks for garbage disposal. Switching to natural gas as a transportation fuel reduces GHG emissions by displacing higher carbon fuels like diesel and gasoline, and by adding load, optimizes use of the gas distribution system.

5.5 Beyond 2011- Future EEC Funding Scenarios

5.5.1 IMPACT ON ENERGY DEMAND AND EMISSIONS

TGI and TGVI's current EEC budget expires on December 31, 2011. We are planning to submit a request for on-going funding as part of the 2012 RRA for both TGI and TGVI. We believe additional funding for EEC activities will benefit multiple stakeholders. Through various consultation activities and regulatory processes, the Utilities' customers and other stakeholders have indicated support for increased and ongoing funding due to the additional customers that can be reached and savings that can be achieved through the continuous and consistent availability of EEC programming.

To determine what level of ongoing funding should be implemented; we examine the potential impact on natural gas demand and GHG emissions in three scenarios of future funding for EEC programs below. It should be noted that the scenarios have been

Taking Leadership in Development of Solar Projects

Solar Homes Pilot is a program in partnership with Terasen, City of Vancouver, SolarBC and Offsetters, financing up to 50 percent (about $3,500) of the cost of installing a sola hot water system, which will be available to 50 new houses on a first-come, first-servec basis, beginning January 2010 through March 2011.

Terasen CITY OF VANCOUVER SolarBC Tap into the Sun OFFSETTERS developed using the best available data, but will be updated once the results of the CPR are received. These scenarios are discussed below in detail.

- **Funding Scenario A**

This is the "status quo" scenario, which assumes that the currently approved funding and resultant EEC activity will cease after 2011. The expected energy savings in this case are based on the programs planned from 2009 to 2011, and the number of participants and measure life of equipment were determined using the best available data[114]. Scenario A assumes that these funding levels are not renewed and revert back to pre-2009 levels of ~$4 million.

We believe the savings from this scenario are underestimated for a number of reasons. The energy savings from industrial programs have not been incorporated into this scenario, as they are currently in the development phase. Also, the Utilities are still developing the Innovative Technologies portfolio, and have only incorporated the expected increase in demand from the replacement of high carbon diesel heavy-duty trucks with low carbon natural gas by 2011. As NGV demonstration projects and first adopters in the province show success, we expect that markets will begin to grow and assumptions used to calculate energy savings will have to be revised as that data becomes available. Finally, the total energy conserved is likely underestimated in this case because savings from behavioural changes and some Commercial DSM programs have also been excluded due to difficulty estimating the conservation impact of these activities, even though there is significant energy savings potential.

Should this scenario come to fruition, the Terasen Utilities and our customers will be subjected to all of the pitfalls of inconsistent and uncertain funding and growth in energy savings and the resultant emission reductions will cease.

- **Funding Scenario B**

To develop Scenario B, the Utilities have assumed the same funding levels, approximately $35 million annually, that were awarded in 2010 and 2011 will be sustained until the end of the long range planning period (i.e. from 2012 until 2030)[115]. The following is a list of assumptions used to build this scenario, though they may change as data on new programs and market potential becomes available from the CPR:

- Conventional EEC programs similar to that in Scenario A will continue to be implemented throughout the planning period.

[114] The total savings are subject to change based on programs and technologies available, as well as participant uptake rate.
[115] The net energy savings calculated are based on the following assumptions in absence of any information on future programs and participation rates.

- The measure life and participation rates will remain constant at the 2010 levels for all the planned programs.

- The same number of incremental vehicles that were assumed in Scenario A in 2011 will be funded every year until 2030. This is a conservative estimate but is based on the most recently available data and successes.

- Industrial programs and the possibility of other programs being developed under the Innovative Technologies portfolio are excluded under this scenario.

➢ **Funding Scenario C**

The third scenario assumes that funding will be fixed at 5 per cent of the Terasen Utilities' annual revenues, which would equate to ~$80 million in 2012. This represents funding of slightly more than twice currently-approved funding levels, and was felt by the Utilities to be a reasonable starting point for funding a highly aggressive approach to EEC. Terasen Utilities recognize that the success of its initiatives will help transform the market throughout the planning period, and the scenario assumes that funding levels and associated savings begin to taper off by $5 million annually starting in 2022. To reiterate, this scenario has been developed using the best available data, but timelines and funding level requirements may change once the results of the CPR become available, or as we progress through the planning period. We believe that funding increases will be necessary to expand the current EEC programs and implement new initiatives. For example, increased funding will allow for the implementation of a large-scale accelerated stock retirement program for inefficient heating systems, further development of industrial programs, expansion of NGV initiatives across broader market segments, and other Innovative Technologies projects.

For the purposes of estimating the net savings in Scenario C, we have assumed the following:

- No funding will be allocated to additions of other natural gas transportation, such as transit vehicles or marine transportation, due to the absence of thorough information for these particular end uses at this point in time.

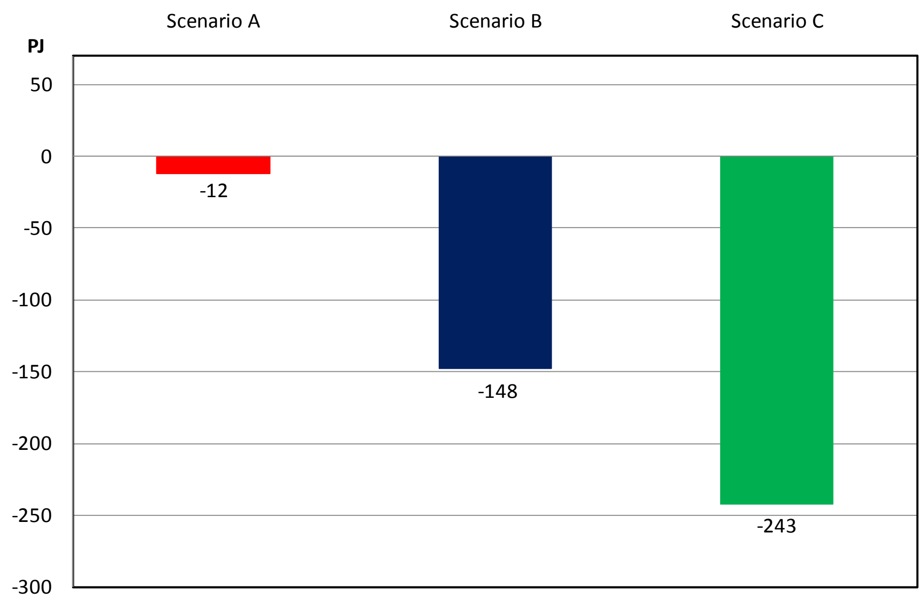
- All the funding for transportation has been allocated to heavy vocational trucks (waste haulers), heavy duty trucks (tractor trailers), medium trucks (postal vans). This may change as additional data and customer interest develops, as Terasen Utilities hopes to use EEC funding to help alleviate the initial capital cost for sectors such as marine and transit vehicles in order to reduce GHG emissions.

- The Utilities will only be claiming the consumption and GHG emissions reduction from the adoption of vehicles that were accelerated by EEC funding. In other words, the Utilities acknowledges that NGVs will gain market share in the future, but strongly believes that EEC funding is instrumental to transform the market and Terasen Utilities can therefore claim a portion of those savings.

5.5.2 IMPACT ON ENERGY SAVINGS AND GHG REDUCTIONS IN SCENARIOS A, B, & C

Each of the scenarios described above will have a significantly different impact on energy conserved. Figure 5-1 depicts the impact on energy savings from the above mentioned scenarios. As can be seen, Scenario C will conserve significantly more energy than Scenario A, 213.38 PJs (equivalent to 213,380,000 GJs) versus 11.75 PJs (11,750,00 GJs)[116.]

Figure 5-1: Year 2009 - 2030 Cumulative Natural Gas Savings from EEC Scenarios



Given that Scenario A is based on current, approved funding for EEC, the current demand forecast presented in Section 4.2.6 includes this level of energy savings. The impact of Scenarios B and C on the Reference Case current demand forecast is shown in Figure 5-2. Although the scale of energy savings against total energy demand may appear small on this graph, the declining consumption in Scenarios B and C occurs in conjunction with continued customer additions and results in significant cumulative energy and GHG savings as shown in Figure 5-2 and 5-3. Scenario C will aid in reducing GHG emissions by more than 16,000,000 tonnes, versus Scenario A which would reduce GHG emissions by more than 820,000 tonnes.

[116] The total cumulative savings have been calculated using the sum of energy conserved from conventional EEC programs and efficient load building from the addition of NGVs.

Figure 5-2: Impact of EEC Scenarios B and C on Reference Case Demand - 2010-2030 (All Utilities)

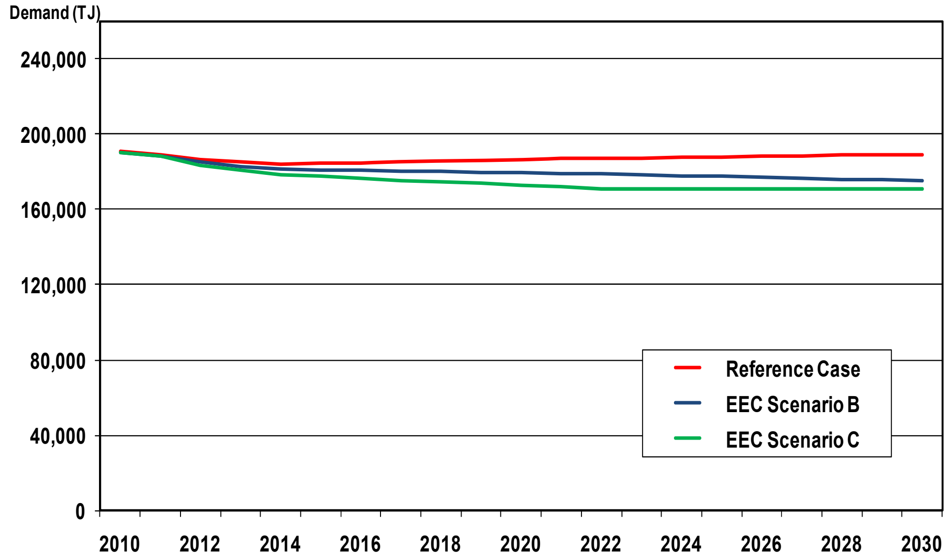
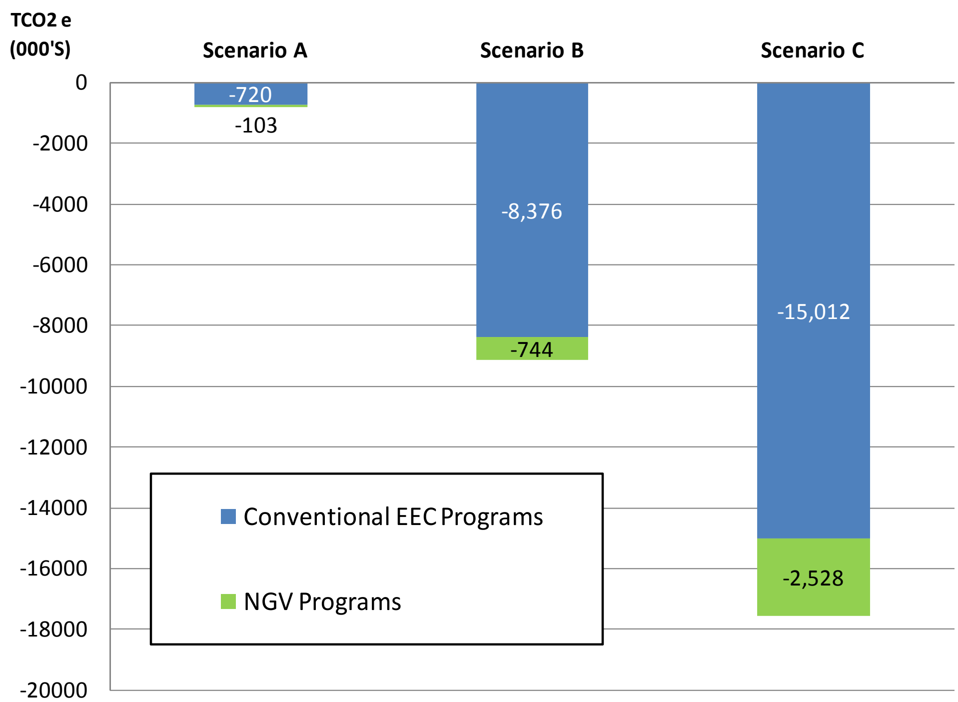


Figure 5-3: Year 2009 - 2030 Cumulative GHG Savings from EEC Scenarios



5.6 Managing Uncertainties in Developing and Implementing EEC Programs

A number of factors can influence the effectiveness and impact of EEC initiatives. Terasen Utilities have taken a variety of factors into consideration when estimating how EEC activities will impact demand. This section summarizes some of those factors and how they are managed.

5.6.1 IMPACT OF NEW AND CHANGING EQUIPMENT EFFICIENCY REGULATIONS AND BUILDING CODES AND STANDARDS

The B.C. government's aggressive GHG emissions reduction goals have led to the proposal and implementation of a variety of building codes and standards, as well as equipment efficiency regulations that impact the EEC initiatives primarily by providing the Utilities with areas of support for market transformation efforts in support of these proposed regulations and building codes and demand for natural gas.

5.6.1.1 British Columbia Building Code

The provincial government has recently announced that they are working toward the implementation of a new provincial residential building code that will be equivalent to Energuide 80 rating to take effect in late 2010[117]. The current rating of 77 and the new 80 rating are stepping stones toward a "Net Zero Community Energy"[118] level set for 2020. The primary goal of the building code revision is Net Zero energy utilization[119], with a secondary goal of Net Zero GHG emissions. Preliminary analysis has shown that this may lead some customers to adopt electric equipment for space and water heating, due to lower upfront capital costs[120]; however, the Utilities believe that the energy cost of using natural gas in the long run will be lower and therefore benefits the customer. Terasen Utilities can play a part in mitigating the impact of this regulation by working with industry professionals to identify the prescriptive construction measures so that individuals and organizations can meet the building code requirements while continuing to use natural gas for space and water heating. The Utilities will also play a role in communicating the benefits of high efficiency natural gas equipment to customers, and supporting the government in enforcing regulation.

[117] "The Province is developing a Building Code change proposal to require energy performance for new Part 9 housing that, combined with provisions under the BC Energy Efficiency Act, will be equivalent to EnerGuide 80" from http://www.housing.gov.bc.ca/building/green/index.htm

[118] These buildings will be the most energy efficient ever constructed in British Columbia to minimize the need for energy supplies. While those buildings will require purchased energy from utilities, these will be offset through the generation of heat and power from on-site or community-based, clean and renewable energy resources. (http://www.empr.gov.bc.ca/EEC/ProgramsActionsInitiatives/NetZero/Pages/default.aspx)

[119] A net zero home at a minimum, supplies to the power grid, an amount equal to the total amount of energy consumed.

[120] Higher capital cost is derived from the equipment and installation cost, and the requirement for ventilation and air circulation systems.

5.6.1.2 Proposed Water Heater Regulations

Water heating represents the second largest household energy usage, equating to approximately 20% of household energy use in Canada[121]. The federal and provincial government have announced plans to introduce a three-tier efficiency plan leading to a regulation requiring a minimum energy efficiency factor ("EF") of 0.80 as shown in Table 5-2.

Table 5-2: Three Tier Water Heater Efficiency Plan Summary

Type	Minimum Efficiency	Effective Date
Gas Storage- 151 L Water Heater	0.62 EF	September 1, 2010
Gas Storage- 189 L Water Heater	0.61 EF	September 1, 2010
Gas Storage Water Heater	0.67 EF	TBD
Gas Storage Water Heater	0.80 EF	TBD

* For the first two items, EF rating is based on a formula EF= 0.70 – (0.0005*V)
** V=volume of storage water tanks in liters
***Storage tank volumes of 151 L and 189 L are typical residential heater sizes

In order to reach 0.80 EF, water heater manufacturers will need to use tankless or condensing technology. Terasen Utilities have been joined by manufacturers of natural gas heaters in voicing concerns with the proposed regulation, as there are currently no condensing water tanks that are appropriately sized for the residential market. Terasen Utilities have identified that there is a major risk to gas water heating load as both tankless and condensing technologies have different venting requirements than technologies generally installed today, and tankless technologies may not be appropriate for some applications. Furthermore, both technologies have significantly higher upfront capital costs than electric alternatives. The result may be load shifting from natural gas to electric water heating, with a spill over loss to space heating. We are working alongside our partners, including the government and manufacturing industry, to ensure that technologies are available and proven before the regulation is implemented.

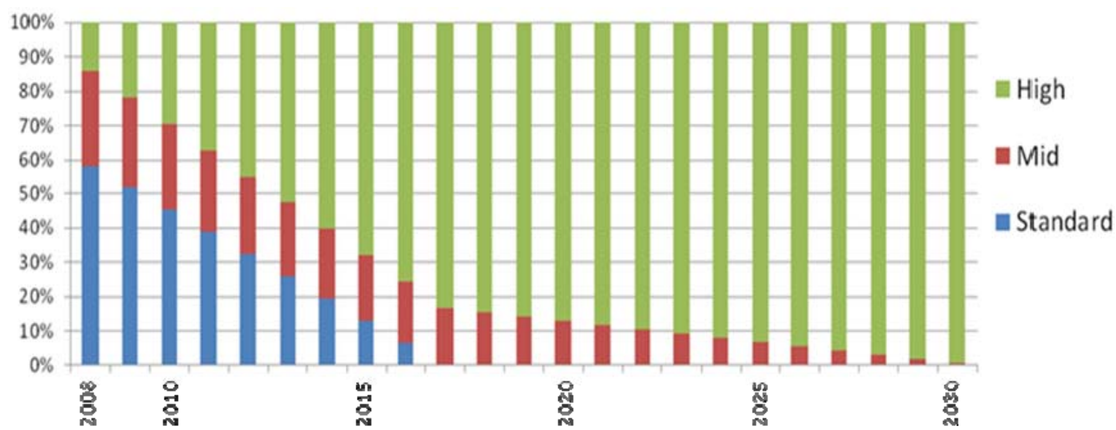
5.6.1.3 Home Heating Systems Regulation

Terasen Utilities assisted in preparing the B.C. residential market for the furnace regulation passed by the Province in 2009, which states that gas furnaces manufactured on or after December 31st, 2009 must have a minimum fuel efficiency level of 90% Annual Fuel Utilization Efficiency ("AFUE"). We began providing information and offering rebates to customers in support of this regulation in 2001. Terasen Utilities have used a variety of marketing techniques to increase adoption rates including bill inserts, internet, print media, radio, sales force efforts, relationship building with industry professionals, and customer outreach at community events and trade shows. Our goal in offering rebates for furnaces was to transform the market until the regulation was implemented, as it has now been. However, preliminary research has shown that there is still a high percentage of mid and low-efficiency stock available for sale in the marketplace.

[121] Condensing DHW Study: Habar & Associates Consulting Inc, March 2010

For example, as of 2009, almost 80% of furnaces in TGI service territory were low or mid efficient, and given current adoption rates, it could take up to 20 years for all furnaces installed to be high efficiency[122]. We have reason to believe this 20 year time period is understated, as these estimates were designed with the assumption that most people would replace their furnaces once they reach an expected service life of 18 years. Without incentives in place to support the early retirement of stock, some customers may keep their furnaces for as long as 30 or 40 years, which data from the 2008 REUS revealed is already happening in the TGI customer base. The Utilities believe that a Terasen-run furnace retirement program would be a significant contribution to achieving the Province's energy and greenhouse reduction goals. Unfortunately the existing benefit-cost tests that are currently applied to utility DSM programs are not the appropriate analysis tool for initiatives such as a furnace early retirement program as they do not recognize benefits beyond the avoided cost of energy, such as contributions to the greater policy goal of greenhouse gas emission reductions. Terasen Utilities are working on a proposal for such a program which would include a proposal for the appropriate evaluation of programs that support policy objectives, and hope to bring such a proposal before stakeholders for feedback within the next year. Figure 5-4 displays the breakdown by efficiency level of furnace stock in the TGI service territory.

