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March 25, 2014

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Utilities[1] (FEU)

2014 Long Term Resource Plan

On February 1, 2011, the British Columbia Utilities Commission (the Commission) issued Order No. G-14-11 accepting the FEU[2] 2010 Resource Plan.

In accordance with the Commission's Resource Planning Guidelines and Section 44.1 of the *Utilities Commission Act* (the Act), the FEU respectfully submit the attached 2014 Long Term Resource Plan (LTRP) for the Commission's review.

There are no approvals being sought by the FEU as part of this LTRP submission. While the LTRP includes five-year capital plans and statements of facilities expansion, the FEU are not requesting approval of those capital plans with this submission. Each of the FEU will file separate applications for Certificates of Public Convenience and Necessity, if and as necessary, for any of those projects in accordance with the Commission's guidelines.

The FEU are seeking acceptance of this LTRP in accordance with Section 44.1 of the Act. A discussion of how the LTRP addresses the requirements of the Act is included in various sections throughout.

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[1] comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.
[2] then Terasen Utilities.

FORTIS BC™

If further information is required, please contact Ken Ross at (604) 576-7343 or ken.ross@fortisbc.com.

Sincerely,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachment

cc (email only): FEU 2010 Resource Plan Registered Parties

FORTIS BC

2014 Long term resource plan

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EXECUTIVE SUMMARY

1. Introduction

The long term vision of the FortisBC Energy Utilities (FEU, Utilities or Companies)[1] is to be B.C.'s trusted energy provider for safe, reliable and cost-effective natural gas delivery services, and to be a healthy, growing contributor to B.C.'s economy and to the well-being of B.C.'s communities. This 2014 Long Term Resource Plan (LTRP) presents a long term view of how the FEU will meet future demand and reliability requirements at the lowest reasonable cost to customers over the next 20 years.

The FEU's resource planning process proceeds through several planning stages: examining the planning environment, forecasting energy needs, examining demand-side management potential and options to meet needs for system growth and sustainment, conducting portfolio analyses and ultimately, developing a four-year action plan to act on the plan's recommendations. Throughout this iterative and on-going process, the Utilities engage customers and stakeholders in order to capture valuable insight and to help ensure that customer and stakeholder needs are met.

At the outset of the resource planning process, the FEU establish a set of planning objectives to guide the planning strategy. These objectives underpin all potential resource planning decisions and reflect the Utilities' commitment to providing customers with the highest level of quality energy services. The FEU's resource planning objectives are to:

- Ensure a safe, reliable and secure energy supply;
- Provide innovative and cost-effective energy solutions;
- Provide cost-effective energy efficiency and conservation initiatives;
- Contribute to provincial energy objectives and emission targets; and
- Consider a range of possible future conditions.

The FEU submit this 2014 LTRP under Section 44.1(2) of the *Utilities Commission Act* (*UCA* or *Act*) and are not seeking approval of any particular elements of the plan. Any requests for approval of specific resource needs that are identified within this plan will be further evaluated and brought forward at the appropriate time for approval under different sections of the *Act*.

2. Planning Environment

A wide range of factors influence the FEU's long term analysis and planning decisions; the 2014 LTRP focuses on those areas that the Companies believe are among the most important.

[1] The FortisBC Energy Utilities consists of FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW).

These planning environment considerations are grouped into three main areas: the competitive environment for natural gas, the policy and regulatory context, and customer solutions.

Advanced production methods and technologies have unlocked the potential of North America's vast shale gas deposits which has led to significant growth of natural gas supply and a low price environment. As a result, various interests including government and industry across B.C., the Pacific Northwest (PNW),[2] and North America more broadly are looking to take advantage of the economic, environmental and social benefits of using natural gas.

Energy and climate policy provides the framework through which the Utilities deliver customer energy needs and, at the same time, can heavily influence the energy choices that customers make. As policymakers balance economic concerns with a previous, ambitious climate policy agenda, today's policy and regulatory context de-emphasizes carbon pricing and focuses more heavily on sustainable energy solutions. As a result, natural gas is increasingly viewed as a fuel that can be used to help reduce greenhouse gas (GHG) emissions by displacing more carbon-intensive fuels (such as diesel and gasoline in transport applications and coal in power generation), provide firm backup for renewable energy, as well as present the ability to mitigate customer rate impacts from electric rate increases.

The competitive environment for natural gas supply is influenced not only by regional energy markets and commodity pricing but also by the available supply infrastructure and end-use equipment installation and operations. New energy technologies and gains in energy efficiency have led the way to changing natural gas use. As energy consumers are increasingly faced with numerous energy services and equipment choices, conflicting information may influence energy installation decisions that have a long term impact on energy consumption. New energy technologies and energy production at or near the end-use are also beginning to create challenges for the traditional utility model. These new, efficient technologies are changing energy use patterns, making it difficult to accurately predict how such factors may influence the demand for natural gas or its long term competitive position. To help maintain the competitiveness of natural gas rates for customers, the Utilities continue to focus on growing the customer base and adding load to the natural gas system, such as through the Companies' natural gas for transportation initiatives and opportunities to secure new, large industrial customers.

The dynamic nature of these planning environment factors makes it difficult to predict with certainty how these factors may influence the demand for natural gas or its competitive position over the 20-year planning horizon. The FEU therefore examine a number of planning environment outcomes to identify a range of future scenarios for which to plan. The long term integrated resource planning process assists the FEU to remain alert and agile in order to overcome any challenges, capitalize on opportunities to add new system load, and continue to serve the Utilities' customer needs for safe, reliable and cost-effective energy in an evolving energy marketplace.

[2] The Pacific Northwest is referred to in this LTRP as the three northwestern states of Washington, Oregon, Idaho and the Province of B.C.

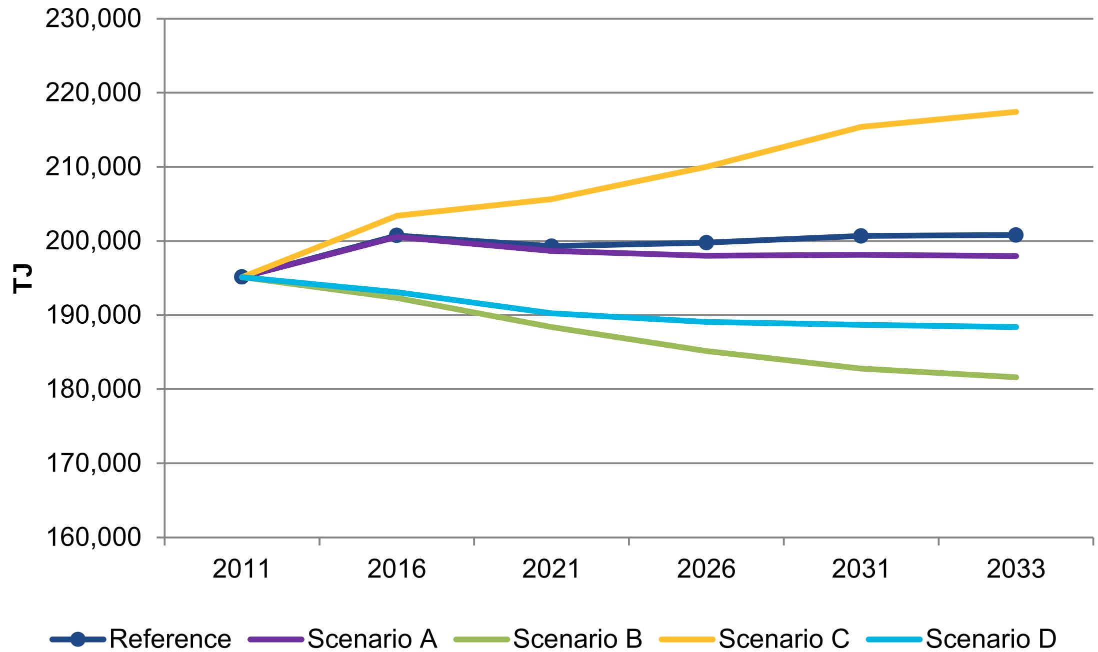
3. Energy Demand Forecasting

Customer and energy demand forecasts provide critical insight into the amount of energy the Utilities need to provide and the load characteristics that the Utilities' energy systems must be designed to provide. B.C.'s growing population is an important driver of the demand for new energy installations at the same time that infrastructure systems require major investments to maintain system integrity. This poses a significant challenge in making critical investments to rebuild aging infrastructure while balancing the need to moderate the impact on customer rates.

As directed by the BCUC, the FEU have developed a new approach to modelling the 20-year horizon which will provide a more insightful forecast of the long term range of potential demand. This approach uses a number of future scenarios that allow the FEU to examine changes in natural gas demand at the end-use level. A reference case is based on the 2010 Conservation Potential Review, recent customer additions data and market research, while four additional future scenarios examine a range of alternative demand scenarios. These scenarios are based on key uncertainties—such as an abundance or limitation of natural gas supply, or centralized versus decentralized energy delivery systems—that may unfold over the planning horizon and incorporate varying assumptions for gas commodity and carbon prices, the policy environment, and the development of renewable and district energy systems.

The FEU's end-use annual demand forecast methodology captures and analyses the impact of shifting trends in customer behaviour, energy choice and energy consumption that the Utilities have begun to observe. The new, end-use annual demand forecasting approach is applied to the range of potential future demand scenarios (shown in Figure ES-1) so that the Utilities can ensure that they have the appropriate resources in place to meet customer needs across the range of future demand scenarios. It is important to note that the end-use forecasting methodology does not assign any probabilistic outcomes to the future scenarios—the scenarios are considered together to provide a reasonable range of potential future demand that the FEU will need to serve over the 20-year planning horizon.

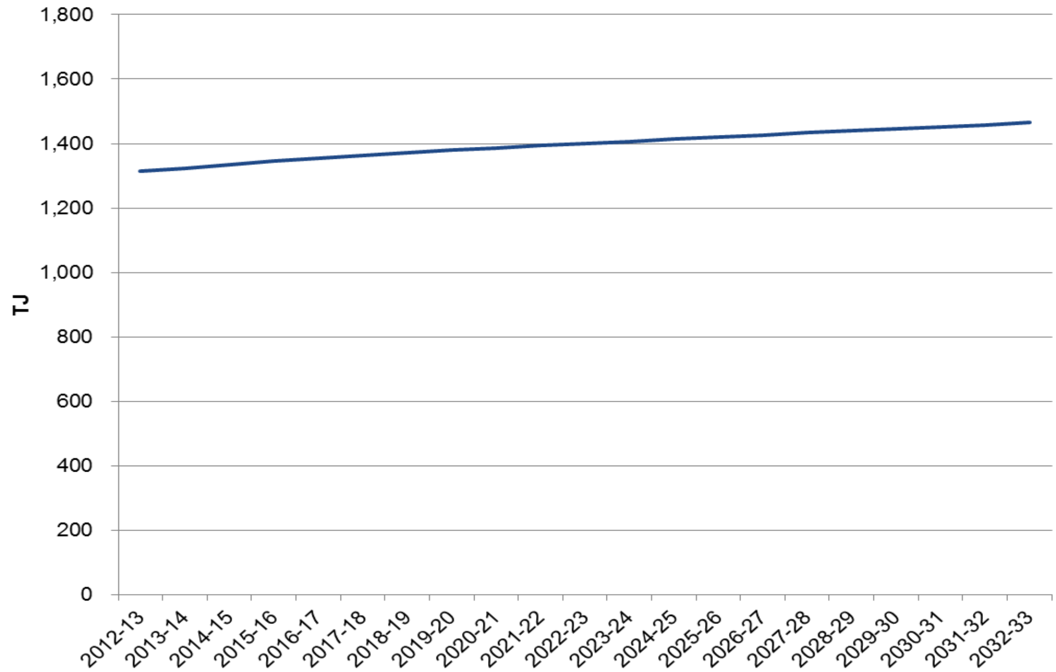
Figure ES-1: End-Use Annual Demand Forecast



In each of the five scenarios (including the Reference Case), an overall decrease in annual residential demand is anticipated, with variations in the degree of each decline related to the assumptions used for each planning environment. On the other hand, continued moderate growth is expected in commercial demand. Based on the current customer base, industrial demand also has the potential to grow or decline over the planning period, as three scenarios assume that recent increases in demand persist while two scenarios see this increase as short term with industrial demand returning to 2011 levels. Shown in Figure ES-2 below, the FEU expect to see modest growth in Core[3] peak day demand over the next 20 years, which stems from modest growth in customer additions.

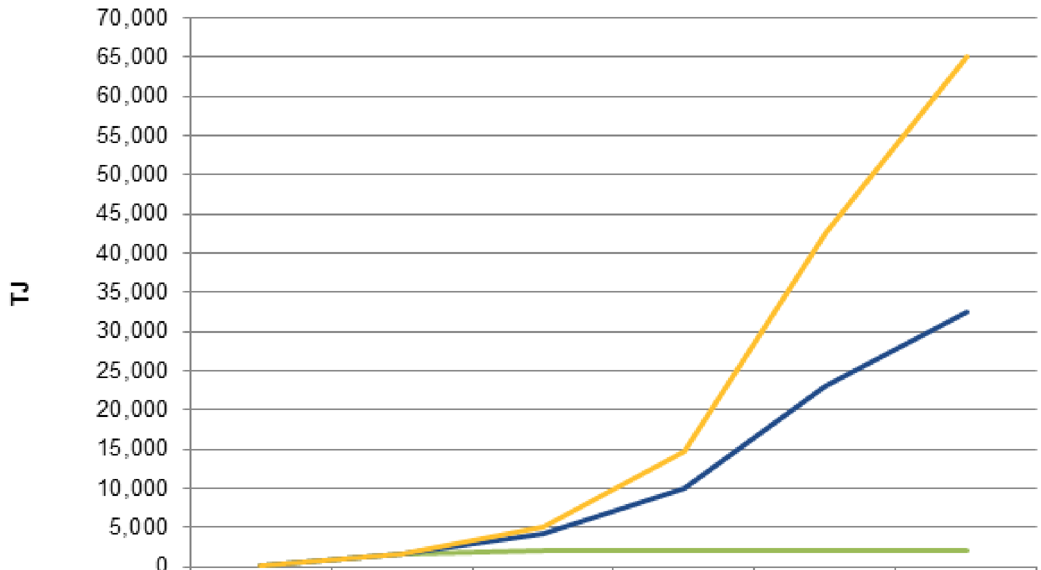
[3] 'Core' customers include FEI's rate class customers 1 through 6, all FEVI customers except for Island Generation and the Vancouver Island Gas Joint Venture, and all FEW customers.

Figure ES-2: FEU Core Peak Day Demand



The FEU have developed a strategy to stimulate growth in natural gas as a transportation (NGT) fuel and therefore also forecast demand for this market segment in FEI's service territory. NGT loads are expected to contribute to base load growth on the FEU's systems thereby mitigating variability of the load demand profile. The NGT forecasts presented in Figure ES-3are based on FEI's experience from the NGT Incentive Program, allocated government funding until 2017, and actual NGT customer additions to date. In the Low case, the NGT market share of all eligible conversion vehicles is a 1% market share in 2033, the Reference Case reflects a 15% market share, and the High case reflects a hypothetical 30% market share in 2033.

Figure ES-3: NGT Annual Demand



	2010-2011	2016	2021	2026	2031	2033
Low	195	1,676	2,168	2,168	2,168	2,168
Reference	195	1,676	4,267	9,946	23,183	32,522
High	195	1,676	5,075	14,689	42,518	65,045

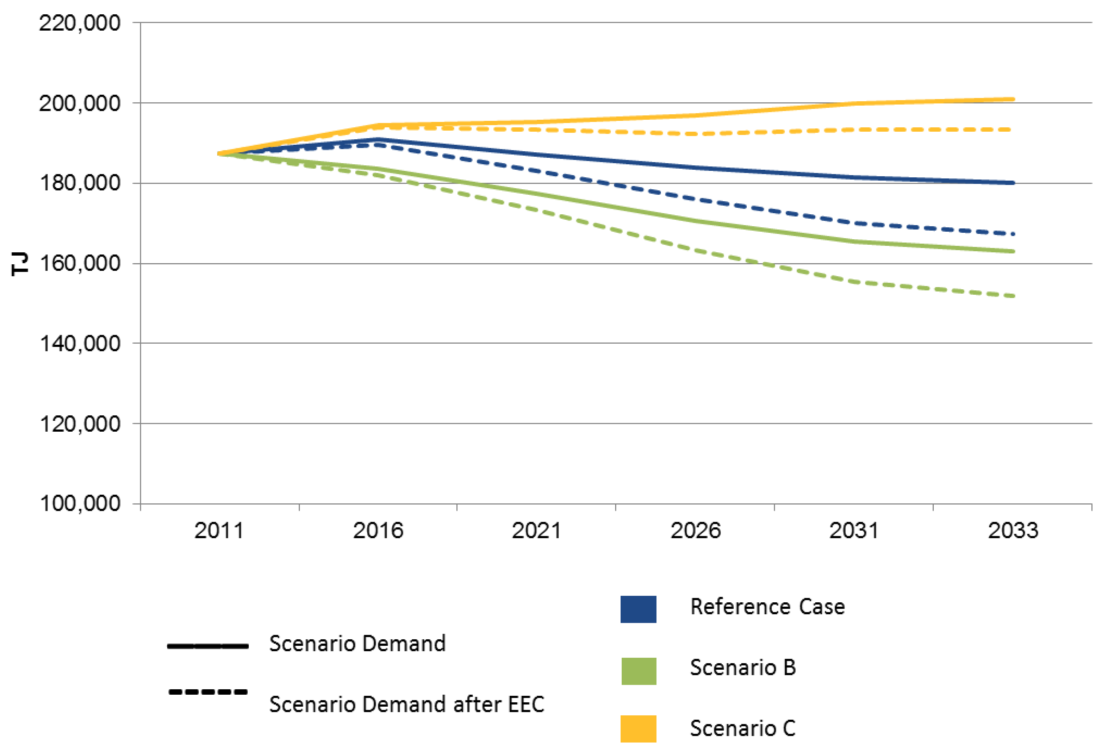
The FEU's demand forecasts are used to determine gas supply resources and also to provide a baseline against which to analyse the impact of proposed or future initiatives such as expanded energy efficiency and conservation activities or growth in natural gas sales for fuelling transportation. The FEU's end-use annual demand forecasting methodology enables insight into gas usage by end-use, rate class, new customers, existing customers and the vintage of housing stock for use in long term planning activities.

4. Demand-Side Resources

The FEU maintain strong focus on a range of demand-side management (DSM) activities to meet customers' energy needs, help keep customer energy costs down, and support meeting the province's energy efficiency, conservation and carbon reduction goals. The FEU's energy efficiency and conservation (EEC) initiative is a portfolio of efficiency and conservation activities that help meet the above goals while adhering to the statutory definition of 'demand-side measure' that the Companies must follow in developing a plan to take cost-effective demand-side measures as set out in the *UCA*. As such, the Utilities use the term EEC for programs that meet the DSM definition in B.C.'s statutory context. However, there are also other types of fuel substitution, load building and customer retention activities that the Utilities must consider in the broader DSM context to continue to provide safe, reliable and cost-effective energy to customers.

The Companies' EEC analysis in this LTRP is grounded in the results of the most recent Conservation Potential Review study completed by the FEU in 2010. The study provides a comprehensive assessment of the energy efficiency opportunities within the FEU's service territories, identifying both the sectors and end-uses that offer the most significant opportunities for natural gas efficiency and conservation over the next 20 years. The LTRP's EEC analysis assumes that current funding levels of approximately $35 million annually (in 2013 dollars, excluding inflation) for all service regions combined continue over the planning horizon. Under these parameters, the FEU estimate that future energy savings could range from nearly 8 million to 13 million gigajoules (GJ) annually[4] by 2033 (shown in Figure ES-4), with estimated GHG emission reductions of over 650,000 tonnes of carbon dioxide equivalent per year in the Reference Case scenario. The EEC analysis recognizes that a broad range of potential future scenarios may unfold over the planning period; the demand forecast from which each EEC scenario is developed considers the changing nature of customer behaviour before the influence of EEC programs.

Figure ES-4: Annual Demand Before and After Estimated EEC Program Savings



4 For clarity, this is a forecast range of the annual energy savings from all the energy efficiency measures estimated to be installed during the planning period. For example, an energy efficient boiler (with a useful life of 20 years) installed as part of an EEC program in 2016 will continue contributing to the annual energy savings that occur in each remaining year of the planning period.

The FEU's approach to EEC programming incorporates four primary categories of activity: incentives for equipment and building upgrade programs to improve residential, commercial and industrial efficiency; education programs to promote energy efficient behaviour; codes and standards activity; and enabling activities that support the first three categories The EEC analysis in this LTRP shows that significant energy and carbon emission reductions can be achieved over the planning horizon through on-going programming and expenditure levels consistent with those in place today. Specific EEC activities undertaken throughout the 20-year planning period will depend on factors such as the availability of new technologies, future energy prices and changes to public policy. Nevertheless, continuity of program offerings is critical to maximizing the success of EEC activities over time.

In the broader context, EEC measures that meet the Provincial definition of demand-side measure are only one type of DSM activity. The Companies must also continue to examine opportunities for all types of DSM that provide customer benefits such as adding natural gas load and meeting other provincial energy objectives—including fostering the development of clean or renewable resources and innovative technologies, encouraging economic development, reducing B.C.'s GHG emissions, and reducing waste by using waste heat, biogas and biomass. Two existing offerings that fall into this broader DSM context and help to build system load while reducing energy costs and GHG emissions are the High Carbon Fuel Switching program and the FEU's NGT initiatives. The FEU must continue to examine other opportunities to develop DSM initiatives that offer similar benefits, such as adding load from new, large industrial customers and also retaining existing customers. The Companies believe that these types of initiatives are vital components of the FEU's efforts to provide customers with reliable, cost-effective energy; the Companies also believe that adding cost-effective new load to the system will help to optimize use of the natural gas infrastructure thereby putting downward pressure on customer rates.

Over the 20-year planning horizon, the FEU intend to: implement the 2014-2018 EEC Plan in accordance with the BCUC's (pending) decision on the FEI 2014-2018 Performance Based Ratemaking Plan Application; conduct a new CPR in 2015 or 2016 in conjunction with other utilities and the province; continue to examine the potential for all forms of DSM activity to meet customer energy needs, optimize the use of utility infrastructure, keep energy rates down and reduce customers' GHG emissions; and continue to work with all levels of government and other potential partners to explore and identify ways in which the FEU DSM activities can continue to help meet government objectives while ensuring benefits for the FEU and their customers.

5. System Resource Needs and Alternatives

Continued growth in peak demand and managing an aging system of natural gas delivery infrastructure are among the biggest challenges for the FEU's long term planning. Since the FEU's planning efforts are undertaken to ensure that planned improvements optimize operation of the system as a whole, the reinforcement options that are under consideration to meet the

FEU's capacity needs have been integrated with the system upgrade requirements identified through the long term system sustainment planning process.

Annual increases in forecast peak demand and potential new sources of demand from industrial sources and NGT applications are anticipated to create a need for system reinforcements in various areas of the FEU's delivery system within the 20-year planning period. The FEVI transmission system is expected to face a capacity constraint late in the planning period (in 2028), however, both operational and infrastructure solutions exist to meet the constraint. These include adjusting contractual obligations between FEI and FEVI for storage and send-out services from the Mt. Hayes LNG storage facility, installing a new single compression station at V2 Squamish, or renegotiating an existing peaking agreement with BC Hydro for its Island Cogeneration Plant. The Nichol to Coquitlam pipeline on FEI's Coastal Transmission System is also expected to face a capacity constraint in 2027, with options to alleviate the constraint including a number of looping alternatives or using the Mt. Hayes LNG storage facility to provide support. In addition, FEI's Interior Transmission System is expected to become capacity-constrained in the Okanagan region by 2018; potential system expansion alternatives include a number of looping alternatives or constructing an LNG storage facility near Vernon. Accommodating significant new industrial or transportation loads would likely require installing additional pipeline loops or additional compression, though detailed analyses on timing and capacity requirements are not carried out until firm commitments have been made for any such load additions.

The FEU have enhanced their asset management processes by developing and implementing a Long Term Sustainment Plan (LTSP) process that uses a relative risk framework to continually measure asset health and identify specific areas of concern that require further evaluation or action. This proactive decision making tool assists the Utilities in ensuring that asset replacements are made only where needed and are supported by data, thereby reasonably minimizing the need for early asset retirements. The LTSP process has identified a prioritized list of important near-term and longer term system renewal requirements, particularly in the Lower Mainland area of the FEI system. Certificate of Public Convenience and Necessity (CPCN) applications will be filed in 2014 for these capital projects (identified below in Table ES-1) and no project approvals are being sought as part of this resource plan. The LTSP process has also identified certain areas on FEI's Interior Transmission System that warrant further examination and will inform more in-depth analysis. As the FEVI Transmission System is comparatively new, the relative risk of failure associated with the system is lower than for the FEU's other systems.

Table ES-1: Portfolio of Proposed Projects for the Lower Mainland Service Area

Pipeline	Sustainment Issue	Proposed Solutions
508 mm Coquitlam Gate IP Pipeline	A number of leaks have been experienced on this pipeline and subsequent investigative digs led to the identification of active corrosion on multiple sections.	Replace the 508 mm pipeline—consider increasing pipe diameter to improve security of supply and to enable mitigation of seismic issues on the Fraser Gate IP pipeline (see below). Estimated cost $125 to $200 million.
762 mm Fraser Gate IP Pipeline	High risk of failure from seismic movement. Analysis indicates either replacement or stabilization of 700 m of the 762 mm pipeline is required.	To enable work on seismic upgrade, back-feed capacity must first be reinforced/ increased through the Coquitlam 508 mm pipeline. Estimated cost $3 to $4 million.
Nichol to Coquitlam	The current pipeline capacity is inadequate to supply Coquitlam Station and reinforce the Fraser Gate IP outlet.	• Loop the 508mm TP pipeline from Cape Horn to Coquitlam. Estimated cost $28 million; AND • Loop the 610 mm TP pipeline from Nichol to Port Mann (to be done first, see below).
Nichol to Coquitlam	In-line pipe inspections are required between Fergusson Station and Port Mann Station.	• Loop Nichol to Port Mann with 914 mm pipeline. Estimated cost $24 million. • Move the 610 mm receiver from Fergusson Station to Port Mann. Estimated cost $3 million.
Nichol to Roebuck	Analysis of risk from a security of supply perspective indicates a pipeline loop is required.	Loop Nichol to Roebuck with 1067 mm pipeline. Estimated cost $22 million.

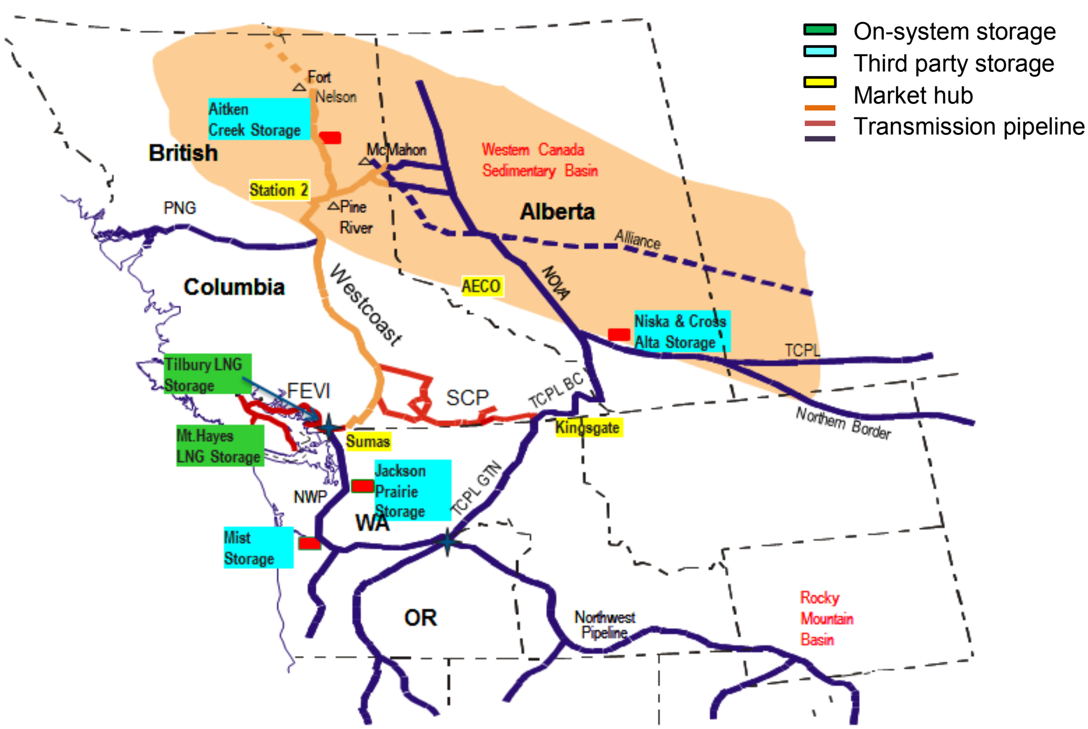
The FEU take a broad outlook that considers long term system capacity and sustainment plans, potential new, large increases in industrial load and growing NGT demand to determine the most effective system improvements. To address system capacity and sustainment needs, the FEU will: develop comprehensive CPCN applications based on the Lower Mainland LTSP process for submission to the BCUC in 2014; continue to monitor and study the system capacity constraint identified to occur in 2018 in the Okanagan region of the ITS; prepare detailed system sustainment plans for the FEI Interior South and North and FEVI service regions following completion of the project application and approval processes related to the Lower Mainland LTSP process; and implement the FEI and FEVI Capital Plans as approved by the British Columbia Utilities Commission (BCUC or the Commission). The FEU's long term planning efforts continue to focus on ensuring safe, reliable and cost-effective gas delivery service on the coldest day expected over a 20-year time frame.

6. Gas Supply Portfolio Planning and Price Risk Management

The FEU must be able to acquire and deliver the total quantity of energy that the Utilities' customers will need throughout the year, adjusting for seasonal variations and changing market conditions. Gas supply portfolio planning and price risk management are key elements that the FEU use to provide secure, reliable and cost-effective supply for customers over the long term. Discussion of the Companies' gas supply portfolio and price risk management activities is included in the LTRP in order to provide context for the resource planning, price risk management and market price environment rather than for specific Commission approval.

As new supply basins are developed in northern B.C. and the United States, significant regional changes are occurring that may impact the FEU's operating region and supply sources for long term gas supply contracting (refer to Figure ES-5 below). Regional market developments such as infrastructure initiatives to facilitate the movement of natural gas from production areas in northern B.C. toward the Alberta market and west to supply LNG export projects may change traditional regional gas flows, along with supply and demand balances and pricing. The FEU continue to examine these regional developments and participate in regional project approval processes where the Utilities see a need to protect their customers' interests in maintaining secure, cost-effective supply sources and infrastructure over the long term. This includes continuing to examine potential opportunities on the FEU's own transmission and storage systems, such as expanding the FEI transmission system between Kingsvale and Oliver in order to diversify supply alternatives for major regional demand centres.

Figure ES-5: Regional Supply Resources



Though natural gas prices are near their lowest levels in a decade, market price volatility and price forecasts suggest that future market prices will be higher as supply and demand come into a more sustainable balance. The FEU believe the current market price environment creates opportunities for longer term strategies that could include tools to improve long term cost certainty and help provide stability in rates as well as ensuring security of supply for customers. The FEU continue to explore a range of price risk management activities to mitigate the impacts of price increases and volatility on customer rates in both the near and long term; the Companies will continue to make separate applications to the Commission for approval of the risk management activities that the Companies believe to be in the best interests of their customers.

Effective gas portfolio planning and price risk management on both a short and long term basis enables the FEU to secure cost-effective, reliable gas supply while also reducing rate volatility for customers. Given the significant marketplace developments in terms of North American gas supply, demand, pricing and regional infrastructure changes, the Utilities continue to monitor market changes while being proactive in assessing challenges and identifying opportunities in order to provide safe, reliable and cost-effective natural gas service.

7. Stakeholder Engagement

Connecting with customers, communities and other stakeholders on long range planning issues is of critical importance to the FEU. In addition to facilitating open communication, effective stakeholder engagement provides the Utilities with valuable insight that can impact the entire energy planning process. Since filing the 2010 LTRP, the FEU have improved the scope and quality of the stakeholder consultation activities including developing a dedicated Resource Planning Advisory Group (RPAG) of strategic interests from municipalities, government, First Nations, customers, industry associations and organizations. RPAG workshops are held in addition to conducting Community Consultation workshops to obtain key insight and solicit valuable feedback from the communities served by the FEU. The FEU's consultation activities continue to include dialogue and engagement with First Nations communities, the EEC Advisory Group (EECAG), presentations to municipalities throughout the province, and focused meetings with select stakeholders seeking input on a range of energy issues and system expansion needs. The FEU will continue these activities to provide regular engagement with the Companies' diverse stakeholders and to ensure that stakeholder and customer needs are met.

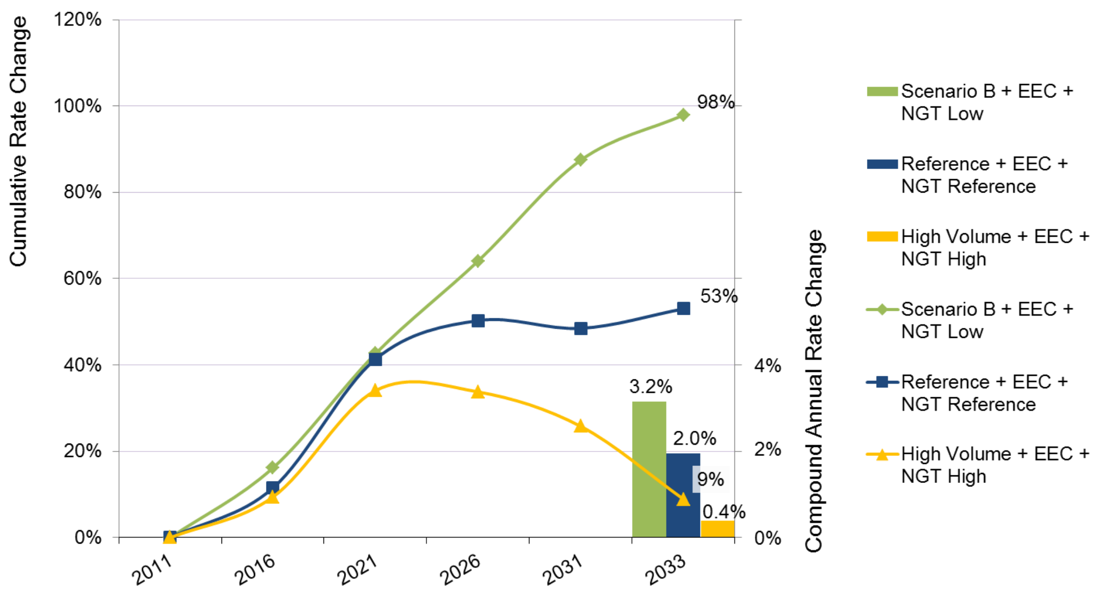
8. 20-Year Vision for the FortisBC Energy Utilities

The FEU's long term vision is to be B.C.'s trusted energy provider for safe, reliable and cost-effective natural gas delivery services, and to be a healthy, growing contributor to B.C.'s economy and to the well-being of B.C.'s communities. In response to the Commission's directive (from the 2010 LTRP decision) to provide a 20-year vision for the FEU, in Section 8, the Companies explain how and where in the plan the LTRP addresses a number of items related to this vision.

Among these items (and not addressed elsewhere in the LTRP) are a discussion of how demand for renewable thermal energy solutions may impact demand for natural gas under different future scenarios, and the extent to which FEU initiatives contribute to GHG reductions in B.C. Renewable thermal demand is expected to displace between 3.7 PJ and 4.3 PJ (2.0 and 2.5 percent) of natural gas demand over the planning period. While the numbers are small in comparison to total gas demand, this trend merits close monitoring. Current FEU initiatives with the highest potential to reduce GHG emissions within B.C. are the Companies' EEC activities and NGT initiative, though the overall contribution of these initiatives to provincial emission reduction targets is relatively small at approximately 2.5% of the Province's GHG reduction targets by 2033 (in the Reference Case).

The FEU also analyse how variations in demand over the planning period can influence customer rates. Figure ES-6 shows that while EEC activity reduces demand and puts upward pressure on rates, the additional demand from FEU's NGT initiative has a significant opportunity to reduce pressure on customer delivery rates. This analysis is a directional look only at variations in demand—all else remaining equal—and is not indicative of a detailed rate forecast.

Figure ES-6: Delivery Rate Direction – All Rate Classes, EEC and NGT



9. Action Plan

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

- Continue to monitor and analyse the energy planning environment including market and policy developments that may impact regional gas flows, supply, demand and pricing as well as emerging technologies and advancements in gas metering infrastructure.

- Continue to implement the Companies' NGT initiatives to provide an important source of load growth on the FEU's natural gas distribution system while also assisting in reducing the GHG emissions of B.C.'s transport sector.
- Discontinue using the traditional annual demand forecasting method for all sectors. The Companies will update the end-use forecasting model to a 2012 base year and will continue to incorporate relevant new information in future long term forecasting work.
- Pursue approval of EEC funding for the 2014-2018 period through the FEI 2014-2018 PBR application and regulatory proceeding. The FEU will continue to examine the potential for all forms of DSM activity to optimize the use of the province's energy infrastructure.
- Plan for and prepare CPCN applications for near-term system requirements identified in the FEU Five-Year Capital Plans. The Utilities will conduct further inspection and analysis on pipelines in the Burns Bog area to determine an appropriate course of action for the project.
- Work toward expanding the Tilbury LNG facility in accordance with the B.C. Government's Special Direction No. 5 to the BCUC.
- Continue to monitor and evaluate system expansion needs in the Okanagan area, including monitoring FortisBC Inc.'s potential requirements and timing for natural gas service as well as monitoring demand from potential new, large industrial load customers.
- Protect and promote the interests of the Utilities' customers by securing a reliable, cost-effective long term gas supply while minimizing costs of the annual portfolio. This includes exploring opportunities for longer term price risk management strategies such as using fixed price purchases, investing in natural gas reserves and financial hedging.

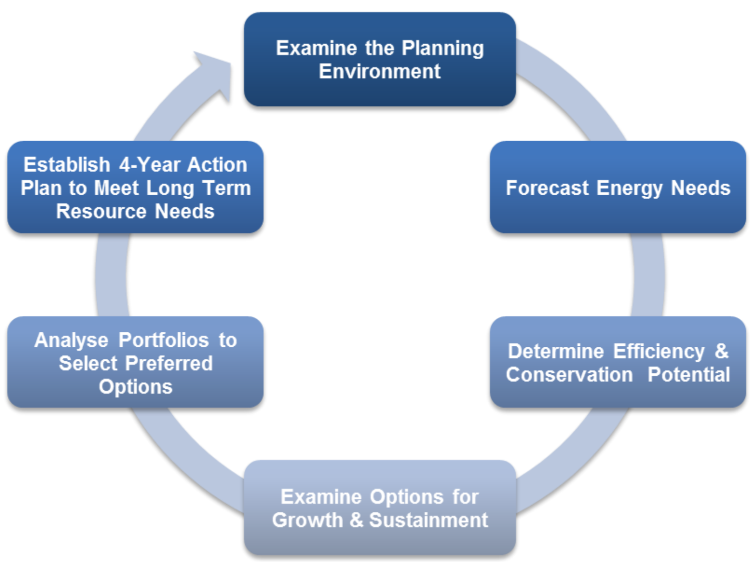
The FEU's Action Plan continues the Utilities' effort to further develop new natural gas markets while continuing to serve our customers' needs for safe, reliable and cost-effective energy.

1. INTRODUCTION

Integrated resource planning[5] is a tool for identifying long-range infrastructure requirements and resource acquisition strategies and for sharing this information with stakeholders; it is also a requirement of the *Utilities Commission Act* (*UCA* or the Act). This 2014 LTRP presents a long term view of the demand- and supply-side resources identified to meet expected future natural gas demand and reliability requirements at the lowest reasonable cost to FortisBC Energy Utilities[6] (FEU, Companies or Utilities)'s customers over the next 20 years.

The resource planning process begins by closely examining the planning environment in which the Companies operate and by identifying expectations for future customer and demand growth. The demand- and supply-side resource alternatives for meeting future demand are then assessed, and actions are recommended to ensure that the proper resources are in place to deliver the preferred energy solutions to meet future customer needs. The final stage of the process is developing a four-year action plan which identifies the near term activities needed to meet the long term resource requirements identified in the LTRP. Figure 1-1 outlines the resource planning process for the FEU.

Figure 1-1: FEU Long Term Resource Planning Process



The Utilities continue to engage customers and stakeholders as a critical part of the LTRP process. Furthermore, the FEU believe that as part of the planning process, it is important to understand the planning issues, competitive environment and resource requirements for other utilities in the Pacific Northwest (PNW) region as well, due to common regional infrastructure

[5] The terms 'integrated resource planning,' 'long term resource planning' and 'resource planning' are used interchangeably in this document.
[6] The FortisBC Energy Utilities consists of FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW).

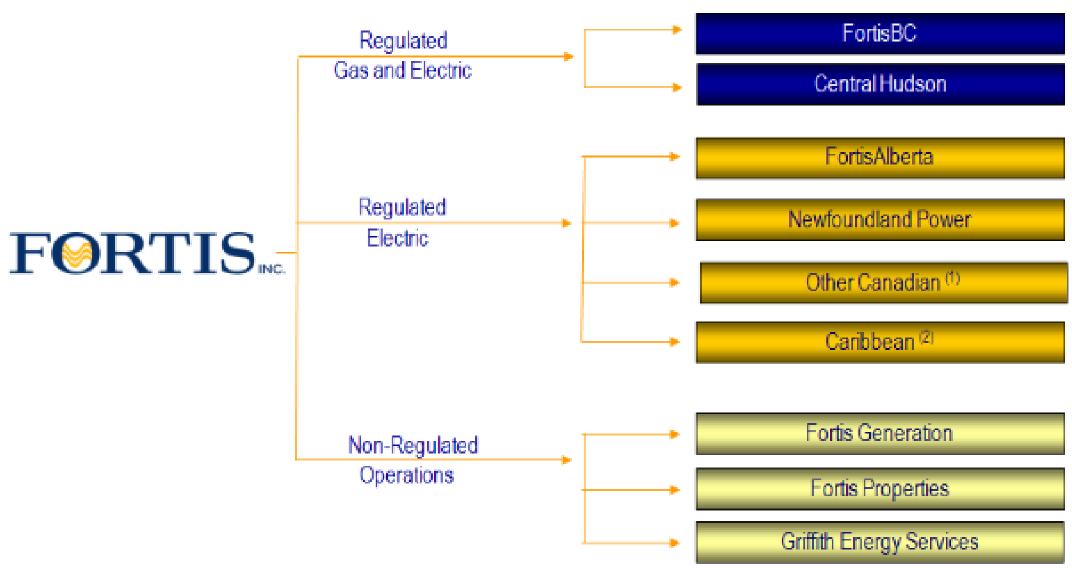
used to serve both electricity and natural gas demand. As such, the FEU actively participate as a stakeholder in the resource planning efforts of other gas and electric utilities in the region such as BC Hydro, FortisBC Inc., Puget Sound Energy, Avista and NW Natural. To facilitate understanding and response to regional resource issues, the FEU also participate in planning, 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 also inform the analyses and recommendations in this LTRP.

The FEU submit this 2014 LTRP under Section 44.1(2) of the *UCA* and are **not seeking approval of any particular elements of the plan**. Any requests for approval of specific resource needs that are identified within this plan will be further evaluated and brought forward through a separate application to the BCUC.

1.1 *FORTISBC ENERGY UTILITIES*

The FEU consist of the regulated utilities FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW), and are subsidiaries of Fortis Inc., the largest investor-owned gas and electric distribution utility company in Canada. Figure 1-2 outlines the corporate structure of the FEU's parent company, Fortis Inc., however, the diagram shows the FEU and FortisBC Inc. as a single FortisBC entity. FortisBC Inc. is a separate Fortis Inc. subsidiary and sister company to the FEU. The long term planning considerations and business activities of FortisBC Inc. are not included in this LTRP.

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



1. *Includes Maritime Electric on Prince Edward Island and FortisOntario*
2. *Includes Caribbean Utilities on Grand Cayman, Cayman Islands and Fortis Turks and Caicos*

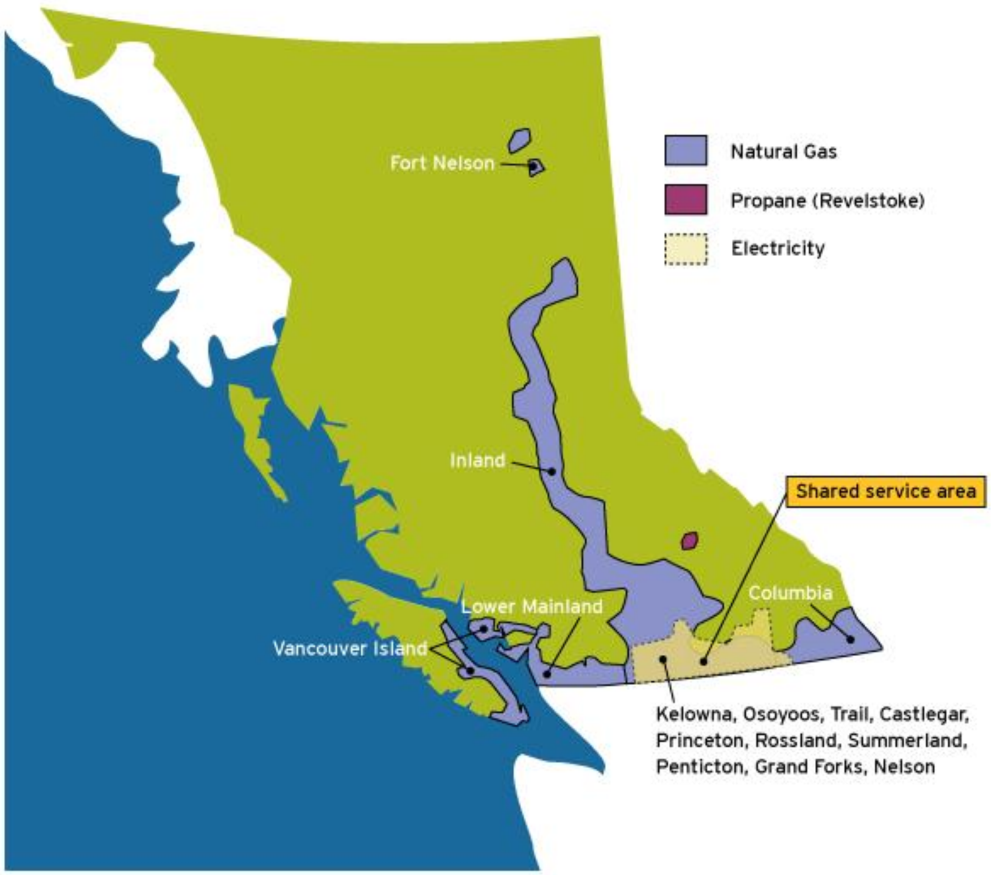
The FEU provide natural gas services to more than 945,000 residential, commercial, and industrial customers in more than 135 communities throughout British Columbia. This puts the FEU among the largest gas utilities in Canada and the largest in the PNW. Table 1-1 provides a summary of customer, demand and pipeline characteristics for each of the regulated gas utilities (FEI, FEVI, FEW), with FEI broken out into the Interior and Lower Mainland service areas. Figure 1-3 shows the Utilities' service area locations.

Table 1-1: 2012 FEU Service Statistics

	FEI Lower Mainland	FEI Interior	FEVI	FEW
Number of Customers	583,979	257,484	101,098	2,612
Annual Demand (TJ)	120,378	59,355	33,926	652
Peak Day Demand (TJ/d)	887	316	104	7
Length of Transmission Pipeline (km)	260	2,071	626	N/A
Length of Distribution Pipeline* (km)	11,155	8,413	3,533	99

** Includes both low and intermediate pressure pipelines*

Figure 1-3: Map of the FEU Service Areas by Fuel Source



1.2 *REGULATORY CONTEXT*

In addition to being good utility practice, the FEU have a regulatory obligation to file integrated resource plans under Section 44.1 of the *UCA*. The *UCA* and any directives from the Commission related to the FEU's previously filed resource plans establish the requirements for what must be included in the plans. Additionally, the Commission has issued Resource Planning Guidelines which provide general guidance as to BCUC expectations of the FEU's process and methods of developing the LTRP.

1.2.1 Utilities Commission Act

The *UCA* provides the BCUC with the jurisdiction to regulate public utilities in British Columbia and requires utilities to submit a long term resource plan. Section 44.1(2) of the *Act*, "Long-Term Resource and Conservation Planning," outlines the specific elements that are to be included in resource plans. The FEU have met each of these requirements in this 2014 LTRP. Table identifies where each specific requirement is addressed.

Table 1-2: *UCA* Requirements and Areas Addressed in the 2014 LTRP

Requirement of *UCA* Section 44.1(2)	Addressed in the 2014 LTRP
a. An estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;	See Section 3.3.5
b. A plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;	See Section 4.2.4
c. An estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;	See Section 4.2.3
d. A description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);	See Section 5 and Appendix D-1. Appendices D-2 through D-4 contain the Five-Year Capital Plans for FEI, FEVI and FEW.
e. Information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);	See Section 6 and Appendix E-1
f. An explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures; and	See Section 5.1.1.2
g. Any other information required by the Commission.	Recent BCUC Directives from the 2010 LTRP Decision have been incorporated throughout the LTRP. Directives relating to GHG reduction targets, EEC planning and impacts of new initiatives are addressed in Sections 3 and 4. Details of the new business environment and approach to demand forecasting are provided in Section 3; and Discussion of the FEU's 20-Year Vision is provided in Section 8.

In determining whether to accept a long term resource plan, Section 44.1(8) of the *UCA* requires the Commission to consider the applicability of B.C.'s energy objectives, whether the plan shows that the utility intends to pursue adequate, cost-effective demand-side measures, and the interests of the utility's existing or potential rate payers. The FEU believe that these considerations support the Commission accepting this LTRP.

1.2.2 Summary of Commission Directives

In the BCUC's acceptance of the 2010 LTRP (Order G-14-11), the Commission provided a number of directives and suggestions for the FEU to integrate in future resource plans. These directives, suggestions and related FEU actions are outlined in the following table:

Table 1-3: List of Commission Directives and FEU Action Pursuant to Order G-14-11

Commission Directive/Suggestion	FEU Action
20-Year Vision Develop a longer term vision that "could describe what [the FEU] may look like in the future: its business lines, its customers, the expectations for supply and demand and the major issues it will deal with over the 20 year resource plan timeframe." Appropriate areas to cover may include: • Market transformation • Impact of GHG reductions on demand • The importance and significance of new technology and new initiatives on FEU's business • FEU's contribution to B.C.'s energy objectives • Key drivers impacting the need and timing for resource requirements	Section 8 discusses a 20-year vision for the FEU that fits within the current regulatory context. The FEU have acquired end-use market information and conducted research to develop new scenario analyses and an end-use forecasting process. The FEU's NGT demand analyses explore a number of market transformation scenarios over the next 20 years. The impact of GHG emissions reductions on demand, the FEU's initiatives and market trends are incorporated in the end-use forecasting methodology under different future scenarios that extend to 2033 (discussed in Section 3). Emissions reductions from the FEU's Energy Efficiency and Conservation and other demand-side activities are discussed in Section 4.
GHG Reduction Targets – EEC Planning and Impacts of New Initiatives Integrate the EEC programs, New Initiatives[7] and GHG reduction targets in demand forecasting. This should include: • An analysis of the GHG targets as set out in B.C.'s energy objectives and an estimate of the portion of the required reduction that the FEU believe their programs can reasonably attain over time • Greater coordination between EEC planning and the development of future resource plans	Discussion of GHG reduction targets and the impact that FEU activities will have on GHG reductions is provided in Sections 3 and 4. The new end-use forecasting modeling was utilized to examine the energy savings potential of EEC programs and the resulting GHG emission reductions under three of the five planning scenarios. The GHG reductions resulting from EEC

[7] As a result of the BCUC Inquiry into FEI's Alternative Energy Solutions and Other New Initiatives (2011-2012), the FEU no longer provide thermal energy services as part of the Utilities' "New Initiatives".

Commission Directive/Suggestion	FEU Action
• Development of a limited number of scenarios detailing the impacts of varying degrees of EEC Planning measures on the demand forecast and GHG emission reductions • An outline of the impact of the implementation of New Initiatives on the demand forecast and GHG emission reductions.	programming, NGT initiatives and the biomethane program are presented in Section 4.
New Business Environment and Approach to Demand Forecasting "Future LTRPs need to more adequately convey FEU's understanding of the new energy and business environment, its impact on gross demand and how resource plans will be reflective of future demand growth." Future resource plans should include: • A description of the new end-use forecasting methodology, comparison with the traditional demand forecasting approach, and reconciliation of the results of the different approaches • A reference case demand forecast and outline of underlying assumptions • Integration of the reference case demand forecast with the EEC scenarios and a description of the impacts • An outline of New Initiatives and their impact on future demand and GHG reduction targets • A description of the impact of each scenario on future resource requirements with consideration of the variables which could further affect these scenarios.	Section 2 provides an overview of the planning, or business, environment while the new end use methodology for examining annual demand is presented and compared with the previous methodology in Section 3. The FEU have provided a reference case based on current planning conditions and have examined alternative potential legislative and market transformation conditions through the planning scenarios discussed in Section 3 and elaborated upon in Appendix B-2. The long term EEC planning exercise is built from the end-use scenarios and is presented and discussed in Section 4. Section 8 provides an estimate of the extent to which the FEU's initiatives and proposed programs contribute to B.C.'s energy objectives.
The FEU is also directed to provide an estimate of the extent to which its proposed programs and initiatives will contribute to the achievement of British Columbia's energy objectives.	See above

1.2.3 BCUC Resource Planning Guidelines

In 2003, the BCUC issued resource planning guidelines which outline a process to assist in the development of resource plans to be filed with the Commission.[8] According to the guidelines, "resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run." The

[8] http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf

guidelines do not distinguish between utilities that provide generation, transmission or distribution services; therefore, some items (such as supply-side portfolio analysis[9]) apply more readily to integrated electric utilities. The BCUC reviews resource plans in context of the unique circumstances of the utility in question. The FEU adhere to the BCUC's planning guidelines where relevant and applicable to the Companies' operating context.

1.3 *LONG-TERM RESOURCE PLANNING OBJECTIVES*

The FEU's resource planning objectives form the basis for identifying and evaluating potential resources in the LTRP including major infrastructure projects, gas supply alternatives and demand-side programs. These objectives reflect the Utilities' commitment to providing customers with the highest level of quality energy services. The FEU's key resource planning objectives are to:

Ensure a Safe, Reliable and Secure Energy Supply

A secure energy supply is essential for all of FEU's 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 and protect customers from potential outages.

Provide Innovative and Cost-Effective Energy Solutions

Customers and regulators expect the Utilities to procure and deliver energy in a cost-effective and efficient manner. 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. Cost-effective demand-side management strategies can add value to customers through more effective use of the gas delivery infrastructure and more efficient use at the burner tip. The FEU deliver innovative energy solutions through natural gas initiatives for the transportation sector and carbon neutral biomethane for residential and commercial customers.

Provide Cost-Effective Energy Efficiency and Conservation Initiatives

Energy efficiency and conservation is a key theme identified in B.C.'s *Clean Energy Act* (*CEA*) to meet the province's greenhouse gas (GHG) reduction targets. As energy companies search for additional energy resources to serve increasing demand for energy, efficiency and conservation remain among the lowest cost alternatives. To acquire these resources, efficiency and conservation program spending by utilities must be long term and substantial enough to truly impact customer decisions and behaviour across all customer groups. The FEU's EEC activities are governed in part by B.C.'s *UCA, CEA,* and Demand-Side Measures Regulation.

9 Supply-side portfolio analyses are conducted outside of the FEU's LTRP planning process and are submitted for approval to the BCUC through the Annual Contracting Plan (ACP) and Price Risk Management Plan (PRMP).

Contribute to Provincial Energy Objectives and Emission Targets

The FEU provide natural gas distribution service to over 945,000 customers across 135 communities in B.C. This wide reach enables the FEU to play a role in assisting customers to understand and reduce their energy consumption and GHG emissions. The FEU's EEC activities, natural gas for transportation and renewable natural gas initiatives are key avenues through which the FEU contribute to advancing B.C.'s energy and GHG emission goals; the Companies continue to examine potential programs, technologies and initiatives that will contribute to B.C.'s energy and GHG emissions goals.

Consider a Range of Possible Future Conditions

Long-term resource planning is an important exercise that the Utilities use to develop strategies to meet customer energy needs over a 20-year time horizon. Since uncertainty is a factor in any forecast, the FEU examine a broad range of future planning environment possibilities by incorporating a diverse set of assumptions into scenario planning analyses. In this way, the FEU can identify expected energy supply requirements within a reasonably expected range, infrastructure needs and demand-side management plans to provide safe, reliable and cost-effective energy over the planning horizon.

1.4 STATUS OF THE 2010 LTRP ACTION PLAN

In each resource plan, the FEU present a list of actions to implement the recommendations outlined throughout the plan. The following table provides an update of the items identified in the Four-Year Action Plan of the 2010 LTRP.

Table 1-4: 2010 Resource Plan Action Items

	Action Item	Status
1	Secure funding approval for expanded and ongoing EEC beyond 2011.	• EEC funding of $72.315 million over the 2010-2011 timeframe was approved by Commission Order No. G-141-09 (FEI) and G-140-09 (FEVI). • EEC funding of $36.304 million over the 2012-2013 timeframe was approved by Commission Order No. G-44-12. • A five year plan and funding request was submitted as part of the 2014-18 Multi-Year Performance Based Ratemaking Plan application for FEI. A Commission decision anticipated in 2013-2014.
2	Develop a new long term energy forecast approach, including additional end-use and customer research, to examine energy choice implications.	• A new end-use methodology and future scenarios were developed using both FEU resources and external consultant ICF Marbek. The approach and methodology are described in detail in Section 3 and Appendix B-2.

	Action Item	Status
3	Continue working with other utilities to explore the development of a baseline forecast for thermal energy demand in B.C. against which to assess energy choice impacts.	• The FEU has begun to work with other utilities but full development of baseline thermal energy demand has not yet been completed. • Thermal energy demand is incorporated into the new end-use demand forecast methodology which is described in Section 3.
4	Pursue integrated energy and carbon-reducing customer solutions.	• Commission recommendations that came out of the Alternative Energy Solutions inquiry now guide the integration of the FEU's alternative energy initiatives. • The FEU continue to pursue carbon reducing activities through the natural gas for transportation and renewable natural gas initiatives.
5	Continue enhancement activities for the FEU's comprehensive asset management strategy and develop a Long Term System Sustainment Plan.	• The FEU introduce a long-term capital planning approach, which has resulted in a Long Term Sustainment Plan (LTSP) approach as an asset management tool. The LTSP approach has resulted in the development of long- and short-term asset replacement plans. The details of these plans, including CPCN timelines, are included in Section 5.
6	Plan for and prepare CPCN applications for near-term distribution system requirements identified in the FEU Five-Year Capital Plans.	• The Victoria Regional Office – Land, Purchase and Building CPCN was approved by Commission Order No. C-6-11 and the project was completed in October 2012. • The Kootenay River Crossing Project was approved in 2010 by Commission Order No. C-9-10. Pipeline replacement was completed in 2012. • The Muskwa River Crossing Horizontal Directional Drilling Replacement CPCN was approved by Commission Order No. G-27-11 and an in-service date of May 2014 is expected. The Huntingdon Bypass CPCN is currently under Commission review.
7	Continue monitoring and evaluating system expansion needs in the Okanagan area.	• The FEU continue to monitor and evaluate the Interior Transmission System and expect a system capacity constraint to occur in 2018. Discussion of system expansion options is contained in Section 5.
8	Protect and promote the needs of our customers to secure long term gas supply while minimizing costs.	• The FEU maintain supply reliability and moderate commodity price uncertainty primarily through Annual Contracting Plans and Price Risk Management Plans.
9	Influence provincial and regional energy and climate related policy development.	• The FEU have worked with the Provincial government to develop regulation enabling public utilities to engage in programs and expenditures that promote natural gas as a transportation fuel in the heavy duty vehicle and marine sectors. This combined effort resulted in issuance of the Greenhouse Gas (Clean Energy) Reductions Regulation (GGRR) in May 2012.

	Action Item	Status
10	Identify and pursue innovative solutions for waste heat, advanced metering technologies, Customer Information Systems and other energy technologies, uses, supplies and systems.	• The FEU's Innovative Technologies program has successfully included .67 EF and .80 EF water heaters into the Residential Energy Star Water Heater Program and has also integrated HVAC occupancy sensors as an eligible measure within the Commercial Custom Design Retrofit Program. The program continues to pilot other technologies such as condensing rooftop units, solar thermal water heating systems, solar pool heating and air handling unit coil cleaning. • The FEU's Codes and Standards group has worked with the Canadian Gas Association and Measurement Canada to advance thermal metering for gas-heated buildings.

The actionable items that the FEU intend to pursue over the next four years are provided in Section 9 of this plan.

1.5 *ACCEPTANCE OF THE 2014 LTRP*

The FEU submit this 2014 LTRP under Section 44.1(2) of the *UCA.* The FEU are not seeking approval of any particular elements identified within the plan—any future requests for approval will be submitted under a different section of the *Act*. The FEU submit that this LTRP demonstrates that the FEU have met the requirements of the *UCA* and the Commission's directives provided in the 2010 LTRP Decision and have followed the BCUC Resource Planning Guidelines. The Commission should accept this 2014 LTRP under Section 44.1(6) of the *Act*.

2. PLANNING ENVIRONMENT

This 2014 LTRP is being submitted during a time of continuing change in market forces, energy technology and government policy. At a growth rate higher than the national average, British Columbia's population is poised to expand from today's 4.6 million to over 5.8 million in 2033.[10,11] This increase in population will drive the demand for new housing, and with it, the demand for new energy installations. At the same time, infrastructure systems across B.C. and North America are aging and will need major investments to maintain system integrity and to serve the growing population. This poses a significant challenge in making critical investments to rebuild aging infrastructure while balancing the need to moderate the impact on customer rates.

A wide range of factors influence the FEU's long term analysis and planning decisions. This section discusses a number of those factors that the Companies believe are among the most important. It begins with a discussion of the competitive environment for natural gas supply, which is influenced not only by regional energy markets and commodity pricing but also by supply infrastructure availability and end-use equipment installation and operations. Energy and climate policy provides the framework through which to deliver our customers' energy needs and can heavily influence the energy choices that consumers make. While governments across North America were keen to introduce climate and green energy policies a number of years ago, today's setting is more tempered and discussion of the policy and regulatory context highlights a shift in focus away from carbon pricing and toward sustainable energy solutions. Another key factor is where natural gas sits within B.C.'s competitive energy marketplace from an end-user perspective and the initiatives that the FEU have implemented to date to influence this competitive position.

Presently, the natural gas supply outlook looks different than it did even a few years ago. Horizontal drilling and hydraulic fracturing technologies have unlocked the potential of North America's vast shale gas deposits, which has led to a significant growth in supply and lower commodity prices than in recent years. As a result of the supply growth, governments across B.C., the Pacific Northwest and North America more broadly, are looking to take advantage of the environmental, social and economic benefits of using natural gas. Natural gas is increasingly viewed as a fuel that can be used to help reduce GHG emissions by displacing more carbon-intensive coal-fired power generation, providing firm backup for renewable energy, and more recently, by displacing dirtier fuels such as diesel and gasoline in transport applications. B.C.'s Natural Gas and LNG Strategies suggest that natural gas will continue to play an important role in B.C.'s energy mix far into the Province's future.

New energy technologies and gains in energy efficiency have led the way to changing natural gas use, particularly as customers look for innovative solutions and improved information about energy and consumption patterns. Energy consumers are increasingly faced with numerous

[10] Statistics Canada, http://www12.statcan.ca/census-recensement/2011/dp-pd/hlt-fst/pd-pl/Table-Tableau.cfm?LANG=Eng&T=101&S=50&O=A, Accessed Sept. 25, 2013.
[11] BCStats, British Columbia-Level Population Estimates and Projections, April 2013.

energy services and equipment choices, often with conflicting information with which to make decisions that have a long term impact on energy consumption. New energy technologies and energy production at or near the end-use are also beginning to create challenges for the traditional utility model. These new, efficient technologies are changing energy use patterns, making it difficult to accurately predict how such factors may influence the demand for natural gas or its competitive position in the long term. To help maintain the competitiveness of natural gas rates for customers, the Utilities continue to focus on growing the customer base and adding load to the natural gas system, such as through the Companies' NGT initiatives and opportunities to secure new, large industrial customers.

This section is not intended to address any specific requirements under section 44.1 of the *UCA*. Rather, Section 2 provides relevant context for the analysis, results and recommendations that are made throughout the LTRP to address the requirements for resource planning within the *Act*. The remainder of this section is organized as follows:

- Section 2.1 discusses the competitive environment for natural gas,
- Section 2.2 discusses the policy and regulatory context, and
- Section 2.3 discusses the FEU's customer solutions.

2.1 *COMPETITIVE ENVIRONMENT FOR NATURAL GAS*

The competitive environment for natural gas is influenced by factors that affect the full value chain for energy services. Section 2.1 discusses issues that affect natural gas production and supply (upstream), infrastructure (midstream) and end uses (downstream). While technological advancements have contributed to a supply boom and low price environment, a number of other factors beyond commodity cost influence the competitive position of natural gas relative to other forms of energy.

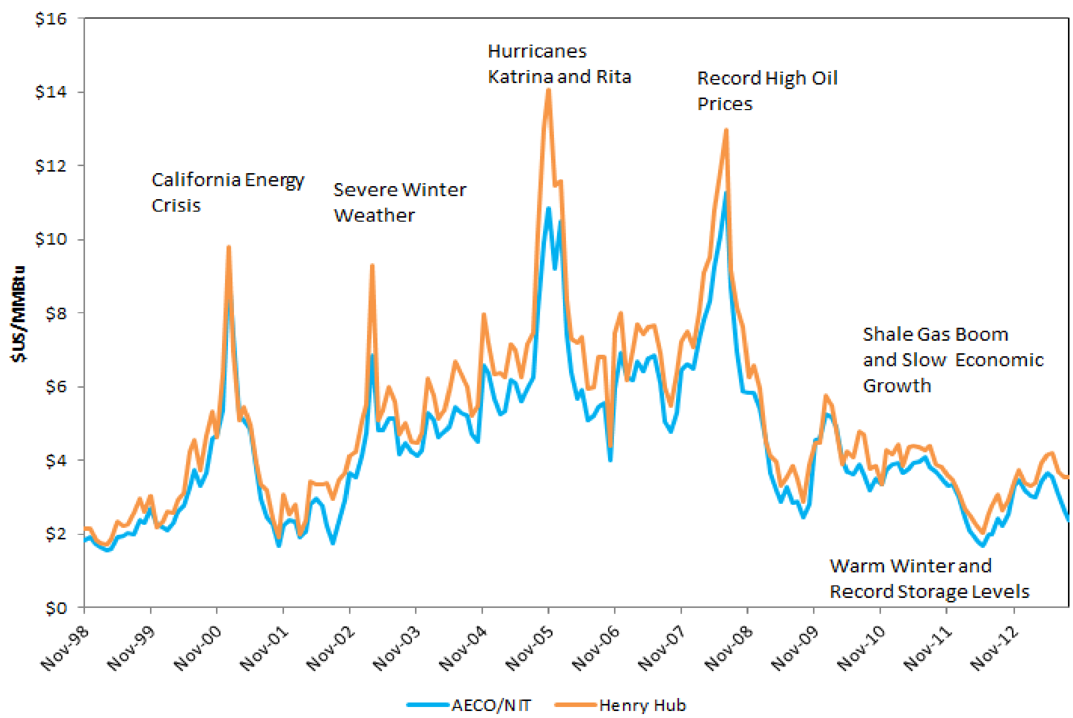
2.1.1 Market Dynamics and Commodity Pricing

The natural gas marketplace continues to undergo change as a result of the development of shale gas. Given an interconnected North American market, this change affects supply and demand dynamics and, consequently, directly impacts the region in which the FEU operate. The following discussion highlights overall trends in the natural gas marketplace while Appendix A-1 provides a detailed overview of the market factors that affect the North American natural gas industry.

The proliferation of unconventional supply development, in particular shale gas, has been considered a 'game changing' event in terms of natural gas supply availability and price. Technological advancements in drilling and reduced well completion times have led to significantly greater natural gas well productivity. This productivity increase has enabled the development of new sources of gas supply across North America, resulting in record high production. A significant outcome for consumers is the decline in commodity costs since 2008.

Prior to these changes, there were general concerns regarding sustainability of supply and the potential need to import natural gas into North America. Figure 2-1 shows the impact that this shale gas boom has had on natural gas prices in recent years. The figure shows two prices – those for AECO/NIT[12], the benchmark for the Alberta gas market and western Canada, and Henry Hub, the benchmark for North America.

Figure 2-1: Historical North American Natural Gas Prices and Related Market Events



Source: FEU based on Platts

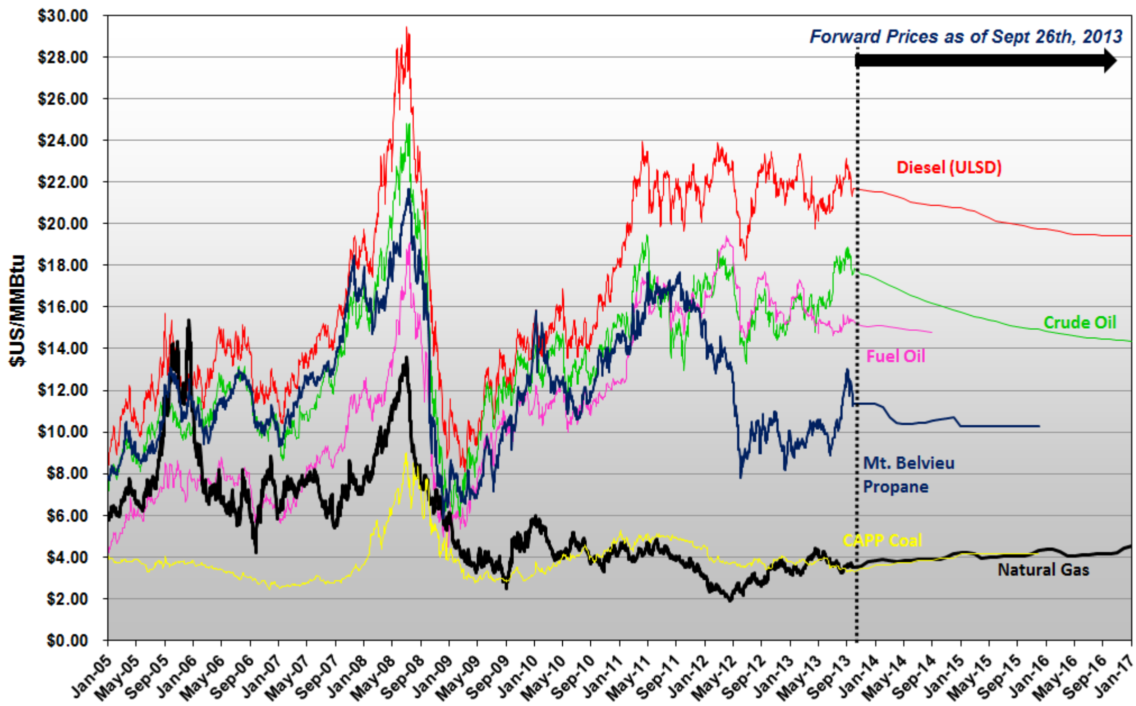
As depicted in Figure 2-1, natural gas prices fell to their lowest level in a decade when the warm winter of 2011-12 (primarily in the eastern U.S. and Canada, where most of the consuming population lives) created record high natural gas storage levels. While prices have rebounded somewhat since the warm 2011-12 winter, natural gas prices remain favourable for consumers and a number of large volume customers have indicated interest to the Companies in developing new major industrial facilities that use natural gas as a feedstock.