Figure 5-4: Furnace Market Broken Down by Efficiency Level – TGI



5.6.2 SUPPORT FOR CODES, STANDARDS, AND REGULATIONS

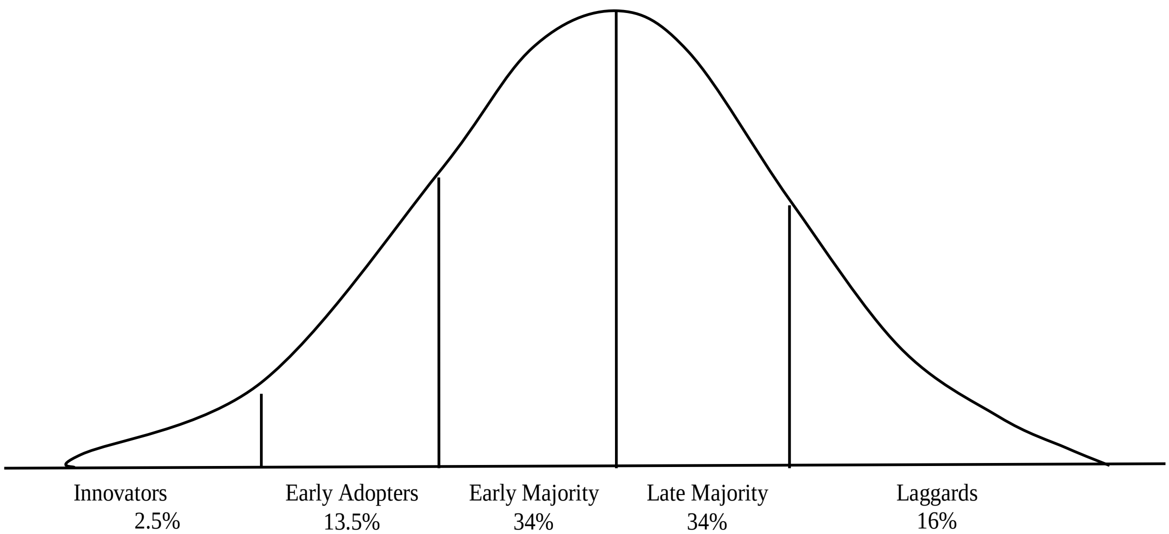
The Terasen Utilities work alongside various levels of government in developing and implementing codes, standards, and regulations. We believe that government regulation is a critical final step in transforming markets to adopt energy efficient equipment.

[122] 2008 Residential End Use Study- Sampson Research

5.6.2.1 The End Goal of EEC: Market Transformation

The end goal of the Utilities' EEC programs[123] is market transformation, which can be defined as transforming the market to a point where energy efficient equipment/systems/buildings are the new baseline for regulation. Market transformation utilizes the concepts of "Diffusion Theory," which state that innovation occurs in five stages for consumers, to shift the curve shown in Figure 5-5 to the left, and encourage adoption of new technologies faster than would occur organically. EEC programs are developed to address barriers which prevent consumers from adopting energy efficient appliances.

Figure 5-5: Market Diffusion Curve



One of the outcomes of market transformation is regulation through Codes and Standards. Prematurely aggressive efficiency target levels, with a lack of equipment and service history to meet these performance levels could slow down or stop market transformation. This could result in substantial load shift to other energy sources, disturbing the energy supply balance thus effecting energy delivery rates to all customers. One example of this is our work on analyzing impacts of British Columbia's proposed water heater regulation. The Terasen Utilities hired Habart & Associates Consulting to provide a strategy paper which assesses the impact of the water heater regulation and provides a conceptual framework for transforming the market to support the introduction of the proposed water heater regulation. We believe an increase in EEC funding will be required to provide incentives that encourage manufacturers to develop residential 0.80 EF water heater technologies, and to educate the marketplace on the benefits of the systems.

[123] This goal is defined in Principle #12 of the Terasen Utilities' EEC Application, 2008. http://www.terasengas.com/_AboutUs/RatesAndRegulatory/BCUCSubmissions/LowerMainlandSquamishInterior/EnergyEfficiencyConservationPrograms/default.htm

5.6.3 RISKS ASSOCIATED WITH PROGRAM SAVINGS ESTIMATES

A challenge in developing EEC programs is estimating program uptake rates and energy savings. There are a number of factors that affect participation rates including emergence of new technologies, economic conditions, the political climate, changes in adoption rates for current technologies, energy price fluctuations, changes in consumer behaviour and consumption patterns, and initiatives by other utilities or government. Inconsistent incentive funding hinders program development, as staff cannot develop programs with long term goals in mind, and communications with participants and market factors such as equipment installers about program lifetimes are erratic.

5.6.4 MITIGATING THE PROGRAM SAVINGS ESTIMATION RISKS

The Terasen Utilities take analysis of energy impacts from EEC activity very seriously and obtains up-to-date market information about different technologies to ensure accuracy. When developing programs, we review the inputs and savings through formal engineering estimates, ongoing market research studies and program evaluation. Terasen Utilities carefully monitor assumptions and inputs on program costs, participation rate, energy savings per participants, and incentive amounts to ensure efficient use of funding. The Terasen Utilities contract with external third parties to evaluate programs and assess their marketplace success.

Terasen Utilities also conduct a CPR every few years to examine the technologies available in the marketplace and determine the "conservation potential," including the amount of energy savings that can be achieved through EEC. The CPR analyzes the potential impacts of identified energy efficiency and fuel choice programs and initiatives to a base case scenario, and acts as the guiding document in designing future programs. The 2009 EEC decision approved funding for an updated CPR, understanding that the study is a fundamental piece in developing DSM initiatives. The results from the 2010 CPR will be imperative in determining how EEC activities are going to impact demand and will help Terasen Utilities:

- Develop a long range energy efficiency and fuel choice strategy, including an analysis of the savings opportunities available from the implementation of the above mentioned scenarios and large-scale, Alternative Energy Systems;
- Design and implement energy efficiency and fuel choice programs and initiatives;
- Assess the impact of energy efficiency and fuel choice program on both peak and annual loads;
- Identify equipment and technologies that could be used for energy efficiency and fuel choice programs, including new technologies that are commercially available but have very low market penetrations
- Set annual energy efficiency and fuel choice targets and budgets

In addition, the Utilities have requested a discussion paper as part of the CPR that reviews how our energy efficiency and conservation efforts could support government policy. The paper should detail potential alternative EEC analysis approaches that look beyond the traditional economic focused California Standard Practice tests. These tests were developed to support "traditional" utility energy efficiency activity, and only consider the avoided costs of energy and the costs associated with energy efficiency activity, which is a very narrow view of energy efficiency activity in the larger context of support for long-term government policy goals. Based on these economically focussed analysis tools as they are defined in the California Standard Practice Manual, the Terasen Utilities would not be able to engage in such programs as a furnace replacement initiative, funding the full cost of furnace upgrades for low-income households, or implementing geo-exchange systems for schools, all of which are laudable initiatives that support government's larger GHG emissions reduction goals. The Utilities look forward to working with government and other key stakeholders in developing more suitable analysis tools for utility EEC programs that support government policy goals, but that are not seen as "cost-effective" when viewed through the narrow lens of the California Standard Practice Tests.

In conclusion, the results from the 2010 CPR will be imperative in determining how EEC activities are going to impact demand and will form the primary basis of Terasen Utilities EEC funding requests for 2012 and beyond.

5.7 Conclusion

While TGI and TGVI is currently implementing programs and activities as a result of the increased EEC funding from Orders G-36-09, G-141-09 and G-140-09, which approved a total of $72.315 million in EEC expenditure over 2010 and 2011, still more can be done. For market transformation efforts to take hold, approved utility EEC funding needs to be of sufficient magnitude to support market transformation efforts, and stable and long-term enough to provide consistency in utility communications and activities with customers, market players and stakeholders. For this LTRP, Terasen Utilities analyzed 3 Scenarios, and concluded that in Scenario C, where EEC funding is approved up to 5 per cent of gross utility revenues, EEC activity could make a significant contribution of 16,000,000 tonnes of GHG reduction to government's GHG emissions reduction targets. Such a funding envelope would allow for a significant NGV uptake in the medium and heavy-duty "return to home" fleet market, a furnace retirement program and a water heater market transformation program.

The Utilities will be conducting an updated CPR that will support an application for approval of EEC funding in the future 2012 RRA. The results of this CPR will be imperative in determining how EEC activities are going to impact demand for 2012 and beyond. Further, Terasen Utilities have concluded that the California Standard Practice tests may not be the appropriate analysis tool for Utility EEC programs of the future.

6 Gas Supply Sources

The Terasen Utilities and their predecessors have been buying, transporting and delivering natural gas to the communities of B.C. for more than 50 years. Today, our gas customers number more than 935,000 and that number continues to grow. Annual demand expectations are levelling off, but peak day demand continues to grow. The Utilities must plan their gas supply requirements, system infrastructure and other resources to meet both annual and peak day demand, looking forward to anticipate the evolving needs of our customers and changing gas supply trends in the region.

Section 6.1 of the LTRP discusses the current status of the Utilities' natural gas transmission infrastructure and the resource requirements for continuing to provide our customers with safe, reliable, secure and cost effective gas delivery services. Planning for the types of resources needed to acquire biogas supplies and deliver lower carbon transportation fuel solutions being sought by our customers is presented. Finally, the development of enhanced asset management practices to address the aging nature of portions of our infrastructure, develop a long term asset management plan and incorporate continuous improvement into asset decision making is introduced. Section 6.2 summarizes our gas supply portfolio and price risk management planning, explains the changing nature of the gas supply market for B.C. and presents the infrastructure and service alternatives that the Terasen Utilities are pursuing to protect and promote our ability to cost effectively acquire gas supplies to meet our customer's needs over the long term.

6.1 On-system Natural Gas Infrastructure Planning

The Terasen Utilities' natural gas transmission and delivery infrastructure remains vital to B.C.'s energy future. Today, natural gas serves as much or more of B.C.'s end-use energy needs as electricity[124], with Terasen Utilities' infrastructure delivering 96%[125] of that gas. The ability of our infrastructure to meet growing peak demand and serve the annual energy needs of our customers safely, reliably, cost effectively and in a socially and environmentally responsible manner is the focus of planning efforts for our natural gas system.

This section discusses the condition of and planning for our natural gas system infrastructure. We review the capacity of our transmission system across each of the service regions and make recommendations for system expansion where needed, primarily in TGI's interior service region, to meet growing peak demand. We provide an overview of expected distribution system projects needed either to meet system growth or to sustain system integrity and performance, within the context of our 5-year capital planning process. We describe types of infrastructure solutions that the Terasen Utilities will need in order to acquire and deliver carbon neutral

[124] 2007 NRCan data shows that natural gas served 21.8% of B.C.'s end use energy demand - electricity served 21%.
[125] Based on average daily deliveries.

biogas and deliver natural gas to new customers as a low carbon transportation fuel. Finally, the need to enhance our asset management processes to manage an impending wave of aging assets and continuously improve decision making for system sustainment and infrastructure development is presented.

6.1.1 SYSTEM EXPANSION REQUIREMENTS - TRANSMISSION & DISTRIBUTION

The capacity of a pipeline system is determined by the diameter and length of the pipeline, the supply and required delivery pressures, and the allowable maximum operating pressure ("MOP"). To overcome friction and allow gas to flow through the pipeline, a pressure differential between the supply and delivery points is required. Compressors are used to increase the pressure differential and move large volumes of natural gas at high pressures through the transmission pipelines to major delivery points. The end pressures, which vary with flow, are controlled by pressure regulating stations before the natural gas enters the intermediate pressure or distribution systems.

The Terasen Utilities generally have three new resource options to evaluate when planning system expansions:

- **Pipelines**

To increase the effective cross-sectional area of a pipeline section to increase throughput capacity, an existing pipeline can be replaced by a larger diameter pipe, or a parallel pipeline (a loop) can be added to an existing one.

- **Compression**

Compressors are added to increase capacity in two ways. The first is adding new compressor units at existing stations or replacing existing units with larger ones to increase the station throughput capacity. The second is adding new compressor stations along the pipeline to maintain a higher average operating pressure along a pipeline.

- **On-system Storage**

Storage facilities located within a service region are considered 'on-system' supply side resources. Terasen Utilities consider LNG storage as an on-system resource. Natural gas is typically injected into storage during low-demand periods and is withdrawn during high demand periods. During high demand periods, these storage facilities provide direct deliverability into the system to maintain pipeline operating pressure and increase system capacity without the need for additional throughput capacity from pipeline and compression facilities. Since the Terasen Utilities can call upon their own resources to utilize on-system storage, these facilities also increase system security and reliability.

The transmission systems for each service region are shown in Figure 1-3 of Section 1. The TGVI Transmission System transports gas to communities and industrial users on the Sunshine

Coast and on Vancouver Island, as well as TGW distribution system and the TGI distribution system in Squamish. TGI operates and maintains two major transmission systems: the Coastal Transmission System (CTS) serving the Lower Mainland, and the Interior Transmission System (ITS) serving the North Thompson, Okanagan and Kootenay regions. In addition, in northern and eastern areas of the province, TGI has transmission laterals that connect to Spectra Energy's T-North and T-South pipelines (Westcoast Pipeline) and the TransCanada Inc. B.C. System pipeline (TransCanada Pipeline) to serve communities and industrial users in those regions.

6.1.1.1 Transmission System Planning Considerations

Supply side resource requirements are identified by system hydraulic analyses. Important considerations in determining the need for transmission system expansion are:

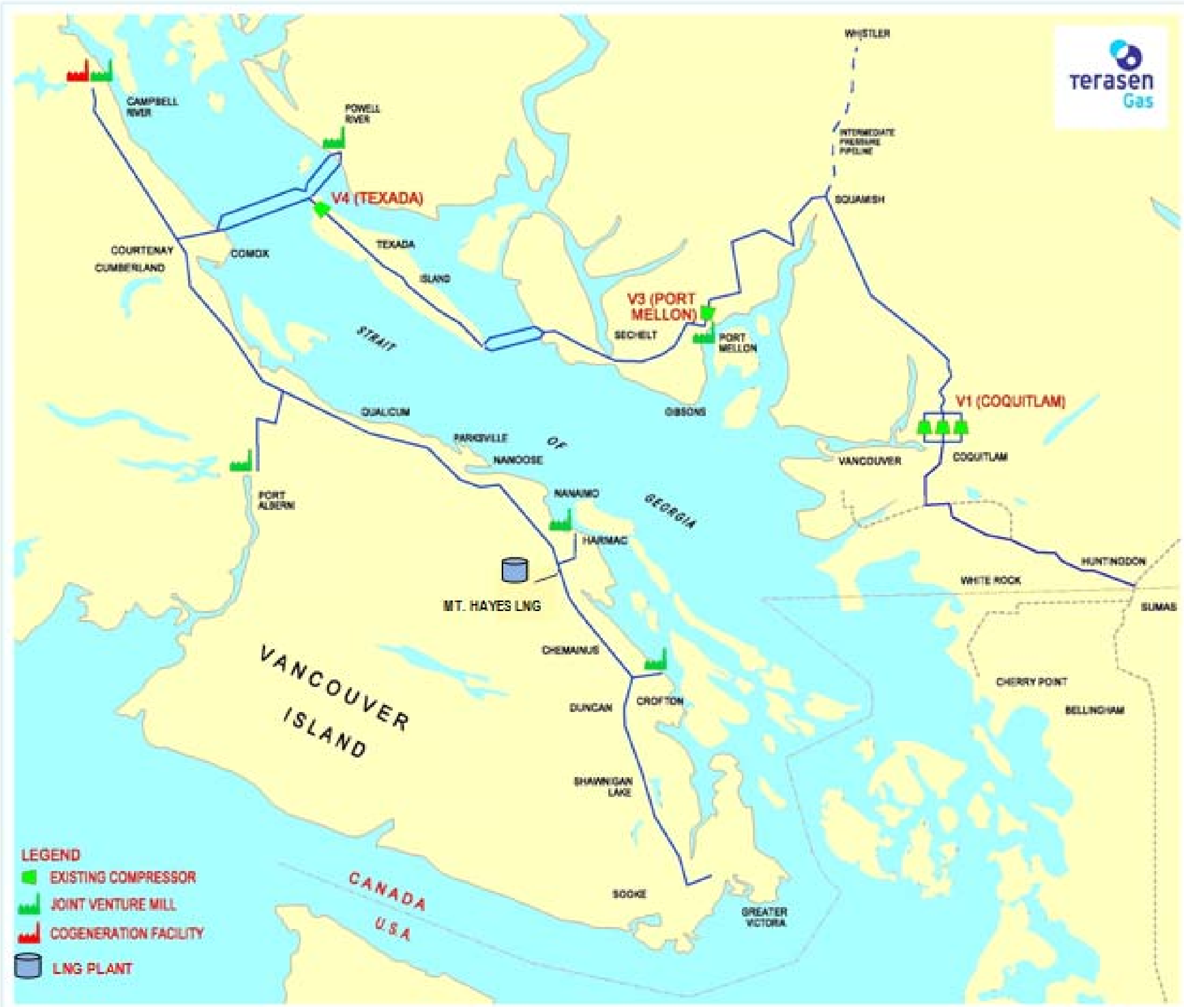
- Optimization of resource capacity addition(s) to meet demand requirements over a 20 year planning period.
- Expected demand under design temperature conditions.
- Firm transportation demand only for capacity planning purposes (i.e. capacity additions are not planned to meet interruptible demand).
- Demand variations from core market customers on an hourly basis. Core demand typically has a morning peaking period between 6 and 10 am and an evening peaking period between 5 and 9 pm. The peak hour demand for these customers can be as much as 40% above the hourly average of the daily demand. A transmission system must have sufficient capacity to handle these daily fluctuations.
- The amount of line pack available within the transmission system. Properties of natural gas allow it to be stored temporarily within the pipeline as the compressors increase pressure to move gas through the system. As demand increases and pressure in the pipeline is drawn down, the amount of gas "packed" in the pipeline ("line pack") is reduced. Pipeline length and operating pressure determine the amount of line pack available in the system. Longer, higher pressure systems can be designed for peak day conditions, while smaller systems must be designed for the peak hour.
- Long lead times for large infrastructure projects (due to regulatory reviews, public consultation, conceptual design, detailed engineering, and construction schedules).

6.1.1.2 TGVI System Resource Needs and Alternatives

- **TGVI Transmission System Description**

The TGVI transmission system serves Vancouver Island, Sunshine Coast and feeds the communities of Squamish and Whistler. It consists of 615 km of high pressure pipelines, including three twinned marine crossings of the Georgia and Malaspina Straits, three compressor stations as well as the Mt. Hayes LNG storage facility currently under construction. Natural gas for TGVI customers is delivered from upstream sources on the Westcoast Pipeline system to the Huntingdon-Sumas trading point. From Huntingdon, TGVI contracts for transportation capacity across the TGI CTS to the start of the TGVI System at Eagle Mountain in Coquitlam. A major improvement to TGVI system reliability and increased operational flexibility of the TGI CTS will be provided by the Mt. Hayes LNG plant scheduled to begin operating in 2011/2012. Figure 6-1 shows the layout of the transmission system including the location of the Mt. Hayes Storage facility, compressor stations, major industrial customers and distribution networks.

Figure 6-1: Layout of TGVI System



➢ TGVI Demand and Capacity Balance

The TGVI transmission system serves natural gas demand for is its core market customers located on Vancouver Island and the Sunshine Coast, in Squamish (for TGI), and in Whistler for TGW. TGVI also transports gas for the pulp and paper mills represented by the Vancouver Island Gas Joint Venture ("VIGJV"), and to BC Hydro's Island Cogeneration Project ("ICP") pursuant to a long term Transportation Service Agreement.

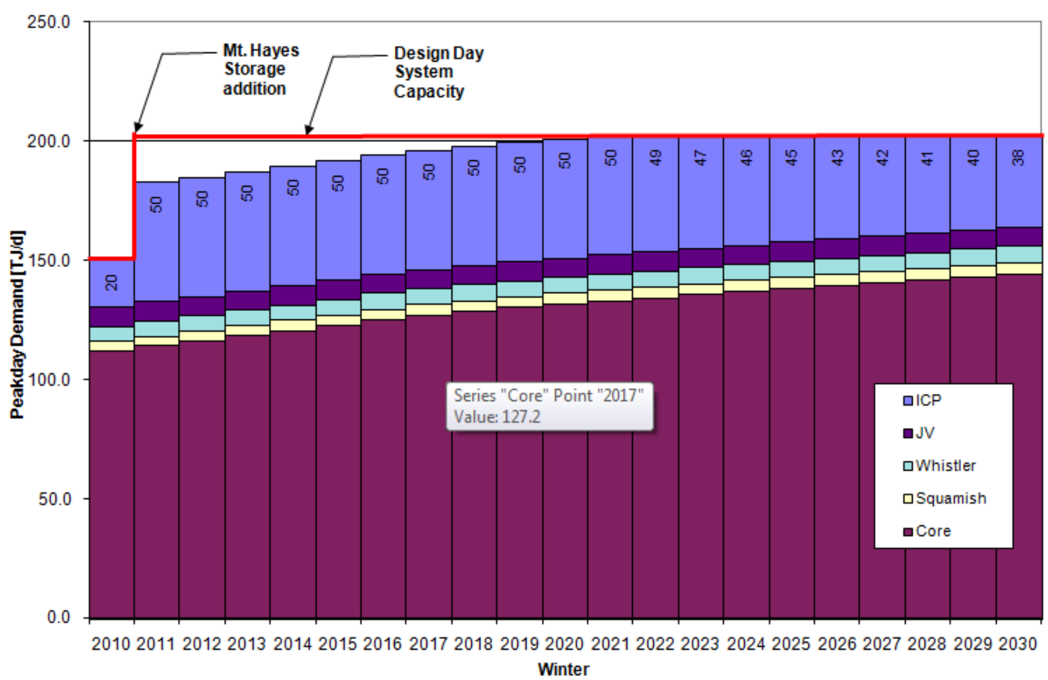
Peak demand for TGVI's core customers is presented in Section 4.2.7 and Appendix B-2. Current contract demand requirements for the VIGJV and the ICP are 8 and 50 TJ/d respectively. The TGVI System is currently fully subscribed and relies on a right to call back capacity to ICP from BC Hydro during design weather events in order to serve its core market design day requirements.

➢ TGVI System Resource Needs and Alternatives

TGVI is currently constructing a new natural gas storage facility near Mt. Hayes on Vancouver Island which is expected to be in service for the 2011/12 winter period. This project was approved by the BCUC in November 2007 as the major component of the preferred resource portfolio which provides the added benefits of operational flexibility, regional storage resource benefits for both TGVI and TGI, optimization of the existing system infrastructure and improved system reliability.

The Mt. Hayes facility will have a storage capacity of 1.5 Bcf, a liquefaction capacity of 7.5 million cubic feet per day ("MMcfd"), and a sendout deliverability of 150 MMcfd. TGVI is to retain a portion of the Mt. Hayes storage and sendout capabilities for supply and system capacity needs, while TGI will contract the remainder. Figure 6-2 shows that further capacity constraints on the TGVI system are not expected until 2021, based on the requirement to meet peak demand for core TGVI customers under the reference case demand forecast, plus transportation requirements for the VIGJV mills (8 TJ/d) and the Island Cogeneration Project (50 TJ/d).

Figure 6-2: TGVI Demand-Capacity Balance with Mt. Hayes Facility



The identified system capacity constraint coincides with the expiry of the TGVI - BC Hydro Transportation Service Agreement ("TSA") for service to the ICP on Vancouver Island in April 2022. If Terasen Gas and BC Hydro extend the TSA beyond 2021, TGVI would have three resource options to manage the forecast demand for the core market customers, plus the transportation requirements for the VIGJV and the ICP. The first option is to retain more than 1/3 of the storage and sendout capabilities from Mt. Hayes to provide the TGVI System with additional on system supply during peak demand period. The second option is the addition of V2 Squamish Compressor Station with a single compressor unit. Finally, Terasen Gas could seek to renew an existing peaking agreement with BC Hydro allowing curtailment of flows to ICP to meet the core market requirements.

- **TGVI Demand Forecast Sensitivity**

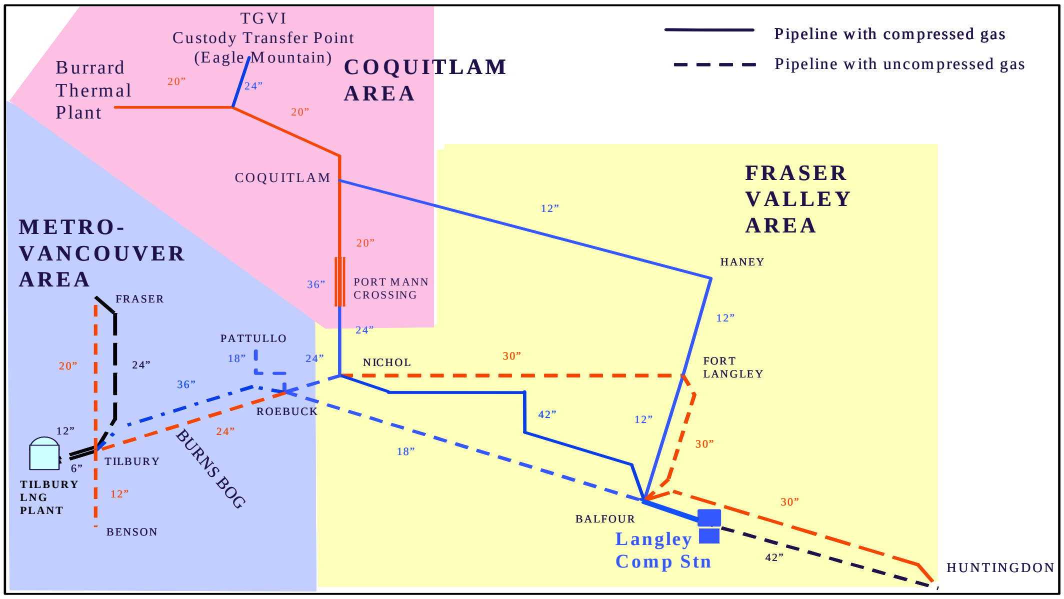
Capacity requirements for TGVI have also been analyzed against the low and high core market demand forecast presented in Section 4.2. If demand actually turns out to be closer to the low forecast, the next TGVI system constraint could be delayed as far as 2027. If demand closer to the high forecast occurs, the constraint could occur as soon as 2017. Within this timeframe, the planning environment for the Terasen Utilities and their stakeholders could change significantly. Conducting a detailed evaluation to select the next preferred system expansion solution is premature at this time. We will continue monitoring TGVI's demand capacity balance, using enhanced asset management practices and working with BC Hydro and other stakeholders to ensure the needs of all TGVI customers are met.

6.1.1.3 TGI – Coastal Transmission System Needs and Alternatives

- **Coastal Transmission System Description**

The Coastal Transmission System ("CTS") consists of a 265 km network of pipelines providing gas transportation from the Huntingdon-Sumas trading point to various metering and regulating stations in the Fraser Valley, Metro-Vancouver and Coquitlam areas. Other transmission related facilities include the Langley compressor station used to maintain transmission pressures under design conditions, and the Tilbury LNG storage facility used to provide peaking gas supply to increase system deliverability to the CTS. This system delivers gas to the core market distribution networks in the Lower Mainland, as well as providing transportation service to BC Hydro's Burrard Thermal Generating Station ("Burrard Thermal") and to the TGVI transmission system at Eagle Mountain in Coquitlam. Figure 6-3 is a schematic diagram showing the CTS layout.

Figure 6-3: CTS Schematic



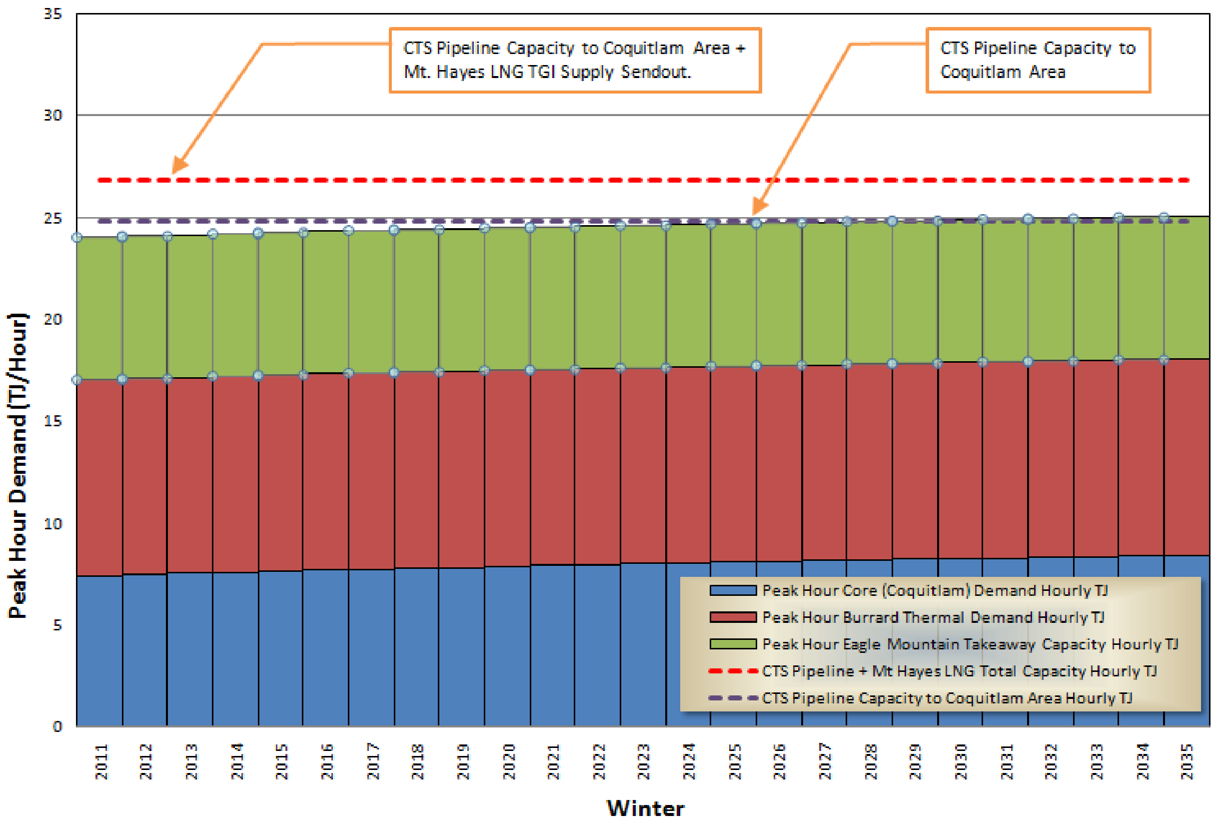
The majority of the CTS in the Fraser Valley and Metro Vancouver areas is already looped and consequently has sufficient capacity to meet long-term demand requirements. The Coquitlam area, however, is primarily fed by a single pipeline from Nichol in Surrey. This single feed carries 15% of the total peak day demand from core market customers in the Lower Mainland, combined with the concentrated demand for Burrard Thermal and TGVI. A secondary line through Fort Langley and Haney serves only approximately 5% of the peak day demand from the Coquitlam area. The Nichol to Coquitlam pipeline could potentially be capacity constrained within the planning period.

➢ CTS Demand / Capacity Balance

The peak day core demand for TGI's CTS is discussed in Section 4.2. To assess the resource requirements for the Nichol to Coquitlam pipeline, the peak day demand – capacity balance includes core demand for the Coquitlam area, TGVI take-away requirements including TGVI, TGW and Squamish area core demand as well as VIGJV and ICP demand, and finally the demand required to serve Burrard Thermal.

BC Hydro has indicated that the six gas fired generating units at Burrard Thermal will be viewed as an emergency rather than a base load resource in accordance to Bill 17 of the Clean Energy Act. TGI therefore evaluates the capacity of the CTS to satisfy peak system demand based on 6 units operating at Burrard Thermal. The resulting peak day demand – capacity balance is shown in Figure 6-4.

Figure 6-4: TGI Demand and CTS Capacity to Serve Coquitlam Area



➢ CTS System Resource Needs and Analysis

Figure 6-4 shows that the addition of the Mt. Hayes storage facility, slated to be in service by the winter of 2011/2012, alleviates the capacity constraint identified on the CTS for the duration of the planning period. The operational flexibility available as a result of the Mt. Hayes facility allows Terasen Gas to manage gas flow to Vancouver Island in two ways:

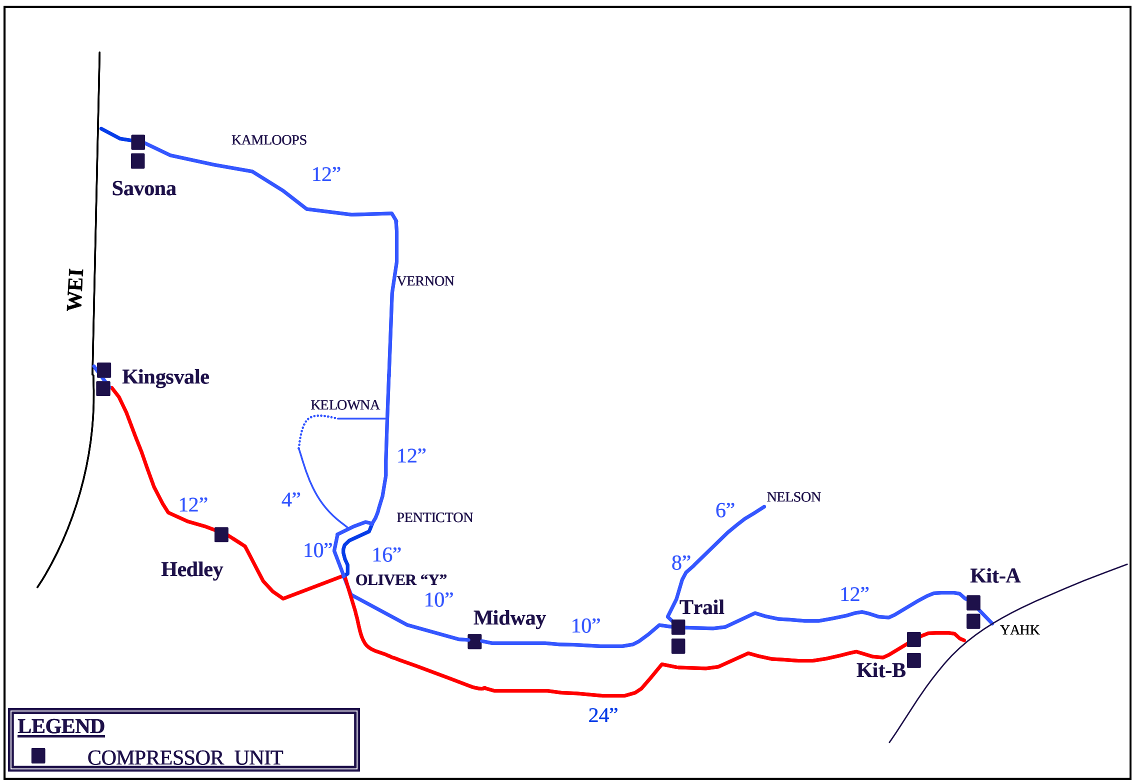
- With the Mt. Hayes Facility providing an on-system supply to TGVI during peak demand periods, TGVI's transport requirements across the CTS are reduced.
- TGI will contract two thirds of Mt. Hayes' storage capacity and deliverability. The delivery of TGI's peaking supplies from the Mt. Hayes facility is largely done through displacement, further reducing physical transport requirements to TGVI across the constraint location. Therefore the capacity constraint on the CTS has been deferred beyond the planning period, even with six units operating at Burrard Thermal. TGI may still consider expansion of the Tilbury storage facility, based on the gas supply benefits of additional storage located in the Lower Mainland as described in Section 6.2.

6.1.1.4 TGI - Interior Transmission System Needs and Alternatives

- **Interior Transmission System Description**

The Interior Transmission System ("ITS") consists of 1,515 kilometres of transmission pipelines operating at maximum pressures between 669 and 1,440 psig. Gas received from the Spectra Energy's Westcoast Pipeline at Savona supplies customers in the Thompson and North Okanagan regions, while gas received from the TransCanada Pipeline at Yahk supplies customers in the West Kootenay region via pipelines to Trail and Oliver-Y. The Southern Crossing Pipeline ("SCP") is a bi-directional transportation pipeline between Yahk and Oliver-Y. From the Oliver-Y hub, pipelines transport gas to serve customers in South and Central Okanagan. In the winter periods, another pipeline transports gas from the SCP via Oliver-Y hub to Kingsvale for re-delivery to the Lower Mainland via the Westcoast Pipeline. Figure 6-5 is a simplified schematic of the ITS.

Figure 6-5: ITS Schematic



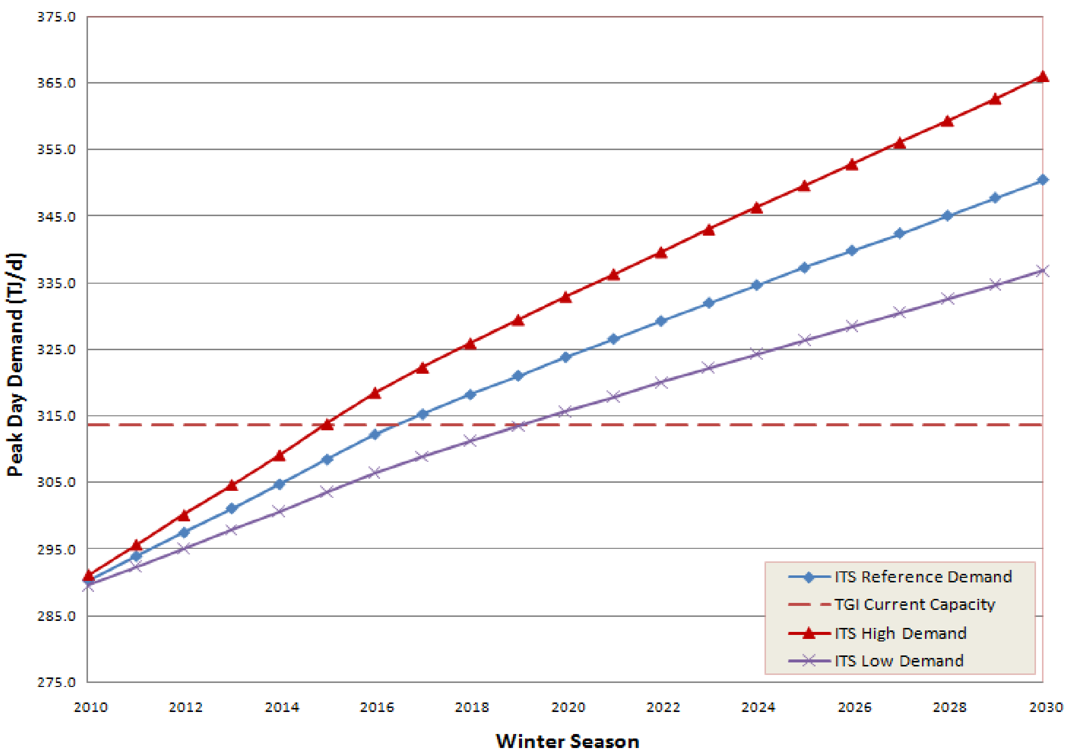
- **ITS Demand / Capacity Balance**

Compared to the modest growth rate forecasted in the Lower Mainland, the B.C. interior, particularly around the South, Central and North Okanagan regions are expected to see continuous demand growth in the coming years. Approximately 60% of the current ITS core residential and commercial market demand is concentrated in these areas. This growth is driving the location of future incremental capacity additions on the ITS.

Since gas is delivered to the ITS from two upstream pipelines - the Westcoast Pipeline at Savona and the TransCanada Pipeline at Yahk - the ITS system capacity will be reached when the system capacity from both supply feeds are fully utilized. The current peak day system capacity for the ITS is approximately 313 TJ/d.

Figure 6-6 shows the 2010 demand forecasts against existing system capacity for the ITS. Facility additions will be required when the peak day forecast demand reaches the existing system capacity. The peak day demand growth is approximately between 2.6 and 3.5 TJ/d each year. With current peak day demand at approximately 290 TJ/d, it will take 7 years for demand growth to reach the current system capacity. System expansion will therefore required to serve the Okanagan area by 2017, with a second resource addition required in the longer term (2030) forecast due to a higher demand forecast. For the High and Low demand forecasts, the first resource addition is required in 2015 and 2019 respectively.

Figure 6-6: ITS Facility Timing



➢ ITS Portfolio Development

On the ITS, three resource options have been identified:

- Phased pipeline looping between Penticton and Winfield, north of Kelowna. This pipeline looping would increase gas supply delivered from the TransCanada Pipeline at Yahk via the SCP. The high growth area between Penticton and Kelowna is currently served by a single pipeline. The first two phases of the pipeline looping – Penticton to Naramata (23.7 km) and Naramata to Mission (15.0 km) – would follow the existing pipeline right-of-way. Due to population growth in Kelowna, the final phase if necessary would bypass Kelowna and terminate at Winfield. This phased looping will accompany the addition of a compressor unit at Kitchener-B Compressor Station.

- Phased pipeline looping between Savona and east of Kamloops. This pipeline looping would increase gas supply delivered via the Westcoast Pipeline at Savona. All three phases total almost 58 km of pipeline looping.

- LNG storage facility between Falkland and Vernon. A LNG storage facility allows natural gas to be stored in times of low demand when excess pipeline capacity is available, and provides on-system delivery to the Okanagan regions during high demand periods to augment the delivery capacity of the ITS.

Figure 6-7 indicates the potential geographical locations of the three system resource expansion options on the ITS. Table 6-1 summarizes the required timing for ITS facility additions for the three resource options.