Figure 2-2 below shows prices (historical prompt month and futures) for various competing fuels with natural gas as of September 26, 2013. At the current time, forward natural gas prices are expected to average near the $4 US/MMBtu level. This can change quickly, however, in response to weather and supply and demand balances. In addition, Central Appalachian (CAPP) coal prices and NYMEX natural gas prices are near the $3.50 US/MMBtu level and

[12] Located in Alberta, AECO/NIT (Alberta Energy Company/Nova Inventory Transfer) is an important storage and exchange point for Canadian natural gas. AECO/NIT is commonly used to refer to the benchmark pricing index for the Alberta natural gas marketplace.

when natural gas prices fall below CAPP coal prices, demand for natural gas increases. This is due to fuel switching, mostly from power generators that can deploy natural gas generation in lieu of coal depending on the price differential. As a result, CAPP coal prices tend to act as a soft cap for natural gas prices.

Figure 2-2: Competing Fuel Prices, North America



Source: U.S. Energy Information Administration & CME Group, September 26, 2013

Natural gas prices remain disconnected from other competing fuels—such as heating and fuel oil—which are derived from crude oil and can be used as substitutes for natural gas in applications such as space heating and power generation. Whereas crude oil prices are highly influenced by global supply, demand and geopolitical factors, North American natural gas prices tend to be relatively isolated from such factors and are more dependent upon aspects that pertain to regional supply and demand (discussed in section 2.1.2 with additional detail in Appendix A-2).

While North American natural gas supplies continue to grow, the pace of this growth has slowed because decreased commodity prices have approached production and development break even costs. With oil and liquids pricing remaining high relative to historical averages, producers have focused their drilling efforts on oil and liquids-rich plays rather than dry gas plays. However, the North American gas supply potential remains very high, with enough supply to meet over 100 years of current demand. For example, continental U.S. state reserves (excluding Alaska) are recently estimated to be 318 Tcf[13] by the end of 2015, compared to a previous estimate of 227 Tcf[14] only a few years ago. Many industry observers view today's environment as the 'golden age' for natural gas, with greater supply certainty and favourable pricing helping to drive incremental demand.

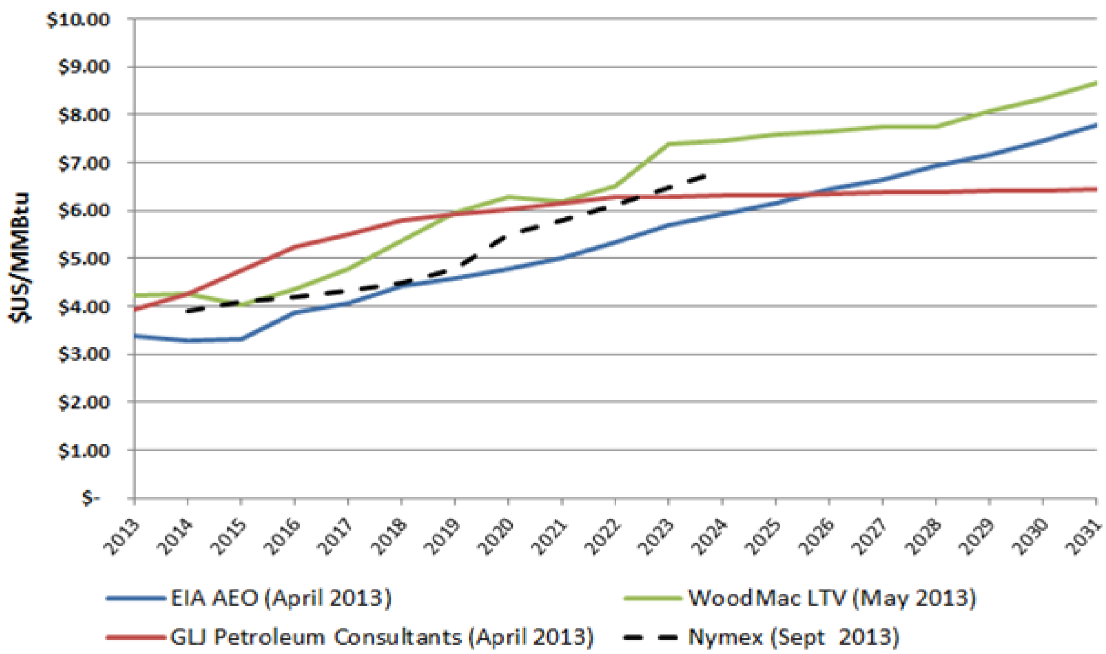
Natural Gas Demand

In the North American market, natural gas demand is expected to come from a variety of sources. In the short term, new incremental gas demand will be driven primarily by coal-to-gas switching for power generation and new industrial demand. Over the medium to long term, gas demand will be driven by further fuel switching or retiring coal-fired power generation facilities in favour of gas-fired power generators, new industrial demand, U.S. export to Mexico, development of an LNG export sector, and to a lesser degree, development of the NGT sector due to high diesel and gasoline prices coupled with regulations to reduce GHG emissions. Continuing high crude oil prices are expected to increase natural gas demand in Canada for oil sands production in which gas is used for oil extraction.

This increase in demand should enable the natural gas supply potential to be more fully developed by producers. The end result may be a transition away from a currently over-supplied gas market towards one that is more balanced. This rebalancing of supply and demand in the natural gas marketplace will place upward pressure on gas prices as they are not currently at a level that will balance long run supply and demand. As depicted in Figure 2-3, by 2020, analysts forecast that gas prices could be between \$4.75 US/MMBtu (\$4.64 Cdn/GJ) and \$6.25 US/MMBtu (\$6.10 Cdn/GJ); and by 2025, forecasts predict that gas prices could be between \$6.00 US/MMBtu (\$5.86 Cdn/GJ) and \$7.50 US/MMBtu (\$7.32 Cdn/GJ).

[13] U.S. Energy Information Administration (EIA), Annual Energy Outlook 2013.
[14] U.S. EIA, Annual Energy Outlook 2008.

Figure 2-3: Natural Gas Price Forecast[15]



Source: FEU based on U.S. EIA Annual Energy Outlook, GLJ, WoodMac Long Term View and Nymex

These future higher commodity prices are not expected to minimize the significant role that natural gas will play in the energy marketplace in North America or the region within which the FEU operate. The opportunities for the increased use of natural gas in North America, the PNW and on the FEU's own system are expected to provide economic and environmental benefits to customers for years to come.

2.1.2 Supply Infrastructure

In order to provide reliable supply to customers, the FEU must purchase the gas commodity, secure capacity on third party transmission or transportation pipelines that connect supply to market, and move gas to and from storage facilities as required. To successfully manage these requirements, it is critical that the FEU understands market dynamics including identifying regional infrastructure opportunities that could benefit customers over the long run. Competition among market participants for favourable gas pricing and for physical capacity on the regional transmission infrastructure means that the Utilities must always be vigilant in identifying regional trends that could negatively impact customers or, conversely, identify opportunities that could provide benefits to customers. The FEU are involved in key regional issues that include ensuring the availability of regional gas supply for their marketplace as well as the development and tolling of infrastructure that will facilitate the movement of supply to market.

[15] Long term price forecast for natural gas based on the Henry Hub market; all prices presented in nominal dollars.

Significant changes are occurring in the natural gas marketplace in western Canada, driven by the development of new supply basins and interest in this supply by new markets. Within North America, the natural gas potential in northern B.C. is second only to the Marcellus shale gas play that is being developed in the northeast region of United States. In a few short years, B.C. reserve estimates have grown from 55 to 1200 trillion cubic feet. These changes will likely impact traditional supply and demand dynamics and regional gas flows, as well as regional market prices.

The prospect of developing new markets for production is welcome news for producers active in the Western Canadian Sedimentary Basin (WSCB). The traditional Canadian and U.S. consumption markets for natural gas produced in the WCSB have declined steadily over the past few years. This decline is driven primarily by the development of shale gas basins, in particular the Marcellus shale gas play, that are located much closer to traditional key consuming markets in eastern North America. While increased industrial, power generation, and oil sands demand will help offset reduced demand from traditional markets, significant new markets are required in order to fully develop the potential of the WCSB and the new supply basins located in northeast B.C.

New consuming markets may affect the availability and cost to obtain gas supply for B.C. and PNW markets. Competition for natural gas may increase as gas is increasingly directed toward the AECO/NIT market hub in Alberta and also toward B.C.'s west coast to support LNG exports; to date, over a dozen projects have been proposed to export LNG from B.C. to Asian markets. To provide the FEU with access to cost-effective supply over the long term, opportunities may arise to develop alternative solutions to meet the potential load growth of these markets. The Kingsvale Oliver Reinforcement Project (KORP) is an example of one such opportunity to expand the FEU's transmission system to support gas flows south from northeast B.C. toward new base load markets that are emerging in the Lower Mainland and PNW. Further detail regarding LNG export projects, alternative infrastructure solutions, and other regional market developments is provided in Appendix A-2. As traditional gas flows and pricing may change in the future, the FEU must continue to monitor regional developments and adapt the supply portfolio to ensure access to reliable and cost-effective supply for customers.

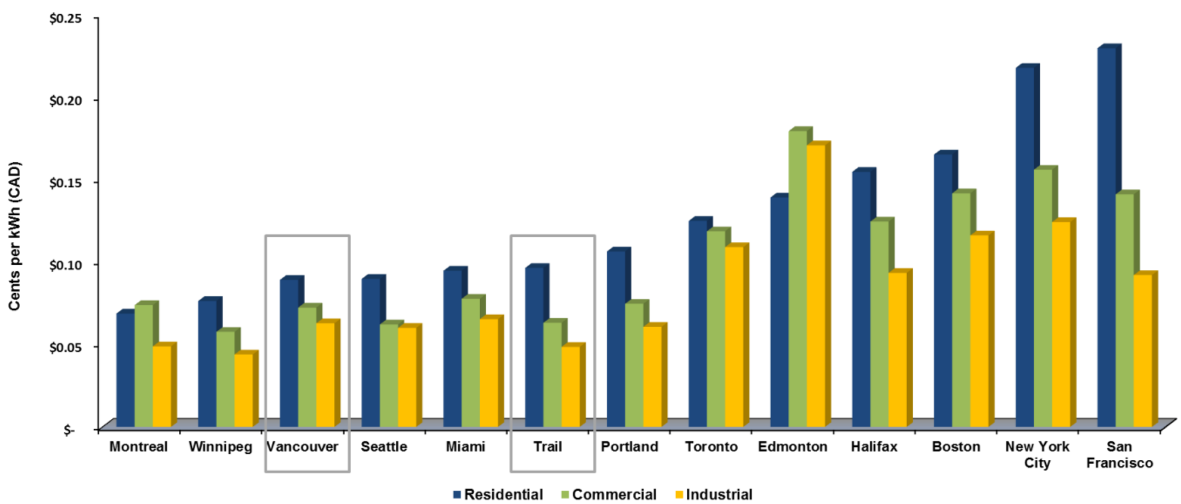
2.1.3 Competitive Environment in B.C. for Energy End Uses

The relatively new abundance of natural gas supply in North America and recent low price levels have impacted the commodity's competitiveness with other sources of energy. The low price environment has improved the price competitiveness of using natural gas on an operating cost basis though natural gas direct use applications (such as space and water heating) typically require higher capital, installation and maintenance costs than for electricity and other fuel alternatives. Since the competitiveness of renewable thermal energy systems is determined on a case-specific basis, the Utilities need to better understand how these new end-use technologies are impacting natural gas demand and use (Section 3 provides information on how the Utilities are incorporating changing end-use trends to long term demand forecasts). A multitude of factors beyond those relating to commodity cost influence consumer, builder and developer preferences relating to the use of natural gas versus other sources of energy. Capital costs, installation requirements, operating and maintenance costs, government policies (outlined in Section 2.2) and public perception all play a role in this regard. Appendix A-3 elaborates on the impact of operating and capital costs on natural gas competitiveness in each of the FEU's service territories.

2.1.3.1 Natural Gas and Electricity Rates

Electricity rates in B.C. are among the lowest in North America (illustrated in Figure 2-4) and since 2010, the province's *CEA* has defined a provincial objective to "ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America."

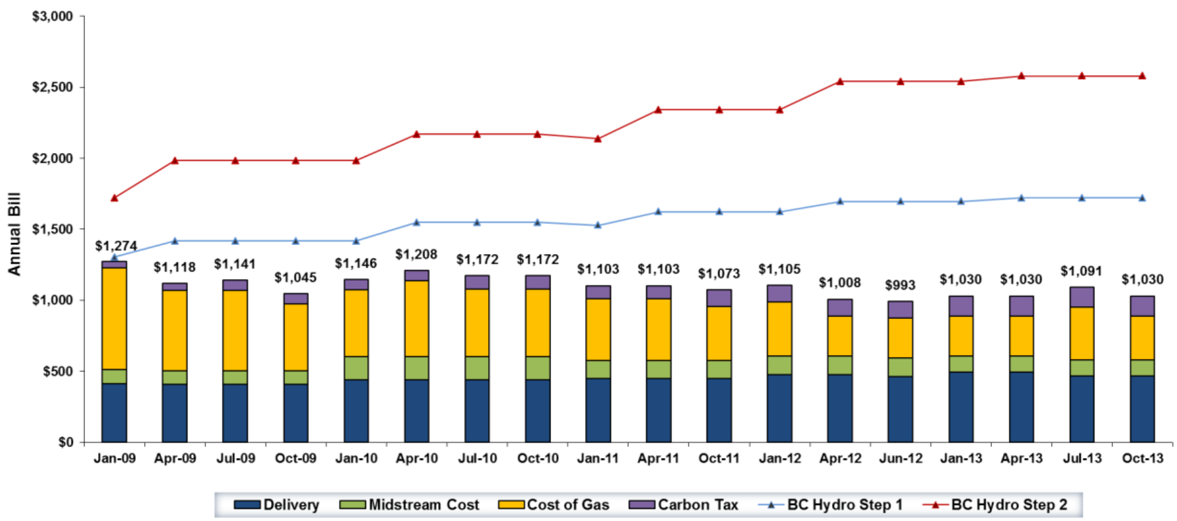
Figure 2-4: Electricity Rate Comparison Across Jurisdictions in North America



Source: FEU based on Hydro-Québec's "Comparison of Electricity Prices in Major North American Cities" effective April 1, 2013

In the past, low electricity rates have contributed to a competitive challenge for natural gas in B.C. but the decline in gas commodity cost and increases to electricity rates in B.C. in recent years has helped to improve the competitiveness of natural gas. Figure 2-5 provides a historical comparison of natural gas bills (based on consumption of 95 GJ/year and 95% efficiency) with comparable electricity bills (assuming 100% efficiency) for an FEI residential customer in the Lower Mainland. This chart demonstrates that today's natural gas rates are cost competitive with electricity rates.

Figure 2-5: FEI Lower Mainland Residential Natural Gas Rates[16]



While today's low natural gas rates contribute to a natural gas operating cost advantage relative to electricity, the Utilities believe that commodity price is only one factor that impacts the price competitiveness of natural gas in B.C. relative to electricity. Other factors include natural gas price volatility (discussed in the North American Gas Market Overview, Appendix A-1) and the installation costs of natural gas appliances relative to electric appliances.

2.1.3.2 Installation and Operation

Capital costs related to natural gas equipment (such as furnaces, ducting and hot water tanks) tend to be costlier than those relating to electric equipment (such as electric baseboards and hot water tanks). In retrofit situations, new and more complicated ducting requirements for high efficiency equipment are making the installation of natural gas equipment more difficult and costly. In addition, it is often not the end user that makes decisions regarding energy sources installed in the home: builders and developers are the primary decision makers regarding the choice of energy and equipment used in new construction. As builders and developers do not ultimately pay operating costs, they tend to be more influenced by capital costs alone. In addition, builders and developers typically aim to maximize the useable square footage available in a development to maximize the return on investment, particularly for multi-unit residential developments. Thus, capital cost savings and the ability to sell more useable living space incents developers and builders to install electricity equipment over natural gas equipment in new developments. The upfront capital cost difference for installing natural gas

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[16] This illustration assumes natural gas use of 95 GJ and the efficiency of gas equipment is 90% relative to 100% for electric equipment. FEI amount includes the basic charge; BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use.

equipment has been identified by the American Gas Association as the "primary impediment to natural gas use in residential and commercial buildings if service can be made available."[17]

Table 2-1 provides an example of the upfront installation (capital) cost difference associated with natural gas versus electricity for a space heating furnace and hot water tank in new construction for FEU customers. The difference in upfront capital costs between gas and electricity means that over the life of the appliance, the operating cost advantage of natural gas over electricity must be significantly greater ($9.93/GJ for space heating and $5.67/GJ for water heating) for the equipment to be economic to the consumer. Appendix A-3 further illustrates the impact of capital costs and rates on the competitive position for natural gas for space and water heating across FEI, FEVI and FEW.

Table 2-1: Capital Cost Difference for Space and Water Heating – Natural Gas vs. Electricity[18]

	Space Heating	Water Heating
Capital costs for natural gas	$9,000	$2,000
Capital costs for electricity	$4,320	$1,023
Upfront capital cost premium for natural gas compared to electricity	**$4,680**	**$977**
Annual difference in capital costs[19]	$446.68	$113.32
Annual maintenance costs	$50.00	$0.00
Total annual difference in capital and maintenance costs	**$496.68**	**$113.32**
Energy consumption per year (GJ)	50 GJ	20 GJ
Difference in cost between natural gas and electricity over measureable life ($/GJ)	**$9.93/GJ**	**$5.67/GJ**

The higher upfront capital cost of natural gas end-use applications erodes the cost advantage of natural gas compared to electricity and plays an important role in influencing customer energy choice. The FEU expect the capital cost difference between natural gas and electricity to continue into the foreseeable future, which highlights the need to develop solutions (such as working with key energy influencers, discussed in Section 2.3.3) to address this challenge.

2.1.3.3 Competition from Renewable Thermal Energy Systems

Numerous new end-use technologies have entered the energy services marketplace in recent years and will likely continue to do so throughout the 20-year planning horizon of this LTRP. In addition to advancements on both natural gas- and electricity-based heating equipment,

17 American Gas Association. Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges, page 32.
18 Assumptions based on the new construction of a 3,000 sq. ft. home in the Lower Mainland.
19 Represents the difference in capital costs per year, assuming a stream of equal annual payments with an interest rate of 6% and measurable life of 17 years for a space heating furnace and 13 years for a hot water tank.

advancements in renewable thermal energy solutions have emerged to take a small but growing slice of the market. Examples of renewable thermal solutions include air and ground source heat pumps for single family residences; geo-exchange and biomass energy systems that can serve one or more multi-family developments; and district energy systems that can employ one or more renewable energy systems such as waste heat from industrial processes, geo-exchange technologies, or biomass solutions often in combination with natural gas-fired heating solutions. The FEU need to continue to understand how these renewable thermal solutions are impacting natural gas demand (outlined in Section 8) and how they are changing the way the Utilities' customers are using natural gas. These growing changes indicate that the traditional utility model may potentially shift over the long term.

The competitiveness of any given renewable thermal energy system with that of a natural gas only system is case-specific. In some cases, high quality renewable energy sources are readily available and in close proximity and match the needs of a development. In other cases, the renewable thermal energy source may not be as well-matched or close to the energy plant, which increases the costs of installation and operation. Generally speaking, capital costs for renewable thermal systems are higher, while the commodity cost can range from zero for heat extracted from the ground, to much higher for biomass, depending on market conditions. These and other factors can result in a renewable thermal solution being more cost-effective than a natural gas system in some cases, and less so in other cases. Adding to the difficulty in understanding how these solutions will impact natural gas demand over time, the decision to choose a renewable thermal energy solution is often not purely based on cost of the system. A homeowner or developer might choose to invest in such a system based on air emission reductions, perceived impact on resale value, municipal development requirements or other reasons. The willingness of the system owner to incur higher capital costs at the outset versus potentially lower operating costs over the long run can also impact the decision to install these systems.

How these factors will affect the rate at which renewable thermal systems enter the B.C. end-use energy market place remains unknown. This LTRP has therefore incorporated a range of market penetration assumptions into the forecast scenarios for annual demand (described in Section 3 and additionally in Appendix B-2).

2.1.4 Summary

The proliferation of shale gas development in North America and recent low price levels continue to influence the competitiveness of natural gas with other sources of energy. Changing market dynamics are likely to impact regional gas flows and prices, particularly as new industrial, power generation and oil sands demand have the potential to affect the availability and cost to obtain gas supply for B.C. and PNW markets. Although market developments have improved the competitiveness of natural gas on an operating cost basis, the higher upfront capital costs of natural gas installations and appliances can negatively influence the competitive position of natural gas relative to other energy forms such as oil, propane, electricity and possibly renewable thermal energy. These factors combine with government policy (discussed below) and influence customer perception, energy choice and energy technologies. In Section 2.4, the FEU discuss how the influence of these factors on their long term analysis is addressed through the remainder of the LTRP.

2.2 *POLICY AND REGULATORY CONTEXT*

North America's shale gas boom has transformed the energy outlook and climate change debate. With the context of relatively lower natural gas prices and increasing supply availability, energy policies are aimed at switching from more carbon intensive fuels such as coal, diesel and gasoline to natural gas, especially in the electricity generation and transport sectors. The Canadian and U.S. governments have narrowed their climate change policy focus by developing fuel economy and efficiency standards for vehicles and power plants, rather than targeting all sectors. Climate change policies are addressed mostly through a bottom-up approach with provinces, states and municipalities driving initiatives to stimulate the production and consumption of low carbon energy and other GHG emission reduction activities. The following discussion outlines how policies in Canada, the United States, PNW states, and B.C. and its municipalities are driving demand for different energy sources and end uses.

2.2.1 Approaches to Energy and Climate Policy in Canada and the U.S.

Since the 2010 LTRP, the Canadian government has continued a commitment to addressing climate change but with a measured approach that considers potential impacts to the economy. In December 2011, Canada announced plans to withdraw from the Kyoto Protocol and affirmed commitment to reducing GHG emissions 17 per cent below 2005 levels by 2020. Although the target aligns with the United States' emissions goal, it reduces Canada's reduction target by nearly 50 million tonnes of carbon dioxide equivalent and allows an additional eight years to meet the target.[20] Despite withdrawing participation from the Kyoto Protocol, in 2012, Canada, along with the United States and a handful of other countries, became a founding member of the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants (CCAC). The CCAC is a global effort to reduce climate change-inducing pollutants such as black carbon (commonly known as soot), methane and hydrofluorocarbons. For Canada, participation in the CCAC marks a shift toward voluntary action in international climate change mitigation efforts.

The United States, on the other hand, has incorporated climate change mitigation measures into a broader agenda that promotes energy security, environmental protection and economic development. In the absence of Congressional support for a price on carbon, the Obama administration has focused on the role of the 'green economy' to stimulate the economy, increase domestic jobs, build local market capacity, and foster innovation in clean energy industries. Fuel switching in the electricity sector away from coal generation to natural gas and hydropower is the primary driver for falling GHG emissions as electricity generation accounts for

[20] Elizabeth May. "Backgrounder: Canada and Climate Change." Retrieved on May 29, 2013. http://elizabethmaymp.ca/news/publications/backgrounder/2012/12/14/backgrounder-canada-climate-change/

the largest portion (33 percent) of U.S. GHG emissions.[21] While some decline in U.S. GHG emissions may be attributable to a slow economy, sector-based technology standards also play a notable role in shaping the U.S. low carbon economy.

The Canadian government has sought to align its climate change policies with those of the U.S.[22] and has embarked on a sector-by-sector approach beginning with Canada's largest sources of GHG pollution: transportation and electricity generation. In the transportation sector, new regulations have been harmonized with U.S. rules for heavy- and light-duty vehicle regulations. In the electricity sector, an emissions intensity-based performance standard for coal-fired electricity generation will come into effect in 2015. And, in the face of international pressure to reduce GHG emissions from Canada's energy exports, draft emissions regulations covering the oil and gas industry are under development. Balancing GHG emissions reductions and economic competitiveness has been a significant challenge in developing policy to address oil and gas sector emissions. For this reason, industry and government stakeholders are likely to negotiate a form of hybrid emissions intensity target combined with a price ceiling per tonne of carbon dioxide equivalent.[23] While the Canadian and U.S. federal governments mandate lower carbon energy regulations, provincial, state and municipal governments continue to chart their own course on climate action.

2.2.2 Pacific Northwest: A Prominent Role for Natural Gas

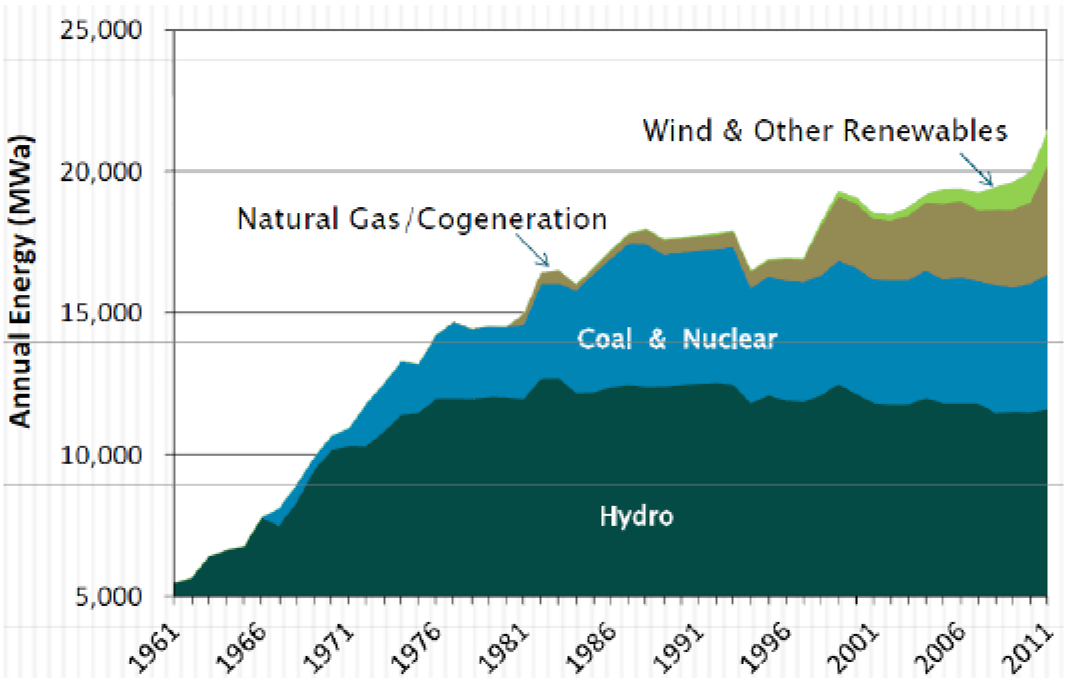
Without an overarching energy or climate policy framework at the federal level, energy and climate initiatives in North America are often developed at the subnational level. Many states and provinces have implemented a host of policies including energy efficiency targets, clean energy mandates, low carbon fuel standards and financial incentives for low carbon energy technologies. This has led to a patchwork of policies across Canada and the U.S., particularly as many provinces and states advance GHG emission reduction targets, cap-and-trade policies and other climate change plans.[24] The challenge of developing universal climate change policies is heightened by distinct regional characteristics and differing natural resource endowments across Canadian provinces and US states.

As energy production and the carbon intensity of electricity generation varies across jurisdictions, different solutions are required to meet GHG emissions reduction objectives. Electricity in B.C. is supplied predominantly through hydroelectric generation and the *CEA* establishes an objective for 93 percent of the province's electricity to be generated from clean or renewable resources.[25] By contrast, though hydro is also the largest source of power

[21] Environmental Protection Agency. "Inventory of U.S. GHG Emissions and Sinks: 1990-2011," April 2013, pg. 21.
[22] Canada's Action on Climate Change, "Canada's Continental Action," http://www.climatechange.gc.ca/default.asp?lang=En&n=A4F03CA6-1, Accessed Oct. 28, 2013.
[23] Oil and Gas Greenhouse Gas Regulations: The Implications of Alternative Proposals. International Institute on Sustainable Development, May 2013. http://www.iisd.org/pdf/2013/oil_and_gas_ggr.pdf, Accessed June 11, 2013.
[24] Energy Policy Institute of Canada, "A Canadian Energy Strategy Framework," August 2012.
[25] Legislative Assembly of B.C., *Clean Energy Act*, SBC 2010 (Victoria, B.C., June 3, 2010), Chapter 22, Part 1, 2 (c).

generation for PNW states, coal-fired electricity generation continues to play a significant role in meeting Washington, Oregon and Idaho's supply needs.[26]

Figure 2-6: U.S. PNW Electric Generation by Fuel



Source: Bonneville Power Administration, 2012

Policy makers and utilities in the PNW region consider natural gas to be a viable solution to meet growing energy demands; due to high generation efficiency, relatively low carbon content and operational flexibility, natural gas provides an ideal source of base load and peaking electric power supply. Therefore, policies are aimed at moving away from coal-based electricity generation to natural gas and other renewable energy. As a result, energy policies are unique among PNW jurisdictions, particularly with regard to the role of natural gas in meeting energy demands.

In the U.S. PNW, natural gas plays a prominent role as a source of base load, peaking and reserve demand. The use of natural gas for electricity generation has grown significantly in recent years and natural gas holds a growing share of generation supply. The Northwest Gas Association (NWGA) forecasts an average annual growth rate of 2.6 percent in gas use for generation, up from 1.0 percent in 2012.[27] At the same time, with the exception of Idaho, PNW states use renewable portfolio standards to promote renewable energy generation. Wind power is considered the most available and cost-effective resource to meet these mandates thus

[26] Bonneville Power Administration. "The Role of Natural Gas in the Northwest's Electric Power Supply," August 2012, pg. 4.
[27] Northwest Gas Association, "2013 Gas Outlook," April 9, 2013.

electricity generation from wind energy has also grown in the PNW. Hydro is currently used to balance the variability in wind generation though it is expected that this balancing capability will not be able to meet planned expansions for the PNW's wind energy fleets. Energy consultant ICF International predicts that an additional 2,500 MW of gas-turbine capacity will be needed by 2025 to firm the PNW's wind generation and that nearly six percent of the regional's total natural gas demand will be for that purpose.[28] The growing use of renewable, intermittent resources may change the way that the region's gas infrastructure will be called upon to meet the region's future energy needs – a possibility for which the FEU must be prepared.

Natural gas in the PNW is also promoted for direct use applications. Direst use refers to natural gas consumed directly in appliances for space and water heating, cooking and clothes drying. In most cases, the natural gas distribution system is considerably more efficient than the electricity system since it avoids the significant losses associated with electricity generation, transmission and distribution; these losses amount to nearly half the energy used in homes and commercial businesses. (For additional information on the opportunities and challenges of the direct use of natural gas, refer to the report provided in Appendix A-4, "Squeezing Every BTU.") Since using natural gas for space heating and thermal applications is more efficient than using it to generate electricity for use in these same applications, utilities such as Puget Sound Energy and Avista Utilities (which provide both electricity and natural gas), promote the direct use of natural gas to avoid new electricity demand—even in service territories where other utilities may benefit from increased natural gas demand.[29,30] The NWGA also advocates policies to promote the direct use of natural gas since gas is seen as a pillar of the region's electricity resource strategy to reduce the use of coal-fired generation and allows integration of a growing fleet of intermittent renewable resources.[31]

As in B.C., natural gas is gaining traction as an alternative transportation fuel and the region will look to retain and secure access to abundant and diverse sources of gas supply while ensuring that that the associated transmission, storage and distribution infrastructure can grow as necessary.[32] An anticipated increase in natural gas demand within the PNW region will provide B.C. with an opportunity to leverage its new natural gas supply resources to fulfill this anticipated market demand.

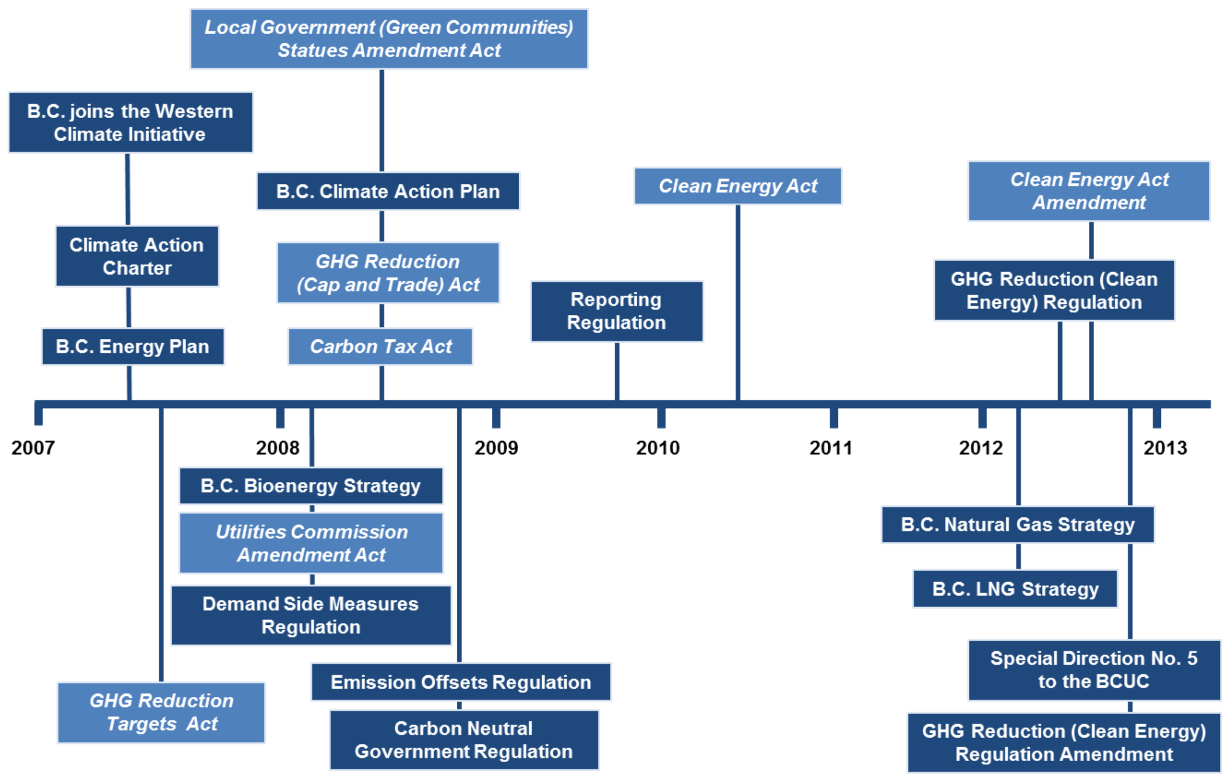
2.2.3 British Columbia: Renewed Focus on Natural Gas

In the years between 2007 and 2010, the Government of British Columbia stated its desire to become a leader of North America's GHG emission reductions efforts with a flurry of low carbon policy activity. A comprehensive approach led to a number of significant legislative pieces

[28] ICF International as noted in Bonneville Power Administration, 2012.
[29] Puget Sound Energy, *Choosing Natural Gas from Puget Sound Energy,* http://www.pse.com/SAVINGSANDENERGYCENTER/FORHOMES/Pages/Choosing-Natural-Gas.aspx, accessed Jun. 13, 2013.
[30] Avista Utilities, *The Benefits of Natural Gas*, http://www.avistautilities.com/services/gas/pages/default.aspx, accessed Jun. 13, 2013.
[31] Northwest Gas Association, "Natural Gas and Climate Change in the Pacific Northwest," Vol. 5, Issue 1, p.3-5.
[32] Northwest Gas Association. "Natural Gas and Climate Change in the Pacific Northwest." Appendix A-2.

covering GHG reduction targets (33 percent below 2007 levels by 2020 and 80 percent by 2050), development of a cap-and-trade program, emission offsets and reporting, and B.C.'s landmark carbon tax legislation. Figure 2-7 outlines the chronological development of B.C.'s energy and climate policy and legislation while Appendix A-5 discusses the legislative acts, regulation and related strategies in more detail.

Figure 2-7: B.C. Energy and Climate Policy and Legislative Timeline



Since 2007, B.C. has been a participant of the Western Climate Initiative (WCI), a regional effort to establish a multi-sector GHG trading market. Nevertheless, in the face of weak economic growth and changing political leadership in some states, all US states except California abandoned the WCI by the end of 2011, leaving only California, B.C., Manitoba, Ontario and Quebec as remaining members. To date, only California and Quebec have adopted cap-and-trade regulations with regard to the rules set forth by the WCI. Though the *Greenhouse Gas Reduction (Cap and Trade) Act* was passed in 2008 to enable development of a provincial cap-and-trade scheme with potential to link with other systems, B.C.'s carbon trading ambitions remain unclear.