Figure 6-7: ITS System Resource Expansion Options

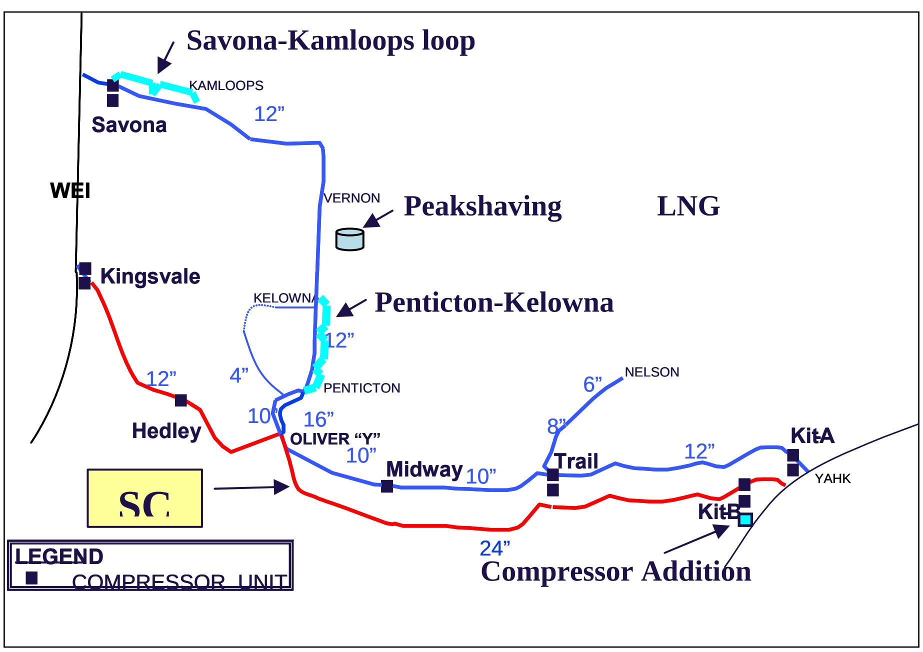


Table 6-1: ITS Resource Requirements

Pipeline Loop from Penticton Option	**Penticton to Naramata Loop** **23 km NPS 20** **3rd compressor unit @ Kitchener-B Station**	**Naramata to Mission Loop** **15 km NPS 20**	**Mission to Winfield Loop** **28 km NPS 20**
Low Demand	2019		
Reference Demand	2017	2030	
High Demand	2015	2025	

Pipeline Loop from Savona Option	**Savona to SN-2 Loop, 17 km NPS 16**	**SN-2 to Kamloops #1 Loop, 15 km NPS 16**	**Kamloops #1 to Lafarge Loop, 26 km NPS 16** **Summerland lateral P-Control Station**
Reference Demand	2017	2023	2027

LNG Option	**LNG Peakshaving Facility**		
Reference Demand	2017		

- **Implications of Potential New Industrial Load on the ITS**

The potential for a large new industrial load being developed in the Okanagan area before the ITS capacity constraint is reached could accelerate the need for the ITS system expansion. For example FortisBC, an integrated, regulated electric utility that generates, transmits and distributes electricity in the southern interior of British Columbia[126], continues to examine the potential need for a new natural gas fired, peaking generating station in the Okanagan. As discussed in FortisBC's current integrated resource plan filed with the Commission in May 2009, such a generating station will be used meet growing peak demand, provide a firming resource for other new renewable generating resources and avoid extensive and costly electricity transmission requirements through the region. The need to provide firm transportation capacity to such a facility could accelerate the ITS expansion to as early as 2014/15. Terasen will continue to work with FortisBC and any other potential new industrial gas users to determine system needs, complete required analyses and prepare appropriate Commission filings to address the need for accelerated system expansion.

[126] FortisBC serves more than 152,000 customers in the Kootenays and Okanagan Regions of BC.

6.1.1.5 TGI Transmission Laterals

TGI operates transmission laterals that connect to the Westcoast and TransCanada pipelines to serve communities and industrial users in north-central and south-eastern British Columbia. One transmission lateral has been identified to have insufficient capacity to meet the forecast demand throughout the 20 year planning horizon. The resource needs for this lateral are discussed below.

- **Cache Creek / Ashcroft Lateral**

The Cache Creek/Ashcroft Lateral is served from the Westcoast Pipeline in the Thompson region. The lateral delivers gas to Cache Creek and Ashcroft which are located approximately 70 km west of Kamloops. The lateral consists of a combination of two pipelines and is at its capacity to meet peak demand. Reductions in available supply pressure from Westcoast are increasing the frequency of curtailment to an industrial customer on the lateral. The addition of a 17 km pipeline loop is required to meet current firm transportation service by the industrial customer, but TGI is currently exploring the option of further reducing this contractual demand, and alternately the possibility of developing a Cache Creek landfill gas project to avoid the need for a pipeline addition.

6.1.2 TERASEN GAS DISTRIBUTION SYSTEMS

By convention, the Terasen Utilities consider infrastructure operating at or below 300 pounds per square inch gauge (“psig”) as distribution assets, which are further divided into:

- Intermediate pressure systems operating from 300 psig to 101 psig.
- Distribution pressure systems operating at or below 100 psig.

For ease of maintenance and operation, safety to the public and reliable service, distribution networks operate at a relatively low pressure. TGI operates its distribution networks at a MOP of 60 psig while TGVI operates its distribution networks at a MOP of 80 psig. Supply resources available for distribution systems include:

- Pressure regulating stations – capacity reinforcement to a distribution network could be obtained by the addition of a new regulating station as an additional supply source; and
- Distribution pipelines - similar to a pipeline except at a lower operating pressure, capacity reinforcement in a distribution network can be increased by increasing the effective cross-sectional area of a distribution pipe section. This can be achieved by replacing an existing pipe with a larger diameter pipe, or adding a parallel pipe (a loop).

Since distribution systems operate at pressure through relatively small diameter pipes, there is essentially no line-pack capability for managing hourly demand fluctuations. Therefore capacity requirements for distribution systems are based on design hourly demand.

The Terasen Utilities conducts two types of studies on its distribution systems to determine the need for resource additions. An overview study of each distribution network is conducted with a 20-year planning horizon to identify strategies for addressing major distribution requirements resulting from customer growth. A 5-year optimization study is also conducted to identify near-term system reinforcement requirements, generally for arterial feeder lines and intermediate pressure pipelines, which support customer growth. In addition, near-term distribution resource upgrade requirements identified during regular integrity assessments from maintenance activities are incorporated with growth related expansion requirements.

While the 20-year overview studies provide a long-term planning and strategy outlook, the Utilities conduct detailed planning for distribution systems through 5-year Capital Planning processes. The 5-year Capital Plans also include planning for other types of capital expenditures such as IT infrastructure upgrades, service programs such as unbundling of natural gas rates and ongoing system maintenance requirements.

6.1.2.1 TGI - Metro Vancouver IP System

Beyond the 5-year capital plan view, only TGI's Metro Vancouver IP System is currently identified as requiring major resource additions (greater than $1.0 million) within the 20-year planning period. The Metro Vancouver IP System, fed mainly from Fraser Gate and Coquitlam gate stations, is a ringed network that deliveries gas to the regulator stations throughout Vancouver, Burnaby, New Westminster and Coquitlam. With continuing re-development and densification in metro Vancouver, the main IP feeder downstream of Fraser Gate Station will require capacity expansion in the long term. The current long range strategy calls for a 2.7 km pipeline loop in 2017, to be followed by a further 2.1 km loop in 2022. Current cost estimates for the Phase 1 and Phase 2 loops are $5.0M and $3.9M in $2007 CDN (excluding AFUDC), respectively.

6.1.2.2 TGI – Revelstoke Propane System

The existing propane system that serves the town of Revelstoke has sufficient pipe, storage and sendout capacity to satisfy the area's forecast growth. However there is a large-scale ski hill and resort development being constructed that will require Terasen Gas to expand the propane system. Due to the phased nature of the development, propane infrastructure will likewise keep in step over a period of several years.

Expansion of the propane system will include pipeline extensions, looping of existing mains, additions of propane storage tanks as well as loading facilities. The initial phase is already in progress, with future expansions planned to meet the expected growth of the ski hill development.

6.1.2.3 5-Year Capital Plans / Statement of Facilities Extensions

The remaining natural gas infrastructure projects being planned for the Terasen Utilities' distribution systems are analyzed and presented through the 5-year capital planning process.

In addition to distribution infrastructure, the 5-year capital plans for each company include requirements for information technology and other capital expenditures required for ongoing business operations, meeting customer needs and remaining competitive for the health of the business. The projects being planned by the Utilities in their capital plans are numerous.

We have segmented our 5-Year Capital Plans as follows:

- Regular Capital Plan
  - Category A – Customer Driven Capital – Mains, Services and Meters
  - Category B – Transmission and Distribution Systems Integrity and Reliability
  - Category C – All Other Plant
- Major Capital Plan
  - Capital Projects that do not require a CPCN
  - Capital Projects that require a CPCN

Regular Capital expenditures have been categorized into Category A, B and C. This category excludes Capitalized Overheads, Contributions in aid of Construction ("CIAC") and Allowance for funds used during construction ("AFUDC"). Major Capital projects have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed.

TGI, TGVI, TGW and Fort Nelson 5-Year Capital Plans for the period 2010 to 2014 are presented in Appendix D to provide additional background and context for the Resource Plan. There are currently no large projects planned for TGW in the 5 year horizon; however, a number of the major capital projects in the TGI and TGVI plans which require submission of CPCN application have already been approved. Those projects for which the Utilities may submit new CPCN applications and will be studying over the coming months are the rehabilitation work for TGI's crossing of the Kootenay River near Shoreacres, the Huntingdon Control Station Bypass, the reinforcement of the ITS, and TGVI's purchase and construction of its Victoria regional office building. A description of each project is provided in the Capital Plans of Appendix D-1, D-2.

The Fort Nelson 5-Year Capital Plan is included as part of the 2010 Resource Plan due to the materiality of capital expenditures anticipated in upcoming years. Specifically, the Muskwa River Crossing HDD Replacement has been identified as a major project, and as such, is included in Appendix D-4 as part of the major capital projects capital expenditure schedule. TGI anticipates filing its Fort Nelson Revenue Requirements Application by the summer of 2010.

The Terasen Utilities are not submitting these Capital Plans for the purposes of approval by the BCUC as part of its review of the 2010 Resource Plan. Consistent with past practice, Terasen

Gas believes that the appropriate forum for review of its Capital Expenditures is its Revenue Requirements Application filings.

As the 5-Year Regular Capital and Major Capital Plans include all planned capital expenditures, Terasen Gas believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the Act. The Terasen utilities have endeavored to provide comprehensive 5-Year Capital Plans for TGI and TGVI as part of its submission. However, the projects and figures contained herein are subject to change and may be revised to reflect additional information as part of Revenue Requirement Application filings, which are anticipated by the early summer of 2011.

6.1.3 BIOMETHANE ACQUISITION INFRASTRUCTURE

In order to acquire Biomethane supplies and inject it into the natural gas distribution network, to meet the demand discussed in Section 3, TGI must add upgrading and interconnection facilities for each new biogas supply project. These new facility additions are not included at this time in the TGI Capital Plan discussion.

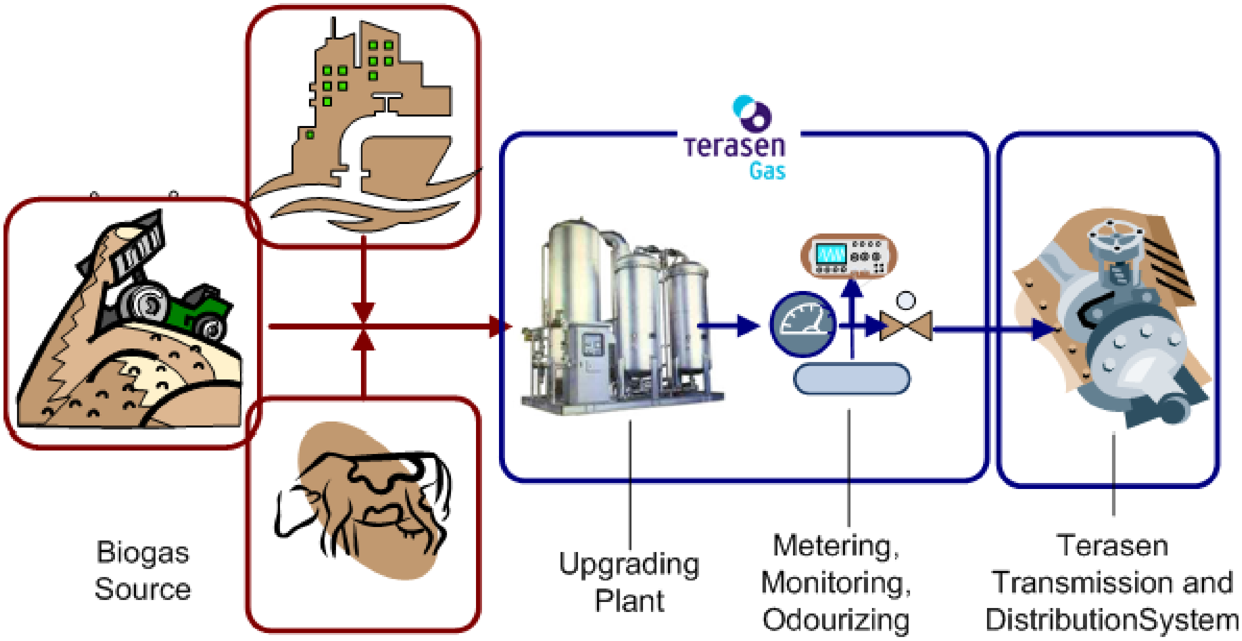
TGI has developed a robust, comprehensive and scalable supply model to ensure the safe, reliable and economical delivery of Biomethane. Taking advantage of the existing natural gas distribution network to displace conventional natural gas with carbon neutral Biomethane, we proposed this model for Commission approval in our Biomethane Application filed with the Commission in June 2010. Although TGI is seeking approval for Biomethane acquisition infrastructure through that application and not as part of our LTRP, we have included summary information from the application in order to guide the LTRP 4-year action plan.

6.1.3.1 Supply Model

TGI does not intend to develop, own or operate biogas production facilities such as landfills, wastewater treatment plants or anaerobic digesters. In the supply model for which we have applied to the Commission, the biogas producer retains ownership and control over the equipment which digests organic material to create raw biogas, as well as those assets required to collect raw biogas from proposed collection locations such as digesters, landfills or sewage treatment facilities. Those assets require the largest investment and currently fall outside TGI's core expertise. However, TGI will generally control the upgrading process and will always control the interconnection facilities. Controlling the upgrading process and associated facilities ensures that the process is undertaken in a manner that produces a consistent and reliable supply of Biomethane. An exception might occur when the biogas producer desires to own and operate the upgrading equipment and can be appropriately relied upon to provide this consistent supply of properly upgraded Biomethane. TGI must control the interconnection equipment to retain complete control over the gas injected into the distribution system.

Under the proposed model (Figure 6-8), TGI owns and operates the upgrading and interconnection equipment. The partner owns the digester. TGI thus purchases raw biogas, and manages the upgrading process to be able to inject Biomethane into the natural gas distribution.

Figure 6-8: TGI's Role in Biomethane Projects



6.1.3.2 Assessment of Future Projects

TGI will assess future supply projects against a number of guiding principles[127]. Key among these principles is an economic test that ensures the delivered cost of Biomethane supply remains within acceptable parameters, described below. The adoption of this framework in advance will facilitate the growth of the supply industry by establishing clear and achievable parameters for our potential supply partners. Subject to Commission approval of the application, the guiding principles allow a streamlined regulatory review process for approval of future biogas supply contracts submitted by TGI.

- **Maximum Biomethane Cost**

Biomethane is a new energy supply source in British Columbia. There are no available external pricing benchmarks specific to Biomethane that assist in setting a threshold price or cost. Conventional natural gas does not provide an appropriate reference point for the price of Biomethane as it is a product that has fundamentally different environmental attributes and

[127] Biomethane Guiding Principles are detailed in Section 8.4.1, Biomethane Application submitted to the Commission on June 8th, 2010.

customer value, even though it may be chemically interchangeable. TGI believes that the price of new B.C. based electricity supply, a competing clean energy source in the province, provides an appropriate initial reference point for Biomethane pricing until the market for this new clean energy resource is better developed.

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

We are therefore proposing that, until such time as an alternative reasonable market-based mechanism or proxy becomes known, TGI will seek to develop Biomethane projects at a maximum unit cost based on a calculation as shown in Table 6-2.

Table 6-2: Proposed Maximum Unit Cost

BC Hydro Tier 2 Rate:[128]		8.78 ¢/kWh		
Conversion to Gigajoules	x	277.778	=	$24.389/GJ
90% Efficiency Adjustment	x	0.90	=	$21.950/GJ
TGI Rate 1 Basic Charge	-	$1.800/GJ	=	$20.150/GJ
TGI Rate 1 Delivery Charge	-	$3.145/GJ	=	$17.005/GJ
TGI Rate 1 Midstream Charge	-	$1.725/GJ	=	$15.280/GJ

Subject to Commission approval of TGI's June, 2010 Biomethane Application, the development of upgrading and interconnection infrastructure will proceed on a project by project basis

6.1.3.3 Supply of Biomethane in B.C.

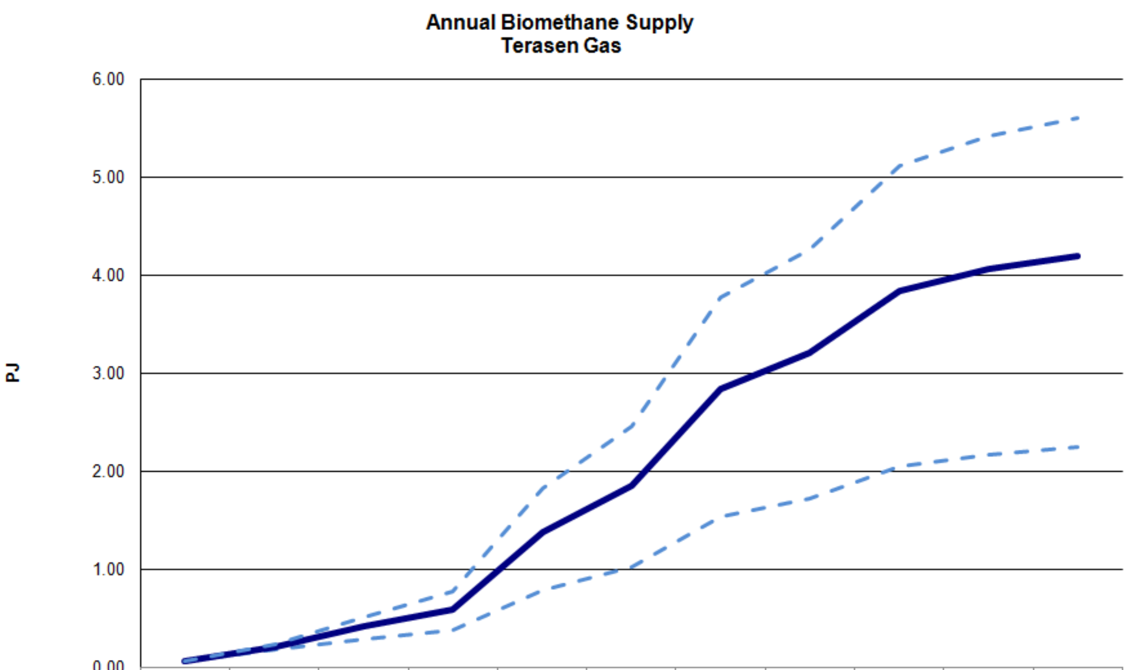
The extent of infrastructure development required for biomethane acquisition is a function of how much supply is developed over time. Biomethane production from an individual project can range from approximately 20,000 to 300,000 GJ annually. TGI prepared its preliminary Biomethane supply forecast in four basic steps:

[128] BC Hydro F2011 Revenue Requirement, Appendix A1, Page 2, Table 2

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

The result of the near-term supply assessment was combined with the high level forecast to create an aggregate forecast. The ten-year and four-year forecasts were then combined to give an aggregate estimated Biomethane supply until the year 2020. The resulting total supply curves, shown in Figure 6-9, are a combination of the foregoing factors.

Figure 6-9: Terasen Gas Forecast for Annual Biomethane Supply



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

Applying this analysis, the estimated annual Biomethane supply volumes by 2020 will be between a low of 2.42 PJ and a high of 5.60 PJ, providing and expected volume of 420 PJ. The forecast supply until the end of 2013 is between 0.38 PJ and 0.76 PJ annually.

The data used to produce the ten year estimate is new and the supply forecast methodology is still in development. The size and success rates of projects, the total amount of bioenergy available within proximity to our system and the sources of the waste material feed stocks are not well-established. We believe that the estimate for the first four years is more accurate than the longer term forecast because it is based on existing discussions and project locations, but it is still subject to some uncertainty. As TGI gains experience and continues to evaluate potential new projects, we will refine our outlook for biomethane production and acquisition infrastructure. Based on the strong interest from various potential partners to work with TGI to develop Biomethane projects within proximity to our distribution network, we believe that sufficient Biomethane supplies can be developed to meet demand for the planned customer offering in the near term.