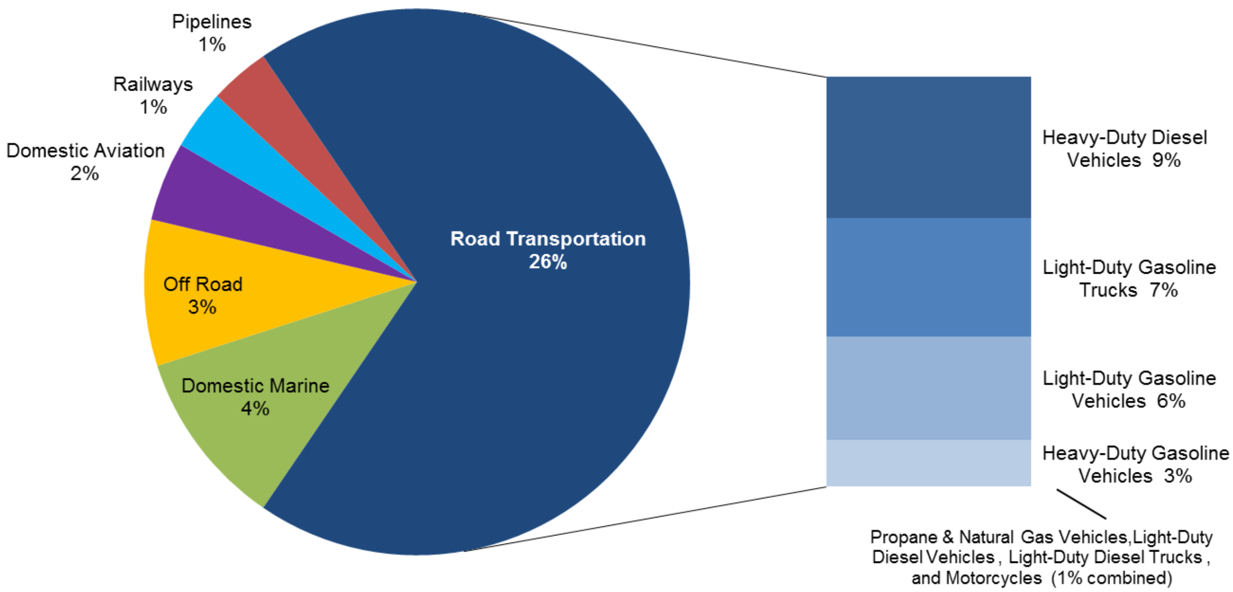
British Columbia's most notable climate policy is the carbon tax, which applies to all fossil fuels at the point of consumption. Introduced in 2008 at a rate of \$10 per tCO_2e, the tax increased by \$5 per tCO_2e annually until it reached a threshold of \$30 per tCO_2e in 2012. At that time, the government launched a review of the tax and confirmed that there would be no further rate increases or changes planned. At the current \$30 per tCO_2e, the tax adds \$1.50 per gigajoule to the cost of natural gas, which is *almost half the price of the commodity itself*. Carbon tax rates are expected to remain at \$30 per tCO_2e for the next five years while government leaders pressure other jurisdictions to adopt a similar consumer-based tax. In October 2013, the governors of Washington and Oregon made a public commitment to advance some form of carbon pricing policy though it remains unclear how or when the states would implement a price on GHG emissions.[33]

Since the *CEA* was introduced in 2010, the province has aggressively focused on the role of clean or renewable energy and energy conservation to set B.C. on a path toward energy self-sufficiency. The *CEA* establishes key provincial objectives such as generating at least 93 percent of the province's electricity from clean or renewable resources (except when used to develop LNG for export as noted in Section 2.2.3.2 below); fostering the development of First Nation and remote communities through the use and development of clean or renewable resources; and encouraging energy switching to achieve lower GHG emissions. Natural gas, electricity and hydrogen are thus encouraged as vehicle fuel alternatives to higher emitting fuels such as gasoline and diesel. Nevertheless, the *CEA* does not promote the use of natural gas over electricity where gas is more efficient such as in thermal applications; in fact, the *CEA* defines "demand-side measure" in B.C. to specifically exclude any fuel switching activities that lead to an increase in GHG emissions. Excluding electricity-to-gas fuel switching as a demand-side measure may cloud customer and public perception of natural gas as an efficient fuel. This, combined with heavy government and media emphasis on B.C.'s electricity as a clean, renewable energy source, may contribute to customer and stakeholder confusion regarding the role of natural gas.

However in the last few years, the government has begun to actively promote the role that natural gas can play in both economic development and in reducing emissions. Figure 2-8 shows B.C.'s transport-related GHG emissions and highlights the relative contribution of road transportation emissions. Transport emissions (37 percent of B.C.'s total emissions), and road transportation emissions in particular (26 percent of B.C.'s total emissions), make the largest contribution to B.C.'s GHG emissions profile and emphasize a need to target emission reduction strategies in these areas in order to address the province's climate change goals.

[33] Bloomberg News, "Western U.S. States, British Columbia Agree on Carbon," http://www.bloomberg.com/news/2013-10-28/western-u-s-states-british-columbia-sign-climate-change-pact.html, Accessed Oct. 28, 2013.

Figure 2-8: 2011 Transport and Road Transportation GHG Emissions in B.C.



Source: FEU from B.C. GHG Inventory Report, 2011 Update (2013), Climate Action Secretariat

A handful of energy- and climate-related policy developments that reflect the government's evolving view of the role of natural gas have occurred since filing the FEU (formerly Terasen Gas) 2010 Long Term Resource Plan: issuance of B.C.'s Natural Gas Strategy, LNG Strategy and the Greenhouse Gas Reduction (Clean Energy) Regulation, and an amendment to B.C.'s *CEA* to classify natural gas as a clean resource when used for power generation in the province's nascent LNG export market. These policy developments present an opportunity for the FEU to catalyze the marketplace for compressed natural gas (CNG) and liquefied natural gas (LNG) as a main fuel for return-to-base vehicle fleets.

2.2.3.1 B.C.'s Natural Gas and LNG Strategies

On February 3, 2012, the Government of B.C. unveiled its Natural Gas Strategy and LNG Strategy (provided in Appendix A-6), which outline a vision to become an international leader in LNG development and recognize the role of natural gas as a transition fuel to a low carbon global economy. B.C.'s LNG Strategy commits the province to having three LNG facilities in operation by 2020 and represents an attempt to create a new industry that is intended to bring significant job-creation and economic benefits to the province. Critical priorities that guide the strategies include: maintaining B.C.'s competitiveness in global LNG markets; promoting natural gas as a transportation fuel; developing new markets for gas-related industries such as a gas-to-liquids, methanol and fertilizer production; and ensuring a reliable supply, available infrastructure and effective royalty regime to encourage investment in B.C.'s natural gas sector. The Natural Gas Strategy also continues to build on B.C.'s Bioenergy Strategy by reinforcing a commitment to encourage biomethane opportunities and offering consumers low carbon natural gas (Section 2.3.2 and Appendix A-7 discuss FEI's initiatives to provide its customers with renewable natural gas). With recognition of natural gas as the cleanest burning fossil fuel and strong government support for the development of a new LNG export market, natural gas is poised to play a central role in B.C.'s economy. As such, the province's energy demand and energy infrastructure needs are also set to expand. The FEU are well-positioned to assist in meeting the government's objectives in B.C.'s Natural Gas and LNG Strategies.

2.2.3.2 B.C.'s Energy Objectives Regulation

Building on momentum from the B.C. Natural Gas and LNG Strategies, in June 2012, the Government of B.C. declared natural gas as a 'clean' fuel when used to generate power for B.C.'s LNG export market (Appendix A-2 provides further information on expected LNG projects, pipeline routes and implications for the regional gas marketplace). Using the Government's rationale that natural gas can be used to reduce global GHG emissions, the Companies believe the efficient use of natural gas for heating applications in B.C. can provide a similar benefit for global emissions when displaced electricity load results in clean electricity supply available for export to offset coal and gas fired generation in neighbouring jurisdictions, or reduces the need to import electricity from neighbouring jurisdictions.[34] The change to the designation of natural gas as a source of clean energy, made through B.C.'s Energy Objectives Regulation, enables production of relatively cheap and abundant electricity to fuel the LNG export market without compromising the requirements of the *CEA*. As a result, natural gas will be used for both liquefaction and as a power-generating fuel, and demand for natural gas in B.C. will increase.

2.2.3.3 Greenhouse Gas Reduction (Clean Energy) Regulation

As part of the province's strategy to encourage the use of natural gas as a transportation fuel, on May 14, 2012, policymakers introduced the Greenhouse Gas Reduction (Clean Energy) Regulation through a "prescribed undertaking" under sections 18 and 35(n) of the *CEA.* The regulation authorizes a utility to spend up to $104.5 million in natural gas transportation program funding including:

- Offering incentives to transportation fleets that may use natural gas such as busses, trucks or ferries;
- Building, owning and operating CNG or LNG fuelling stations; and
- Providing grants to meet safety guidelines for operating and maintaining natural gas vehicles.

[34] This assertion is supported by comprehensive analysis conducted by the Center for Climate and Energy Solutions (C2ES) in its June 2013 report, "Leveraging Natural Gas to Reduce GHG Emissions." http://www.c2es.org/publications/leveraging-natural-gas-reduce-greenhouse-gas-emissions

As a result, FEI applied to the BCUC to convert the existing interruptible LNG sales and dispensing service tariff (Rate Schedule 16) from a five-year pilot program into a permanent tariff offering to customers. The BCUC granted approval to extend the pilot rate for an additional seven years to December 31, 2012 albeit at a higher rate to capture the full cost and value of the LNG service.[35]

On October 29, 2012, FEI was granted approval of rate treatment of up to $62 million in expenditures on administration, marketing, training and education as established in Section 2(1)(c) of the Greenhouse Gas Reduction (Clean Energy) Regulation.[36] However, in November 2013, the B.C. government amended the GGRR to include mine haul trucks and locomotives as vehicles eligible for incentives while increasing expenditure caps on items such as grants for safety practices or maintenance facilities, expenditures on stations and a tanker truck load-out.[37] The GGRR amendment also repeals the regulation's April 1, 2017 expiry.

Although NGT demand is expected to comprise a relatively small portion of FEI's overall gas supply portfolio in the short term, there are immediate benefits from adopting natural gas for transportation such as reduced fuel and operating costs for NGT customers, better air quality due to reduced emissions, and minimizing environmental hazards associated with oil storage tanks. In addition, NGT demand adds value to new and existing customers by increasing the year-round load on the gas distribution system, thereby reducing delivery rates for all natural gas customers. The FEU's NGT efforts will further assist B.C. in achieving its GHG reduction goals by converting the province's transportation fleet from more carbon intensive fuels, such as diesel and gasoline, to relatively cleaner burning natural gas. Additional details on FEI's NGT initiatives are provided below in Section 2.3.1 and in Appendix A-8.

2.2.3.4 Special Direction No. 5 to BCUC

In November 2013, the B.C. Government issued Special Direction No. 5 to the BCUC under Section 3 of the *UCA.* The direction exempts from review expenditures on an expansion of the Tilbury LNG facility up to $400 million and effectively lowers the LNG dispensing rate to $4.35 per GJ. These developments are likely to lead to increasing NGT demand, however, the changes are currently under analysis to determine the potential impact on the forecast of annual NGT demand. While the effect of these recent developments is not considered in the NGT demand forecasts of this LTRP, the potential effect of adding NGT load is considered in determining future system resource needs and alternatives (Section 5).

[35] BCUC Order G-88-13, June 4, 2013.
[36] BCUC Order No. G-161-12, October 29, 2012.
[37] B.C. Order of the Lieutenant Governor in Council, Order in Council No. 556, Deposited Nov. 28, 2013, B.C. Reg 235/2013.

2.2.4 Municipal Governments

Municipal governments across B.C. are required by law to set GHG reduction targets and to create more compact, efficient and greener communities.[38] To this end, governments are empowered to use development permits to promote energy and water conservation, reduce GHG emissions, and encourage alternative transportation options for off-street parking. In addition, 180 municipalities have voluntarily signed the B.C. Climate Action Charter, which commits the municipalities to becoming carbon neutral by 2012 and working together to address these challenges. Consequently, municipal governments across B.C. have been promoting sustainable community development and low carbon, energy efficient measures, which has an impact on how the FEU's customers are using natural gas.

As municipalities make these changes—including, in some cases, modifications to building codes and regulations—local governments are playing a greater role in influencing the energy options that are available to FEU's customers. For example, as part of its "Green Home Building" strategy, the City of Vancouver has established rules for new one- and two-family homes to be adaptable to future energy generation technologies as they become available. Such rules include mandatory pre-piping for future installation of roof-mounted solar energy generating equipment, in addition to infrastructure that will facilitate the installation of electric vehicle charging stations. According to the City of Vancouver, by 2020, all new homes will consume up to 33% less energy, and by 2030, all new homes will be carbon neutral. In a similar manner, the City of Surrey is building a district energy system and to ensure adequate customer levels, Surrey's *District Energy System By-Law* requires all city centre buildings of a specified size to be built with a hydronic system such that they will be compatible with the district energy system for space heating and hot water heating.[39] **The actions by local governments to encourage adoption of a variety of renewable energy sources carry significant negative implications for natural gas demand and future throughput on FEU's systems**.

2.2.5 Summary: Impact of Energy and Climate Change Policy Initiatives

Though the Canadian and U.S. governments recognize the importance of reducing the GHG impact of various economic sectors, neither have shown the political will to impose broad-based GHG restrictions throughout the economy. In the absence of an overarching federal energy or climate change initiative, B.C. and the province's municipal governments have stepped in with aggressive energy and climate policies. These policies emphasize lowering energy consumption and improving energy efficiency and conservation while also encouraging the development of renewable energy sources and alternative technologies.

[38] Under the *Local Government (Green Communities) Statutes Amendment Act.* See Appendix A-5 for more detail.
[39] Hydronic systems use water as the heat-transfer medium in heating and cooling systems. Energy used to heat the water may be from natural gas, biomass, geothermal or waste water. This technology is adaptable and the type or the mix of energy sources may be changed over time to produce a desired outcome.

At the same time, natural gas is commonly recognized throughout the PNW as a clean, efficient transition fuel toward a low carbon economy. The Government of B.C. has begun to promote natural gas use in the transportation and LNG export sectors as a key strategy to developing a sustainable provincial and global economy.

Low carbon energy policy frameworks are attempting to shift energy consumption patterns due to their influence on energy infrastructure and the energy choices that customers are encouraged to make. But whereas government clean energy and green community agendas serve to restrain natural gas consumption, a number of key provincial policies are, at the same time, likely to increase natural gas consumption. While current legislation and the actions of municipalities to reduce the use of gas create risks for the FEU as a result of potential residential, commercial and/or industrial demand reductions, natural gas is also increasingly recognized as playing an important role in B.C.'s overall energy portfolio, resulting in the potential for demand growth, particularly in the industrial sector. These countervailing forces create a measure of uncertainty in the market and thus the Utilities must be prepared for a range of possible outcomes. Section 2.4 discusses how the FEU's long term analysis accounts for these countervailing forces and resulting uncertainty throughout the remainder of this LTRP.

2.3 *CUSTOMER SOLUTIONS*

The Companies believe that developing innovative and integrated customer solutions is an important part of positioning natural gas services competitively within B.C.'s energy marketplace for the benefit of all customers. Using the right fuel effectively for the right use and developing customer-driven energy services remain a key focus of the Companies' customer solutions activities.

Following the BCUC Alternative Energy Solutions Inquiry in 2011-2012, FEI's new initiatives in thermal energy service projects are being undertaken by a separate, regulated FEI affiliate.[40] Nonetheless some customers continue to demand efficient, low carbon, integrated end-use energy solutions.

Although the FEU are no longer delivering renewable thermal energy alternatives, the Companies are enabling a number of customer solutions through programs to promote energy efficiency and conservation (discussed in Section 4), provide natural gas as a transportation fuel alternative, capture carbon neutral biomethane sources to displace conventional natural gas, explore advanced metering solutions and improve the competitive position of natural gas service to better meet the needs of builders, developers and end-use customers. The initiatives discussed below are provided to illustrate the types activities that the FEU continue to explore, implement and expand where there are benefits to customers and where they create an opportunity for the Companies to assist in meeting government energy and GHG emission

[40] BCUC report, "Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives," Dec. 27, 2012. http://www.bcuc.com/Documents/Arguments/2012/DOC_33032_12-27-2012-G-201-12_FEI-AES-Inquiry-Report_WEB.pdf

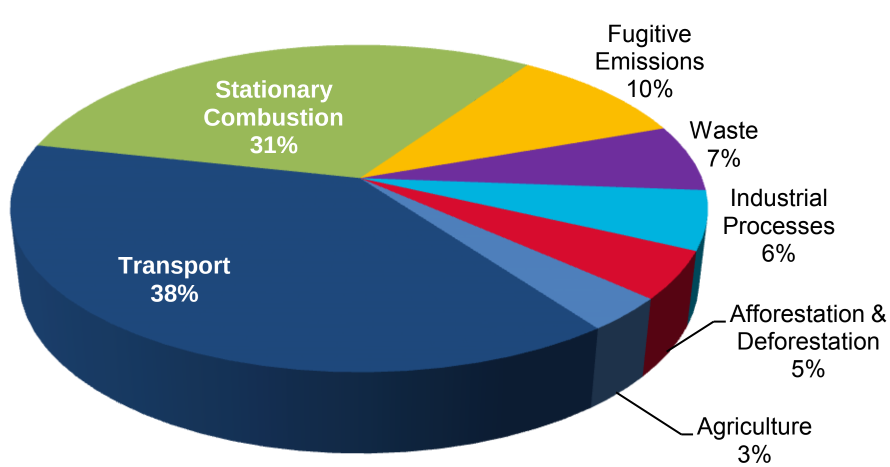
goals. There are no approvals sought by the FEU within this LTRP related any new initiatives; such approvals, where required, will be sought prior to program implementation.

2.3.1 Natural Gas for Transportation

Natural gas transportation solutions are a vital opportunity for the Utilities to serve the energy needs of customers and help reach the impressive GHG reduction targets legislated by the Province. Natural gas is a lower carbon alternative to conventional transportation fuels and can play a significant role in reducing emissions, reducing reliance on petroleum-based fuels and supporting technology development in B.C. Using natural gas instead of gasoline or diesel reduces GHG and other emissions such as nitrogen oxides, sulphur oxides, carbon monoxide and particulate matter. In addition, using natural gas as a transportation fuel reduces customers' fuel and maintenance costs. To capture this benefit, however, customers must make significant investments in vehicles and equipment designed to use natural gas. Given the financial risks, customers look to the FEU as a trusted partner that can be depended upon to deliver the transportation energy they need for years to come.

The Utilities see the development of NGT services, programs and markets as a key part of their low carbon strategy to help meet changing customer needs and the GHG reduction targets legislated by the province. Shown in Figure 2-9, the transportation sector is responsible for more GHG emissions than any other sector. As such, it provides B.C.'s biggest opportunity to contribute to a reduction of GHG emissions and other air pollutants over the next 20 years.

Figure 2-9: 2010 Greenhouse Gas Emissions by Sector in B.C.



Source: FEU from B.C. GHG Emission Inventory Report 2010, Climate Action Secretariat

Since 1996, FEI has offered NGV service and modest levels of vehicle incentive grants through Rate Schedule 6, and has offered interruptible LNG sales and dispensing since 1999.[41] The incentives and supporting activities that the FEU can provide under B.C.'s *GHG Reduction (Clean Energy) Regulation* (referenced in Section 2.2.3.2) are important to assist customers in overcoming the initial capital cost barrier and to support a viable CNG and LNG fuelling station infrastructure. The Companies NGT solutions capture the opportunity for emission reductions in the transport sector and provide an important source of load growth on the FEU's systems which ultimately benefits all FEU customers. These NGT initiatives have been extensively reviewed through other regulatory process and the Companies are not asking for approval of any NGT programs as part of this LTRP. The FEU's current NGT initiatives set the framework for consideration of growing NGT demand not included in previous LTRPs. Additional background on the FEU's NGT initiatives and supporting government policies is provided in Appendix A-8.

2.3.2 Renewable Natural Gas Offering

In response to customer demand for sustainable energy options and to support the Province's energy and climate change goals,[42] FEI has become the first utility in North America to offer an end-to-end biogas supply and service program. FEI initiated development of a low carbon product offering in June 2010 and today, the Renewable Natural Gas (RNG) Offering gives customers the means to support low carbon energy initiatives. Customers that elect to purchase the RNG Offering continue to receive natural gas supply from the FEI distribution system but notionally replace a percentage of their traditional gas supply with biomethane,[43] or renewable natural gas. Because the B.C. Government considers biomethane as carbon neutral, customers with GHG emission reduction targets (such as public sector organizations or municipalities) can purchase a portion of their natural gas supply through the RNG Offering to offset their climate emissions.

The BCUC approved the RNG Offering on a permanent basis in December 2013 including a supply cap at 1.5 PJ annually, due primarily to the program's support for a number of B.C.'s energy objectives.[44] Additional details on the RNG Offering, existing and potential supply projects, and the outlook for biomethane demand are reviewed in Appendix A-7. Though supply and demand for the RNG Offering is small when compared against the FEI's traditional gas service, the program remains an important part of the Utility's customer offering. The FEU are not proposing any changes to current RNG initiatives through this LTRP. The RNG Offering is

[41] BCUC Orders No. G-28-11 and G-65-09.

[42] The B.C. Bioenergy Strategy aims to "launch British Columbia as a carbon-neutral energy powerhouse in North America [and] help B.C. achieve its targets for zero net greenhouse gas emissions from energy generation, improved air quality, electricity self-sufficiency and increased use of biofuels." *B.C. Bioenergy Strategy, 2009.*

[43] Biomethane is derived from biogas, which is produced from decomposing organic waste from landfills or agricultural waste. When captured and cleaned, biomethane is interchangeable with conventional natural gas and can be injected into the existing natural gas pipeline system. Biogas is readily available in British Columbia and most importantly, it is a renewable fuel. Once upgraded, biogas is called biomethane or renewable natural gas.

[44] BCUC Decision G-210-13, Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis, Dec. 11, 2013.

provided here to illustrate an example of an activity that the FEU should continue to explore, implement and expand where there are benefits to customers and where it may create an opportunity for the Companies to assist in meeting government bioenergy and GHG emission goals.

2.3.3 Other Activities

The Utilities are improving customer engagement through education and awareness of the benefits of natural gas use, along with providing customers with energy management tools facilitated through multiple communication channels. As such, the Companies continue to explore ways to engage a wider network of builders and developers along with other influencers of residential gas use including architects, engineers, contractors, manufacturers, dealers and homeowners. This activity is aimed at building natural gas load, mitigating declining market share in some sectors, and improving customer and stakeholder engagement through opportunities to promote natural gas education, awareness and training.

2.4 CONCLUSION

The development of unconventional natural gas supply has opened up vast reserves of natural gas throughout North America. Advances in drilling and well productivity have led to record high production and as natural gas supplies have grown, commodity prices have fallen. A low price environment is generating new sources of natural gas demand; the availability and cost to supply gas to traditional B.C. and PNW markets may change in the future as the commodity moves from production areas to areas of high demand growth.

Although the decline of natural gas commodity rates has improved the fuel's price competitiveness against electricity on an operating cost basis, this decline has been offset by increases in B.C.'s carbon tax along with the relatively higher capital, installation and maintenance costs for natural gas equipment. Furthermore, the role of natural gas in its traditional use of space and water heating, which makes up over 80 percent of residential natural gas throughput, continues to be challenged by changing environmental policies, appliance standards and regulations. These declining trends negatively impact throughput and load growth, and increase the importance of the Utilities' actions to mitigate this pressure. Though the evolving natural gas marketplace presents a number of utility challenges, the FEU are also presented with opportunities to capitalize on new areas to add new system load.

To help maintain the competitiveness of natural gas rates, the Utilities are focusing on growing the customer base and increasing throughput on the natural gas system by developing new markets for natural gas use. The FEU continue to develop sustainable energy solutions such as NGT, renewable natural gas, thermal metering and demand-side management programs to satisfy customer and stakeholder demand for new, innovative solutions while simultaneously reducing customers' energy costs and environmental impact. The Utilities continue to remain flexible in their service offerings in order to overcome the challenges presented by an evolving energy marketplace while capitalizing on opportunities to serve customer needs for safe, reliable, efficient and cost-effective energy.

This LTRP addresses the evolving elements of the planning environment discussed in this section by examining a range of possible scenarios in the Utilities' analysis for annual and peak demand forecasting, demand side management programs, system resource needs and gas supply portfolio planning:

- Section 3 provides a range of annual and peak demand forecasts based on a number of future scenarios that incorporate a variety of outcomes based on these planning environment uncertainties.
- Section 4 examines a range of potential energy savings for the Companies' Energy Efficiency and Conservation programs based on consideration of the same potential outcomes that are used to examine demand forecasts.
- Section 5 examines how a range of potential future peak demand scenarios could be influenced by these planning environment uncertainties and the effect that these could have on the timing to address future constraints on the FEU's gas delivery systems.
- Section 6 includes consideration of how these planning environment uncertainties may impact resource cost and availability for the Companies to secure a stable, reliable and cost-effective source of gas supply.

3. ENERGY DEMAND FORECASTING

3.1 *INTRODUCTION AND BACKGROUND*

Two key elements that underpin the FEU's resource planning activities are the forecasts of annual demand and peak demand for natural gas. The annual demand forecast represents annual consumption by region and customer class, and allows the FEU to consider directional rate impacts and annual gas supply in the Companies' long term planning efforts. The peak demand forecast provides an estimate of the maximum daily natural gas demand that would be expected under extreme weather conditions. In addition to gas supply planning, peak demand is also used for system capacity planning purposes. The FEU's demand forecasts are used to ensure adequate system capacity, to plan gas supply resources, and also to provide a baseline against which to analyse the impact of proposed or potential future initiatives such as expanded energy efficiency and conservation activities or growth in natural gas sales for fuelling transportation.

The current planning environment has many uncertainties. The FEU recognize that gas utilization is changing and that their customers are using natural gas in different ways and amounts than they did in the past. Heating equipment installed in new buildings and in retrofit situations is more efficient and, in some cases, results in a different demand profile than the older equipment it replaces. Potential new demand from the transportation and industrial sectors may also impact the FEU's overall demand profile. While recent demand history is appropriate for short term demand forecasting, a new approach to modelling the longer term horizon is required.

The following discussion includes the new end-use forecasting methodology for residential, commercial and industrial annual demand (as required by the Commission[45]), a comparison to the traditional annual demand forecast methodology, a forecast of demand from the transportation sector and a general discussion of other demand issues or trends that might impact future demand for natural gas in B.C. The peak (or design day) demand forecast is also presented along with a discussion of the considerations that go into forecasting peak demand.

This section of the LTRP addresses Section 44.1(2)(a) of the *UCA,* which requires utilities to include an estimate of the demand for energy the utility expects to serve in the absence of taking new demand-side measures; it also addresses Commission directives from the 2010 LTRP Decision regarding the FEU's "new business environment and approach to demand forecasting".[46] The discussion is organized as follows:

- Section 3.1 provides a background to the FEU's residential, commercial and industrial customer demand and identifies the milestone years used in the end-use demand forecasts.

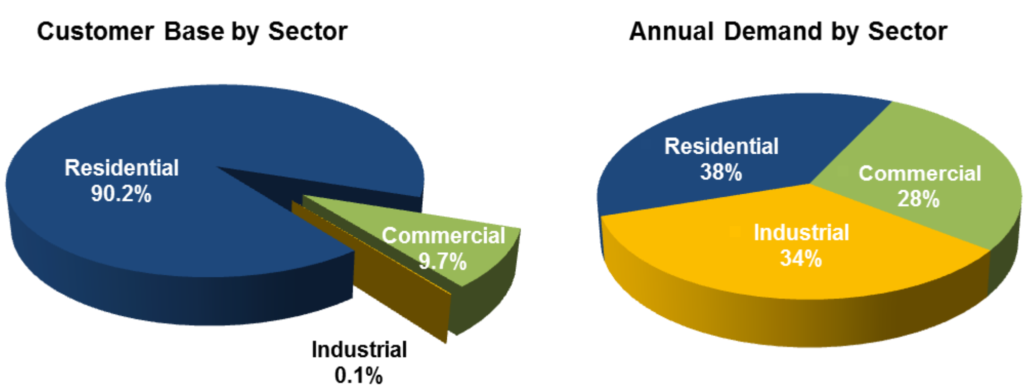
[45] BCUC, Terasen Utilities 2010 Long Term Resource Plan Decision, Feb. 1, 2011
[46] Ibid., pg. 25.

- Section 3.2 presents the long term customer additions forecasts for the residential, commercial and industrial rate classes. The methodology used to develop these forecasts remains consistent with previous LTRP filings.
- Section 3.3 discusses the annual demand forecast. The traditional methodology used to forecast annual demand is presented in Section 3.3.1, while the new end-use methodology explanation and results are provided in Sections 3.3.2 through 3.3.5. The new methodology results are compared to the traditional methodology results in Section 3.3.6. Annual demand for natural gas as a transportation fuel is discussed in Section 3.3.7 and the forecast of total annual demand is provided in Section 3.3.8.
- Section 3.4 discusses the peak day demand forecast for Core[47] customers, NGT customers and analyses the impact of potential large, new industrial load on peak day demand.
- Section 3.5 presents the GHG emissions that are expected to result from the FEU's natural gas sales in the residential, commercial and industrial sectors, as well as the GHG emissions reductions that may be attained from NGT initiatives over the planning horizon.
- Section 3.6 summarizes the FEU's energy demand forecasting efforts.

3.1.1 Existing Residential, Commercial, & Industrial Customer Demand

The FEU customer base includes over 945,000 customers, consisting predominantly of residential customers that account for approximately 90% of the overall customer base (see Figure below). However, on an annual demand basis, there is a more even split between the residential, commercial, and industrial groups. The makeup of the FEU's customer base and demand patterns has implications on infrastructure requirements and conservation goals as discussed throughout this Resource Plan.

Figure 3-1: FEU Customer Base and Demand Overview, 2011



[47] 'Core' customers include FEI's rate class customers 1 through 6, all FEVI customers except for Island Generation and the Vancouver Island Gas Joint Venture, and all FEW customers.

3.1.2 Milestone Years

Preparation of the new end-use forecast and the traditional long term forecast resulted in a data set comprised of nearly ***20 million records***. Due to the volume of data involved, it was necessary to prepare the LTRP forecasts at a series of milestone years, rather than on a year-by-year basis. Starting with 2011, milestones were set every five years thereafter. An additional milestone was set at 2033 to present a 20-year forecast from 2013 through 2033. The milestone years are 2016, 2021, 2026, 2031 and 2033.

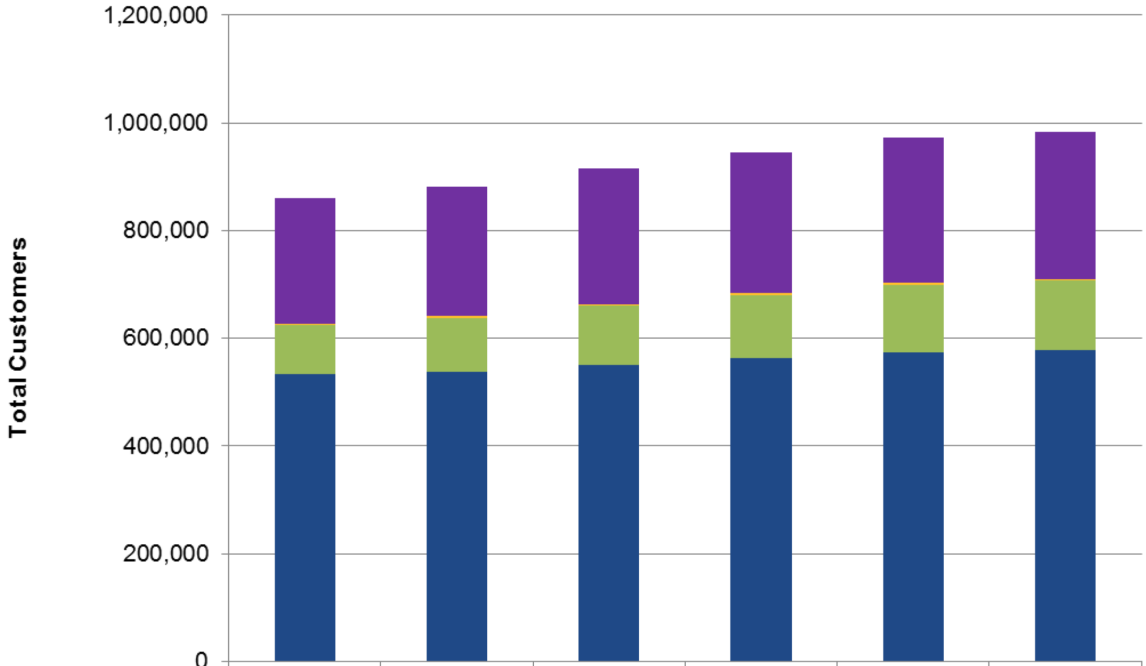
3.2 CUSTOMER ADDITIONS FORECAST

The FEU use a well-established methodology to forecast customer additions that remains consistent with previous LTRP filings. The forecast of residential customer additions is grounded in the Conference Board of Canada housing starts forecast for British Columbia, while commercial customer additions are forecast based on recent trends in growth for the commercial customer group. The customer additions forecast by rate class for each of the milestone years is included in Appendix B-1.

Residential

The forecast of residential customers for each of the FEU's service regions is shown by milestone in Figure 3-2, by service region.

Figure 3-2: Long Term Account Forecast by Region – Residential

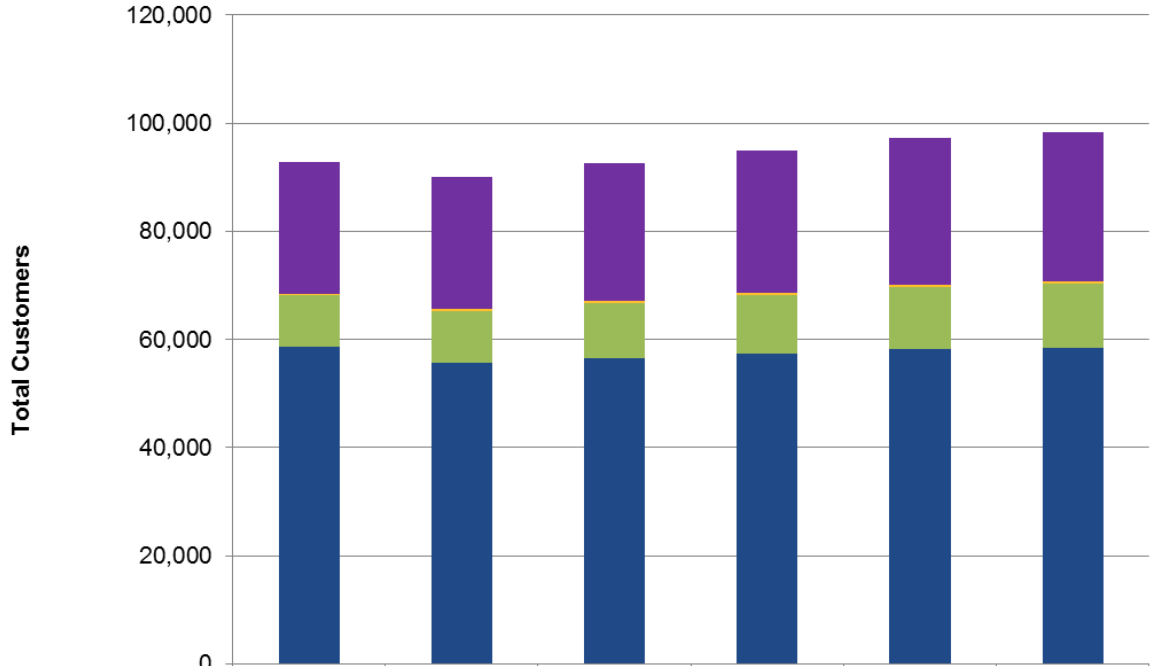


	2011	2016	2021	2026	2031	2033
Interior	233,646	241,003	251,664	261,046	269,575	272,924
Whistler	2,296	2,485	2,761	3,000	3,244	3,341
Vancouver Island	92,554	99,869	109,478	118,094	126,492	129,931
Lower Mainland	532,550	538,391	551,166	562,686	573,339	577,389

Commercial

Recent trends in commercial customer additions are used to predict future additions. The net customer additions are estimated based on actual additions in the latest three years. Recent additions are not as strong as in previous years, averaging in the range of 400 per year. The long term account forecast for commercial rate schedule customers is shown in Figure 3-3 for each of the FEU's service regions.

Figure 3-3: Long Term Account Forecast by Region – Commercial



	2011	2016	2021	2026	2031	2033
Interior	24,329	24,423	25,388	26,269	27,123	27,486
Whistler	353	373	412	447	486	502
Vancouver Island	9,534	9,530	10,205	10,853	11,539	11,839
Lower Mainland	58,632	55,708	56,565	57,368	58,139	58,440

Industrial

The FEU had 909 industrial customers in 2011. Though interest from potential new industrial customers in acquiring gas service has increased recently, at the time the long term forecast was prepared, there were no firm commitments for new industrial customers to take natural gas service or for existing customers to close their accounts. Hence, no growth or decline in industrial customers has been forecasted.

3.3 *ANNUAL DEMAND*

The amount of natural gas that the FEU expects their customers to use over the course of a year determines two important factors: the amount of gas that the Companies need to acquire and transport on behalf of their customers on an annual basis, and the number of units of energy per year over which the companies are able to recover their cost of service and approved return on investments. Hence, the forecast of annual demand is a key early step in identifying the resources the FEU needs to put into place in order to meet customers' future energy needs.

In past LTRPs, the FEU used total annual demand divided by the Companies' number of customers to determine average use per customer (UPC). These use rates were then applied to the forecast of future customers to determine the total annual demand expected for each year of the forecast period. The underlying assumption was that for long term annual demand, historic usage patterns were a reasonable indicator of future gas use.

In their 2010 LTRP, the Companies proposed to examine an alternative methodology to long term annual demand forecasting based on current and future end-use trends—an approach that received support from the BCUC and other stakeholders. For this LTRP, the FEU prepared a reference case demand forecast using the traditional approach, and a separate reference case forecast using the new end-use approach. This new end-use approach also allowed the FEU to develop alternative annual demand forecasts based on a broader range of potential future scenarios that could be expected to unfold.

The move to an end-use approach represents a significant improvement to the Companies' ability to examine potential future "what if" scenarios, and has been made possible by a series of important market based research studies beginning with the Conservation Potential Review completed in 2010. Through the remainder of this section, the Companies describe the traditional methodology and results, explain the new end-use methodology, describe the future scenarios that were developed to guide alternative future demand scenarios, explain how those scenarios became inputs into the demand forecast model, and finally, compare the new end-use forecast results to the traditional methodology results. The forecast of annual demand for natural gas as a transportation fuel is then presented and combined with the residential, commercial and industrial results to provide a total annual demand forecast. Finally, a review of the potential impact of possible new large industrial customers on annual demand is discussed.

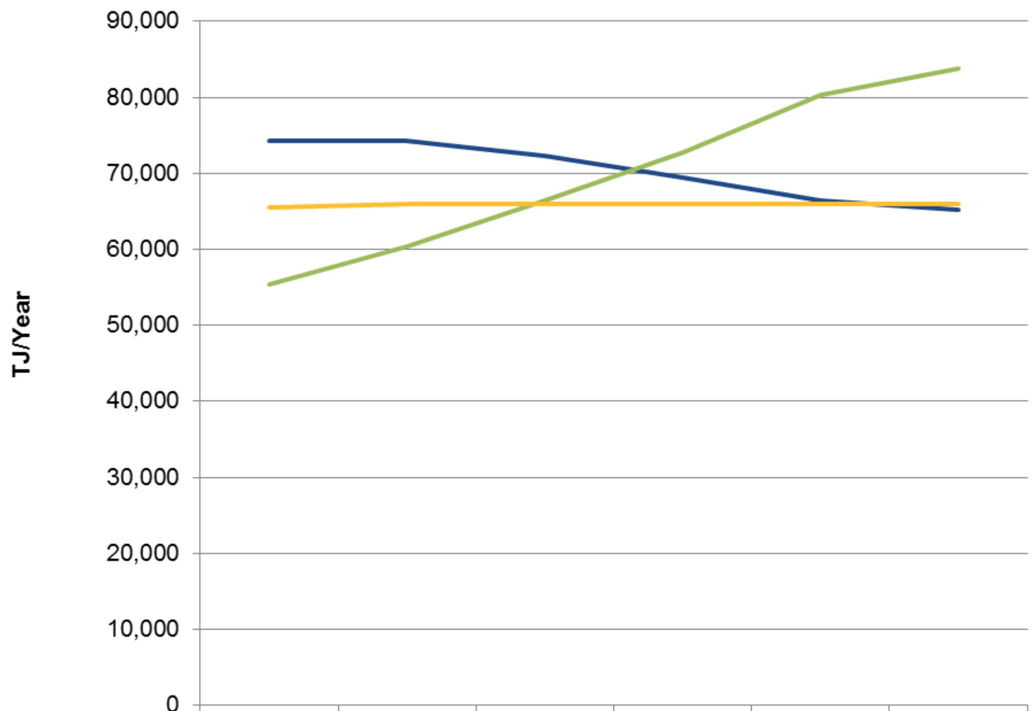
3.3.1 Traditional Annual Demand Methodology – Residential, Commercial and Industrial

The FEU's traditional methodology for forecasting residential and commercial demand involved determining an average UPC and multiplying it by the number of customers forecasted for each year of the study period. UPC was determined by examining historical actual demand after normalizing the data to remove the effects of weather. A regression analysis was used to identify any significant trends in average UPC. These trends implicitly included the impact of broad changes in consumption patterns that might have been caused by such factors as energy efficiency, economic activity, policies and equipment standards up to the time of the most recently available annual usage data. The analysis was conducted for each residential and commercial rate class, based on the most recent five years of data. The trends were then extended into the next 20 years for the purposes of providing a long term forecast.

The FEU utilized the results of the annual industrial customer survey to identify expected changes in industrial customer demand. The survey was conducted as part of the FEU's short term demand forecasting process used for gas supply planning, revenue requirements and other BCUC submissions. The intentions of industrial customers over the next five years were held constant over the LTRP planning horizon as this represents the best available information using the traditional methodology.

The annual demand in each year of the forecast for each rate class in each customer category was then summed to determine the total overall residential, commercial and industrial demand. The result is a reference case demand scenario using the FEU's traditional long term annual demand forecasting methodology. Figure 3-4 shows the traditional reference case demand for each of the rate class categories and is followed by a general description of the forecast results for each category. Figures 3-7 through 3-9 show the total annual demand for the residential, commercial and industrial rate classes using the traditional annual demand methodology.

Figure 3-4: Long Term Annual Demand by Rate Class – Traditional Methodology



	2011	2016	2021	2026	2031	2033
Residential Traditional	74,252	74,277	72,345	69,408	66,434	65,259
Commercial Traditional	55,330	60,308	66,353	72,760	80,373	83,859
Industrial Traditional	65,540	66,008	65,996	65,996	65,996	65,996

Residential Demand

Declining residential use per customer in the FEU's service territories is resulting in an overall decline in residential annual demand, even though the FEU continues to add residential customers through the forecast period. This decline in residential use per customer is now a common occurrence affecting mature natural gas utilities across North America. The Companies believe that the drivers lowering UPC include, but are not limited to, efficiency improvements, changes in building stock, changes in appliance uptake and switching between energy sources (from gas to electric). Efficiency improvements include the retrofit of older, less efficient appliances with new high efficiency units, and also upgrades to insulation, window, doors, and more generally speaking, building shells. Efficiency improvements are driven by a number of factors such as technological advances, construction of smaller, less energy-intensive multifamily dwellings, natural gas prices, public policies and programs and the state of the economy. This declining trend is expected to continue through the planning period.

Commercial Demand

In the traditional forecast method, the recent demand increases seen in the commercial rate classes are assumed to continue into the long term and thus, commercial demand grows significantly over the 20 year planning horizon. Increases in commercial annual demand drive the overall increase in the traditional forecast of annual demand shown in Figure 3-4.

Industrial Demand

The industrial demand survey results suggest that a slight increase in industrial demand occurs in the early years of the planning period, but overall industrial demand is forecast to be stable through the planning horizon.

3.3.2 End-Use Annual Demand Methodology – Residential, Commercial and Industrial

Using historical trend data to forecast future consumption is a common and accepted industry practice, particularly for short-term analysis or decision making where historical data is used to forecast a few years into the future. This methodology provides a high level of confidence for near-term business decision making. All short-term revenue requirement forecasting at FEU has successfully been conducted in this way and this method is embedded in the short-term Forecast Information System, which has been in use for over a decade.

However, as described in Section 2, ongoing changes in the end-use energy solutions available to customers and the way in which customers are using energy means that historical trends no longer provide the best basis on which to forecast the long term potential range of future demand. For this reason, the FEU proposed in the 2010 LTRP to consider an approach to demand forecasting that involves examining different ways that end-use trends in energy use could potentially impact future demand for natural gas. The new end-use approach was encouraged by the Commission and interveners during the regulatory review of the 2010 plan.

To undertake this new annual demand forecasting methodology, the FEU turned to their best source of existing end-use demand characteristics for the development of a base year data set, the 2010 Conservation Potential Review. This base year data set has been enhanced by more recent customer additions data and additional market research undertaken since preparation of the 2010 CPR. The FEU also engaged ICF Marbek (who prepared the 2010 CPR) to repurpose their CPR modelling software with FEU base data to apply it to a long range demand forecasting effort. This partnership provides an effective combination of knowledge about the customer base data from the FEU and expertise in modelling end-use energy consumption within the B.C. marketplace from the consultant. The exercise resulted in an extensive raw data set provided to the FEU, on which the FEU is able to conduct further analysis of potential future demand implications.

The process first involved the development of a reference case forecast. The reference case is based on end-use patterns observed in the base year and keeps these patterns constant throughout the planning period. The impact of EEC programs up to and including 2011 were thus implicitly included in the end-use characteristics identified for the base year, but were not assumed to continue through the planning period for the purpose of demand forecasting. The impact of future EEC activities is considered in Section 4.

The following discussion presents an overview of the reference case end-use demand forecast, four additional future scenarios—A through D, which are used to examine a range of alternative potential future demand—and the results of the 20-year end-use demand forecast for residential, commercial and industrial demand for each scenario.

3.3.3 Development of the Reference Case for Annual Demand

The Reference Case began with the development of a base year, in this case 2011. The FEU provided a database of accounts with normalized consumption data for their service territory categorized by region, rate class, and industry (for industrial and commercial customers). To further subdivide natural gas consumption by end use, ICF Marbek drew on the detailed customer knowledge assembled for the 2010 CPR, including end use consumption, market saturation[48] and gas share.[49] Some of this information has been derived from end-use surveys commissioned by the FEU, while other aspects emerged from detailed building modeling. In the residential sector, a new category of dwellings built since 2005 was added to the model to reflect the results of a recent survey of new homes. The resulting model, calibrated to the actual normalized sales of natural gas in the FEU's service territory, is subdivided as follows:

[48] Market saturation is a percentage indicating what portion of the population of buildings has a given end-use. For end-uses such as space heating and water heating, this is assumed to be 100% of dwellings. For an end-use such as clothes drying, where the logical unit of analysis is the appliance, the percentage is the number of clothes dryers divided by the number of dwellings. Market saturation in the commercial sector is based on the percentage of building floor space with a given end-use, instead of percentage of dwellings. Market saturation is not employed in the industrial model – saturation is taken into account in the overall end-use consumption for a given plant type.

[49] Gas share is the percentage of the energy end-use that is supplied by natural gas. For clothes dryers, this translates into the percentage of dryers that are natural gas-fired. Note that that gas share is based on the percentage of useful energy supplied to accomplish the end-use, which is different from the energy actually consumed (because of differences in efficiency).

- By region: Vancouver Island, Lower Mainland, Interior (divided into Northern Interior and Southern Interior) and Whistler;
- By sector: Residential, commercial and industrial;
- By sub-sector: In residential—by dwelling type, by detachment type, dominant heating fuel, and vintage; in commercial—sixteen building types, by predominant use (office, retail, school, hospital etc.); in industrial—10 plant types;
- By rate class: Up to 11 rate classes in a given sector or region, for a total of 32 rate classes; and
- By end use: Seven residential, five commercial and 17 industrial gas end-uses.

Beginning with the calibrated base year, the reference forecast was built using the FEU's 20-year account forecast, with new dwellings, commercial floor space and plant capacity added based on the account growth rates. Anticipated efficiency improvements, such as the natural replacement of furnaces, were incorporated in both existing buildings and new construction. Anticipated changes in the saturation and gas shares for specific end-uses were also included. In the industrial sector, a recent uptick in consumption was assumed to continue for the short-term, after which industrial gas consumption was assumed to approximately level off. The forecast consumption values have been provided at the same level of granularity as the base year, for each of the milestone years.

3.3.4 Alternative Future Scenarios

The Reference Case provides a baseline against which forecast demand under four different alternative future scenarios is examined. The four future scenarios are intended to provide insight into the impact on demand of a broader range of potential future conditions than has been examined in previous LTRPs. These four scenarios were developed based on critical uncertainties identified with input from both internal FEU stakeholders and members of the external Resource Planning Advisory Group. The critical uncertainties represent those future conditions that stakeholders felt could have the biggest impact on the FEU's business. While numerous individual key uncertainties were identified, two main themes emerged.

> *Theme 1 - Abundance or constriction of natural gas supplies. This theme is not about whether there are enough gas reserves in the ground to serve customer needs, but rather whether or not market factors will occur that make accessing those supplies easier (less costly) or more difficult (more expensive). For example, technological improvements that allow safe, year-round drilling and processing of gas in northern climates will act to make access to supply easier and therefore less costly, whereas opposition to pipelines, more stringent rules for gas drilling and production, or greater competition for supply will increase the cost of accessing gas supplies. The scenarios that have been developed do not attempt to identify specific causes, but instead examine the impact on demand if access to supply becomes more or less constricted.*

Theme 2 – Centralization versus decentralization of energy delivery systems. Centralized energy systems can be explained as the type of grid-based electric and natural gas energy services that have been in place for many decades, and for which the energy supply and maintenance costs, safety controls and customer service conditions are shared across large customer bases. Decentralized energy systems are characterized by an accelerated movement toward off-grid, or end-of-grid energy production and utilization where the end-use customer or their representative takes a greater role in developing and maintaining the energy equipment.

The potential range of energy and carbon emission policies that could unfold over the planning horizon also emerged as a third very important critical uncertainty that needed to be examined within these scenarios. Each of the scenarios incorporates varying assumptions for gas commodity and carbon prices, the policy environment and the penetration of renewable and district energy systems. Economic conditions were assumed to be cyclical over the planning horizon, and while a different overall economic trend helped to frame each of the scenarios, these trends translated to actual model inputs only for industrial demand.

Applying the two themes of abundance or constriction of natural gas supplies and centralization versus decentralization of energy delivery systems results in a matrix of four scenarios as shown in Figure 3-5. Figure 3-5 includes the Reference Case, or starting point for the end-use demand forecast scenarios, and the traditional methodology demand forecast, which provides a point of comparison for the end-use methodology. General scenario descriptions follow.

Figure 3-5: End-Use Demand Forecast Scenario Development

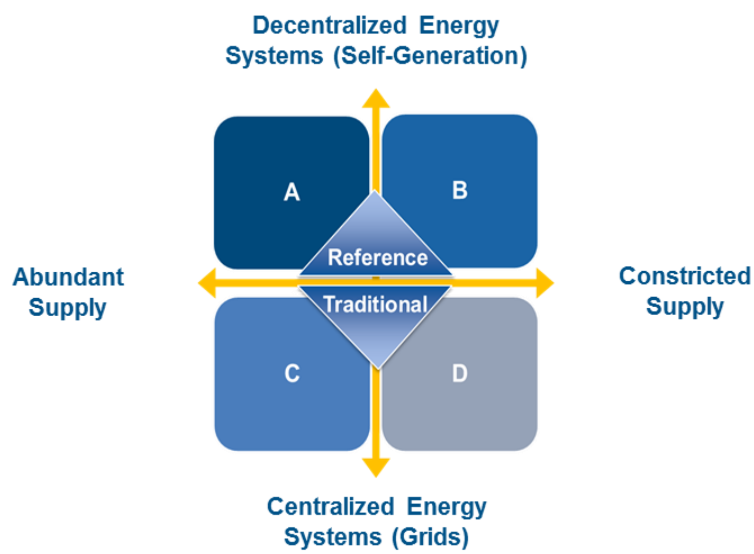


Table 3-1: Alternative Future Scenario Descriptions

Scenario	General Theme	Policy Expectations	Directional Implications for Demand[1]
Scenario A (Abundant Supply, Decentralized Energy Markets)	Abundant natural gas supply and corresponding low natural gas prices are tempered by high carbon prices and a policy environment focused on GHG emission reductions. There is a transition to decentralized energy markets, more so than centralized energy markets, and as such there is a moderate amount of renewable energy uptake. Overall, this scenario shows a change in the energy mix such that renewable thermals and electricity are favored by policy and carbon pricing, but low natural gas prices mitigate substantial fuel switching.	The policy focus is on carbon emission reductions. Energy strategies are consistent within regions, but may be disparate among regions. For example, the Western Climate Initiative or an alternative cap-and trade program could proceed in this scenario, but other Canadian provinces or U.S. states and the federal government would not necessarily follow suit or put in place similar carbon pricing programs.	We may expect to see significant demand for natural gas for transportation because of the low cost and the resulting emission reductions associated with switching from diesel/gasoline, although the additional natural gas load is offset by some fuel switching to electricity (the main low-carbon alternative) and an increase in decentralized renewable thermal options, particularly district energy, geo-exchange, and additional new technologies. The market penetration of renewable thermal technologies, while moderate, is not high because the low cost of natural gas makes alternative technologies somewhat less competitive. There is moderate participation in EEC initiatives, due to a drive to reduce fossil fuel use, although the low cost of natural gas acts as a barrier to substantial EEC uptake.
Scenario B (Constricted Supply, Decentralized Energy Markets)	Natural gas supply is constrained and new, decentralized technologies emerge rapidly to meet future energy needs. Carbon policy is not a driver in this scenario and B.C.'s carbon tax is held constant at 2012 levels; rather, generalized environmental policies contribute to constricted natural gas supply and support renewable thermal development.	Policy is focused on the environmental impacts of energy as a whole, not specifically carbon impacts. Additionally, there are coordinated energy strategies among regions and all levels of government, which allows for the creation of a national energy strategy.	With a moderate to high price for natural gas and no carbon-specific regulations in place, there is likely little uptake in natural gas for transportation, and the price of natural gas does cause consumers to look for alternatives to natural gas for thermal applications. This scenario would likely drive fuel switching to decentralized renewable thermal applications, and potentially a corresponding overall decrease in demand for natural gas. There is moderate to high participation in EEC initiatives as customers who do not switch fuels are looking for ways to reduce their energy consumption in response to high natural gas prices.

Scenario	General Theme	Policy Expectations	Directional Implications for Demand[1]
Scenario C (Abundant Supply, Centralized Energy Markets)	Natural gas supply is abundant while energy technology remains centralized, leaving natural gas as an important means to meet long term energy needs. Overall, natural gas is viewed positively and is perceived as an integral part of B.C.'s energy picture.	Policy is focused on economic growth rather than environment, carbon, or climate issues, and energy strategies are disparate among regions and levels of government, meaning that other jurisdictions may or may not implement carbon pricing, renewable thermal subsidies, etc.	Abundant supply results in a low gas price, and coupled with current technologies and a policy environment that is not focused on carbon emission reductions, the scenario drives an increase in overall demand for natural gas. In particular, low gas prices likely drive an increase in Industrial demand. A high fuel cost differential between oil and natural gas paves the way for higher than expected uptake in NGT. Convincing customers to participate in EEC programs will be more difficult, as the low fuel costs and abundant supply create less incentive for consumers to focus on saving energy. The conditions in this scenario also mean that renewable thermals will likely play a smaller role in the energy picture in B.C.
Scenario D (Constricted Supply, Centralized Energy Markets)	Natural gas supply is constricted and a slower economy minimizes technological development and decentralization, limiting the energy alternatives available to meet consumers' long term needs. Overall, energy is expensive in this scenario and customers are looking to reduce their energy needs.	Policy is focused on economic growth, with some advancement of carbon regulations, while the energy strategies among regions and levels of government are disparate and uncoordinated.	Overall demand for natural gas is likely low as natural gas supply is constricted and prices are correspondingly high. Demand for NGT is also potentially minimal, as the fuel costs are higher and will not pay back the conversion cost quickly. EEC is likely to see extremely high participation rates, as consumers are paying high energy prices and do not have technology alternatives. Renewable thermals are not likely to obtain a substantial market share as technology is more centralized, but may see some uptake because they are more cost-competitive with higher natural gas prices.

The modeling process involved turning each of these assumptions into concrete changes to the input numbers for buildings in the three sectors. For example, in response to higher or lower gas prices, adjustments were made to the number of new buildings using natural gas for specific end-uses, or to the number of existing buildings whose owners might opt to change fuels when equipment needs replacement. In response to higher or lower economic growth, adjustments were made to the heat demands of industry. The policy environment affects assumptions about the number of customers who would opt to install energy efficient equipment naturally, without influence from utility programs. The assumptions for developing renewable and district energy systems resulted in adjustments to the fuel shares for those options: increases in those fuel shares would generally displace the demand for natural gas. Renewable energy systems include systems such as geo-exchange, waste heat recovery, and solar thermal energy. In the new end-use forecasting methodology, renewable thermal energy demand features prominently in Scenarios A and B, where markets move toward decentralized or self-generated energy systems. This has the effect of displacing natural gas consumption, particularly for space and water heating. With limited but growing market penetration of renewable thermal energy systems, the FEU must continue to monitor this growth to gauge its impact over time on the Utilities' natural gas infrastructure, annual and peak day demand, system capacity needs and rate design issues.

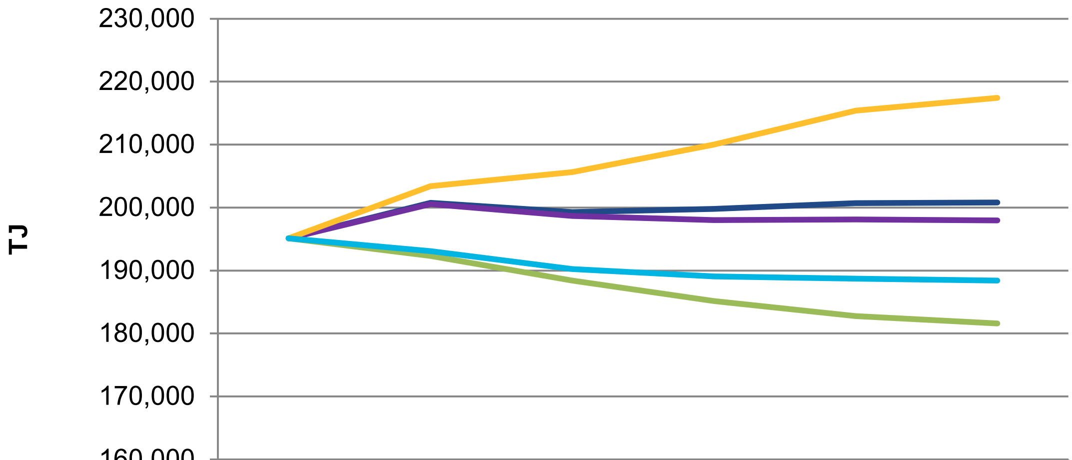
The model results for Scenarios A through D have the same level of granularity as the Reference Case, with results available for the same set of milestone years. Note that the FEU does not predict which scenario will unfold in the future. Rather, the five scenarios considered together provide a reasonable range of possible future demand that the FEU will need to serve over the next 20 years.

3.3.5 End-Use Demand Forecast Results by Scenario

Figure 3-6 shows the overall demand forecasts for residential, commercial and industrial demand in all scenarios as well as the Reference Case end-use demand, for all service regions. The results, separated by service region, are provided in Appendix B-1, Demand Forecast Tables. Figures 3-7 through 3-9 show the scenario results for each of the residential, commercial and industrial customer groups respectively for all regions and contain the following general observations:

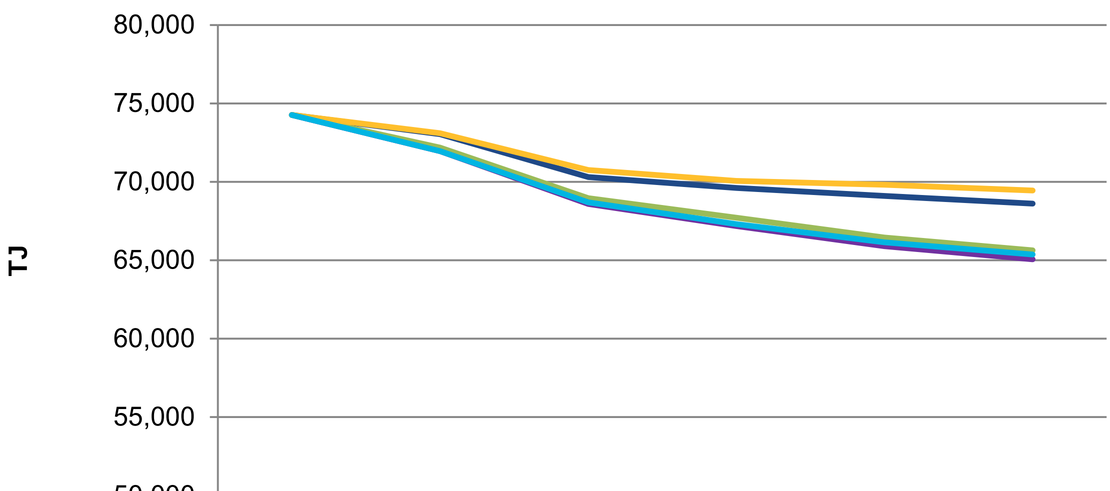
- For all of the five scenarios (including the Reference Case), an overall decrease in annual residential demand is predicted. The degree of each decline depends on the assumptions used for each planning environment.
- The potential exists for commercial demand to grow or decline, though continued growth can be observed in most of the scenarios.
- Industrial demand based on the current customer base also has the potential to grow or decline over the planning period. Three of the forecasts, including the Reference Case, assume that recent increases in actual demand persist, while two see this increase as short term with industrial demand returning to 2011 levels.

Figure 3-6: Total End-Use Forecast, Annual Demand by Scenario – All Regions



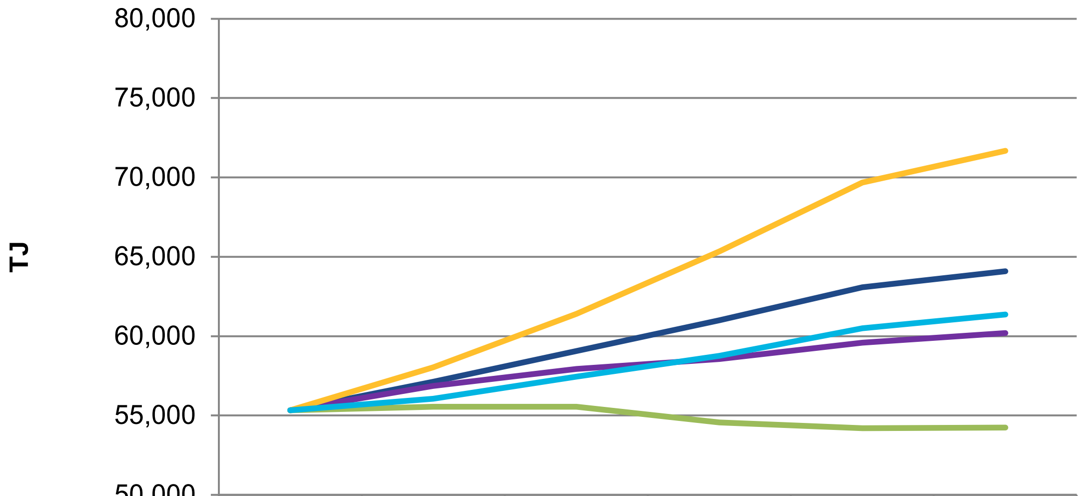
	2011	2016	2021	2026	2031	2033
Reference	195,122	200,735	199,304	199,777	200,679	200,817
Scenario A	195,122	200,577	198,662	198,022	198,136	197,961
Scenario B	195,122	192,333	188,399	185,148	182,773	181,608
Scenario C	195,122	203,393	205,630	210,022	215,388	217,430
Scenario D	195,122	193,094	190,242	189,060	188,709	188,378

Figure 3-7: Residential End Use Forecast, Annual Demand – All Regions



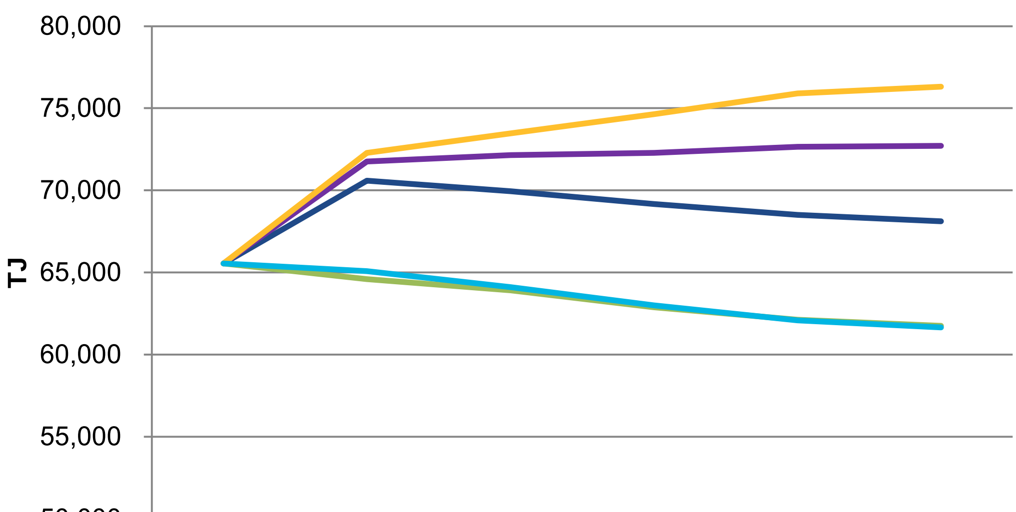
	2011	2016	2021	2026	2031	2033
Reference	74,252	73,027	70,301	69,605	69,095	68,614
Scenario A	74,252	71,945	68,588	67,175	65,893	65,069
Scenario B	74,252	72,177	68,947	67,707	66,456	65,632
Scenario C	74,252	73,097	70,747	70,055	69,811	69,437
Scenario D	74,252	71,959	68,693	67,299	66,132	65,363

Figure 3-8: Commercial End-Use Forecast, Annual Demand – All Regions



	2011	2016	2021	2026	2031	2033
Reference	55,330	57,123	59,057	61,000	63,088	64,081
Scenario A	55,330	56,869	57,937	58,564	59,586	60,182
Scenario B	55,330	55,557	55,540	54,568	54,199	54,232
Scenario C	55,330	58,024	61,411	65,336	69,682	71,672
Scenario D	55,330	56,047	57,451	58,767	60,491	61,364

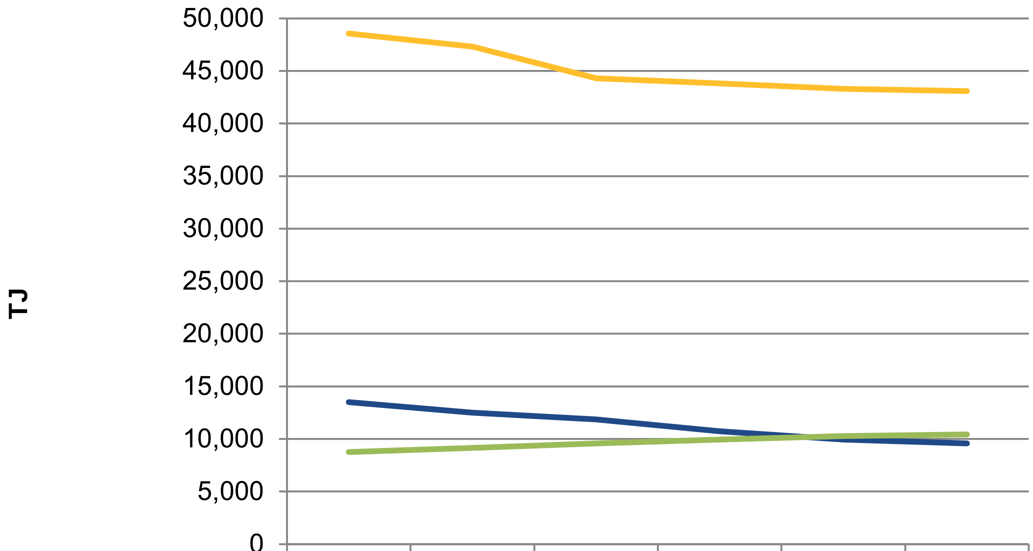
Figure 3-9: Industrial End-Use Forecast, Annual Demand – All Regions



	2011	2016	2021	2026	2031	2033
Reference	65,540	70,584	69,946	69,171	68,496	68,121
Scenario A	65,540	71,763	72,137	72,282	72,657	72,709
Scenario B	65,540	64,600	63,913	62,872	62,118	61,744
Scenario C	65,540	72,272	73,473	74,631	75,895	76,321
Scenario D	65,540	65,087	64,098	62,994	62,085	61,651

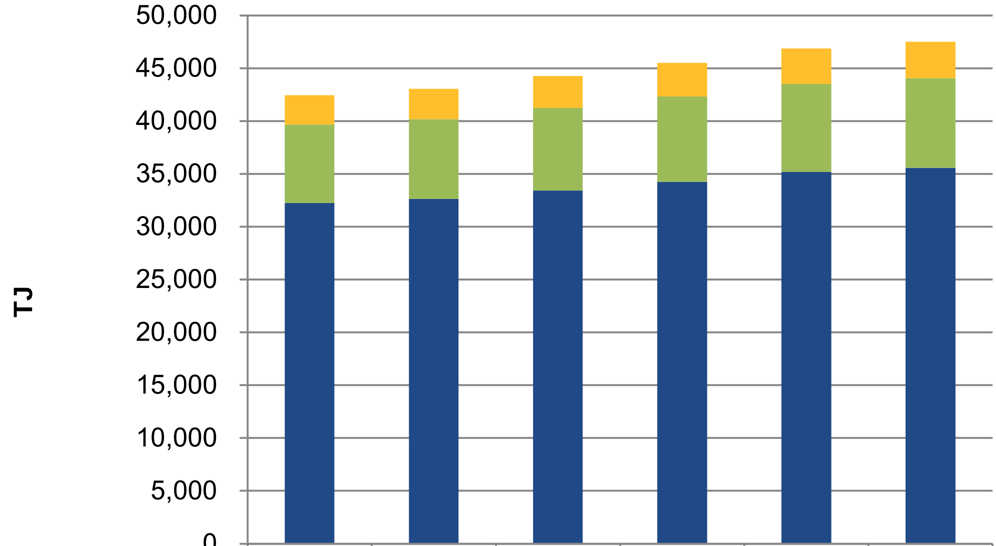
The end-use forecast methodology allows the Utilities to track gas usage by end-use, sector, rate class, new customers, existing customers and the vintage of housing stock. Figures 3-10 and 3-11 provide an example using the Reference Case forecast for the three highest gas consuming residential end-uses and three highest gas consuming commercial end-uses respectively. For residential customers, natural gas for fireplace demand is increasing while demand for space heating and domestic hot water is decreasing. In the Reference Case, natural gas for fireplace demand is set to overtake the demand from domestic hot water, which currently ranks second in residential end-uses. This trend is delayed in Scenario C, but accelerated in the other scenarios. For commercial customers, space heating, hot water and cooking demand are all growing in the Reference Case scenario and may constitute approximately 77% of the annual commercial demand in 2011.