6.1.4 FUELING INFRASTRUCTURE FOR NATURAL GAS VEHICLES

Natural Gas is expected to play a significant and important role in reducing GHG and other emissions from B.C.'s transportation sector[129]. Both compressed and liquefied natural gas transportation fuel solutions are being successfully utilized throughout the world because of their low emissions characteristics. Yet these solutions have very limited penetration into the B.C. marketplace due in part to infrastructure development barriers that currently exist for their implementation. The Terasen Utilities are ideally positioned to develop the necessary infrastructure and encourage adoption of NGV technologies for a number of reasons:

1. Development of NGV infrastructure will fulfil the demand as outlined in Section 4.3.3, which will help new customers reduce their GHG emissions in a cost effective manner, while providing benefits to existing customers by improving the utilization of the existing natural gas infrastructure.
2. Customers want a "complete solution"[130] or service offering. The Terasen Utilities can provide such a service.
3. The Terasen Utilities have the skills sets to operate and maintain the NGV fueling infrastructure in a safe and reliable manner.

In contrast to previous NGV initiatives in B.C.[131], the Utilities see the best near-term opportunities for more widespread adoption of NGV solutions is in the return-to-base, fleet vehicle marketplace rather than the personal vehicle market. This section describes the current service offerings available to Terasen Utilities' customers for both CNG and LNG technologies and the types of infrastructure required to overcome the aforementioned infrastructure barrier and deliver complete solutions to our customers.

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[129] The role of government policy in implementing low carbon fuel solutions for the transportation sector is discussed in Section 2.
[130] Complete Solution is defined as: Offering the customer services that covers commodity, delivery, compression, storage and dispensing.
[131] Section 5.1 discusses the history of NGV services provided in B.C.

6.1.4.1 Existing CNG Service and Infrastructure Needs

To provide CNG fueling service, the gas must be compressed, stored at high pressure and delivered to the vehicle's storage tank. Currently, only TGI has a customer service class specifically available to NGV customers, although TGVI does deliver service under a large commercial rate service[132]. TGW does not yet serve NGV customers. Under current tariffs, TGI and TGVI provide natural gas for transportation applications to the meter set located at fueling stations. Terasen considers the present service offering to have limitations, which forces customers to supplement the offerings from Terasen, either directly themselves or through an additional contract with a third party, for the provision of fueling infrastructure and maintenance. The lack of a complete service offering (commodity, delivery, compression, storage and dispensing) that can be directly compared to conventional fuels as a price delivered into the customer's fuel tank is a barrier to increased adoption of NGV's within the service territory. The last such NGV fueling station installed in B.C. was in 2002.

The typical components for a commercial customer CNG station are:

- Compression equipment,
- High pressure storage,
- Fuel dispensers.

Figure 6-10 shows a typical return to base installation example servicing 40 garbage trucks.

Figure 6-10: Return-to-Base Installation

Installation and equipment costs have been estimated for a similar installation serving 25 buses in the Lower Mainland at between $750,000 and $1,000,000. In addition to the equipment

[132] TGI currently provides NGV service through the Rate Schedules 6 and 6A (http://www.terasengas.com/Business/Rates/LowerMainlandSquamish.htm)
TGVI serves one fueling station in the Victoria area under the Large Commercial Service Rate High Load Factor (http://www.terasengas.com/_AboutUs/RatesAndRegulatory/RatesTariffs/VancouverIsland/default.htm)

costs a significant amount of project engineering and system integration expertise is required to deliver a successful installation - activities that the average fleet manager is not well qualified to undertake directly and may feel uncomfortable contracting to third parties.

6.1.4.2 Existing LNG Service and Infrastructure Needs

LNG is considered a cryogenic fuel since to liquefy natural gas it must be cooled to very low temperatures. To provide LNG fueling service, the LNG must be transported to a fueling station, stored in a local tank and then pumped and dispensed into vehicle fuel tanks. Under Rate Schedule 16, TGI can provide LNG to customers in tank truck quantities from the Tilbury LNG bulk storage facility. Terasen considers the current LNG service offering to be incomplete and problematic for customers. The customer must take on increased work and responsibilities to supplement the offering either directly themselves or through a third party service provider for the on-site storage, pumping and dispensing equipment and maintenance. As with CNG, the lack of a complete service offering that can be directly compared to conventional fuels as a price delivered into the customer's fuel tank is a barrier to increased adoption of NGV's within the service territory. Although interest in the benefits of LNG as a transportation fuel is growing, there are currently no LNG fueling stations installed in B.C. other than for research and development support facilities at one facility in Vancouver owned by Westport Innovations Inc.[133]

The typical elements of a fueling facility (Figure 6-11) for a commercial LNG customer are:

- Cryogenic storage tank including secondary containment
- Pump and Metering equipment
- Dispenser

Figure 6-11: Typical LNG Fueling Installation

[133] www.westport.com

Installation and equipment costs for a facility that would service nine tractor-trailer rigs in the Lower Mainland has been estimated at between $700,000 and $900,000. As with CNG the issues and complexities of establishing a fueling station for a cryogenic fuel are issues that the average fleet manager would not be well qualified to undertake directly and may feel uncomfortable contracting to third parties.

6.1.4.3 Conclusion

The task of establishing fueling infrastructure is not trivial and requires experience and expertise with respect to compressed gas facilities and / or cryogenic fuels facilities. The provision of these services is consistent with the Terasen Utilities' role as a trusted supplier of energy products and services. Terasen has a role to play in removing the barriers that will enable the development of an NGV industry in B.C., which will help new customers reduce their GHG emissions in a cost effective manner, while providing benefits to existing customers by improving the utilization of the existing natural gas infrastructure. As discussed in Section 3, TGI intends to bring forward an application to the Commission in the summer of 2010 for approval of more complete transportation fuel service offerings. That application will include the requirement for and appropriate treatment of CNG and LNG fueling infrastructure being sought from the Utilities by existing and potential future customers. Extension of a more complete NGV service to the TGVI and TGW service territories is contemplated at a later date pending future unbundling of gas delivery rates for these utilities.

6.1.5 LONG TERM SYSTEM SUSTAINMENT: ENHANCING ASSET MANAGEMENT PRACTICES

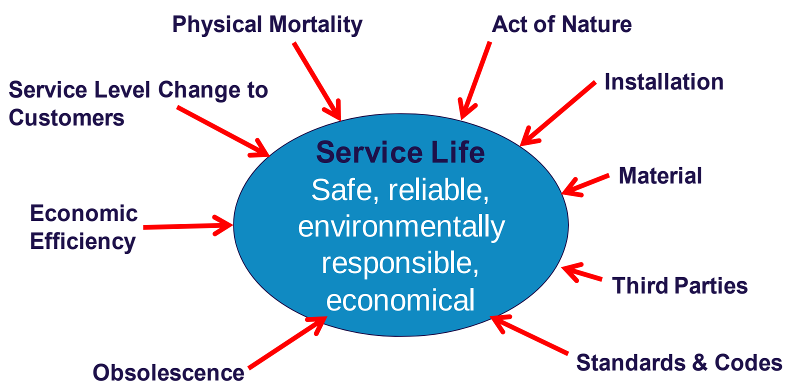
Like many other entities in B.C. that manage the province's energy, transportation, water and wastewater infrastructure the Terasen Utilities, particularly TGI, are experiencing the impact of aging assets. The Utilities have embarked on a plan to enhance their asset management practices to deal with having a large portion of their assets reach expected retirement age at the same time. These enhanced practices will also serve the long term needs of managing a growing stock of new assets as we implement a widening range of integrated, conventional natural gas and alternative energy solutions.

6.1.5.1 Background

The Terasen Utilities and their predecessor companies have a history of providing safe, reliable, environmentally responsible, and cost effective natural gas delivery to its customers. Since the introduction of natural gas in British Columbia and the initial buildup of gas transmission and distribution infrastructure in the late 1950s, as well as ongoing growth of the system to meet new customer demand, the Utilities have built a reputation of operational excellence and sound asset management activities. Today, a host of challenges are confronting the Utilities in addition to the age of large portions of our infrastructure: ongoing safety and reliability, increasing regulation, tightening scrutiny on costs, heightened stakeholder expectations, continuing environmental responsibility, avoiding rate shocks and volatility and delivering customer value.

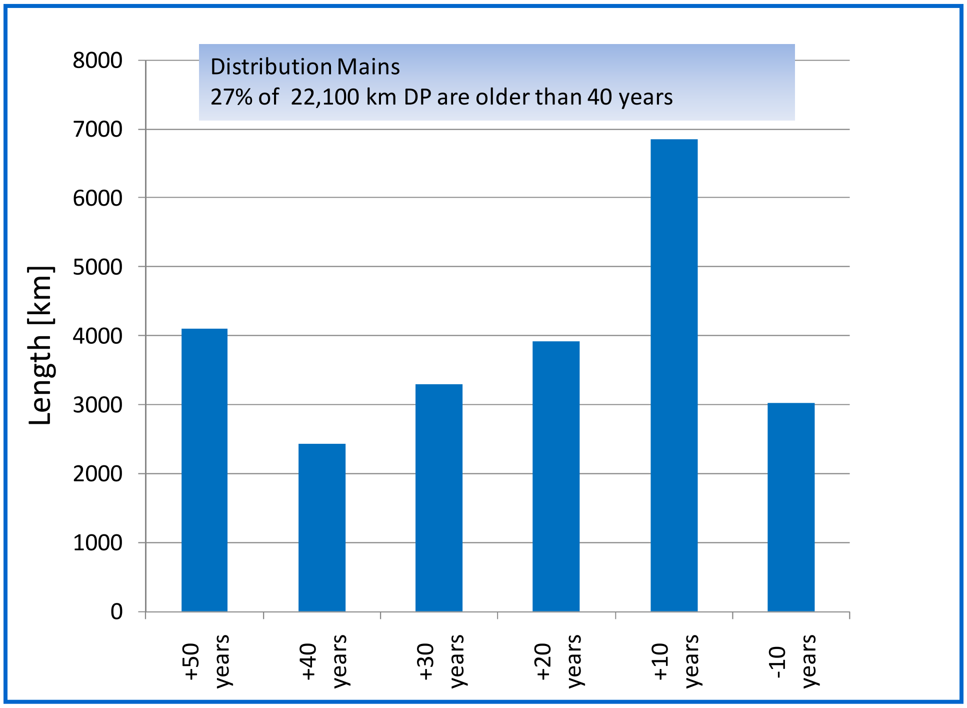
There are factors that cause infrastructure to degrade over time, and we must continue to prudently manage any emerging risks. While Terasen has managed these assets effectively, there comes a time when asset renewal is required. Through normal wear and tear, external factors such as obsolescence, changes in codes and standards, economic efficiency and changes in service requirements (Figure 6-12), these aging assets face an increasing rate of deterioration and are approaching the end of their expected service life.

Figure 6-12: Factors Affecting Service Life of Assets



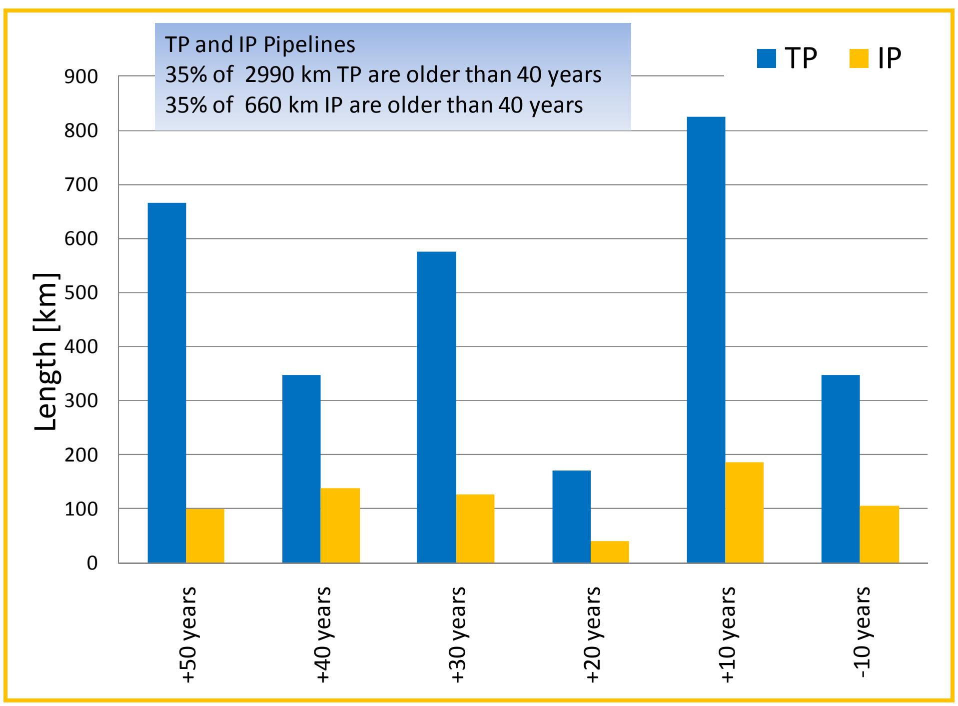
The result is a potential wave of system reliability concerns, increased corrective maintenance work and a jump in capital replacement. Today, the Utilities are responsible for gas transmission and distribution assets with a book value of approximately $2.9 billion and approximately potential replacement value worth of up to $6.8 billion. Close to 25% of distribution mains and 35% of intermediate and transmission pressure pipelines (Figure 6-13 and Figure 6-14) have been in service for well over 40 years. These assets will face the potential need for renewal within the next 10 years. Over a span of 40 years, approximately two–thirds of these assets, are expected to need renewal.

Figure 6-13: Distribution Mains by Age



(+10 years means more than / -10 years means less than)

Figure 6-14: Transmission and Intermediate Pressure Pipe by Age



(+10 years means more than / -10 years means less than)

6.1.5.2 Introduction to Enhanced Asset Management

Asset management practices in the utility industry are evolving and improving. We believe it is important to stay abreast of these changes and integrate best practices where appropriate. For example, the Canadian Gas Association ("CGA") released a Guiding Document on Asset Management in 2009 (Appendix E) that provides a basic framework for enhanced Asset Management practices. The CGA defines asset management as:

> *"A strategic management system used to optimally manage assets over the life cycle by balancing performance, risk, and expenditures to achieve corporate strategic objectives",*

and clarifies that the term

> *"…refers to a comprehensive and strategic application of a set of concepts, techniques, and tools that, when adopted and used effectively, can enhance a company's current management of its assets."*

The document goes on to describe the evolution of asset management practices:

> *"asset intensive industries such as aerospace, defence, oil and gas refineries, roads, bridges, railway works… have been developing this asset management discipline since the late 1970...* ***In more recent years, asset management has been gaining attention among North American transportation/municipal infrastructure managers and electric and gas utilities*** *(emphasis added)."*

Within B.C., the British Columbia Transmission Corporation ("BCTC") provides a very recent example of the implementation of enhanced asset management practices in its Transmission System Capital Plan F2009 to F2018, approved by Commission Order G-107-08. BCTC has documented that it uses several asset management practices to guide its capital decisions, including a formal prioritization methodology, the use of performance indices, asset health assessments, and risk assessment frameworks.

Within the Terasen Utilities, asset management practices have also evolved over time. Examples of existing practices include:

- meter inspection and replacement programs based on a statistical sampling,
- seismic vulnerability assessments for pipeline river crossings,
- assessment of safety risk to justify the cast iron main replacement, and
- an in-line inspection program to assess pipeline conditions identify repair and re-inspection frequencies.

Over the past few years, Terasen has implemented and improved its Asset Integrity Management Plan ("AIMP"). The AIMP is a management system with a focus on pipeline integrity, safety and loss to provide safe, environmentally responsible, and reliable service. This system improves some elements of asset management employed by the Utilities, such as documentation management, records management, change management, training, risk management, and performance measurement and metrics. The AIMP is the Terasen Utilities' first step towards fully a fully enhanced, holistic asset management process and a Long Term System Sustainment Plan that strikes an optimal balance between asset performance, business risk and economics.

6.1.5.3 Implementation – Five steps of Asset Management

The Terasen Utilities continue to enhance its asset management practices involving five steps as depicted in Figure 6-15. The five steps are summarized below.

Figure 6-15: Five Steps of Asset Management

An **Asset Registry** links all other asset management modules, such as financial, geographic, maintenance and control systems, and establishes a clear and systematic hierarchy of assets and their inter-relationships so the overall system effectiveness can be measured.

The **Business Values** defined for asset management purposes translate the corporate objectives of safe, reliable, environmentally responsible and cost effective energy service delivery into a set of measures (quantitative and qualitative) that can be assessed against the impact of service failure.

A comprehensive **Asset Health Review** includes a framework for asset failure prediction to ensure the correct data is collected and measurements are conducted to examine asset performance against expected service levels. A risk assessment is then conducted to quantify the impact on the Utilities' business values of both the consequence and probability of asset failure.

The identification of defined levels of risk exposure triggers the preparation of a **Business Case** in which the problem is defined, feasible options are identified and evaluated, a preferred solution is selected, cost and resource requirements are determined and a project schedule is presented.

The final step, **Capital Planning**, prioritizes the various business cases for system sustainment projects by the business value benefits to cost ratio, producing an optimal and levelized portfolio of capital investments.

While there is an immediate need to apply these steps of asset management practice enhancements to the system sustainment challenges before the Terasen Utilities today, these steps can and will also be incorporated into the system capacity reviews, identified constraints and expansion requirements discussed in Section 6.1.

6.1.5.4 Conclusion – The Terasen Utilities' Long Term Sustainment Plan

The asset management practice enhancements we are undertaking will move the Terasen Utilities from an organization with:

- a good, general understanding of asset management principles,
- an organizational structure reflecting the asset management/service provider split,
- a commitment to improving asset management effectiveness and competence over time,
- role clarity among asset managers, operators, and service providers, and
- accessibility to key information and systems needs,

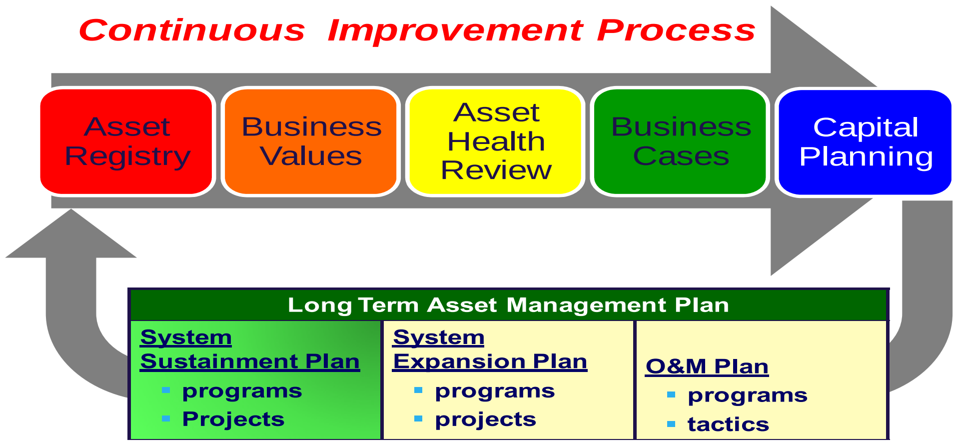
to an organization with the following competencies and capabilities:

- rigorous understanding of all asset management principles,
- best appropriate asset management process design,
- robust asset registry with accurate and timely information,
- effective asset management information systems that fully meet asset management decision support needs,
- roles and relationships clearly defined and functioning well,
- full life cycle plans, integrated into business action plans.

Ultimately, the cycle of conducting the asset management steps, leading to the development of integrated System Sustainment Plans, System Expansion Plans and Operation and Maintenance ("O&M") Plans[134] will be ongoing and continuously improving (Figure 6-16).

[134] Operations and Maintenance Plans are not discussed within the Long Term Resource Plan.

Figure 6-16: Continuous Improvement Process for Asset Management



A number of activities are already underway to move the Terasen Utilities along the five asset management steps. These activities will culminate in the delivery of a Long Term System Sustainment Plan containing a prioritized list of transmission and distribution gas asset sustainment projects and programs for all of the Utilities. Ultimately, the System Sustainment Plan will consider a sufficiently long time period to ensure an ongoing and orderly approach to asset renewal projects that sustain a long term balance of asset performance and cost effectiveness with an appropriate level of risk.