Figure 3-10: Reference Case Demand for Three Largest Residential End-Uses by Consumption – All Regions



	2011	2016	2021	2026	2031	2033
Domestic Hot Water	13,496	12,495	11,871	10,738	9,955	9,584
Fireplace	8,745	9,159	9,573	9,941	10,282	10,416
Space Heating	48,566	47,322	44,295	43,819	43,293	43,076

Figure 3-11: Reference Case Demand for Three Largest Commercial End-Uses by Consumption – All Regions

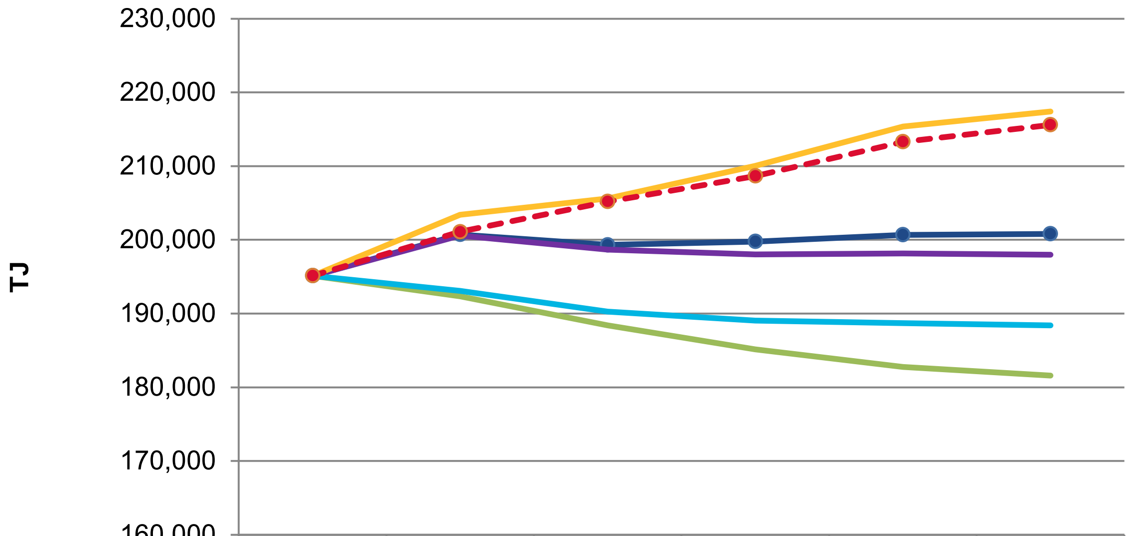


	2011	2016	2021	2026	2031	2033
Commercial Cooking	2,765	2,883	3,036	3,195	3,373	3,451
Domestic Hot Water	7,426	7,555	7,804	8,059	8,342	8,468
Space Heating	32,246	32,622	33,433	34,254	35,167	35,580

3.3.6 Comparing the Traditional and End-Use Methodologies

The FEU have found implementation of the end-use demand forecasting methodology to be both successful and useful, and intend to continue using this methodology for long term planning and analysis purposes. Before retiring the traditional method and to satisfy the Commission directive to compare the new end-use forecasting methodology and results with the traditional forecasting approach and results, a comparison of the two methodologies is necessary. Figure 3-12 shows the demand forecast results (all regions) from the traditional methodology compared to the results of the new end-use methodology for the Reference Case and four alternative scenarios. Since the forecast using the traditional methodology falls within the highest and lowest boundaries of the end-use methodology results, the FEU are confident in the ability of the new methodology to provide a reasonable long term demand forecast.

Figure 3-12: Traditional Versus End-Use Demand Forecast Results – Total Demand, All Regions



	2011	2016	2021	2026	2031	2033
Reference	195,122	200,735	199,304	199,777	200,679	200,817
Scenario A	195,122	200,577	198,662	198,022	198,136	197,961
Scenario B	195,122	192,333	188,399	185,148	182,773	181,608
Scenario C	195,122	203,393	205,630	210,022	215,388	217,430
Scenario D	195,122	193,094	190,242	189,060	188,709	188,378
Traditional	195,122	201,083	205,183	208,653	213,293	215,604

3.3.7 Forecast of Annual NGT Demand

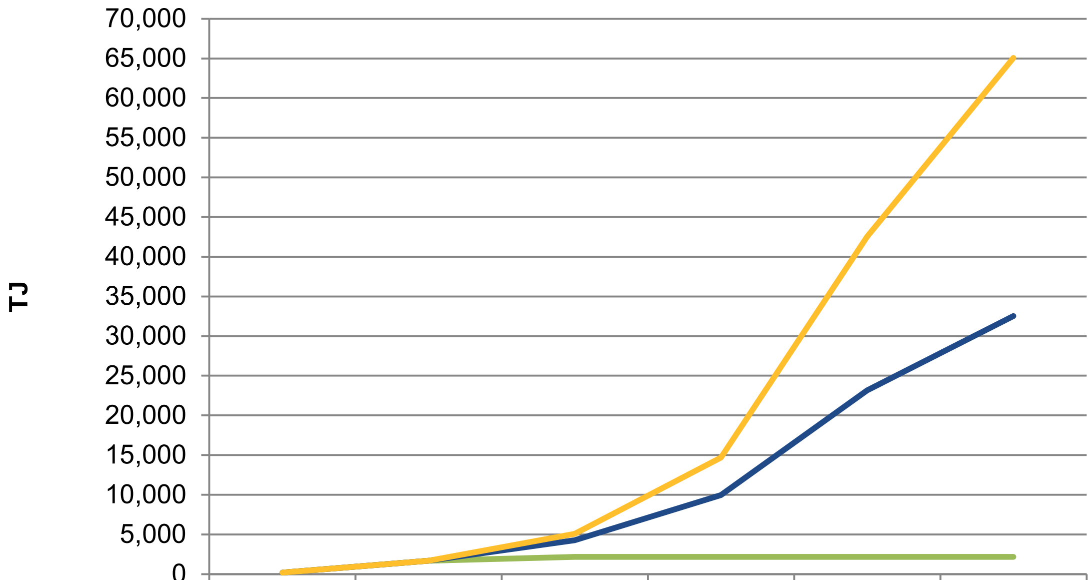
Natural gas as a transportation fuel has emerged as a growing market in B.C., both for long-established compressed natural gas rate class customers and for newer, liquefied natural gas rate class customers. The FEU have developed a strategy (outlined in Appendix A-8) to stimulate this growth and service the market by focusing on heavy duty and return-to-base fleet vehicles (including marine vessels). As discussed in Section 2 and Appendix A-8, the Companies have established an incentive mechanism to assist customers with both the incremental cost of new NGT vehicles and the cost of refuelling infrastructure that would service these vehicle fleets.

At the time of writing, the B.C. Government issued a special direction to the BCUC to exempt from review expenditures on an expansion of the Tilbury LNG facility of up to $400 million and to effectively lower the LNG dispensing rate to $4.35 per GJ. The government also amended the GGRR to include trains and mine-haul trucks, provide tanker-truck delivery services to trucking, mining and marine transportation customers. These developments are likely to lead to increasing NGT demand, however, these recent developments are not considered in Figure 3-13 and the three NGT scenarios described below.

The long term annual NGT demand forecasts are based on FEI's experience learned from the 2012 and 2013 GGRR vehicle incentive calls, the allocated funding period from the GGRR, and actual NGT customer additions to date. This forecast was completed in two parts. The first part covers the period for which the Companies are currently permitted to provide incentives under the GGRR (2013 to 2017). For this period, the FEU have received expressions of interest from potential CNG and LNG customers and have therefore based their NGT demand forecast on the projected number of vehicles in each class of eligible vehicle, multiplied by the typical fuel consumption for each respective vehicle type. Additional discussion of the FEU's NGT initiatives under the GGRR is presented in Appendix A-8.

The second part of the NGT demand forecast covers the period from 2018 to the end of the planning period (2033), with 2018 being the point at which the NGT demand scenarios begin to diverge based on market share capture assumptions. The 2033 transportation market size was calculated by projecting 2010 NRCan data for the transportation market to the end of the forecast period. This exercise focused solely on the market for heavy duty and return-to-base vehicles that could reasonably be expected to utilize natural gas, and did not include the personal vehicle market. A total for medium trucks, heavy trucks, school buses, urban transit, freight rail, and marine from the 2010 NRCan data was scaled up by a 2% annual growth rate to reach an applicable 2033 total vehicle market size. In FEI's service territory, the three natural gas vehicle forecasts in 2033 reach 1% market share in the Low case, 15% market share in the Reference Case, and 30% market share in the High case. The latter two scenarios assume that LNG liquefaction, storage and dispensing facilities are expanded and do not limit the amount of LNG available to serve the transportation sector. The three NGT scenarios are presented in Figure 3-13 and described below.

Figure 3-13: Annual NGT Demand – All Scenarios[50]



	2010-2011	2016	2021	2026	2031	2033
Low	195	1,676	2,168	2,168	2,168	2,168
Reference	195	1,676	4,267	9,946	23,183	32,522
High	195	1,676	5,075	14,689	42,518	65,045

NGT Reference Case Annual Demand Scenario:

Market expands, volumes increase to meet demand

The Reference Case NGT scenario is based on the anticipated outcome of the NGT Incentive Program, and includes anticipated market expansion and a subsequent increase in demand volumes. It is expected that the popularity of NGT vehicles will increase due to the operating cost advantages of natural gas over gasoline and diesel fuels and increasing availability of fueling stations. In the Reference Case scenario, the number of heavy duty and return-to-base fleet NGT vehicles scale up to a 15% market share by 2033.

NGT Low Case Annual Demand Scenario:

Market expands during incentive reward period, volumes stabilize

In the NGT Low Case, the level of demand at the end of the GGRR approval period is assumed to remain stable as existing customers continue to renew their fleet of natural gas vehicles, but the market is not assumed to continue growing. Although it is expected that NGT vehicles will

[50] The Reference, High and Low scenarios in Figure 3-13 are based on FEI's NGT forecast as projected FEVI NGT demand amounts to approximately 0.05% in the Reference Case scenario by 2033.

increase in the marketplace, the possibility remains that without incentive funding beyond 2018, firms will not purchase additional natural gas fueled vehicles regardless of the fuel cost savings that can be achieved. This assumption results in a level demand forecast (neither growing nor declining demand beyond 2017) thus the heavy duty and return-to-base fleet NGT vehicles remain at a 1% market share by 2033. This Low case represents the lower bound of NGT demand that the FEU believe could reasonably be expected to occur over that time.

NGT High Case Annual Demand Scenario:

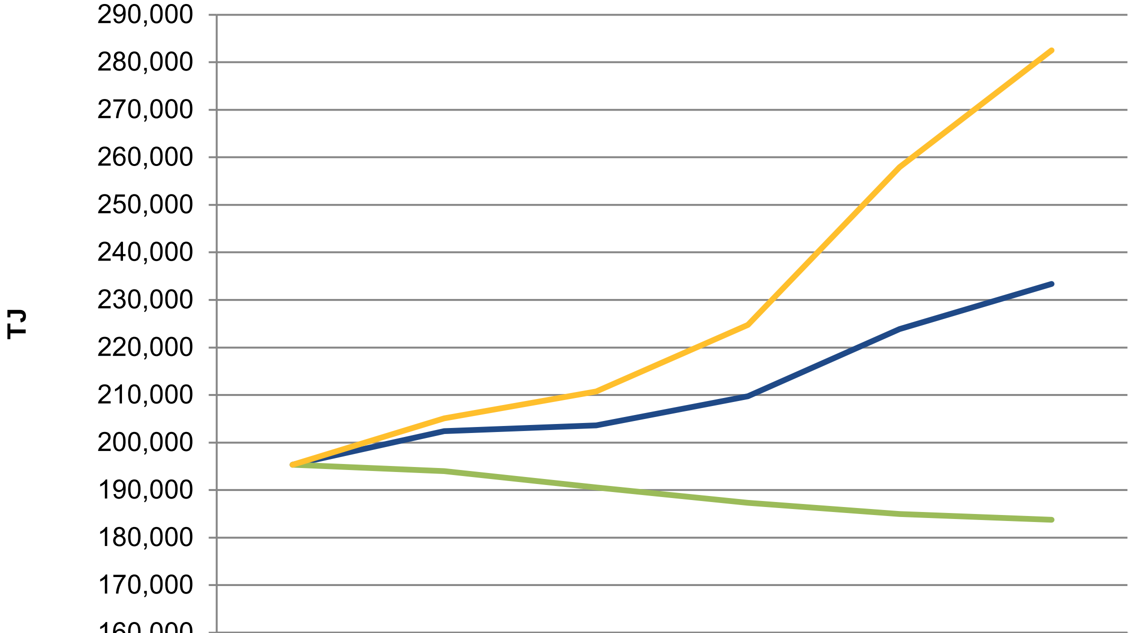
Market expands rapidly, volumes increase to meet demand

The High NGT scenario is based on a higher than anticipated level of NGT demand growth This scenario anticipates that the popularity of NGT vehicles will increase dramatically due to the operating cost advantages of natural gas over gasoline and diesel fuels and increasing availability of fueling stations. In the High case, by the end of the forecast period in 2033, the FEU is expected to capture a 30% market share of B.C.'s heavy duty and return-to-base fleet NGT.

3.3.8 Total Annual Demand

The FEU must be able to serve demand from both the residential, commercial and industrial customer base as well as the NGT customer base. Therefore, to determine the lower limit to the total annual demand forecast, the FEU summed the lowest demand scenario for residential, commercial and industrial customers (Scenario B) with the lowest NGT demand scenario. The same summation was conducted for the highest residential, commercial and industrial demand scenario (Scenario C) and the highest NGT demand scenario to establish the total annual demand upper limit. The Reference Case residential, commercial and industrial demand was added to the expected NGT demand to create an overall Reference Case annual demand forecast. Scenarios A and D were not examined further as these additional scenarios would result in a demand forecast that lie somewhere between the upper and lower demand forecast limits created by the other scenarios. Figure 3-14 shows the sum of total annual demand for the Reference Case, Scenario B and Scenario C, plus the total annual NGT demand (Reference, Low and High cases), and shows the range of total demand that may occur over the planning period.

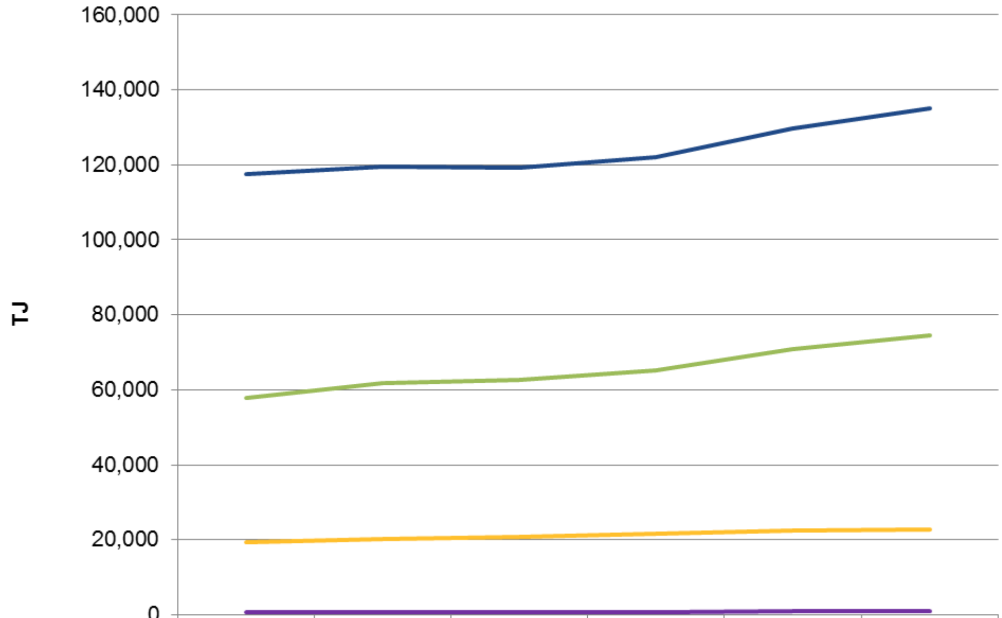
Figure 3-14: Total Annual Demand Including NGT



	2011	2016	2021	2026	2031	2033
Reference	195,317	202,426	203,586	209,738	223,877	233,353
Scenario B	195,317	194,010	190,567	187,316	184,942	183,777
Scenario C	195,317	205,099	210,734	224,741	257,935	282,504

Figure 3-15 below provides a regional look at the total annual demand for natural gas. This graph depicts the effect of adding NGT load to the distribution system and reveals that the majority of NGT load is expected to come onto the system in the Lower Mainland.

Figure 3-15: Reference Case - Total Annual Demand Including NGT by Region

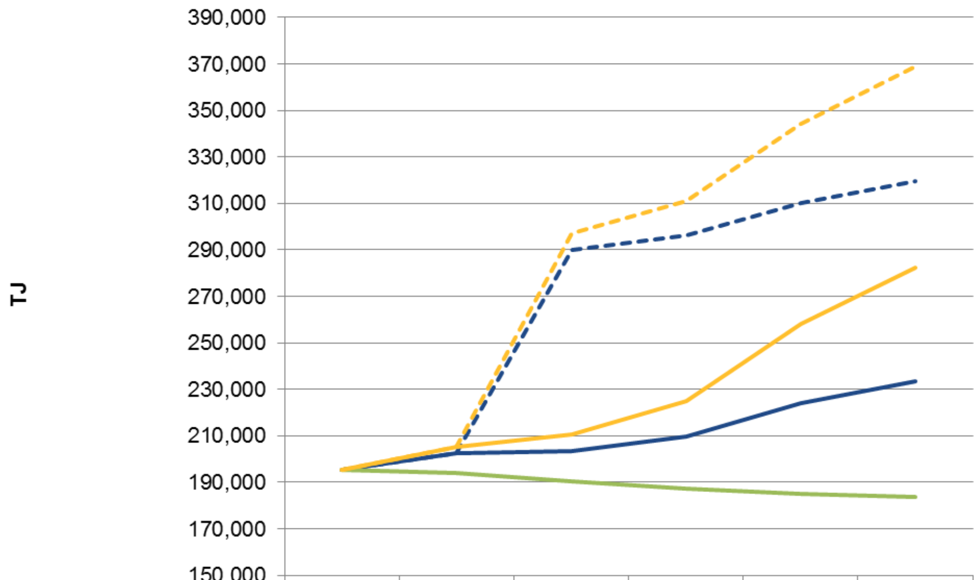


	2011	2016	2021	2026	2031	2033
Lower Mainland	117,425	119,517	119,131	122,086	129,749	135,017
Interior	57,779	61,929	62,757	65,204	70,770	74,623
Vancouver Island	19,368	20,219	20,909	21,623	22,477	22,801
Whistler	744	760	789	824	880	913

3.3.9 Potential New Industrial Annual Demand

The current low gas price environment has created new interest in using natural gas and the potential for new sources of industrial demand. Such demand can have a significant effect on the system due to the size of some of the industrial customers. One example is the proposed Pacific Energy Corporation (PEC) small-scale LNG export and processing facility located on the FEVI system at the former Woodfibre pulp mill site near Squamish. An industrial customer such as PEC can increase demand on the system by 86,000 TJ through a single facility, which would create a step change in the FEVI industrial demand profile in April 2018, or when the facility becomes operational (see Figure 3-16 below). Additional information on the Woodfibre LNG Project and its potential impact on the distribution system is provided in Section 5.1.2.1.

Figure 3-16: Total Annual Demand Including NGT and Woodfibre Example



	2011	2016	2021	2026	2031	2033
Ref + NGT	195,317	202,426	203,586	209,738	223,877	233,353
Ref + NGT + Woodfibre	195,317	202,426	289,986	296,138	310,277	319,753
Scen B + NGT	195,317	194,010	190,567	187,316	184,942	183,777
Scen C + NGT	195,317	205,099	210,734	224,741	257,935	282,504
Scen C + NGT + Woodfibre	195,317	205,099	297,134	311,141	344,335	368,904

Figure 3-16 provides the full range of potential annual demand using the lowest case annual demand and NGT scenarios (Scenario B and NGT Low); the Reference Case annual demand and NGT scenarios; and the highest case annual demand combined with the highest NGT demand scenario (Scenario C and NGT High). The broken lines represent the effect of adding new industrial load such as that of the Woodfibre LNG Project onto the FEU's system.

3.4 *PEAK DAY DEMAND*

3.4.1 Residential, Commercial and Industrial Peak Day Demand

Peak day demand is an estimate of the highest daily gas demand that can be expected to occur on the FEU gas pipeline system(s). In B.C., the majority of natural gas demand is used for heating, thus peak day demand is correlated to cold weather and estimates the maximum daily consumption expected to occur during an unusually cold weather event. The peak demand forecast is a critical input into the FEU's activity of securing an adequate supply of natural gas and ensuring that the system infrastructure is capable of delivering natural gas where and when needed.

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

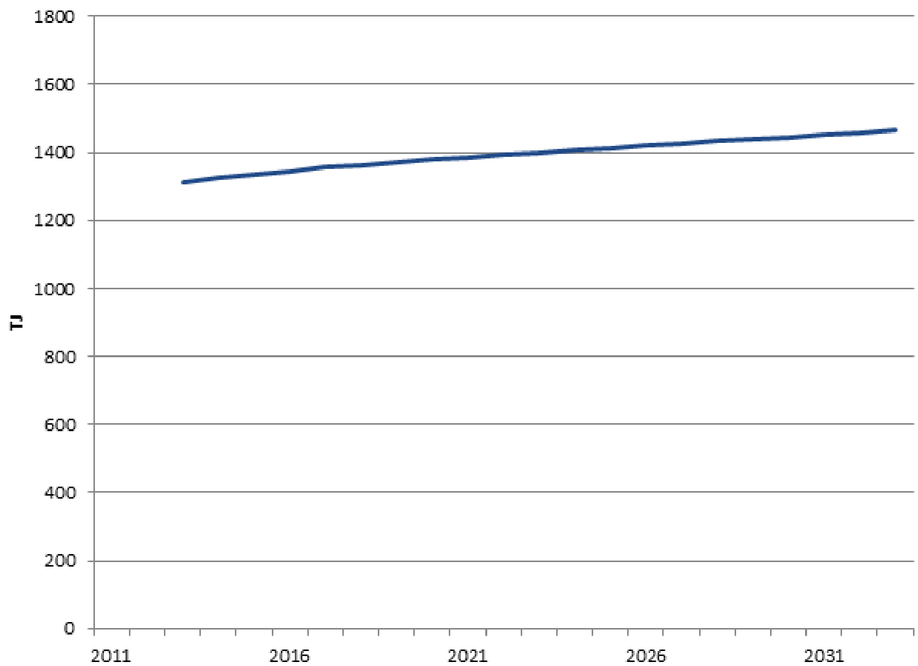
- The peak day temperature; and
- The relationship between consumption and weather.

The peak 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 peak 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 peak day demand remains consistent with the methodology used in previous years.

Peak demand estimates are used for two main purposes. First, system-wide peak day demand is used for gas supply planning purposes to ensure that the FEU have sufficient supply resources to serve Core demand during a peak day event. These are the peak demand estimates discussed in this section. More information about gas supply planning and resources is provided in Section 6. Second, regional peak demand is used for system planning to ensure that there is sufficient capacity on the FEU's transmission systems to deliver gas during a peak weather event. Regional peak demand estimates for capacity planning include demand from large industrial customers that purchase their own gas and contract with the FEU to deliver it to their facilities. These regional peak demand estimates are presented in Section 5 along with a discussion of the system capacity resources needed to meet regional peak demand throughout the planning period.

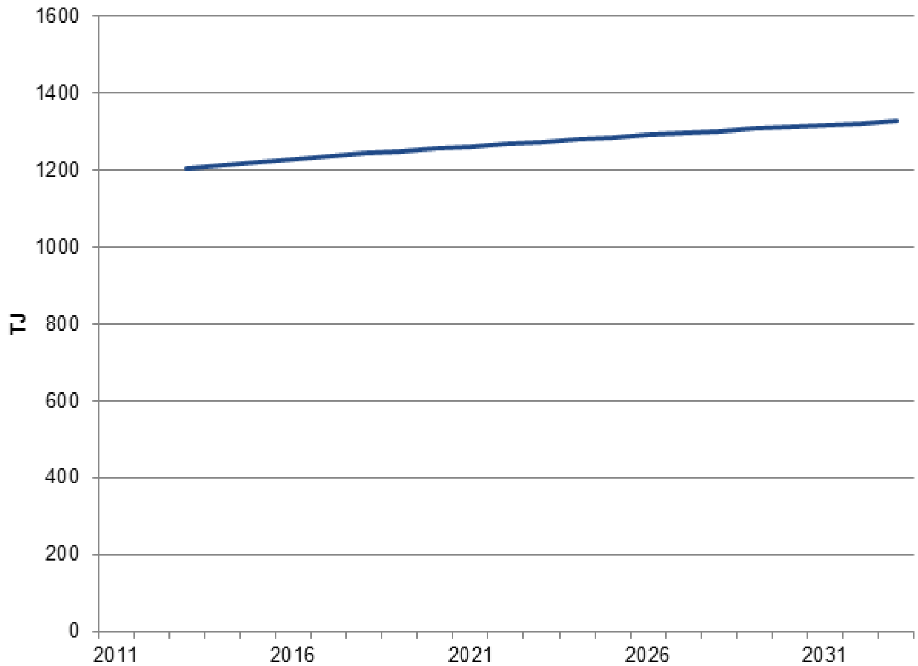
The peak day demand forecast for all of the FEU service territories is provided in Figure 3-17. Figures 3-18 through 3-20 show the Core peak demand estimates for FEI, FEVI and FEW. A modest growth in peak day demand for each of the utilities is estimated for the current planning period, which stems from modest growth in customer additions. High and low peak demand sensitivity analyses are discussed in Section 5 as they relate to the timing of capacity-based infrastructure requirements.

Figure 3-17: FEU Core Peak Day Demand



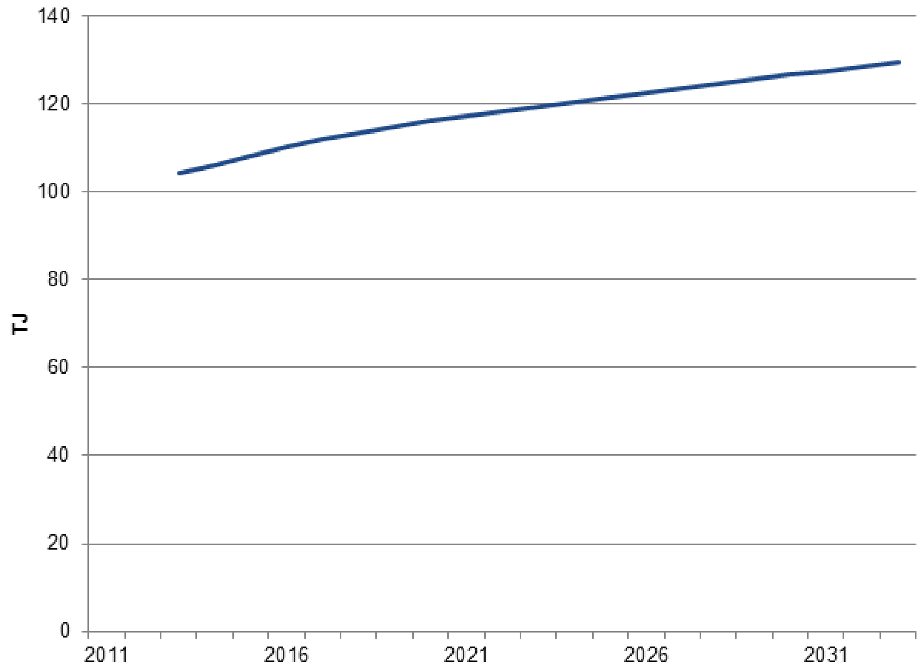
FEU	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
TJ	1,314	1,324	1,335	1,345	1,356	1,364	1,372	1,379	1,386	1,393
2022-23	**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**
1,400	1,407	1,414	1,420	1,427	1,433	1,439	1,446	1,452	1,458	1,465

Figure 3-18: FEI Core Peak Day Demand



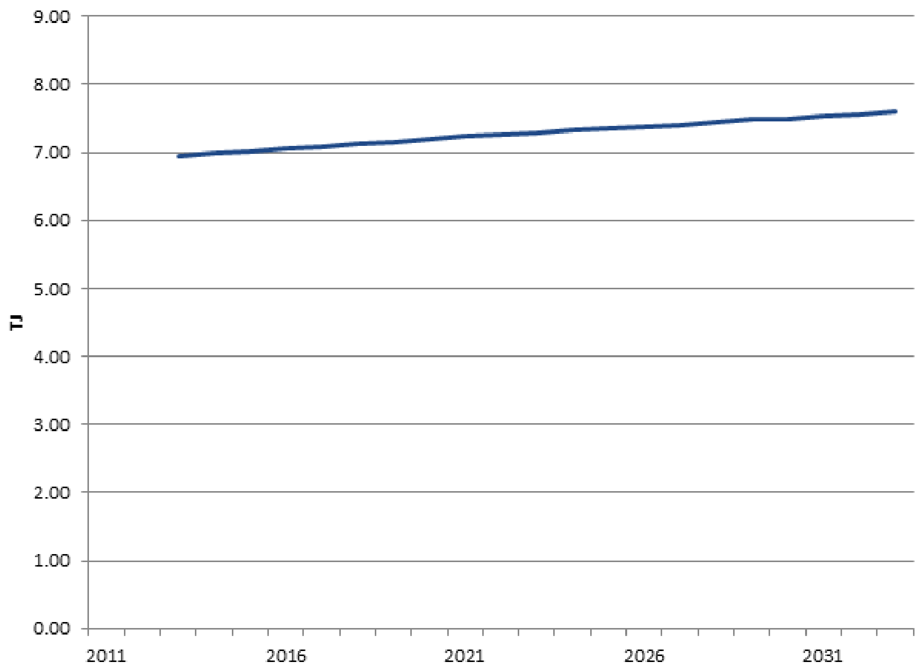
FEI	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
TJ	1,203	1,211	1,219	1,228	1,236	1,243	1,250	1,256	1,262	1,268
2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
1,274	1,279	1,285	1,290	1,296	1,301	1,306	1,312	1,317	1,322	1,327

Figure 3-19: FEVI Peak Day Demand



FEVI	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
TJ	104	106	108	110	112	114	115	116	117	118
2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
119	121	122	123	124	125	126	127	128	129	130

Figure 3-20: FEW Peak Day Demand



FEW	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
TJ	6.96	6.99	7.02	7.06	7.09	7.12	7.15	7.20	7.23	7.26
2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
7.29	7.33	7.36	7.38	7.41	7.45	7.48	7.50	7.53	7.57	7.60

3.4.2 NGT Peak Day Demand

NGT load added to the gas system is expected to contribute to baseload growth, meaning that demand from NGT customers will be a steady, year-round demand. As such, NGT demand will result in an increase in demand on each day of the year, including the peak day. The amount of NGT load added on a peak day (or any day for that matter) is calculated simply by dividing the annual NGT demand by 365 days. Figure 3-21 shows the estimated Reference Case peak demand for FEU Core customers and NGT peak day demand. As the diagram indicates, although new NGT demand will add significantly to annual demand, the impact on peak day demand is not as significant because NGT is not a temperature sensitive load. Also, the majority of NGT demand is expected to occur in the Lower Mainland. Section 5 examines the impact of the peak demand from NGT on the timing of required system capacity upgrades and includes a discussion of higher and lower than expected peak day demand additions from NGT.

Figure 3-21: FEU Peak Day Demand – Core + NGT

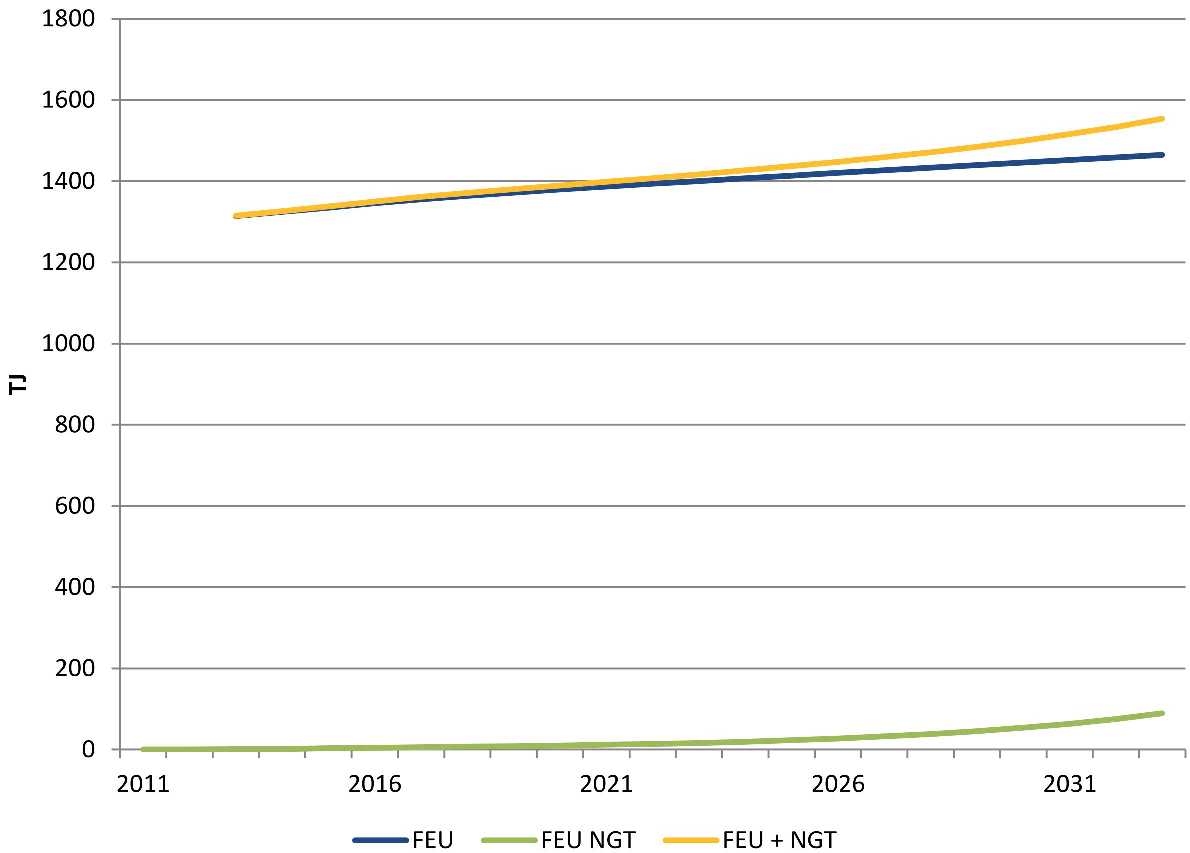


Figure 3-21 does not differentiate between LNG load and CNG load. Compared to LNG, CNG load tends to be smaller in magnitude and distributed across the system. Conversely, due to the cost and specialized facilities required for LNG, increases in LNG demand have a localized effect and, depending upon the amount of LNG required, will result in a more pronounced step change in base load. Regardless, an increase in base load (load that tends to be constant) generally attenuates the "peakiness" of the load demand profile. The discussion of capacity resource needs in Section 5 includes consideration of LNG versus CNG impacts on the system.

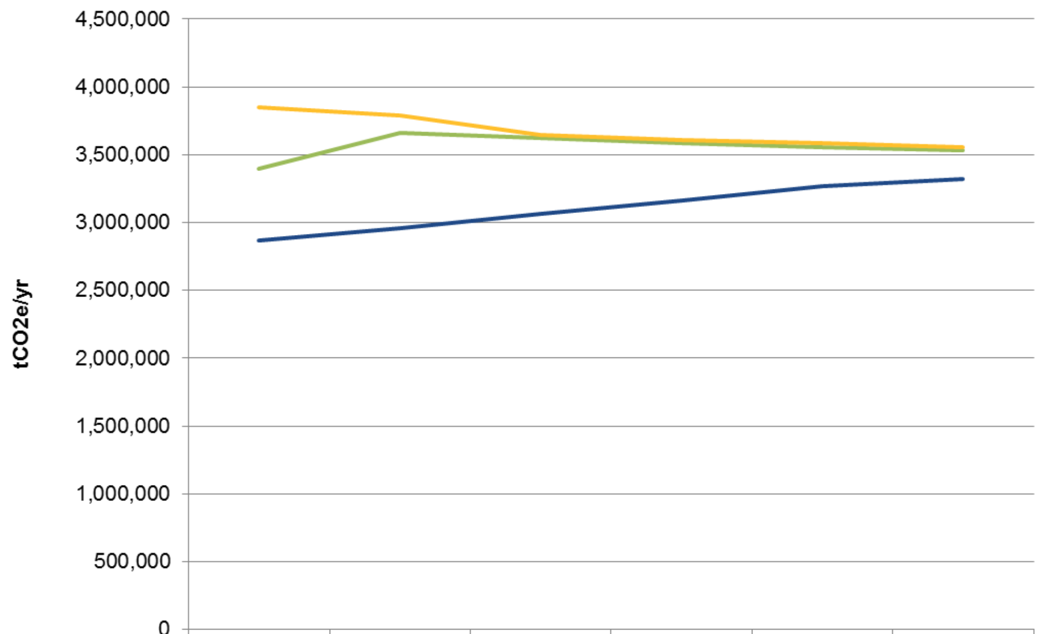
3.4.3 Impact of Potential Large, New Industrial Load on Peak Day Demand

Section 3.3.9 discusses the potential for additional large industrial customer additions to FEU annual demand projections. While not considered Core load, increases in demand from large, new industrial customers could have a pronounced impact on peak day demand from the large daily volume that could be added to the system. The impact of such increases in peak demand will primarily affect system capacity rather than gas supply planning for Core customers. The impact of potential new industrial load on regional peak demand and the need for capacity related system upgrades is discussed is Section 5.