To develop a longer-term view of system sustainment, it will take some time to implement new methodologies, and to collect and assess the appropriate data. This foundation will enable improved trending of asset performance levels and remaining service life prediction for all of the Utilities' assets. Given the approaching wave of aging assets, the Terasen Utilities anticipate initially developing a 5-year capital plan informed by enhanced asset management practices currently underway. A longer term plan will be prepared and submitted as we more fully implement asset management practice enhancements through a yet to be determined regulatory submission and review process.

The long term system sustainment plan will be in the form of an optimal and levelized portfolio of capital investments matching available resources and minimize rate impact to ratepayers. The long term system sustainment plan will enable Terasen Utilities to continually providing safe, reliable, environmental responsible and cost effective natural gas delivery to customers now and well into the future.

6.2 Gas Supply Portfolio and Regional Infrastructure Planning

Upstream from the Terasen Utilities' transmission and distribution systems are networks of larger pipelines, storage facilities and market trading points (hubs) that move gas from production areas and deliver it to end market users such as utilities, large industries and electricity generating stations. These resources are also critical to our objective of providing our customers with safe, reliable and secure natural gas service. Competition among market participants for favourable gas pricing and for physical capacity on the regional transmission infrastructure means utilities must always be vigilant for regional trends and opportunities that could negatively or positively impact customers.

This section discusses the planning process for acquiring the gas commodity that is procured on behalf of customers and the regional resources required to deliver the commodity to the market area. This section also discusses how the Terasen Utilities manage price risks in a fluctuating commodity market and finally important market trends occurring within the regional market that impact our customers. The basic elements of the gas supply portfolio are the gas commodity volumes that must be purchased, the third party transmission or transportation pipelines that connect supply to market and the movement of gas to and from storage facilities as required. These include the Terasen Utilities' own on-system transmission pipelines and storage facilities.

For the Terasen Utilities, understanding market dynamics, including identifying regional infrastructure opportunities that could benefit customers, is critical. The Terasen Utilities are involved in key regional issues on behalf of their customers that include ensuring the availability of regional gas supply for their marketplace and the development and tolling of infrastructure that will facilitate the movement of supply to market. The Terasen Utilities file a plan with the Commission annually called the Annual Contracting Plan ("ACP") in which they assess the overall North American market and evaluate the regional market for supply and infrastructure. The key objectives of the ACP are:

1. To contract for resources which ensure an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet the core customer design peak day and annual requirements.
2. To develop a gas supply portfolio mix which incorporates flexibility in the contracting of resources based on short term and long term planning and evolving market dynamics.

6.2.1 SUPPLY PORTFOLIO PLANNING

The availability of supply and infrastructure must meet the daily normal and design peak day load requirements of our customers particularly in the winter months and throughout the year. Figure 6-17 shows the gas supply resources and transmission network serving B.C. and the Pacific Northwest. These resources provide service to meet annual and peak demand from both end use customers such as residential, commercial and industrial customers as the regions natural gas fired generating stations. The current capability of infrastructure to deliver supply to the Terasen Utilities customers on a peak day can only be facilitated under the condition that no service outages or constraints occur on any part of the various systems that deliver supply to market. However, should a peak day occur in the PNW region simultaneously, then a shortfall of capacity to deliver supply to the entire market is currently projected based on total regional capacity and demand forecasts.

Figure 6-17: Production Areas and Regional Gas Supply Resources Serving the PNW

The primary sources of gas supply serving the Terasen Utilities' customer load requirements originate from:

- the three main processing plants (Ft. Nelson, McMahon and Pine River) in northern B.C. and pipeline capacity operated by Westcoast[135],

[135] T-South Pipeline is operated by Spectra Energy's subsidiary, Westcoast Energy Inc. (https://noms.wei-pipeline.com/)

- the Aitken Creek storage facility in northern B.C. via Westcoast's T-South pipeline,
- various transportation and storage resources off of Williams' Northwest Pipe ("NWP") in Washington State including capacity through the Columbia Gorge section of the NWP system ("Gorge"),
- supply, pipeline and storage resources in Alberta.

The region's pipeline infrastructure provides access to supply from two major production basins; the WSCB and the Rocky Mountain area in the western U.S. ("U.S. Rockies"). The opportunity to shape gas supply to meet the weather driven customer demand profile within the region is provided by underground and LNG storage facilities. Underground storage facilities (Aitken Creek and Carbon) are both located near major production areas but further from load centres while facilities south of Huntingdon (Mist and Jackson Prairie Storage ("JPS")) are located closer to market centres. LNG storage facilities, such as TGI's existing Tilbury facility and TGVI's Mt. Hayes LNG (expected to be online April 1, 2011), are constructed within the Terasen Utilities service region.

Disruptions associated with infrastructure or supply sources will impact our ability to deliver gas to customers, and/or affect the cost of the portfolio as we may need to secure alternative supplies on short notice. Daily load fluctuations, particularly during winter months, dictate that additional gas supply should be available in the pipeline system within a span of a few hours to meet demand or, conversely, to dispose of excess supply that might result from a lack of demand during a warmer than expected day. These extreme conditions can potentially occur continuously spanning from a few days to a few weeks over any winter season which requires the availability of adequate storage and market infrastructure in order to handle the daily fluctuations.

Due to the winter peaking nature of the PNW and B.C. marketplace, producers and marketers are more inclined to sell and ship their supply to markets such as Alberta (AECO[136]), where demand is more consistent throughout the year due to the availability of high volume pipeline capacity to supply markets further east including the mid and eastern U.S. With producers preferring the Alberta market over the PNW, gas is increasingly less likely to be available at competitive rates at B.C.'s trading hubs (Station 2 and Huntingdon), which are the main purchasing points for the Terasen Utilities. Significant price disconnects can therefore occur between the Alberta and B.C. market hubs causing shippers to require a higher price to commit gas supplies to the B.C. trading hubs during short term periods of cold weather. Increasing competition for limited regional storage and pipeline resources are reducing the options available to producers, purchasers and shippers to overcome such price disconnects, further

[136] Alberta Energy Company (AECO) is the historic name of a virtual trading hub on the NGX Canadian Natural Gas Exchange (http://www.ngx.com/overview_an.html).

compounding this situation. The growth of regional infrastructure has not kept pace with the demand growth in the PNW region.

The Terasen Utilities' gas supply portfolio planning also provides commodity balancing and peaking gas supply services to all customers. Our gas contracting resource base stems from the operating climate of its marketplace in relation to other markets such as Alberta. The B.C. and U.S. PNW marketplaces are less flexible compared to the Alberta marketplace for purchasing or selling gas, particularly, for near term trading such as on a 'day out' or 'intraday' spot market. Figures 6-18 and 6-19 depict the daily demand for design year (colder than normal) and normal year annual demand load forecasts for the 2010-11 gas year for TGI and TGVI respectively, along with the portfolio of resources that will be employed to meet that load. TGI manages the portfolio requirements for TGW within its own portfolio. It should be noted in the graphs that there is a difference in the utilization of resources during normal and peak weather conditions in order to meet demand. Contracting for gas supply is a dynamic process each year based on availability and pricing of the various resources.

Figure 6-18: 2010 / 11 TGI Normal & Peak Day Load vs. Recommended Portfolio

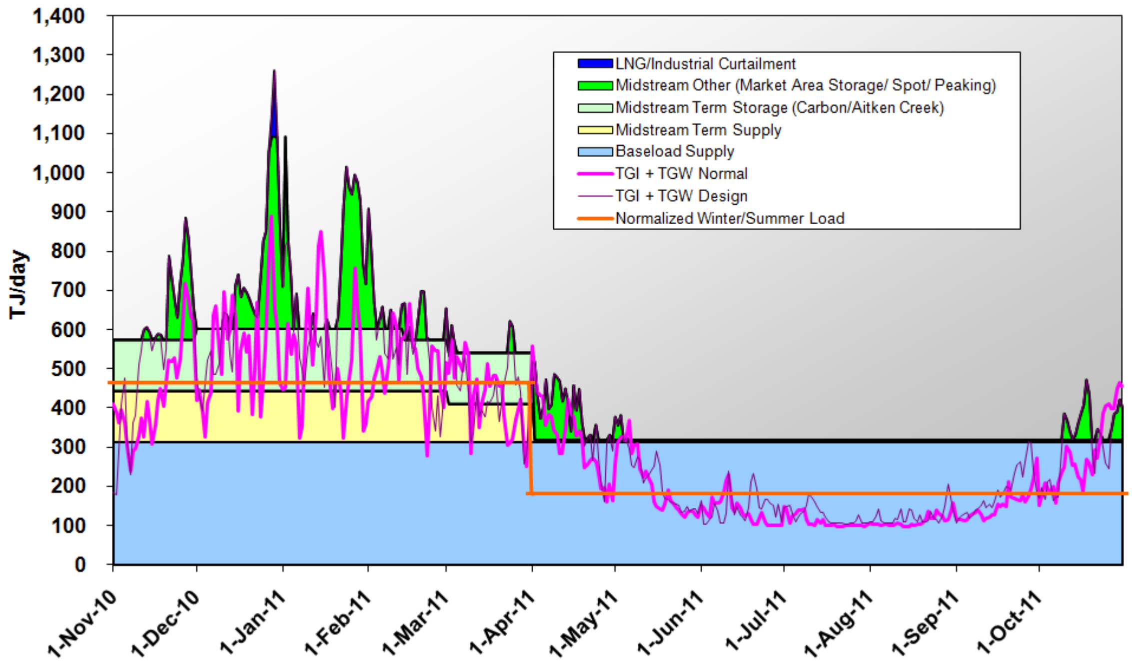
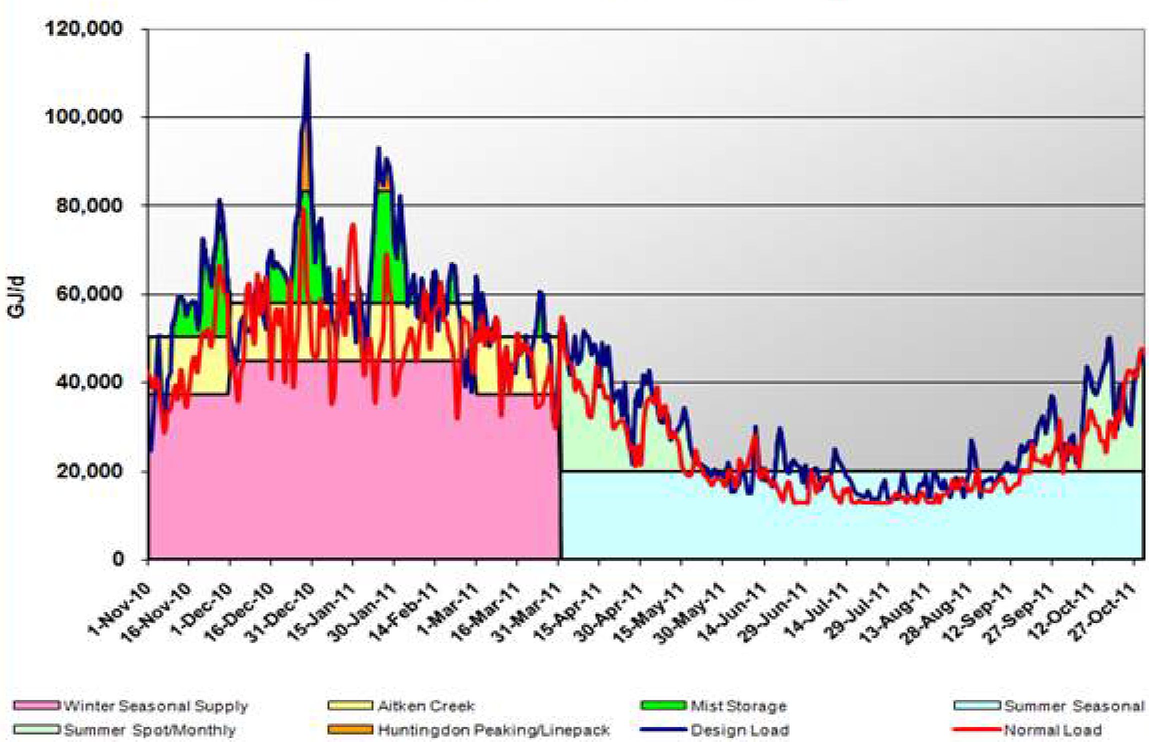


Figure 6-19: 2010 / 11 TGVI Normal & Peak Day Load vs. Recommended Portfolio



Seasonal storage facilities such as Aitken Creek and Carbon (Figure 5-1) provide term supply in the winter months and assist in load balancing during normal winter weather. Market area storage facilities from Mist and JPS provide the Terasen Utilities with a valuable shorter duration balancing tool for further managing intraday load fluctuations particularly during cooler and peak weather conditions. Demand growth in the PNW region including demand from gas-fired electricity generation has increased the competition for very limited market area storage and redelivery capacity in the region. As utilities in the PNW increase their share of contracting for these resources for their own use, the Terasen Utilities are increasingly challenged to maintain the same level of contracting for these resources for the 2010/11 gas year and beyond compared to prior years. Pipeline capacity at Huntingdon and on the Gorge section of the NWP system that is utilized to supply utilities on I-5 corridor is likely to become constrained if the region at large undergoes a severe cold snap or experiences peak weather conditions. The likelihood of these constraints will increase as growth occurs in the region over the next several years and no infrastructure expansion occurs.

As discussed in Section 6.1, the Mt. Hayes LNG storage facility on Vancouver Island will greatly assist the Utilities and their customers with on-demand and on-system gas supply when commissioned in 2011. This new facility reduces our reliance on third party owned storage resources required for short term and peaking supply. As a result, the Terasen Utilities will be able to reduce dependence on the Huntingdon and/or Kingsgate interconnections for peaking gas supply. We are also able to reduce the level of contracting required for other market area storage until such time that the forecasted load growth on the system warrants re-contracting for shorter duration resources and peaking gas supply or expanding the Terasen Utilities' own storage resources.

TGI's biogas initiative represents another opportunity to diversify the gas supply portfolio, reduce reliance on third party infrastructure and provide customers with a carbon neutral source of energy. Initially, biogas volumes from various B.C. projects will be insufficient to alter the TGI existing midstream portfolio contracting strategy. As the volumes increase over time, however, biogas supplies will be incorporated into the gas supply resources of TGI.

Resource procurement at the Terasen Utilities must also consider Gas Marketer involvement in retail sales in the TGI service area to residential and commercial customers since 2007. However, TGI maintains the responsibility of managing the midstream infrastructure and balancing the daily load on the entire system on behalf of all customers.

The Terasen Utilities continually assess the market forces and resource availability in the PNW such as the availability and cost of third party off-system storage and transportation for serving the intraday load in the winter months. Our large operating region requires that the supply portfolio maintains a certain level of diversity in order to access gas supply at a variety of points to cost effectively serve customers on any given day. This diversity is also critical to the utility to ensure security of supply during peak events and emergencies through the availability of alternative supply in the event of emergencies.

6.2.2 MANAGING COMMODITY PRICE UNCERTAINTY (PRICE RISK MANAGEMENT)

TGI and TGVI operate in a marketplace characterized by volatile market prices and competing sources of energy for customers. Ensuring natural gas rates remain competitive with other energy sources and reducing market price volatility are fundamental to retaining existing load and adding economic new load. Both TGI and TGVI develop diversified procurement strategies and utilize a price risk management plan to manage commodity price risk in order to facilitate competitive natural gas rates.

The focus of the price risk management plans is to improve the likelihood that natural gas remains competitive with other sources of energy, and to moderate the impact of gas price volatility on customer rates. Through annual submissions of utility Price Risk Management Plans to the Commission, the Utilities evaluate the hedging strategy to ensure the plan is aligned to changing pricing and contracting environments. Market prices are currently depressed due to weakened industrial demand, steady production and healthy storage levels, providing an opportune time for the utilities to lock in favourable prices. This is particularly important given the volatility inherent in the energy marketplace.

For the TGVI price risk management plan, particular attention is given to the impending expiry of the royalty revenue arrangement with the Province of British Columbia at the end of 2011. After this time, TGVI customers face significantly higher rates and so the hedging program is one of the tools TGVI uses to mitigate this risk.

The gas supply portfolio adopts a diversified resource acquisition strategy to maintain supply reliability and moderate commodity price uncertainty. Volatility in natural gas prices is managed by effective use of the hedging program, maintaining access to liquid trading hubs, acquiring a variety of storage and transportation resources, and using different pricing structures and contract terms. Terasen Gas considers access to appropriate natural gas infrastructure and minimizing reliance on any one price point a critical element of ensuring the long term competitiveness of natural gas rates.

TGI and TGVI will continue to monitor the natural gas marketplace and its inherent volatility and seek Commission approval of the Price Risk Management Plans and Annual Contracting Plans. These Plans enable the utilities to manage commodity price uncertainty, ensure effective resource procurement, maintain competitiveness with other sources of energy within B.C. and provide value to customers.

6.2.3 REGIONAL INFRASTRUCTURE PROPOSALS, IMPLICATIONS AND TG ALTERNATIVES

Utilities and gas transmission entities throughout the PNW are responding to the region's gas supply trends – looming transmission capacity constraints and the drawing away of gas supplies to other markets – with a range of new infrastructure and transmission service proposals. Amid these activities, the Terasen Utilities need to act to ensure the availability of gas at its main purchasing points at competitive rates with other markets to protect B.C. customers from unnecessary cost increases. This section describes the various infrastructure projects being proposed in B.C. that could impair the Utilities' ability to acquire cost effective, reliable supply for our customers. A description of a key infrastructure initiative we have undertaken with Spectra Energy to address the concerns about ensuring access to B.C. supply is provided, as well as a summary of future infrastructure projects being proposed in the PNW. Finally, this section describes the activities that the Terasen Utilities are engaging in to protect and promote the needs and interests of its customers within the marketplace.

6.2.3.1 Northern B.C. Supply

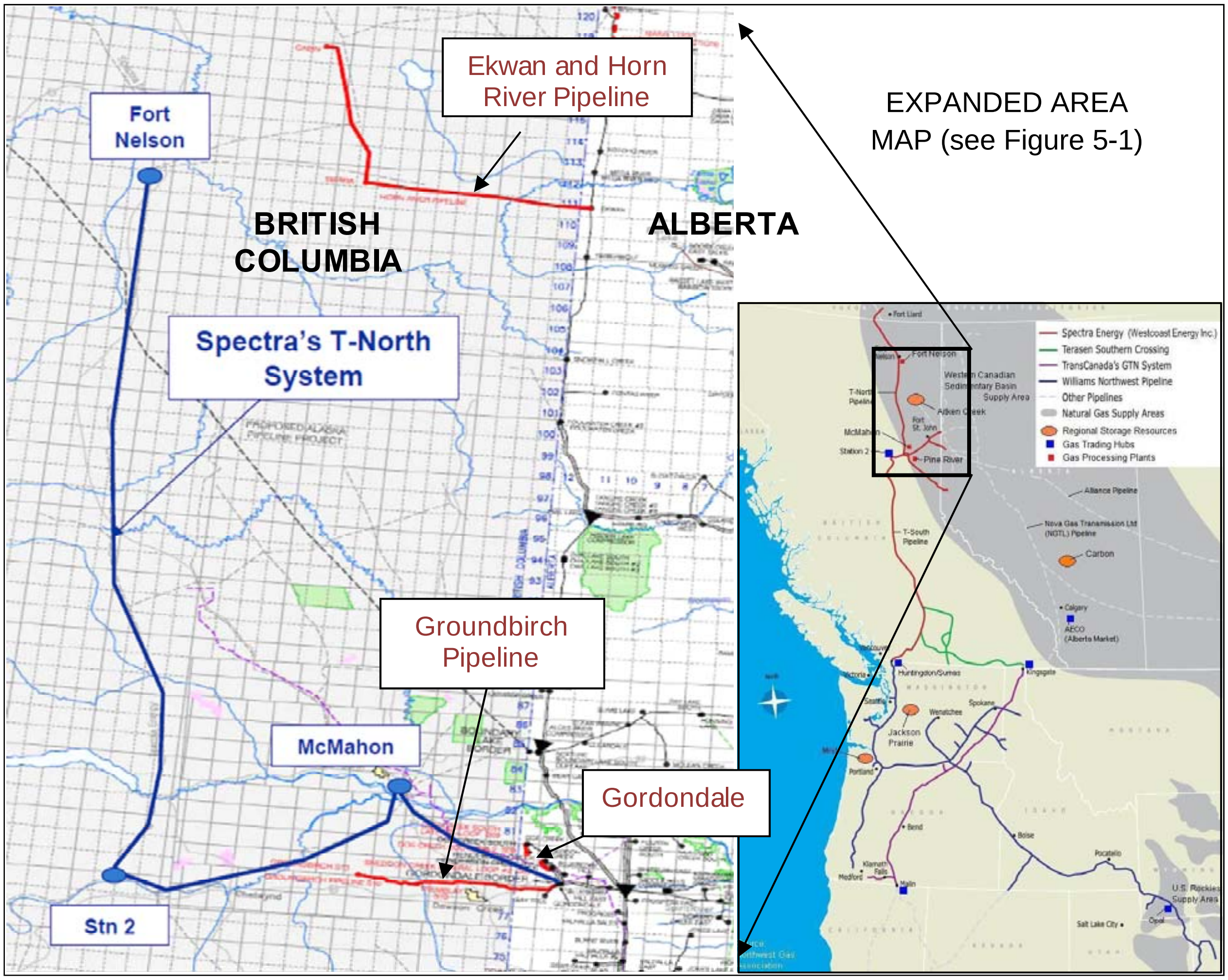
Natural gas sourced from B.C. is integral to meeting the Terasen Utilities and PNW regional demand. The natural gas marketplace in B.C. is evolving rapidly with the prospect of a significant increase in unconventional production in the near future. In recent years, technological advances have greatly improved the economics to extract the unconventional natural gas resources and as a result of the increase in potential reserves have dramatically altered the long term outlook of natural gas as a resource. In Northern B.C. the Horn River and Montney developments are unconventional gas plays with significant resource potential. The favourable economics in B.C. for commercial production of this resource has significantly altered the role that supply from B.C. is anticipated to play over the long run within the WCSB.

In order for this potential to be realized, however, new infrastructure will need to be developed in order to connect the supply to markets.

6.2.3.2 Current Infrastructure

As seen in Figure 6-20 pipelines currently accessing northern B.C. production include Spectra Energy's T-North, Encana's Ekwan pipeline, Alliance pipeline and various smaller, producer owned pipelines. From the T-North system, gas can either flow to Station 2 and down Spectra Energy T-South system or to Gordondale and into Alberta.

Figure 6-20: Existing Pipelines Serving Northern B.C. Gas Production Areas



Spectra Energy's T-South system transports natural gas south from Station 2 to markets throughout B.C. and into the PNW markets, primarily what is referred to as the "I-5 Corridor" from Sumas to Portland. The NGTL system gathers natural gas supply from B.C. and Alberta and serves markets within Alberta and export points on pipelines leaving the province. The Alliance pipeline system gathers natural gas production from both B.C. and Alberta and serves the mid-continent market in the U.S. The Ekwan pipeline and producer owned pipelines all flow directly to the NGTL system while the Alliance pipeline flows to Chicago.

The Station 2 and Sumas markets are critical to the Terasen Utilities' customers as the majority of customer demand is supplied from these two markets. However, a significant portion of the new supply source is expected to bypass the B.C. and PNW markets as new infrastructure expansions are planned to move this supply directly to Alberta to allow access to bigger and more liquid markets. In the medium term the total take away capacity of the proposed new infrastructure developments exceeds the expected increase in production from the new northern B.C. unconventional plays.

Increasing exports of gas to markets outside B.C. and the PNW could significantly alter the dynamics of supply availability to the market hubs at Station 2 and Sumas for the B.C. consumer. Security of supply and cost impacts could be major issues for natural gas customers of the Terasen Utilities in the near future, as the pipeline expansions to take away northern B.C. production alter the competitive access to gas supply within B.C.

6.2.3.3 Market Liquidity as a Driver for Production and Infrastructure Development

The majority of the production in northern B.C. has traditionally served B.C. and PNW markets. These B.C. and PNW markets are primarily weather driven winter season markets. As a result the infrastructure on T-South serving the Sumas/Huntingdon market becomes fully utilized during cold and peak winter days.

In contrast to the B.C. and PNW markets, the AECO (Alberta) market is generally preferred by B.C. producers due to its access via various pipelines to end markets across North America from California in the west, to mid-continent and Eastern U.S markets. This flexibility and the large number of buyers and sellers in the AECO market leads to high liquidity[137] and price transparency.

Since 2001, more than one third of B.C. annual production flowed directly into Alberta. The trend to move B.C. supply east is occurring in response to declining production forecasts in Alberta and the increased demand expected from the oil sands development. The unconventional Montney and Horn River plays in northern B.C. are the primary areas of growth for the WCSB production and will serve to offset declines in Alberta. This increase in supply potential has regional infrastructure players aggressively pursuing new projects to increase the take-away capacity out of the province to eastern markets and abroad[138].

[137] Market liquidity is an asset's ability to be sold without causing a significant movement in the price and with minimum loss of value. The essential characteristic of a liquid market is that there are ready and willing buyers and sellers at all times.

[138] Kitimat LNG is a proposed LNG export facility in north-western B.C., discussed later in this section, being designed to export natural gas from northern B.C. to other parts of the world.

6.2.3.3.1 NGTL Proposals

In early 2009 TransCanada was successful in obtaining approvals to move its Nova Gas Transmission Limited ("NGTL") – see Figure 6-17 system from provincial jurisdiction to federal jurisdiction under the National Energy Board ("NEB"). This change in jurisdictional oversight allows NGTL to extend its transmission system beyond provincial borders and increase NGTL's competitiveness to attract B.C. sourced gas onto its system relative to the Spectra Energy or Alliance systems.

NGTL has since proposed three significant projects to move gas from B.C. into the AECO market and to export points leaving Alberta. These projects are proposed as extensions of NGTL's system and therefore the cost will be rolled into the overall NGTL rate base, improving the NGTL's competiveness for attracting new supply. A description of each project and the response to either a formal bidding process (called open seasons) for capacity or approval applications for construction on each proposed project follows (also see Figure 6-20:

- **Horn River and Groundbirch Expansions**

NGTL received strong commercial support in a binding open season for the Groundbirch pipeline with firm gas transportation contracts that will reach 1.1 Bcf/d by 2014. The Groundbirch pipeline is 78 kilometres long and scalable to 1.7 Bcf/d. NGTL received NEB approval for the Groundbirch pipeline project on March 4, 2010 and is expected to be in service in the fourth quarter of 2010.

In February 2010, NGTL filed their Horn River project application with the NEB. The Horn River pipeline is a 155 kilometres long pipeline that incorporates the existing Ekwan pipeline and connects with NGTL. Horn River has an initial design capacity of 696 MMcf/d. The Horn River pipeline adds 282 MMcf/d of incremental take-away capacity over the existing Ekwan pipeline. The Horn River pipeline project is expected to be in service by mid 2012, subject to Regulatory approvals.

NGTL Horn River and Groundbirch pipeline projects will provide producers an economical avenue to transport over 2 BCF/d of Horn River and Montney supply on to NGTL's Alberta system and to Alberta and eastern markets.

- **NGTL proposed Ft. Nelson & McMahon Receipt Service**

In addition to the construction of the Horn River and Groundbirch pipelines, NGTL has also proposed a Ft Nelson & McMahon Receipt service whereby existing shippers on T-North with capacity to Gordondale would assign their capacity to NGTL and be deemed to have delivered on to NGTL at the outlet of Spectra Energy's existing Ft Nelson and McMahon plants. The proposal has the potential to further decrease the availability of supply at Station 2 which could reduce liquidity and negatively result in cost increases and affect the long term security of gas supply for consumers in B.C. The Terasen Utilities have been actively participating in discussions with Spectra Energy, NGTL and other regional players in the PNW to ensure that the structure of any such proposal does not impact the availability of supply at Station 2.

The uncertainty of these proposals initiated Terasen Utilities to take a proactive approach and diversify its position at Station 2. For example, in late 2009 the Utilities contracted for incremental T-North Long Haul firm capacity with access to the Ft Nelson plant outlet. This strategy allows the Utilities to diversify their position by contracting with producers directly at the plant's outlet for delivery to Station 2. This capacity provides the Terasen Utilities with flexibility and diversity in the portfolio as production from the Ft Nelson plant is projected to increase substantially in the next six to twelve months due to development of the Horn River basin. Since December 2009 the firm capacity on the T-North mainline from Ft Nelson to Station 2 has been completely contracted by shippers.

6.2.3.3.2 Spectra Energy Proposals

In response to the increased B.C. production outlook, Spectra Energy has also undertaken infrastructure projects to expand the Ft. Nelson gas plant, Ft. Nelson North ("Cabin Lake") plant, pipeline capacity to Gordondale where its system interconnects with NGTL, and Ft Nelson plant to NGTL pipeline capacity.

- **Gathering & Processing**

With existing assets, Spectra Energy can make relatively low cost upgrades to produce and transport gas to the existing Ft Nelson plant. The Fort Nelson Plant is being re-fitted to increase production to 900 - 950 MMcf/d depending on gas composition and final design and is expected to be fully contracted by 2012 depending on capital injection and economic recovery. This incremental Ft Nelson supply has the potential to service B.C. markets, however, this supply could also end up serving Alberta markets if the NGTL Ft Nelson & McMahon Receipt service were to proceed.

Spectra Energy Cabin Lake processing facilities involves the construction of a natural gas processing plant that has one processing line connected to existing raw gas transmission pipelines. The plant will have an initial inlet design capacity of approximately 250 MMcf/d of raw gas. Processed gas from Spectra Energy's Cabin Lake Plant will be delivered onto NGTL's Horn River Pipeline via a new 11 kilometre pipeline. This supply will ultimately flow east into the AECO market.

On June 10, 2010, Spectra Energy announced it was responding to customer demand in the Montney by building a new 200 MMcf/d natural gas processing plant west of Dawson Creek. The proposed Dawson Processing Plant will be built in two phases with the first 100 MMcf/d of processing capacity available in late 2011 and the remaining capacity available in early 2013. The expansion facilities are supported by long-term customer commitments. This supply is expected to flow on the Groundbirch pipeline to Alberta.

- **T-North**

Spectra Energy held binding open seasons for transportation capacity running east from McMahon, B.C. on the T-North system through Gordondale and onto the NGTL system. The firm capacity was contracted at 153 MMcf/d bringing the total to 334 MMcf/d. This capacity would flow B.C. supply directly to the Alberta market.

Spectra Energy also recently held an open season to expand capacity up to 200 MMcf/d from the Ft Nelson plant to NGTL with a targeted in-service date of January 2012 to either Gordondale or a new delivery location at Groundbirch. The open season closed May 7 2010 and indications are that all the 200 MMcf/d was contracted. This Ft Nelson to NGTL pipepline expansion has the potential to service B.C. markets, however, the supply flowing on this pipeline capacity could also end up serving Alberta markets if the NGTL Ft Nelson & McMahon Receipt service were to proceed.

6.2.3.3.3 Alliance Pipeline Proposals

Alliance Pipeline also recently had several open seasons in response to the recent developments in northern B.C. that could increase take-away out of B.C.. The first was a binding open season in the summer of 2009 to expand capacity to receive incremental B.C. gas onto its gathering system at new or existing receipt points up to 500 MMcf/d. The second open season was a non-binding offering that would enable deliveries off its system to new interconnections at either AECO or other points. The impact of these two expansions would be increased opportunity for Alliance shippers to gather gas from B.C. and deliver it into the AECO market similar to the NGTL expansions. To date, the results of the open season have not been made public. Most recently, Alliance had a binding open season and secured 20 MMcf/d of service from northeast B.C./northwest Alberta to Chicago that closed March 2, 2010.

6.2.3.3.4 Kitimat LNG

Finally, an LNG export project in B.C. proposes to ship northern B.C. supply on the Spectra Energy system, then along the proposed 463 kilometre Pacific Trail Pipeline to Kitimat where the gas would be liquefied and then exported to markets abroad such as Asia and Europe. The pipeline project proposes to increase the existing transmission capacity from 115 MMcf/d on the Pacific Northern Gas system to approximately 900 MMcf/d for the LNG terminal. The total budget for the project is approximately $4.2 billion excluding upgrades necessary on the Spectra Energy system from Station 2 to Summit Lake. The proponents of this project suggest that the pipeline and LNG terminal could be in operation as early as 2013. To date, several non-binding agreements associated with the project have been announced. On January 13, 2010 Apache Canada Ltd. announced it acquired 51 percent of Galveston LNG Inc and on May 18, 2010 EOG Resources Inc announced it purchased the remaining 49%, bringing the project another step closer to construction.

6.2.3.3.5 Summary of Northern B.C. Expansion Proposals

Cumulatively, the pipeline expansion projects in B.C. could lead to 3.5 Bcf/d of incremental take-away capacity out of B.C. to eastern markets or abroad over the next five years:

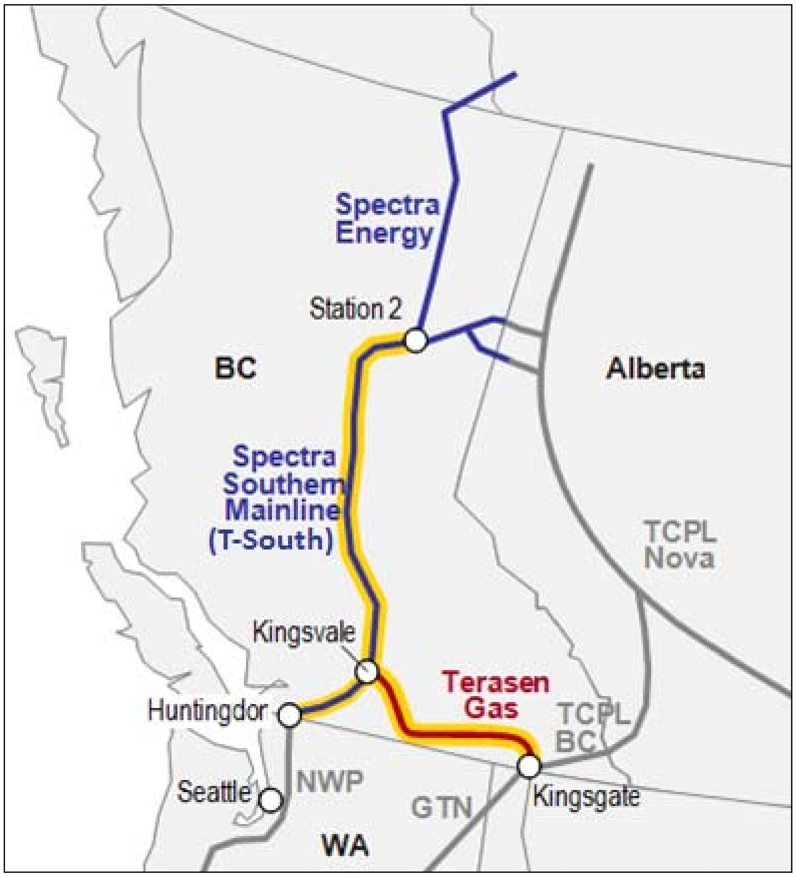
NGTL-Groundbirch	1,656
NGTL-Horn River	282
Alliance	500
Spectra Energy-Gordondale	153
Pacific Trail Pipeline/LNG Export	885
Total (MMcfd)	3,476 (3.5 Bcf/d)

In comparison to this incremental take-away capacity, B.C. production is forecast to increase by only 1.9 Bcf/d from 2009 to 2014. The increased competition for B.C. supply could ultimately lead to higher prices and increased volatility at Station 2 and Sumas, the Utilities' main sources of supply to meet customer demand.

6.2.3.4 Increasing T-South's Competitiveness

T-South, the Terasen Utilities' main supply resource to serve customer demand, provides service from Station 2 in northern B.C. to the Sumas market at the B.C. – U.S. border (Figure 5-1). Although increases in B.C. production are expected to be significant, the T-South system is currently only 71% subscribed under firm annual contracts due to reduced demand during warmer weather. One of the key initiatives the Terasen Utilities have undertaken in collaboration with Spectra Energy to address the threat of increased exports of natural gas out of the province and to provide additional benefits for our customers, is development of an enhanced east-west transmission service ("T-South Enhanced Service" – see Figure 6-21). The advantages offered by this enhanced service set the foundation for exploring a Terasen Utilities system expansion between Kingsvale and Oliver to increase the availability of this service for the benefit of the Utilities' customers and the PNW marketplace.

Figure 6-21: Spectra Energy's T-South Enhanced Service



This regional energy solution promotes the efficient use of existing pipeline infrastructure and encourages firm producer commitment to the B.C. and PNW marketplace. The pilot project is an arrangement between the two Utilities allowing Spectra Energy to offer the T-South Enhanced Service, which provides shippers access to the winter Sumas market and the summer Kingsgate market that supplies California. Spectra Energy is able to provide this service by holding capacity on the TGI system between Kingsvale and Kingsgate. This option promotes re-contracting on T-South by providing access to alternative markets and potentially increased flexibility and liquidity.

The forecasted increase in B.C. production presents an opportunity to attract PNW shippers to the T-South system. The advantages to shippers of the T-South Enhanced Service over the other proposed projects in the PNW include the following:

- Access to growing northern B.C. unconventional production.
- Immediate access to service through existing infrastructure.
- No additional capital costs for the pilot phase.

- A competitive toll.

- Access to the Kingsgate market during summer months and the Huntingdon market in the winter

- New incremental capacity through expansion of the TGI transmission system would bring more supply to the PNW at minimal cost.

- **Kingsvale to Oliver System Expansion Opportunity**

The next phase of the T-South Enhanced service will be to explore options to overcome the physical constraints on the Terasen Gas system between Kingsvale and Oliver, thus extending the service provided by the SCP. Removal of this constraint would allow expansion of the T-South Enhanced service further encouraging producers to remain on the T-South system. An expansion of SCP bi-directional system would also aid in increasing capacity to the region at Sumas that is required for the region during peak weather events and reduce the impact of operational constraints on the NWP.

Spectra Energy and TGI are using the pilot project as a means to assess the long term market potential of this service in B.C. as well as to establish operating practices. In conjunction with the pilot project, TGI is undertaking a preliminary feasibility study to address options to overcome the physical constraints on the TGI system between Kingsvale and Oliver and on the Foothills (South B.C.) Limited system between Yahk[139] and Kingsgate. The outcome of this study will be a scope of work of a potential expansion project including detailed cost and schedule information and a market feasibility assessment.

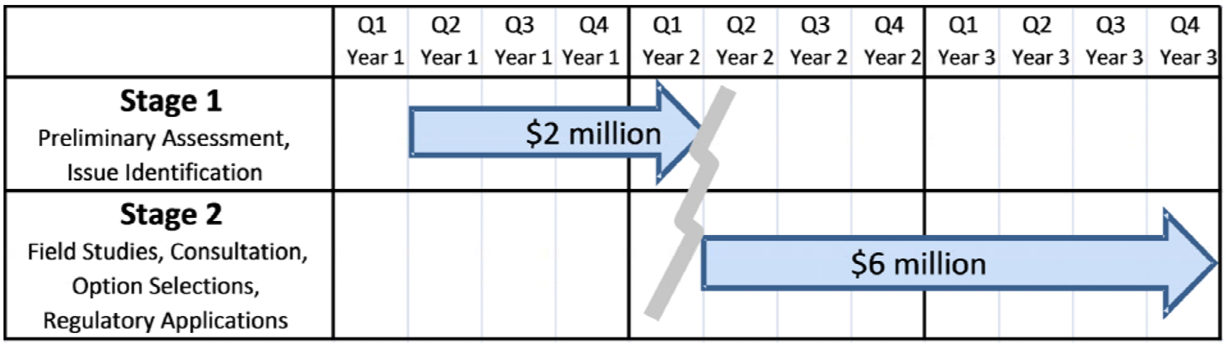
The proposed development activities are divided into two stages prior to TGI filing a CPCN application. In Stage 1, TGI is performing preparatory engineering, environmental, construction, land use, socio-economic impact and stakeholder identification studies to determine the initial feasible route and, as applicable, compressor site alternatives. These studies will provide the framework of the conceptual design of the pipeline and compressor facilities. Stage 2 involves field studies, options analysis, consultation, and regulatory applications. These two development stages are expected to require a period of nearly three years in aggregate.

In Order G-70-10, the Commission approved that Stage 1, Preliminary Assessment costs to a maximum of $2.0 million, be charged to the SCP Mitigation Revenues Variance deferral account. TGI has commenced Stage 1 activities in the second quarter 2010 with the objective of completing the technical feasibility and market assessment by second quarter 2011. Based on the results of Stage 1 activities, the Utilities will assess the timing and support for proceeding with Stage 2 activities leading to a potential CPCN. The earliest Stage 2 activities would

[139] Yahk is the pipeline interconnect between the SCP and BC Foothills systems located, approximately 8 km north of Kingsgate.

commence is 2011; however, the timing will be dependent on market conditions at that time. Table 6-3 shows the Stage1 and 2 timelines.

Table 6-3: Enhanced Service Expansion - Stage 1 and 2 Development Costs and Timelines



6.2.3.5 Infrastructure Development in the PNW

Demand growth in the PNW is forecast to continue despite the recent downturn in the economy which has had a temporary impact on natural gas consumption levels. The Northwest Gas Association's regional Outlook Study (Appendix-A-4) identifies that the I-5 corridor continues to face infrastructure constraints due to demand growth for both end-use sales and electricity generation.