3.5 GREENHOUSE GAS EMISSIONS

Natural gas is one of the cleanest, lowest GHG-emitting fossil fuels. In 2011, total gas consumption for all sectors (residential, commercial, and industrial) was 195 PJ, which resulted in approximately 10 million tonnes of carbon dioxide equivalent (tCO_2e) being emitted from FEU's natural gas sales in the residential, commercial and industrial sectors (refer to Figure 3-22 below).[51] This is the GHG-equivalent of supplying natural gas to over 2.1 million homes in FEI's service territory for one year.[52]

Figure 3-22: GHG Emissions From End-Use Gas Consumption – FEU

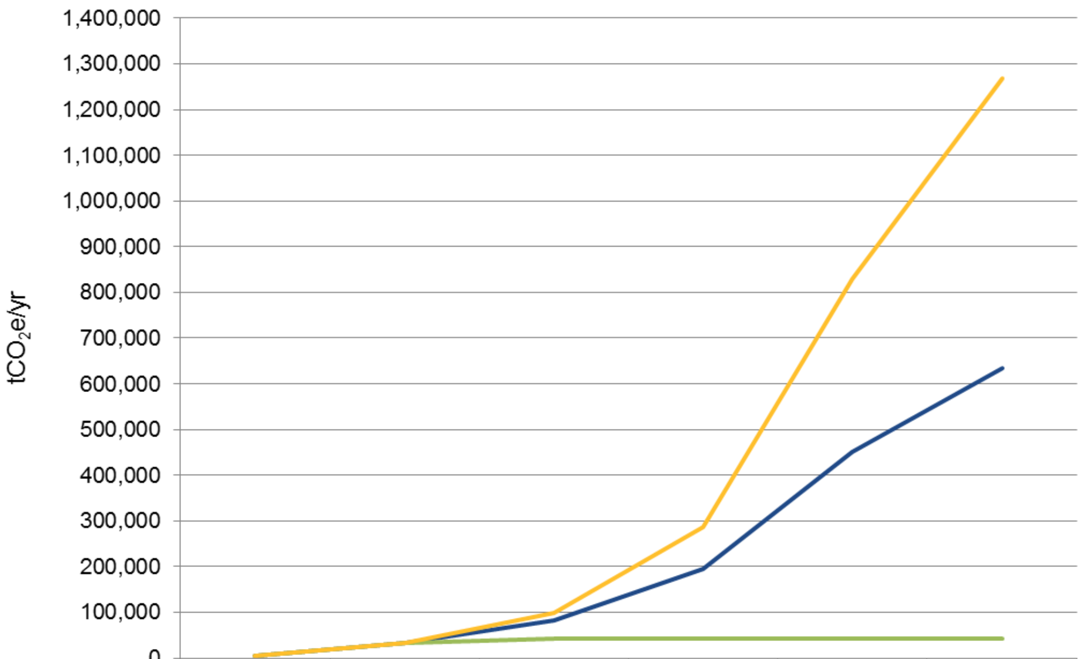


	2011	2016	2021	2026	2031	2033
Commercial	2,869,029	2,961,987	3,062,286	3,163,059	3,271,298	3,322,803
Industrial	3,398,468	3,660,017	3,626,922	3,586,726	3,551,749	3,532,290
Residential	3,850,171	3,786,685	3,645,328	3,609,244	3,582,784	3,557,850

On the other hand, the FEU's NGT initiatives work to decrease the province's GHG emissions and in the NGT Reference Case, B.C. would see over 634,000 tonnes of GHG emissions removed from the atmosphere in 2033 (refer to Figure 3-23 below). This is the equivalent of taking over 132,000 passenger cars off of B.C.'s roads or avoiding consumption of nearly 270 million litres of gasoline.[53]

[51] This figure is calculated using a natural gas emission factor of 0.052 tCO_2e/GJ.
[52] Using the 20120 Mainland Consolidated normalized use per customer rate of 92 GJ per year.
[53] Based on one vehicle emitting 4.8 metric tons of CO_2e per year. U.S. EPA Greenhouse Gas Equivalencies Calculator, 2012, http://www.epa.gov/cleanenergy/energy-resources/refs.html#vehicles.

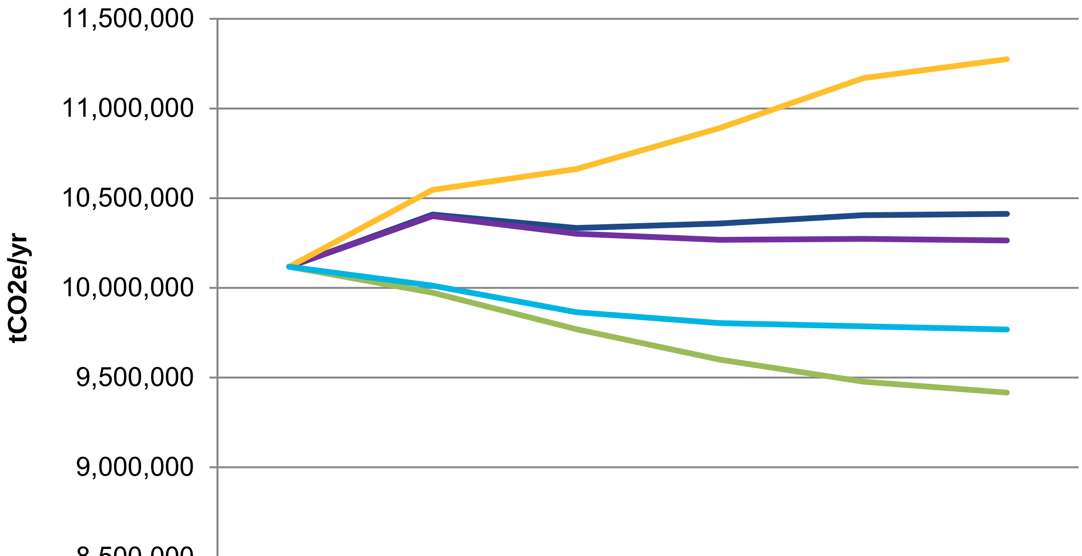
Figure 3-23: GHG Emissions Reductions from NGT



	2010-2011	2016	2021	2026	2031	2033
Reference	3,903	32,316	83,210	193,948	452,060	634,162
Low	3,903	32,316	42,283	42,283	42,283	42,283
High	3,903	32,316	98,955	286,432	829,098	1,268,353

Below, Figure 3-24 shows the expected GHG emissions from end-use gas consumption by scenario throughout the planning horizon. As a result of varying assumptions that underlie the scenarios over the 20-year period such as the prices of natural gas and carbon, economic conditions, new technologies and government regulation (refer to Sections 3.3.3 and 3.3.4 for a full description of the Reference Case and scenario assumptions), the difference between the highest GHG emission scenario (Scenario C) and the lowest GHG emission scenario (Scenario B) is nearly two million tonnes of carbon dioxide equivalent in 2033.

Figure 3-24: GHG Emissions from End-Use Gas Consumption – By Scenario



	2011	2016	2021	2026	2031	2033
Reference	10,117,66	10,408,68	10,334,53	10,359,02	10,405,83	10,412,94
Scenario A	10,117,66	10,400,52	10,301,20	10,268,03	10,273,96	10,264,85
Scenario B	10,117,66	9,973,061	9,769,045	9,600,472	9,477,342	9,416,930
Scenario C	10,117,66	10,546,53	10,662,54	10,890,29	11,168,51	11,274,42
Scenario D	10,117,66	10,012,47	9,864,621	9,803,310	9,785,111	9,767,952

3.6 *CONCLUSION*

Annual Demand

The FEU have provided an estimate of the annual demand for natural gas that they expect to serve over the 20-year planning period as required under Section 44.1(2)(a) of the *UCA*. This estimate is presented in Figure 3-14 as a potential range of future demand that can reasonably be expected to occur under differing potential future conditions impacting residential, commercial and industrial customers, as well as customers using natural gas as a transportation fuel. Since the likelihood of predicting actual future conditions is low, **probabilities are not assigned to the different scenario outcomes; rather, the FEU's planning approach is to identify and implement a set of cost-effective resources that can meet this range of potential future annual demand**. The FEU have based these estimates on the best available information at the time the forecast was prepared. Section 5 of the LTRP discusses the physical resources required to meet this range of demand, including the timing of peak capacity requirements under higher or lower demand growth, while the influence of different annual demand scenarios on customer rates is presented in Section 8.

The end-use approach to annual demand forecasting, based on a plausible but varied range of potential future scenarios, provides an improved view of the way long term demand for natural gas could potentially unfold. For the first time, the FEU have examined future scenarios in which annual demand could dwindle over the planning period, better capturing the risks that the Companies are facing in the current planning environment, particularly with respect to declining residential consumption and competition from other end-use energy types. At the same time, there are significant opportunities for demand growth while helping to meet provincial energy and economic objectives by facilitating the development of natural gas for the transportation market and by being responsive to potential new industrial demand.

The FEU's understanding of the business environment is reflected in the inputs into the demand forecast modelling under the different scenarios, which addresses Commission directives from the 2010 LTRP Decision with respect to demand forecasting. In addition, the FEU provide a comparative analysis of the new approach with the traditional annual demand methodology (Section 3.3.6), and include an analysis of the impact of established new initiatives on demand and GHG emissions by including NGT in the demand forecast (Section 3.3.7). The FEU also present both the GHG emissions from gas use in each scenario and emission reductions from NGT demand in Section 3.5. With successful implementation of the end-use annual demand forecasting methodology, the FEU intend to continue using the new end-use modelling approach and discontinue the use of the traditional methodology.

Peak Day Demand

The methodology for determining long term peak day demand throughout the planning horizon is well-established and has not changed from prior LTRP filings. This continuity recognizes the uncertainty that remains about how different annual trends might be reflected in peak demand. Some end-uses that result in declining annual demand may actually increase peak demand; some may not cause any change in peak demand; and others may cause a reduction in peak demand. Reference Case peak demand shows a slow but steady increase though the planning period, which reflects ongoing customer additions. High and Low peak demand scenarios have not been provided in this section but are discussed in Section 5, since high and low peak demand sensitivities can have an impact on the timing of need for new facilities that are required to meet growing system capacity requirements at the regional level.

4. DEMAND-SIDE RESOURCES

4.1 *INTRODUCTION*

Once an estimate of the demand for natural gas in the FEU's territory is developed (as has been presented in Section 3) the next step in Integrated Resource Planning is to determine what the impact of demand-side management activities will be on the demand forecast. The term 'demand-side measure' has a statutory definition in B.C. that the Companies must follow in developing a plan to reduce demand by taking cost-effective demand-side measures as set out in Section 44.1(2)(b) of the *Act*. In addition, there are other types of activities in the broader context of demand-side management beyond the narrow statutory definition that exists in B.C. that utilities need to consider in providing safe, reliable and cost-effective energy to customers. This section addresses both the statutory requirements for utilities within the B.C. context, as well as other types of demand-side management activities that are also important to the FEU within the broader context. A review of the energy planning environment in B.C. (Section 2) confirms that the Companies need to maintain a strong focus on a range of demand-side activities to ensure that they are: providing the services that customers want, delivering demand-side service offerings that help keep customers' energy costs down, helping to meet provincial emission targets, and playing a major role in optimizing B.C.'s energy infrastructure.

This section is organized as follows:

Section 4.2 addresses the utility demand-side measures defined by B.C. statute that are being met through the FEU's Energy Efficiency and Conservation (EEC) activities. A review of the statutory environment for demand-side measures in B.C. is followed by an analysis of the reductions in annual demand for natural gas that the Companies expect to achieve under the range of future scenarios presented in Section 3. The 2014-2018 EEC Plan (see Appendix C-1 for program descriptions) submitted to the Commission in the FEI's Performance Based Ratemaking Application provides a starting point from which the FEU extrapolate a range of forecast energy savings based on the Companies' most recent Conservation Potential Review. Finally, the plan for how the Utilities will move forward to try to achieve these demand reductions over the planning horizon is presented. Section 4.2 thus addresses Sections 44.1(2)(b) and (c) of the *UCA*. Although there are no specific, government-mandated GHG targets for the FEU or the Companies' customers to meet, the emissions reduction estimates for each of the EEC scenarios are presented. Further discussion on GHG emissions reductions from EEC activities is presented in Section 8 along with other information on GHG emissions reductions from other FEU activities (non-EEC activities).

Section 4.3 discusses demand-side management in the broader context of utility activities beyond B.C.'s limited definition of demand-side measure. The FEU's high carbon fuel switching, natural gas for transportation and exploration of new, large industrial customer demand are presented as examples of activities that, though they do not meet the provincial definition of demand-side measure and are therefore not eligible for EEC funding, are nevertheless important demand-side management activities for the Companies. The FEU activities discussed in Section 4.3 have been approved by the Commission through other regulatory proceedings and the Companies are not seeking approval for any new initiatives or changes to any existing initiatives as part of this LTRP. The Companies believe that these types of initiatives are vital components of the FEU's efforts to provide customers with the energy they are seeking while adding cost-effective, efficient new load to the system that will help to optimize use of the natural gas infrastructure and put downward pressure on customer rates. Section 4.3 is not intended to address the requirements of Section 44.1(2) of the *Act*; however, the initiatives discussed do help to meet B.C. Government energy and emission objectives.

Section 4.4 draws conclusions about the FEU's demand-side resources and recommends actions to be taken in the near term.

4.2 *ENERGY EFFICIENCY AND CONSERVATION*

The FEU's EEC initiative is a portfolio of efficiency and conservation programs and activities that meets the province's DSM definition in the *CEA* and helps customers reduce their natural gas consumption. The Utilities' EEC initiative has a range of other customer and societal benefits such as reducing GHG emissions and water consumption, enhancing human health and comfort, creating jobs, and encouraging a culture of conservation throughout B.C. Specifically, the objectives of the EEC initiative, in no particular order, are to:

- Provide programs to help customers manage their energy use;
- Educate consumers regarding energy efficiency and environmental impacts;
- Improve the overall economic efficiency of buildings and end-use applications;
- Improve the operating characteristics and, in doing so, enhance the safety of customers' energy utilization systems;
- Support government energy and emission objectives; and
- Overcome barriers to market transformation for energy efficient technologies;

In British Columbia, the implementation of demand-side measures is governed by the *UCA*, the Province's Demand-Side Measures regulation made pursuant to the *UCA*, and by the definition of demand-side measure found in the *CEA*:

> *A rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand . . . but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse*

> *gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed.*

In addition, EEC activities provide an opportunity for the FEU to help work toward the B.C. Government's GHG reduction targets as set out in the *Greenhouse Gas Reduction Targets Act* (GGRTA).[54] As discussed in Section 2, the GGRTA does not specify how those reduction targets are to be met. Energy and GHG emissions legislation in B.C. also does not set targets for the FEU's EEC activity. The FEU will, however, continue to work with the provincial and federal governments, other utilities in B.C. and other partners in providing effective energy efficiency and conservation programming that will help to meet B.C.'s GHG emission reduction targets.

Maintaining a cost-effective[55] EEC portfolio throughout the 20-year LTRP planning horizon and allowing the portfolio's energy savings to grow over time is a key part of the FEU's plan for meeting the Utilities' customers' needs for energy. The FEU estimate that by 2033, the cumulative natural gas savings from EEC measures installed over the planning horizon will be almost 13 million GJ[56] on an annual basis for the Reference Case demand scenario. This level of savings is equivalent to the amount of energy used by more than 140,000 residential customers each year at current average annual use rates for the FEU.

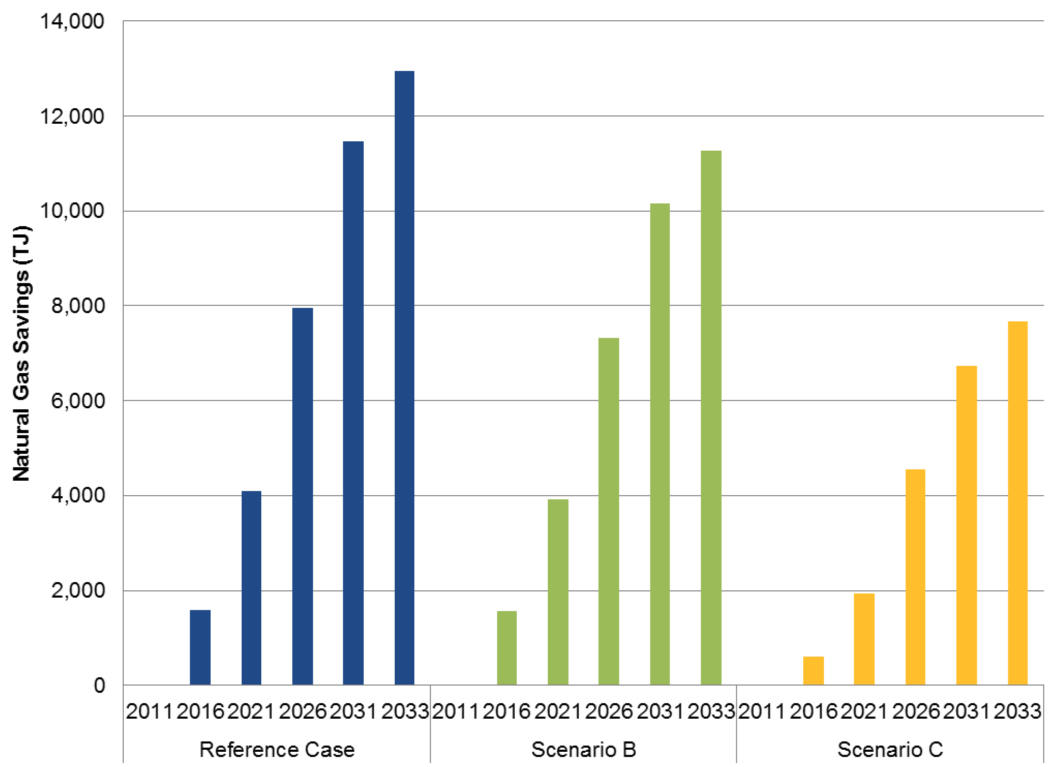
Figure 4-1 shows the range of estimated natural gas energy savings that can be expected from the FEU's EEC activities over the 20-year planning horizon (all service regions). The scenarios for which estimated savings are shown correspond with the scenarios developed for the alternative demand forecasts presented in Section 3. The EEC analysis utilized the same milestone years as did the end-use demand forecasting analysis. The methodology for the development of these estimates follows in Section 4.3.2.

These estimates are grounded in the results of the most recent Conservation Potential Review (CPR) study completed by the FEU[57] and the assumption that current funding levels of approximately $35 million annually (in today's dollars, excluding inflation) for all service regions persist over the planning horizon. Since this level of funding is assumed to be consistent across each of the scenarios, the differences in savings levels result from differences in the scenarios themselves and the portfolios of cost-effective EEC activities available within each scenario. The FEU recognize that this level of funding may change after 2018 depending on a number of factors including: how the policy environment for EEC unfolds, and how quickly EEC activities drive market transformation and thus reduce the amount of savings available from EEC programs over the remaining planning horizon. Since this level of funding has been reviewed in

[54] *Greenhouse Gas Reduction Targets Act*, SBC 2010, c22.
[55] 'Cost-effective' as determined by the Total Resource Cost test (and Modified Total Resource Cost Test, defined by the B.C. Demand-side Measures Regulation) at the portfolio level as per BCUC Order No.G-36-09.
[56] For clarity, this is a forecast range of the annual energy savings from all the energy efficiency measures estimated to be installed during the planning period. For example, an energy efficient boiler (with a useful life of 20 years) installed as part of an EEC program in 2016 will continue contributing to the annual energy savings that occur in each remaining year of the planning period.
[57] FEU 2012-2013 RRA, Exhibit B-1, Appendix K-2, Conservation Potential Review. The full CPR, including the full study regarding the impact on the economy, is provided in Exhibit B-9-1, Attachment 196.1.

detail by stakeholders and approved by the BCUC through three funding applications beginning in 2008, the long term EEC analysis was conducted based on consistent funding through the planning horizon.

Figure 4-1: Estimated Annual EEC Program Savings by Scenario



The FEU are not seeking approval of the funding levels used in this analysis through this LTRP process. The Companies have applied for approval of their most recent EEC Plan for 2014-2018 within the FEI's Performance Based Ratemaking (PBR) Application submitted to the BCUC on June 10, 2013.[58] That application is under review at the time of this LTRP submission.

4.2.1 EEC Background

Long range planning for EEC activity and energy savings potential requires an understanding of the evolution of the FEU's EEC portfolio. The FEU's EEC portfolio of efficiency and conservation programs and activities is set out in the 2014-2018 EEC Plan[59] and meets the province's DSM definition in the *CEA* while helping customers reduce their natural gas

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58 FortisBC Energy Inc. (FEI) Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 ~ Project No.3698715. http://www.bcuc.com/ApplicationView.aspx?ApplicationId=400

59 The Companies' most recent EEC Plan was submitted to the BCUC on June 10, 2013 within FEI's Performance Based Ratemaking Application and, at the time of writing, is currently under BCUC review.

consumption. The FEU's 2014-2018 EEC Plan is 'adequate' for the purposes of Section 44.1(8)(c) of the *UCA* as it includes programs directed at low income participants, rental accommodations and education as required in the following subsections of Section 3 of B.C.'s Demand-Side Measures Regulation:

(a) A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) 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;

(c) An education program for students enrolled in schools in the public utility's service area;

(d) 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.[60]

Whereas the 2014-2018 EEC Plan addresses each of these requirements in detail, the LTRP considers the overall contribution of the individual measures that contribute to energy savings and GHG emissions reductions over the LTRP planning period. Future EEC plans developed beyond 2018 will address any requirements of adequacy that are in place at that time.

Today's EEC expenditure level and activities have been arrived at through a rigorous and transparent development and review process that is both recent and ongoing through the current PBR proceeding. The portfolio of EEC programs has consistently met statutory requirements and BCUC determinations for cost-effectiveness as can be seen in the Companies' EEC Annual Reports.[61] As such, it should be noted that the 2014 LTRP does not begin by examining a wide range of alternative funding levels. Rather, the analysis is anchored on the range of potential EEC measures identified in the most recent Conservation Potential Review conducted for the companies, and examines those measures that are expected to be cost-effective under the range of future scenarios described in Section 3 over the planning horizon. Currently approved funding levels[62] and financial treatment for EEC expenditures are generally assumed to continue in order to complete the analysis. However, the Companies recognize that the actual EEC funding envelope in any given future year will be determined by the development and review of detailed EEC plans and funding requests made at a future time. The current grouping of program areas is also assumed to continue throughout the planning period as follows:

[60] See 2014-2018 PBR Application, "Appendix I: Energy Efficiency and Conservation & Demand-Side Management" (pg. 1093-1094) for additional information on how the EEC Plan addresses the Demand-Side Measures Regulation's requirement of 'adequacy', Sections 3, 6 and 7.

[61] Energy Efficiency and Conservation Program Filings. http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/LowerMainlandSquamishInterior/EECPrograms/EECProgramFilings/Pages/default.aspx

[62] The 2013 approved upper funding limit is $35.6 million, of which a base level of $15 million is included in customer rates while EEC expenditures between $15 million and the upper limit are held in a deferral account until the next revenue requirement application or review.

- Residential
- Commercial
- Industrial
- Low Income
- Conservation Education and Outreach Initiatives
- Innovative Technologies, and
- Enabling Activities

4.2.1.1 Conservation Potential Review

The purpose of a CPR is to examine available energy efficiency technologies, understand the inventory of energy equipment in a utility's service area, and determine the conservation potential that exists. The CPR is a critical tool for use in developing, supporting and assessing current and future EEC expenditure applications, as well as for directional input into program development. FEU's 2010 CPR provided the baseline data on which the 20-year EEC energy savings estimates for this LTRP have been determined. Both the FEU's previous 2012-2013 EEC Plan and proposed 2014-2018 EEC Plan were also built upon 2010 CPR data. The 2010 CPR has provided a comprehensive update of the energy efficiency opportunities within the FEU's service territories, identifying both the sectors and the end-uses that offer the most significant opportunities for natural gas efficiency and conservation over the next 20 years.

The CPR Summary Report is contained in Appendix C-2 and describes the study approach and methodology used to determine the potential for energy savings, along with the study results. The CPR report does not recommend specific programs or targets to be implemented. However, it does identify technology and market priorities as well as the scope of achievable savings potential. This information has assisted EEC Program Managers in the design of their respective Program Area portfolios that make up the 2012-2013 and 2014-2018 EEC Plans, and that form the starting point for the long-term examination of potential energy savings. An overview of the approach to using this information to determine savings estimates for this LTRP is provided in Section 4.2.2.

4.2.2 Applying EEC Potential to the Multi-Scenario, End-Use Demand Forecast

As described above, the CPR provides an understanding of the potential for energy savings from EEC activity, and previous LTRP and EEC funding requests have together examined the appropriate level of funding that the FEU should be investing in EEC activities. The analysis of long term potential natural gas savings in this LTRP therefore focuses on the potential range of savings under scenarios of different future planning environments rather than scenarios entailing different funding levels.

The future scenario descriptions for EEC analysis are the same as those presented in Section 3 for the purpose of estimating a range of potential future demand. For the EEC analysis, however, the scenarios examined were limited to the Reference Case scenario and the scenarios which resulted in the lowest and highest forecast of annual demand for natural gas (Scenarios B and C respectively). In this way, the Companies can present the widest range of potential demand for natural gas after energy savings from cost-effective demand-side measures. The Reference Case forecast assumes that conditions that are present in the planning environment at the time the demand forecasting exercise was undertaken prevail through the planning horizon. For convenience, the descriptions of Scenarios B and C are provided again in Table 4.1.

Table 4-1: Descriptions of Scenarios B (Lowest Demand) and C (Highest Demand)

Alternative Future Scenario Descriptions	General Theme	Policy Expectations	Directional Implications for Demand
Scenario B (Constricted Supply and Decentralized Energy Markets)	Natural gas supply is constrained and new, decentralized technologies emerge rapidly to meet future energy needs. Carbon policy is not a driver in this scenario and B.C.'s carbon tax is held constant at 2012 levels; rather, generalized environmental policies contribute to constricted natural gas supply and support renewable thermal development.	Policy is focused on the environmental impacts of energy as a whole, not specifically carbon impacts. Additionally, there are coordinated energy strategies among regions and all levels of government, which allows for the creation of a national energy strategy.	With a moderate to high price for natural gas and no carbon-specific regulations in place, there is likely little uptake in natural gas for transportation, and the price of natural gas does cause consumers to look for alternatives to natural gas for thermal applications. This scenario would likely drive fuel switching to decentralized renewable thermal applications, and potentially a corresponding overall decrease in demand for natural gas. There is moderate to high participation in EEC initiatives as customers who do not switch fuels are looking for ways to reduce their energy consumption in response to high natural gas prices.

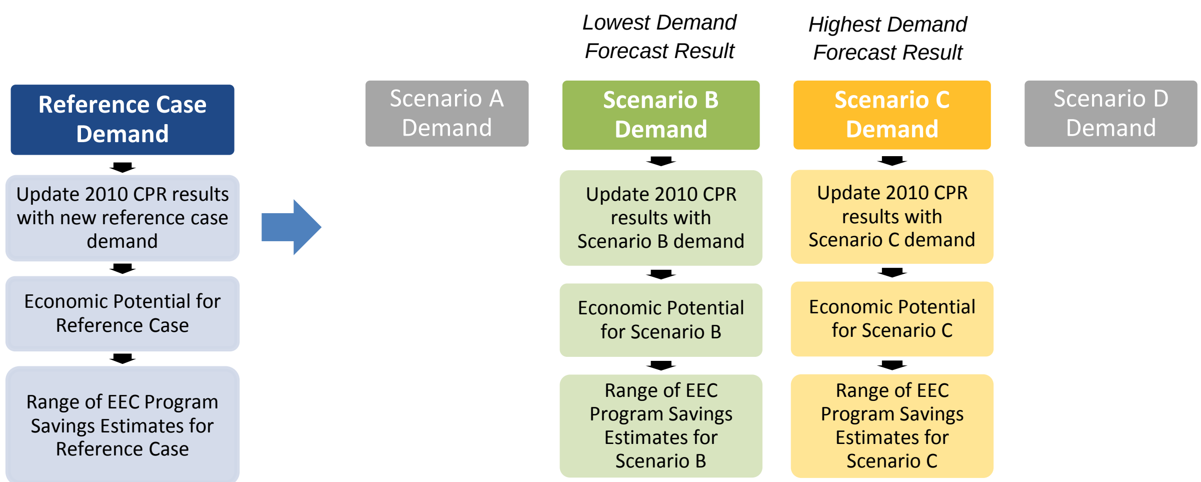
Alternative Future Scenario Descriptions	General Theme	Policy Expectations	Directional Implications for Demand
Scenario C (Abundant Supply and Centralized Energy Markets)	Natural gas supply is abundant while energy technology remains centralized, leaving natural gas as an important means to meet long term energy needs. Overall, natural gas is viewed positively and is perceived as an integral part of B.C.'s energy picture.	Policy is focused on economic growth rather than environment, carbon, or climate issues, and energy strategies are disparate among regions and levels of government, meaning that other jurisdictions may or may not implement carbon pricing, renewable thermal subsidies, etc.	Abundant supply results in a low gas price, and coupled with current technologies and a policy environment that is not focused on carbon emission reductions, the scenario drives an increase in overall demand for natural gas. In particular, low gas prices likely drive an increase in Industrial demand. A high fuel cost differential between oil and natural gas paves the way for higher than expected uptake in NGT. Convincing customers to participate in EEC programs will be more difficult, as the low fuel costs and abundant supply create less incentive for consumers to focus on saving energy. The conditions in this scenario also mean that renewable thermals will likely play a smaller role in the energy picture in B.C.

The end-use forecasting approach and results discussed in Section 3 provide the starting point for EEC analysis and make possible a more thorough examination of different potential future EEC scenarios. Results from end-use market research undertaken by the FEU in recent years and the 2010 CPR were pivotal in being able to complete this EEC planning exercise. With this approach, the FEU have endeavoured to address the concerns of the BCUC and some stakeholders that a broader analysis of alternative EEC scenarios would be helpful. The results of the EEC potential analysis showed that future energy savings could range from nearly 8 million to 13 million GJ annually by 2033 (see Figure 4.1). It is worth reiterating that these different scenario results do not assume a difference in the level of resources that FEU has available to deliver EEC programming, but rather assumes those resources would be focused on somewhat different sets of efficiency measures based on the analysis of cost-effective measures for each scenario.

4.2.2.1 Methodology

Figure 4-2 depicts the steps that were taken to estimate the energy savings potential from EEC programming under different future scenarios. These steps are explained below.

Figure 4-2: Process for Estimating EEC Savings



First, the original conservation potential results from the 2010 CPR were updated with the new Reference Case demand based on 2011 actuals – the most up-to-date information available at the time this activity was initiated in 2012. This activity was completed as part of the end-use demand forecasting analysis discussed in Section 3.3. For reference, an explanation of the CPR methodology is included in the 2010 CPR Summary Report provided in Appendix C-2.

Second, in addition to modelling natural gas savings for the Reference Case demand scenario, the FEU needed to determine what other EEC scenarios to model. Because the FEU needs to understand the range of potential demand that could result after EEC-derived natural gas savings over the planning period, the highest and lowest end-use demand forecast scenarios (Scenarios C and B respectively) were chosen to form the base demand from which EEC natural gas savings were modelled. This resulted in three alternative 20-year EEC scenarios that, once the analysis was complete, encompassed the estimated energy savings to be achieved for the Reference Case demand and the likely range of EEC savings within the future scenarios examined for this LTRP.

Next, with the base level of demand determined for each of the three EEC scenarios, the analysis of economic potential energy savings[63] that was completed for the 2010 CPR was repeated using the new demand information from the new forecast scenarios. This analysis utilized the same gas price assumptions for each scenario that was utilized to develop the pre-DSM, end-use demand forecast scenarios in Section 3.3.4. The work was conducted by consultants ICF Marbek, who also conducted both the original 2010 CPR and the end-use

[63] The economic potential is defined in the 2010 CPR as an estimate of the level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective from society's perspective. All of the energy efficiency technologies and measures that have a positive measure-level TRC are incorporated into the economic potential forecast.

forecasting analysis for this LTRP. The Total Resource Cost (TRC) effectiveness test was used as the primary economic screen for the economic potential.

The final step in estimating the EEC savings over the 20-year planning horizon was to develop an overall energy savings estimate, which is the savings that would come from implementing the available cost-effective EEC measures.[64] This step acknowledges that hurdles such as resource constraints and ramp-up periods inevitably result in energy savings that are less than the economic potential. The demand forecast for each of the scenarios already includes efficiency improvements from changes to government regulations or efficiency related codes and standards that are known, as well as varying assumptions for a certain amount of natural conservation that is not driven by EEC activity (see scenario explanations in Appendix B-3). Potential regulations that are yet unknown were not modelled in any of the demand forecast scenarios and are therefore another item that could impact the amount of EEC potential available over the planning horizon. Appendix B-3 contains the assumptions for each of the demand forecast scenarios and an explanation of how the assumptions were incorporated into each forecast.

The Companies believe it best to provide a range that bounds the estimated achievable measure savings over the long term. This was done by producing a maximum and an applied, long term EEC savings estimate. This range recognizes that actual results sometimes fall short or overshoot the EEC savings projection. Both the planned and achieved savings over the history of EEC programs were examined on a program by program basis to understand and apply this range of savings. The maximum long term EEC savings estimate is an extrapolation of the higher of the planned or actual savings for each program. The applied long term EEC savings estimate is an extrapolation of the lower of the planned or actual savings for each program, and represents a more conservative view of the estimated achievable savings. The analysis did not involve designing a program by program plan for each year of the planning horizon, but rather utilized existing program data and the 2014-2018 EEC Plan, combined with the CPR based efficiency measure data to develop the achievable savings estimate boundaries. This work was also performed by ICF Marbek and was informed by the FEU's program experience to date, the estimated level of funding over the planning horizon, the consultant's extensive experience with the DSM planning environment in B.C. and by the characteristics of the demand scenario that underlies each EEC scenario.

Consideration in this final step was also given to the modified Total Resource Cost (mTRC) test defined in B.C.'s Demand-Side Measures Regulation. The mTRC allows for a 15% adder to the benefits side of the test to recognize the non-energy benefits of DSM such as water savings, job creation and emissions reductions, and also allows for the use of a value for the Zero Emission Energy Alternative to recognize the environmental attributes of natural gas DSM for up to 33% of the EEC portfolio. To account for this, ICF Marbek allowed some residential measures that were close to but below the TRC threshold to be included in the energy savings.

[64] The savings estimate was calculated from the savings per measure for those measures that are cost-effective and could therefore be used to develop EEC programs.

4.2.2.2 Sensitivity of EEC Savings to the End-Use Forecast Scenarios

The availability of potential energy savings will vary from one forecasting scenario to another due to several effects, all of which were incorporated into the demand forecasts for each of the scenarios prior to analyzing the potential savings from EEC (see scenario explanations contained in Appendix B-3):

- Higher gas pricing, due to commodity prices or a carbon price, will cause more measures to pass the TRC test, or will cause measures that already pass to pass in more regions or building types. Conversely, lower gas pricing will cause more measures to fail the TRC test, or will cause measures that pass to fail in more regions or building types.
- Although customer demand is price inelastic over the short term, higher gas pricing over the long term, all else equal, may cause some customers to switch away from natural gas for certain end uses. This will tend to reduce the potential for measures that pass the TRC test. Conversely, lower gas pricing may tend to cause some customers to switch from other fuels to gas for certain end uses, increasing the potential for those measures that still pass the TRC test.
- In the Industrial sector, higher economic growth will tend to increase the potential for savings for most industrial measures; lower economic growth will tend to decrease it.
- A policy environment that encourages more natural adoption of energy efficiency will tend to decrease the potential for energy efficiency that remains for utility programs to capture. Conversely, a policy environment that does not encourage natural adoption of energy efficiency will tend to increase the potential for utility programs.
- An environment with increased development of renewable and district energy systems will tend to decrease the remaining natural gas share and therefore the potential for natural gas savings. An environment with little development of renewable and district energy systems will tend to have more potential for natural gas savings.