The current capacity at Sumas is not adequate to meet the demand on a coincidental peak day when both the Terasen Utilities and utilities in the I-5 Corridor require supply to meet the high demand on their systems. The introduction of Mt. Hayes LNG in 2011 will contribute to overall regional capacity; however, the region's infrastructure will still be fully utilized during peak periods. The tight supply-demand balance in the region provides support for capacity expansion in the region.

Two pipeline infrastructure projects, shown in Figure 6-22, being pursued in the PNW are the Blue Bridge (proposed by Puget Sound Energy) and Palomar (proposed by Northwest Natural). The development of these proposals indicates that shippers are seeking to expand the available transportation capacity in the region. The Blue Bridge and Palomar proposals will allow shippers greater access to supply from AECO or the Rockies markets by increasing capacity from Stanfield into the I-5 corridor. Initially, part of the justification for these projects was to reduce dependence on B.C. sourced supply based on the premise that production from the Western Canadian Sedimentary Basin was in decline. With the significant new supply potential arising from the Horn River and Montney developments, however, the utilities in the PNW are re-evaluating the potential to meet their demand growth by increasing contracting for supply at Sumas and/or Station 2.

Figure 6-22: Pipeline Projects Proposed to Serve the Pacific Northwest

(Source: Northwest Gas Association)

A Sumas to Seattle expansion on the NWP system could be a relatively cost-effective option to bring incremental supply to the I-5 Corridor. However, since the T-South system is full on particularly cold days, expansion on NWP would likely require additional capacity to be added north of Sumas to meet incremental peak day demand. In addition to the benefits described earlier from providing access to the Kingsgate summer market, expansion of the Terasen Utilities' system from Oliver to Kingsvale could bring incremental capacity from Alberta onto the Spectra Energy system and into the I-5 corridor.

Competition is also high for new supplies being developed in the Rockies natural gas basin in the U.S. mid-west. Heading west out of the Rockies, construction of the Ruby pipeline continues to advance and is forecast to be in service in 2011. The Ruby project will deliver Rockies gas to the Malin market hub to serve California markets and potentially markets in the Pacific Northwest. The Rockies Express Pipeline is now in service while the Rockies Alliance Pipeline and Bison Pipelines are also being proposed to bring production east out of the Rockies away from the PNW marketplace.

Table 6-4 provides a summary of these and other regional supply projects proposed in the PNW. While these projects will expand supply capacity and diversity in certain areas within the PNW, they do not necessarily provide any benefit to the B.C. Market place, and could potentially have negative impacts on gas availability and therefore gas costs here. The TGI proposal to expand its system from Oliver to Kingsvale and provide additional capacity for the enhanced T-South transmission service could provide needed expansion capacity that would benefit the entire PNW region, particularly Terasen Utilities' customers.

Table 6-4: Gas Supply Expansion Proposals in the PNW

Access to Rocky Mountain Production				
Pipeline Projects	**Market**	**Supply Source**	**Project Specifics**	**In-Service Timing**
Bison Pipeline **-** Northern Border Pipeline Company	U.S. Midwest Chicago	Rockies	400 – 1000 MMcf/d from Powder River Basin to Morton County North Dakota	2010
Pathfinder Pipeline - TransCanada	U.S. Midwest	Rockies	Consolidated into Bison Pipeline Project	-
Rockies Alliance Pipeline - Alliance Pipeline & Questar	U.S. Midwest, Central Canada	Rockies	1.3 – 1.7 Bcf/d from Rockies to Ventura and Chicago trading hubs	N/A
Rockies Express Pipeline - Kinder Morgan, Sempra Energy, ConocoPhillips	U.S. Midwest, Eastern	Rockies	1.8 Bcf/d from Rio Blanco County Colorado to Monroe County Ohio	2009
Ruby Pipeline - El Paso, Global Infrastructure Partners (GIP)	California, Nevada, PNW	Rockies	1.3 -1.5 Bcf/d from Opal Wyoming to Malin Oregon	2011
Access to LNG Import				
Pipeline Projects	**Market**	**Supply Source**	**Project Specifics**	**In-Service Timing**
Pacific Connector Gas Pipeline - Williams, Fort Chicago (Canada), PG&E	California, Nevada, PNW	Import LNG	1Bcf/d from proposed Jordon Cove import LNG terminal Coos bay Oregon to Malin Oregon	2014
Palomar Pipeline West **-** Oregon Pipeline	PNW	Import LNG	1 – 1.5 Bcf/d from proposed Oregon LNG import terminal Warrenton Oregon to Molalla Oregon	2012
New Supply for the Pacific Northwest				
Pipeline Projects	**Market**	**Supply Source**	**Project Specifics**	**Proposed In-Service Date**
Blue Bridge Pipeline - Williams & Puget Sound Energy	PNW	Rockies Alberta	~0.5 Bcf/d from Stanfield Oregon to points north along NWP existing pipeline corridor to PNW market	2013
Palomar Pipeline - TransCanada & Northwest Natural	PNW Western U.S.	WSCB Rockies Import LNG	1.3Bcf/d bi-directional connecting NWN distribution system at Molalla Portland to GTN system in central Oregon, and to proposed Bradwood Landing LNG pipeline	2011

6.2.4 TERASEN UTILITIES CONTRACTING IMPLICATIONS

The fundamental objectives for the Terasen Utilities are to secure gas supply over the long term while minimizing the cost of the annual portfolio. In order to meet these objectives, the liquidity of the Station 2 marketplace from a supply availability and competitive pricing perspective are of paramount importance. Therefore, the Terasen Utilities will continue to protect and promote the needs of its customers and marketplace via:

1. Relationship building with new producers active in the Horn River and Montney plays including establishing contractual agreements in order to acquire B.C. unconventional supply in the portfolios.
2. Facilitating the increase of gas flow to Station 2 and on T-South in order to increase market liquidity within B.C. which in turn would reduce the likelihood of stranding capacity on the T-South system.
3. Entering into multi-year contracts with producers at Station 2 and upstream at the Ft. Nelson plant's outlet in order to ensure long term access to supply.
4. Representing customers' interests in NGTL and other regulatory proceedings due to their direct affect on the supply and pricing of gas in the B.C. market.
5. Pursuing the T-South Enhanced Service pilot with Westcoast in order to promote southbound gas supply in and through the province.
6. Conducting a preliminary feasibility study to determine how best to address regional constraints including constraints on Terasen Gas' own system. The T-South Enhanced Service pilot project sets the foundation for Terasen Gas to evaluate the feasibility of expanding the system between Kingsvale and Oliver and between Yahk and Kingsgate. Tearsen Gas has begun conducting Stage 1 preliminary assessment activities in accordance with Commission approvals. Based on the results of Stage 1 activities, Terasen Gas will assess the timing and support for proceeding with Stage 2 activities leading to a potential CPCN.
7. Continuously monitor the developments related to B.C. supply and infrastructure in order to meet the objectives of the ACP over the long term.

7 STAKEHOLDER CONSULTATION

Stakeholder needs and concerns are critical to resource planning. Effective stakeholder consultation provides insights that can impact the entire planning process, from trends that influence energy choices, demand forecasting and EEC program development though to the development of an action plan for implementing preferred solutions. The Terasen Utilities' consultation activities include EEC Advisory Group engagement, stakeholder workshops, presentations to municipalities throughout the province, web site communications and focussed meetings with select stakeholders seeking input on a range of regional and provincial energy issues and solutions. Terasen Utilities has a record of conducting effective stakeholder consultation programs and continues to do so in preparing this plan.

Terasen Gas considers stakeholder consultation for resource planning to be an ongoing process and an element of many stakeholder activities we undertake for a broad range of purposes. In addition to conducting planned events to share information and gather feedback specific to the Resource Plan, information from other community, customer and stakeholder engagement informs the planning process. In many cases, Terasen Gas has been able to combine focused discussion of resource planning issues with other community and energy industry consultation. Stakeholder input on previous resource plans also continues to influence the development of the current plan.

For the completion of this LTRP, the Terasen Utilities conducted two rounds of workshops. The first took place in the Lower Mainland in February 2010 and involved a focused dialogue with stakeholders[140] on the energy issues facing B.C. and the role that the Terasen Utilities need to play to support its customer's priorities and help meet legislative targets. Generally the stakeholders were supportive of the Utilities approach to becoming a fully integrated energy utility and expressed that it makes sense for the Terasen Utilities to develop renewable thermal solutions as part of the service offerings. Stakeholders asked us to work more closely with other utilities and the government in B.C. on energy issues and solutions. Other themes raised at this workshop included support for using pilot studies to test new ideas and technologies as and the idea of assurances that the implementation of community energy systems would lead to integration of lower carbon emitting solutions in a timely manner. All stakeholders appeared to want more opportunities to discuss energy planning issues with us.

The second round of workshops took place in May and June 2010 in Victoria and Vancouver. The issues discussed at these workshops generally followed the presentation topics below:

[140] Stakeholders represented our customers, commission staff, government and non government organizations

➢ **Energy Solutions for B.C.**

- Support for an integrated energy approach with natural gas as a foundation and the renewable thermal technologies.
- The growth in and ability of district energy solutions to contribute to carbon reductions over time to reach 2050 targets and Terasen specific projects.
- Ensuring that DES transitions to lower carbon intensity are timely, cost effective, and ongoing.
- Terasen strategies for promotion and adoption of NGVs, including incentives and approach on development of fueling infrastructure.
- Support that Terasen pursue and work more closely with other utilities and government.
- A call that Terasen provide more opportunities for dialogue and learning.
- Implications of the forecasted growth of district energy systems as the primary thermal energy provider in B.C. And the impact on natural gas usage and other traditional thermal energies.
- Interest in Terasen having robust scenario planning that takes into consideration the rapidly changing energy environment including technological, social, and regulatory changes.

➢ **Long Term Resource Planning Backgrounder**

- Impact of Clean Energy Act on efforts to work with Government and other Utilities on strategies and development of a baseline thermal demand forecast.
- Role of and interaction with the BCUC in development of LTRP.
- Use of scenario analysis in developing and analysing a range of alternative future demand forecasts.
- Consistency of Terasen's LTRP with B.C. government climate change targets and other aspects of the Clean Energy Act / benefits of Terasen's contrition through integrated, alternative energy initiatives.

➢ **Energy Efficiency and Conservation Programming**

- New EEC programs and their current and forecasted impact on energy savings.

- Current and future funding amounts and program areas – benefits from ongoing and additional funding levels, how to pursue increased and ongoing funding levels.

- Funding and timing for industrial programs (core industrial and interruptible industrial customers).

- Opportunities for more EEC programs and demand side activities, particularly, with commercial and industrial customers.

- Accounting for economic swings and fuel switching within estimated savings calculations.

- The cost benefit analysis and the balance between achieving short term financial objectives versus a cost benefit analysis that measures and targets longer term economic, social and environmental costs and objectives like GHG reductions or government objectives for energy efficiency.

- Additional funding for EEC programs targeted at low income residential customers represents a potential area for significant energy savings.

- Potential savings within some of the as yet un-tapped commercial sectors.

- Historic savings from furnace change-out programs and free-ridership.

- Ability for program participants to access funding from more than one program.

- Unintended consequences of implementing codes and standards changes without full consideration of impacts (hot water efficiency standard example).

➢ **Community Energy Solutions**

- DES and individual alternative energy solutions for residential, commercial and mixed use developments – thermal energy technology such as geo-exchange, waste heat and solar thermal.

- Terasen's biogas initiative and projects, particularly anticipated demand from both residential and commercial customers.

- Phased biogas program roll out to residential and commercial customers.

- Roll of gas marketers in biogas initiative.

- Notional versus physical points of delivery for biogas.

- Alignment of natural gas for transportation with the changing energy environment; Terasen's strategies and approach in developing a natural gas for vehicles program.

- Differences in the policy and environmental regulations that suggest growth in NGV programs now versus the past.

- Natural gas vehicle solutions, benefits and vehicle emission regulations.

➢ **Energy Demand**

- Support for working with other utilities and the government on a coordinated, total thermal energy demand baseline forecast for B.C.

- Development and use of alternative forecast scenarios in preparing applications to the Commission.

- Expectations for customer additions in future – drop expected in 2017.

- Expectations for relatively flat annual demand for total (all utilities) over the next 20 years versus growth in peak demand.

- Impact of integrated alternative energy on natural gas demand and GHG emissions.

- New ways of examining future energy demand given the Terasen Utilities' alternative energy initiatives.

All of these workshops were very well attended, and by a broad range of interest groups as energy issues are becoming more important to all consumers. Main themes offered throughout stakeholder engagement have been:

- More of conservation is required

- Environmentally sound solutions are important

- Terasen Utilities' integrated energy solutions provide important energy and climate change solutions for B.C.

- Work with other Utilities and government on energy planning issues and solutions.

Both resource planning and stakeholder engagement are ongoing activities. The Terasen Utilities intend to conduct additional meetings and / or workshops in service regions and communities across the province to continue discussing the issues and solutions presented in this LTRP as well as in preparation for the Utilities next Resource Plan filing. Further, the Utilities intend to establish an external Resource Planning Advisory Group to engage our most interested stakeholders in ongoing dialogue on energy planning issues and the Utilities planning activities.

Skill Builder
An Aboriginal Training Initiative

Vision
An industry collaboration supporting initiatives to promote meaningful employment for Aboriginal peoples.

Objectives
To promote industry leadership in Aboriginal corporate relations and employment initiatives
To develop a common foundation for training in the utility sector
To support and promote programs that emphasize certified, transferable skills
To increase qualifications and confidence of Aboriginal participants
To develop a pool of skilled workers that can be accessed by companies and contractors

Skill Builder Partners

Terasen Gas FortisBC BC hydro FOR GENERATIONS BC Transmission Corporation Spectra Energy Corix Utilities TransCanada Kinder Morgan Enbridge Northern

8 ACTION PLAN

The Action Plan describes the activities that Terasen Utilities intends to pursue over the next four years based on the information and recommendations provided in this Resource Plan.

1. Secure funding approval for expanded and ongoing EEC beyond 2011

The Utilities are currently implementing programs and activities from the current EEC funding approval of $72.315 million over 2010 and 2011. Going forward, the Utilities will be seeking long-term funding approval to support market transformation efforts and to provide consistency in utility communications and activities with customers, market players and stakeholders. The Utilities will be conducting an updated CPR that will support an application for approval of EEC funding and determine potential energy and GHG emission reductions.

Additionally, the Utilities will explore a furnace early retirement program that would have a significant contribution to achieving the Province's energy and greenhouse reduction goals. In exploring such a program, the Utilities will also evaluate the benefit-cost tests that are currently applied to utility DSM programs as these tests may be not effective in allowing utilities to pursue programs that contribute to greater policy goals such as greenhouse gas emission reductions.

2. Continue development of new energy forecast approaches including additional end-use and customer research to examine energy choice implications

The Utilities will continue to develop and evaluate methodologies to forecast energy demand as part of their integrated, alternative energy services and new natural gas vehicle initiatives, in order to plan for the natural gas and alternative energy resources needed to deliver these solutions. Through such process the Utilities will identify the tools, data, research and resources needed for these activities to analyze the potential impact of future policy decisions and energy initiatives by governments and customers. The Utilities will continue to engage stakeholders as we undertake these activities.

3. Continue working with other utilities to explore the development of a base-line forecast for thermal energy demand in B.C. against which to assess energy choice impacts

Terasen Utilities will continue working with other utilities and governments to understand the complete nature of thermal energy demand within the province. Acting on the feedback that Terasen Utilities received in its stakeholder workshops, we have started a dialogue with other utilities in the province on the potential for developing a cooperative all-energy base-line forecast for the province's thermal energy needs against which examine alternative future scenarios and energy choice implications.

4. Pursue integrated energy and carbon reducing customer solutions

The Terasen Utilities will be offering a full range of efficient, low carbon intensity energy alternatives to meet the needs of customers and communities. To deliver the benefits of alternative energy services to our customers, Terasen is incorporating an integrated approach to energy delivery for the ultimate benefit of all our customers, who are seeking integrated solutions to improve their energy efficiency and reduce GHG emissions. The Commission approved this initiative as part of a Negotiated Settlement Agreement with respect to TGI's 2010-11 Revenue Requirement Application. Going forward the Utilities will seek approval of an overall business and regulatory model and seek CPCN approval of specific projects.

Our low carbon transportation fuel strategy targets return-to-base fleet vehicles for CNG solutions where fueling infrastructure economics make sense and vehicle ranges can match fuel capacity. To help facilitate the development of a market for natural gas in the transportation sector, Terasen Utilities plans to submit an application to the Commission in the summer of 2010 to outline the business plan and provide a comprehensive solution for customers.

Subjected to commission approval for the currently filed 2010 Biogas application, the Utilities seek to build consumer demand and drive supply project initiatives to achieve government's energy policy objectives favouring the use of renewable energy, the efficient use of energy and reducing GHG emissions.

5. Continue enhancement activities for the Terasen Utilities' comprehensive asset management strategy and develop a Long Term System Sustainment Plan.

Given the approaching wave of aging assets, the Terasen Utilities anticipate initially developing a 5-year capital plan informed by enhanced asset management practices currently underway. A longer term plan will be prepared and submitted as we more fully implement asset management practice enhancements through a yet to be determined regulatory submission and review process.

6. Plan for and prepare CPCN applications for near-term distribution system requirements identified in the Terasen Gas 5-year Capital Plans.

The projects for which the Utilities may submit new CPCN applications and will be studying over the coming months are the rehabilitation work for TGI's crossing of the Kootenay River near Shoreacres, the Huntingdon Control Station Bypass, the reinforcement of the ITS, and TGVI's purchase and construction of its Victoria regional office building.

Also, the Muskwa River Crossing HDD Replacement has been identified as a major project. TGI anticipates filing its Fort Nelson Revenue Requirements Application by the summer of 2010.

7. **Continue monitoring and evaluating system expansion needs in the Okanagan area.**

The Utilities have identified an approaching constraint in the Okanagan area of the ITS. We will continue to monitor FortisBC's Integrated Resource Plan and their potential need for natural gas generation as a back-up to renewable electricity production during peak electric demand periods. Should FortisBC proceed with its gas fired peaking generation station in the Okanagan as early as 2014 according to its recently filed Resource Plan, this could result in the need to submit a CPCN for facility expansion in the near-term.

8. **Protect and promot the needs of our customers to secure long term gas supply while minimizing costs.**

The fundamental objectives for the Terasen Utilities are to secure gas supply over the long term while minimizing the cost of the annual portfolio. In order to meet these objectives, the liquidity of the Station 2 marketplace from supply availability and competitive pricing are of paramount importance. Therefore, the Terasen Utilities will continue to protect and promote the needs of its customers and marketplace by:

a) Relationship building with new producers active in the Horn River and Montney plays including establishing contractual agreements in order to acquire B.C. unconventional supply in the portfolios.

b) Facilitating the increase of gas flow to Station 2 and on T-South in order to increase market liquidity within B.C. which in turn would reduce the likelihood of stranding capacity on the T-South system.

c) Entering into multi-year contracts with producers at Station 2 and upstream at the Ft. Nelson plant's outlet in order to ensure long term access to supply.

d) Representing customers' interests in NGTL and other regulatory proceedings due to their direct affect on the supply and pricing of gas in the B.C. market.

e) Pursuing the T-South Enhanced Service pilot with Westcoast in order to promote southbound gas supply in and through the province.

f) Conducting a preliminary feasibility study to determine how best to address regional constraints including constraints on Terasen Gas' own system. The T-South Enhanced Service pilot project sets the foundation for Terasen Gas to evaluate the feasibility of expanding the system between Kingsvale and Oliver and between Yahk and Kingsgate. Tearsen Gas has begun conducting Stage 1 preliminary assessment activities in accordance with Commission approvals. Based on the results of Stage 1 activities, Terasen Gas will assess the timing and support for proceeding with Stage 2 activities leading to a potential CPCN.

g) Continuously monitor the developments related to B.C. supply and infrastructure in order to meet the objectives of the ACP over the long term.

9. Influence provincial and regional energy and climate related policy development.

Terasen Utilities will continue to work with policy makers and energy planners to communicate the benefits and importance of using natural gas in the regional and provincial energy mix to reduce greenhouse gas emissions and keep energy rates low.

10. Identify and pursue innovative solutions for waste heat, advanced metering technologies, Customer Information System and other alternative energy technologies, uses, supplies and systems.

Customers are looking for the Terasen Utilities to provide these solutions as we transform into a complete, integrated energy provider. We will continue to explore new technologies such as combined heat and power, generating electricity from waste heat at our compressor stations, advanced metering and other emerging technologies, and test their appropriateness for inclusion as part of our low carbon initiatives. Some technologies may also prove to be disruptive, rather than complimentary to the Utilities core natural gas service offerings. The Utilities research and investigations will seek to uncover these challenges as well as market opportunities to add to and improve on the secure, reliable and cost effective energy services we provide.