The FEU believe that this methodology provides the best estimates currently available to the Companies of what natural gas savings can be cost-effectively achieved over the long term, in accordance with current Provincial regulation. The methodology recognizes that a broad range of potential future scenarios could unfold over the planning period, and examines the impact that natural gas savings from EEC programs will have on the range of potential future demand under the different scenarios. Because the base level of demand for each EEC scenario has considered natural levels of energy efficiency and conservation under different futures, this methodology also considers the changing nature of customer behaviour before the influence of EEC programs.

4.2.3 Long Term EEC Analysis Results

4.2.3.1 Overall EEC Impact on Annual Natural Gas Demand

Figure 4-1 provides the range of overall long term natural gas savings estimates for the FEU under each of the three demand scenarios. Figure 4-3 shows how those savings will impact the overall natural gas demand for each scenario. Figures 4-4 through Figure 4-6 show the impact of energy savings on natural gas demand for each of residential (including low income customers), commercial and industrial customer groups respectively, based on the "applied" level of estimated long term EEC savings as described above.

Figure 4-3: Natural Gas Demand Before and After Estimated EEC Program Savings – FEU, all Customer Groups

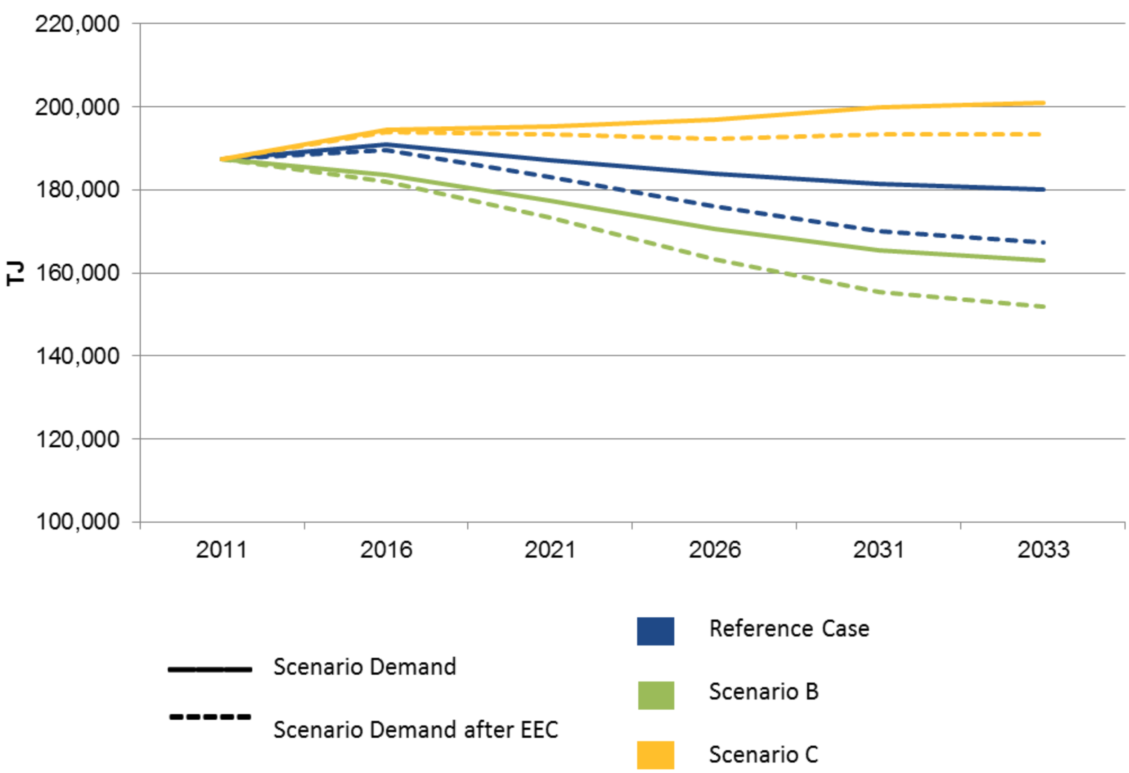


Figure 4-4: Residential Natural Gas Demand Before and After Estimated EEC Program Savings – FEU

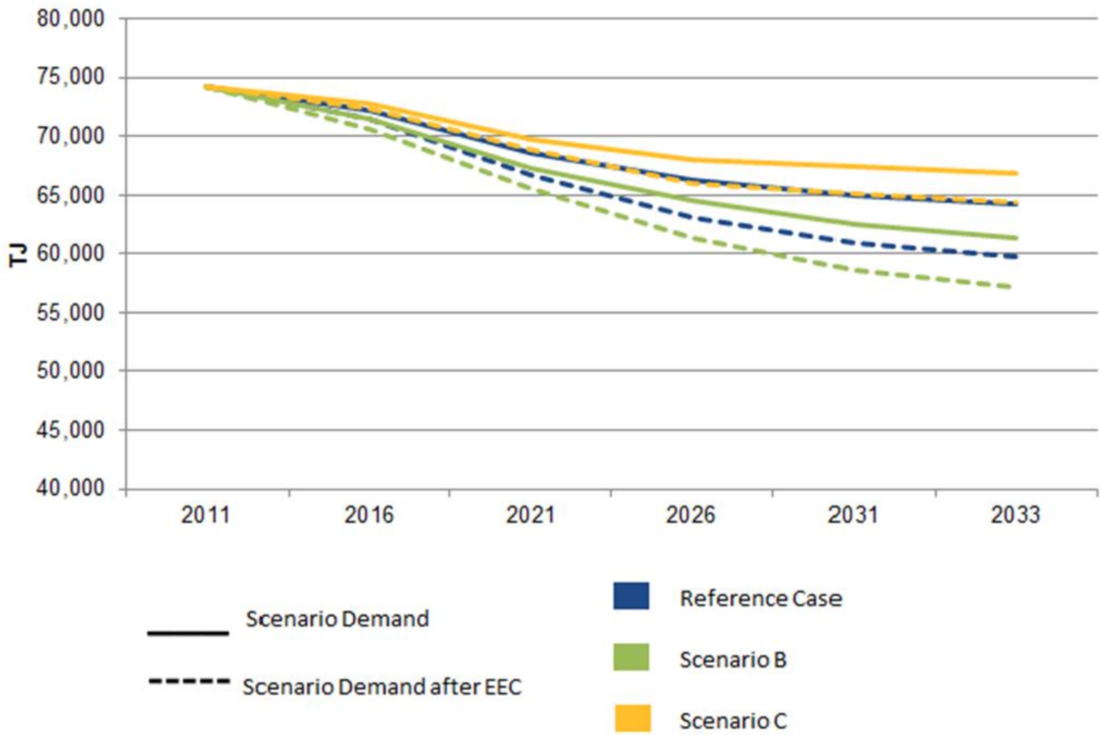


Figure 4-5: Commercial Natural Gas Demand Before and After Estimated EEC Program Savings – FEU

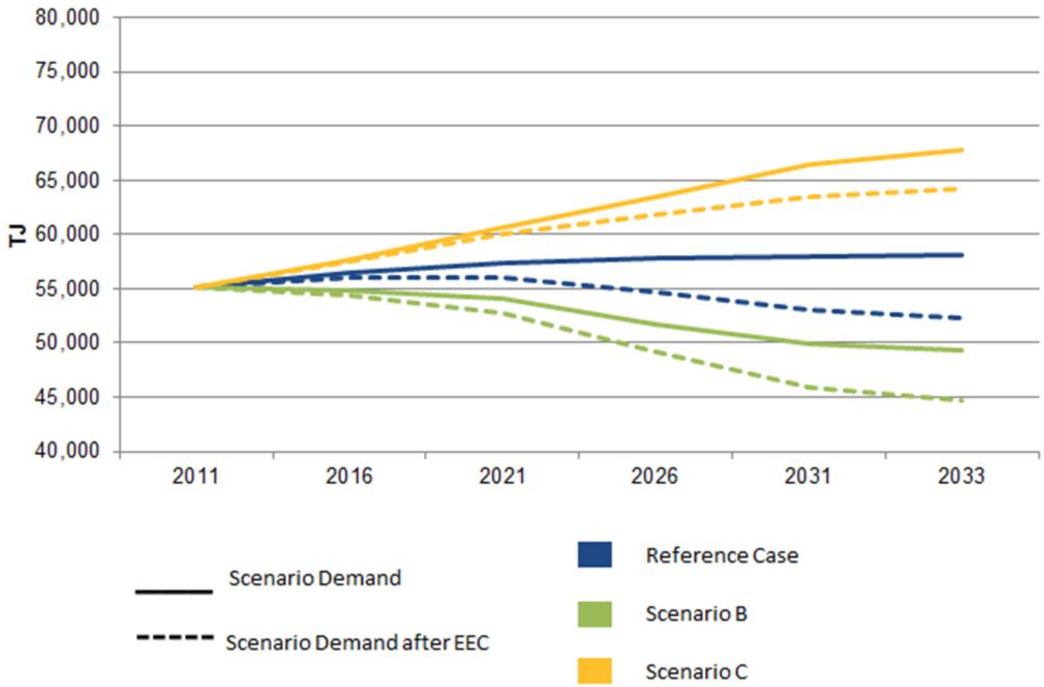
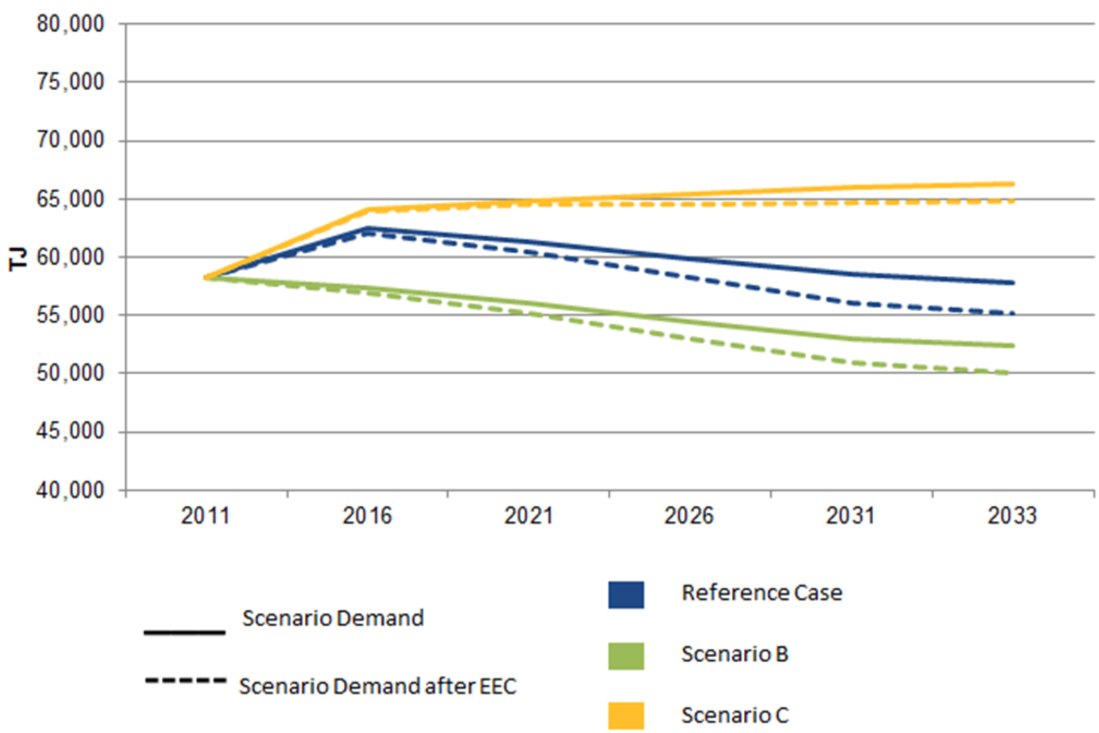


Figure 4-6: Industrial Natural Gas Demand Before and After Estimated EEC Program Savings – FEU



4.2.3.2 Estimated Natural Gas Savings from EEC Measures

Figures 4-3 through 4-6 show the impact of EEC on natural gas demand, which is the primary goal of the long term EEC analysis. The residential program energy savings give an example of the analysis results for all of the FEU service areas. Tables 4-2 and 4-3 show the range of estimated residential GJ savings (Applied) by measure and scenario in 2016 and 2033 respectively. Generally, measures passing the TRC in all scenarios have slightly less savings in Scenario B than in Scenario C. This is due to the relative amounts of natural conservation efforts inherent in those scenarios. Due to the lower price of natural gas in Scenario C, some measures fail the TRC and drop out entirely. For residential measures that would be part of the Residential or Low Income program areas, there are some exceptions to this TRC threshold. Measures for programs that are currently in place or planned in the 2014-2018 EEC Plan and that fail the TRC but are included in portfolio as a result of the B.C. Demand-Side Measures Regulation (i.e. that pass the Modified TRC) are included in the each of the scenario savings.

Table 4-2: FEU Residential Annual GJ Savings by Measure and Scenario, 2016

Measure	Reference Case	Scenario B		Scenario C	
	Est. Program Potential Savings (GJ)	Est. Program Potential Savings (GJ)	% Change from Ref Case	Est. Program Potential Savings (GJ)	% Change from Ref Case
Air Sealing	2,235.7	2,217.9	-0.8%	2,250.7	0.7%
Attic Insulation	69,423.2	69,086.1	-0.5%	0.0	-100.0%
Basement Insulation	39,240.8	39,036.2	-0.5%	0.0	-100.0%
Condensing Gas Boilers	429.9	426.3	-0.8%	433.6	0.8%
Condensing Gas DHW	541.5	538.0	-0.7%	543.3	0.3%
DHW Pipe Insulation	4,853.5	4,802.1	-1.1%	4,853.7	0.0%
DHW Tank Insulation	2,647.4	2,619.3	-1.1%	0.0	-100.0%
Early Retire Gas Furnaces	109,763.9	105,993.0	-3.4%	107,526.4	-2.0%
ESTAR Clothes Washers	4,604.8	4,550.2	-1.2%	0.0	-100.0%
Faucet Aerators	48,020.0	47,512.1	-1.1%	48,021.9	0.0%
Gas Fireplaces	92,095.6	92,095.6	0.0%	93,035.0	1.0%
Heating & DHW	65.1	64.4	-1.1%	65.1	0.1%
Homeowner Air Sealing	279,233.8	277,768.5	-0.5%	0.0	-100.0%
Net Zero Ready Homes	12,699.3	10,992.8	-13.4%	12,672.5	-0.2%
Showerheads	80,969.0	80,112.5	-1.1%	80,972.3	0.0%
Solar Make-Up Air	183.0	181.5	-0.8%	186.3	1.8%
Tankless Gas DHW	1,188.3	1,178.5	-0.8%	1,189.4	0.1%
Wall Insulation	23,285.3	23,165.7	-0.5%	0.0	-100.0%
Grand Total	**771,480.1**	**762,340.7**	**-1.2%**	**351,750.1**	**-54.4%**

Table 4-3: FEU Residential Annual GJ Savings by Measure and Scenario, 2033

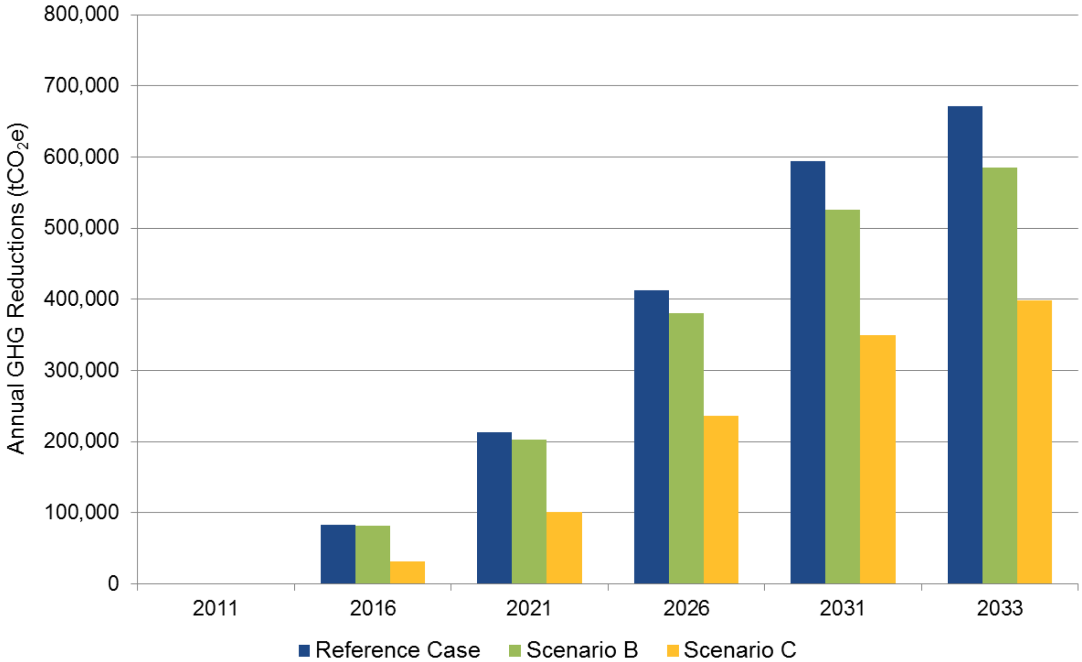
Measure	Reference Case	Scenario B		Scenario C	
	Est. Program Potential Savings (GJ)	Est. Program Potential Savings (GJ)	% Change from Ref Case	Est. Program Potential Savings (GJ)	% Change from Ref Case
Air Sealing	8,208.3	6,987.3	-14.9%	8,487.8	3.4%
Attic Insulation	258,422.5	235,310.7	-8.9%	0.0	-100.0%
Basement Insulation	376,774.3	354,315.6	-6.0%	0.0	-100.0%
Condensing Gas Boilers	6,445.7	6,159.0	-4.4%	6,887.1	6.8%
Condensing Gas DHW	4,502.8	4,251.6	-5.6%	4,640.9	3.1%
DHW Pipe Insulation	8,330.3	7,648.0	-8.2%	8,403.1	0.9%
DHW Tank Insulation	4,602.1	4,229.2	-8.1%	0.0	-100.0%
Early Retire Gas Furnaces	671,887.7	627,502.1	-6.6%	698,322.7	3.9%
ESTAR Clothes Washers	6,082.8	10,291.8	69.2%	0.0	-100.0%
Faucet Aerators	43,334.7	39,787.1	-8.2%	43,699.8	0.8%
Gas Fireplaces	1,575,386.6	1,575,338.5	0.0%	1,580,217.2	0.3%
Heating & DHW	779.5	714.2	-8.4%	789.7	1.3%
Homeowner Air Sealing	1,048,128.8	946,395.7	-9.7%	0.0	-100.0%
Net Zero Ready Homes	96,792.3	91,876.0	-5.1%	102,201.3	5.6%
Showerheads	73,878.4	67,830.2	-8.2%	74,501.2	0.8%
Solar Make-Up Air	658.5	632.1	-4.0%	732.4	11.2%
Tankless Gas DHW	15,975.3	14,702.0	-8.0%	16,239.8	1.7%
Wall Insulation	234,912.2	221,411.5	-5.7%	0.0	-100.0%
Grand Total	**4,435,102.9**	**4,215,382.6**	**-5.0%**	**2,545,122.9**	**-42.6%**

Appendix C-3 contains tables similar to Tables 4-2 and 4-3 and shows the range of estimated EEC measure savings for the commercial and industrial customer groups. As with the residential sector, commercial and industrial measures passing the TRC will generally have slightly more savings in Scenario C than in Scenario B because there are relatively more natural conservation efforts inherent in Scenario B than in Scenario C. Due to the lower price of gas in Scenario C, some measures fail the TRC entirely and drop out. In cases where the potential for a measure is lower in Scenario C, it generally means it failed the TRC for one or more specific building types where it passed in other scenarios. In the industrial sector, there are also substantial changes in the load for process applications and operations, which causes greater variation between the scenarios. In Scenario C, for example, economic growth is assumed to increase levels of production by over 5% by the end of the forecast period relative to the Reference Case. Measures implemented in this scenario are assumed to have greater savings potential because of the higher production volumes and gas consumption in the plants where the production increases are applied.

4.2.3.3 Emissions Reductions from EEC Activity

Figure 4-7 shows the estimated GHG reductions associated with each of the three EEC scenarios. Emissions reductions are discussed further in Section 8.

Figure 4-7: Estimated Annual GHG Emissions Reductions from EEC Activities



4.2.4 Long Term Plan for Implementing EEC Activities

The FEU's plan for implementing EEC activities and reducing demand for natural gas by taking cost-effective demand-side measures involves the following activities:

- Implement the 2014-2018 EEC Plan submitted to the Commission as part of the 2014-2018 FEI Performance Based Ratemaking Application in accordance with the Commission's decision on that application. The 2014-2018 EEC Plan sets out the programs that the FEU intend to implement during the PBR period and will have received rigorous regulatory review by the Commission and interveners prior to approval.
- Conduct a new Conservation Potential Review starting in 2015 to provide new conservation potential data for natural gas in B.C. with which to design EEC programs beyond 2018. The purpose of a CPR study is to examine available technologies and determine their conservation potential, which includes the amount of energy savings that can be achieved through energy-efficiency and conservation programs over the study period. A request for approval of the funding for the CPR and ongoing supporting studies that are important for the design of EEC programs is contained in the 2014-2018 EEC Plan and PBR application.
- Based on the next CPR results, develop an EEC program plan and funding application to be implemented post-2018.

- Based on the next CPR results, conduct a revised long term EEC analysis for inclusion in the next LTRP.

4.3 *DEMAND SIDE MANAGEMENT ACTIVITIES IN THE BROADER CONTEXT*

While the legislative framework for DSM in B.C. focuses on energy conservation as the primary means to achieve demand-side energy reductions, in the broader context, demand-side management encompasses a range of activities in addition to energy conservation. The California Standard Practice Manual, which serves as the general standard of cost-effectiveness analysis in the United States, identifies the following categories of DSM strategies to distinguish between different types of DSM activity.[65]

- **Conservation:** Programs that reduce natural gas consumption during all or significant portions of the year. This includes all energy efficiency improvements. The FEU's Energy Efficiency and Conservation (EEC) programs fall under this category of load management strategies and are discussed in Section 4.2.
- **Load Management:** Programs that may either reduce peak demand or shift demand from peak to non-peak periods. Since the largest portion of natural gas demand in B.C. is for space and water heating which are more difficult to shift, and because the natural gas system acts to store energy allowing it to be drawn down over a longer period of time than with electricity, programs that reduce or shift peak demand for natural gas are more challenging in B.C. However, increasing the load factor by adding customers who use natural gas in a flat manner helps to manage the system. Transportation customers are an example of this type of customer, as are other manufacturing customers such as those in fertilizer production or LNG for export.
- **Fuel Substitution:** Programs that increase annual consumption of natural gas or electricity by inducing the choice of one fuel over another. Two of FEU's current incentive-based initiatives could be characterized as fuel substitution: the residential High Carbon Fuel Switching program and the Utilities' NGT activities. These two initiatives, discussed later in this section, have the benefit of increasing natural gas consumption thereby having a downward impact on customer rates, while at the same time reducing customers' GHG emissions as natural gas replaces the burning of higher carbon fossil fuels.
- **Load Building:** Programs that increase the annual consumption of electricity or natural gas by increasing sales of electricity, natural gas or both. In the broader context of DSM, the FEU's High Carbon Fuel Switching program and NGT initiatives are also examples of load building demand-side activities in that they increase the annual use of natural gas.

[65] California Public Utilities Commission and California Energy Commission. 2001. "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects," pg. 2.

The California Standard Practice Manual also notes that recent utility program proposals aimed at "load retention," "sales retention," "market retention," or "customer retention" may be treated as either a fuel substitution or a load building program since in most cases, the effect is identical to such programs.[66] The FEU's current activities aimed at building load and retaining customers are described here in Section 4.3. This discussion is not intended to address any the requirements of Section 44.1(2) of the *Act*—however, the initiatives discussed below help to meet B.C. Government energy and GHG emission objectives.

Currently, the Companies are undertaking two programs that, although they are not demand-side measures as defined in British Columbia's *CEA*, are demand-side activities in the broader sense. These are the FEU's High Carbon Fuel Switching Program and NGT initiatives. Expenditures and cost recovery mechanisms for the High Carbon Fuel Switching Program and NGT initiatives are separate and distinct from the Companies' EEC activities and have been approved by the Commission at current levels through proceedings separate from the current one. Since the High Carbon Fuel Switching Program is relatively small and NGT initiatives have been extensively reviewed through other regulatory processes, these initiatives are discussed here only to the extent that they provide examples of the types of fuel substitution and load building activities that the FEU should continue to explore, implement and expand where there are benefits to customers and where they create an opportunity for the Companies to help meet government energy and emission goals. The FEU are also examining the potential for adding new, large industrial load customers and are currently engaging a wide network of builders, developers and other influencers of natural gas use in order to increase awareness of the benefits of natural gas and encourage new load.

The impact of the High Carbon Fuel Switching Program, NGT activities, firm contracts for large new industrial customers, as well as every day sales activities for natural gas demand is already incorporated into the energy demand forecasts (Section 3), and therefore, their potential impact on system infrastructure is inherently considered in the system capacity and gas supply analysis discussions in Sections 5 and 6 respectively. The main goal, consequently, is to present them here as examples of load management strategies that the Companies should continue to explore, implement and expand where they are found to be in the interests of customers by adding throughput to the natural gas system thereby reducing rates while also helping to achieve government energy and emissions reduction objectives. GHG emission reductions from demand-side activities other than EEC are discussed in Section 8.

4.3.1 High Carbon Fuel Switching

The FEU's High Carbon Fuel Switching Program supports customer additions and demand growth, and includes initiatives designed to result in lower overall GHG emissions by using natural gas instead of higher carbon emission fuels such as coal, oil, diesel or propane. This program promotes energy efficiency through installation of new high efficiency natural gas

[66] *Ibid.*, pg. 3.

heating equipment and also decreases GHG emissions in B.C. by encouraging a shift from higher to lower carbon-emitting fuels.

The fuel switching program available to residential customers at the time of writing is a retrofit program called 'Switch 'N Shrink,' and is focused on converting oil or propane heating systems to ENERGY STAR® natural gas heating appliances. The Switch 'N Shrink program adds value to new and existing customers through reduced fuel costs, minimizing the environmental hazards associated with oil storage tanks, increasing natural gas throughput, decreasing the need to import propane and heating oil from other provinces, and improving overall air quality. The FEU have attempted to quantify the market potential for high carbon fuel switching and have determined that of the approximately 131,000 dwellings within 100 meters of a gas main that are not natural gas customers, approximately 15% or nearly 20,000 dwellings are estimated to be using oil or propane. The majority of this conversion potential is in the FEVI service territory.

In 2012, the Switch 'N Shrink program converted 557 high carbon fuel users to natural gas, up from 427 in 2011 and 178 when the program was launched in 2010. Based on a technical analysis of the program conducted in 2012, customers consumed 7% less energy on average, which resulted in a 31% average household reduction in GHG emissions (1.6 tonnes of avoided carbon dioxide equivalent emissions).[67] In addition, customers benefited from a 20% average cost savings (or $582 annually) from lower fuel price.[68] The Companies will continue to promote high carbon to lower carbon demand-side measures in order to increase customer growth and reduce GHG emissions in B.C.

4.3.2 Natural Gas for Transportation

As discussed in Section 2 and Appendix A-8, the FEU have developed a strategy to stimulate growth in the NGT market that is focused on return-to-base fleet vehicles. Section 3 provides the demand forecast for natural gas as a transportation fuel while Section 5 discusses the impact of NGT demand scenarios on the FEU's system infrastructure.

4.3.3 New Large Industrial Customers

Additional load from new large industrial customers helps maintain rate competitiveness by increasing throughput on the gas delivery system. With the low natural gas price environment (refer to Section 2.1 for context on natural gas prices), large volume customers have indicated interest to the Companies in expanding operations or developing new major industrial facilities that use natural gas as a feedstock. As a result, the FEU are examining the Utilities' gas delivery systems' ability to accommodate transportation service for new, large industrial demand in various locations across the Companies' service territories. Section 5.1.2.1 illustrates an example of a large industrial customer that has requested firm natural gas transportation service

[67] Or approximately 11 GJ, based on the energy content of the normalized annual heating oil consumption.
[68] InterVistas Consulting, "FortisBC Switch 'N Shrink Program Carbon Emissions and Cost Savings Analysis," Nov. 21, 2012. This report uses a natural gas emission factor of 0.051 tCO_2e.

and the effect that the increased demand would have on system reinforcement requirements. Any major required reinforcements to serve potential new industrial loads would be evaluated as part of a formal submission to the BCUC once firm agreements regarding natural gas services have been made.

4.4 *CONCLUSIONS AND RECOMMENDED ACTIONS*

DSM activity continues to be an important part of the FEU's resources for meeting customers' energy needs, improving energy efficiency, helping to manage customers' energy costs, optimizing use of the energy infrastructure in B.C. and reducing GHG emissions. The EEC analysis shows that significant energy and GHG emissions reductions can be achieved over the planning horizon through ongoing programming and expenditure levels consistent with those in place today under the range of future scenarios examined for the LTRP. The analysis also shows that the EEC measures implemented through the planning period will shift depending on how the future actually unfolds and factors such as energy prices and public policy, which can change over time. **Combined with analysis of the impacts of EEC activities on the capacity requirements of the FEU's natural gas transmission system discussed in Section 5, this 2014 LTRP meets the requirements in Sections 44.1(2)(b) and (f) of the *Utilities Commission Act* to provide an explanation of how the Utilities plan to use EEC activities to reduce energy consumption and help meet customers' demand for energy over the long term, and to explain the extent to which EEC activities can defer the need for new infrastructure projects.**

The FEU should continue to examine opportunities to develop other DSM initiatives that offer similar benefits or to expand existing offerings and where appropriate, seek approval for expenditures related to those offerings.

Recommended actions to acquire and implement demand-side resources over the planning horizon are to:

- Implement the near-term (2014 to 2018) EEC Plan in accordance with the Commission's decision on the FEI 2014-2018 Performance Based Ratemaking Plan Application (PBR) which is before the Commission at the time of writing this LTRP.
- Conduct a new CPR starting in 2015 in conjunction with other utilities and the Government of B.C. that will update the information available to assess the future potential for demand-side activities and guide the development of future EEC Plans.
- Continue to examine the potential for all forms of DSM and analyze the potential benefits and risks for FEU and its customers of implementing new and creative programs that help meet customer energy needs, optimize the use of utility infrastructure, keep energy rates down and/or reduce customer's GHG emissions.

- Continue to work with federal, provincial and municipal governments and other potential partners to explore and identify ways in which FEU's DSM activities can continue to help meet government objectives while ensuring benefits for the FEU and their customers.

5. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

A key aspect of ensuring safe, reliable and secure supply of natural gas to customers is identifying the facilities, or system resources, that the FEU need to construct over the planning horizon. This section discusses the FEU's examination of the Utilities' natural gas delivery infrastructure and identifies any system resource needs in consideration of both regional peak capacity and ongoing system sustainment requirements to ensure that the FEU's systems continue to serve the energy needs of customers across the province. This section is intended to address the requirement in Section 44.1(2)(d) of the *UCA*.

Continued growth in peak demand and managing an aging system of natural gas delivery infrastructure are among the biggest challenges for the FEU's long term planning. System expansion needs are being driven by modest year-over-year increases in forecast peak demand. A low gas commodity price environment and the environmental benefit of using natural gas over traditional fossil fuels are stimulating increased interest from the industrial sector in using natural gas for new or expanded applications, although this interest can change quickly as energy prices change. Growth in natural gas demand as a transportation fuel is also expected as a result of these market conditions. At the same time, the FEU's system sustainment planning process has identified important near-term and longer term system renewal requirements, particularly in the Lower Mainland area of FEI's system. The FEU take a broad outlook that considers long term system capacity and sustainment plans, potential new, large increases in industrial load, and growing NGT demand, which enables an integrated approach to determining the most effective system improvements. This section deals with two general system resource topics, system capacity and system sustainment, in Sections 5.1 and 5.2 respectively.

Section 5.1 discusses the capacity of FEU's natural gas transmission infrastructure to meet current and forecast peak demand for each of the FEU's major transmission service regions – Vancouver Island, Coastal and Interior. Whereas Section 3.4 presents a forecast of system-wide peak demand for the FEU's Core customers, gas infrastructure planning is based on regional peak demand for the pipes that transport natural gas to the load centres. Consideration is also given to potential future new NGT and industrial loads that are not captured in the Core demand forecast. To address system expansion requirements, a number of reinforcement options are presented and discussed for each region.

Section 5.2 discusses system sustainment. As the FEU's planning efforts are undertaken to ensure that planned improvements optimize operation of the system as a whole, the reinforcement options that are under consideration to meet the FEU's capacity needs have also been integrated with the system upgrade requirements identified through system sustainment planning. Section 5.2 highlights the FEU's enhanced asset management practices and discusses improvements required to manage the Utilities' aging assets. For projects occurring within the four year action plan timeframe, timing expectations for applications to the BCUC are based on an integrated approach to both capacity and sustainment planning. The FEU's long term planning efforts continue to focus on ensuring safe, reliable and cost-effective gas delivery service on the coldest day expected over a 20-year time frame.

5.1 SYSTEM CAPACITY

Ensuring adequate capacity within the transmission and distribution systems to meet existing and forecast load is critical to ensuring the safety and reliability of natural gas delivery. This section outlines the natural gas system infrastructure and the system capacity needs to continue delivering energy safely, reliably and at the lowest reasonable cost to the Companies' customers. After determining forecast growth in natural gas demand and the expected impact of demand-side measures across the FEU's service areas, the FEU's system capacity planners examine the capacity of gas transmission systems to meet growth-related demand. When forecast demand exceeds available capacity, a gas system expansion is required. Different system expansion alternatives are then identified in order to examine how to most effectively address specific capacity constraints.

Supply-side system resources must be designed to meet peak demand. However, whereas Section 3 discusses system-wide peak demand for gas supply planning purposes, for system capacity purposes, peak demand must be considered relative to the transmission resources' ability to deliver natural gas to FEU customers. Planning for transmission system expansion is based on a peak forecast of demand for Core market customers and firm, or non-interruptible, demand from transport customers. Peak demand is based upon historical usage correlated against temperature or, for loads that are not temperature dependent, upon firm or maximum consumption values. Information from other studies including the End Use Study (refer to Appendix B-3) is also used to evaluate the impact on peak demand and system expansion timing.

5.1.1 On-System Infrastructure Planning

Gas system infrastructure planning must ensure that gas system assets are of sufficient capacity (in terms of size, compression requirements and volume, for example) to meet the demand on a given system. Peak demand forecasts over a 20-year planning horizon are used for this planning function.

In general, system demand growth is determined by region and applied to hydraulic models which determine resulting pressures at different locations for existing pipe, compression and LNG facilities. Eventually, demand exceeds capacity and a system expansion is required. In addition to load growth, other factors can also reduce system capacity. For example, increased urban density close to existing pipeline assets can lead to a class location change and a subsequent reduction in allowable operating pressure for that pipeline. A reduction in operating pressure will lead to a decrease in available pipeline capacity. These additional factors must be taken into account and are briefly discussed in this section.

5.1.1.1 System Expansion Planning Considerations

Pipeline capacity is determined by the quantity of gas that can be transported from a supply point at a given supply pressure to delivery points at or above required minimum delivery pressures. The key metric driving installation of new resource options is maintaining minimum delivery pressure for a required demand of gas. Physically, pipeline capacity depends on the diameter and length of the pipeline, internal roughness of the pipeline, supply pressure and required minimum delivery pressures. Pipeline pressures are constrained by the maximum operating pressure (MOP). The MOP is established in accordance with standards, codes, and good engineering practice in consideration of original construction specifications. 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 this 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 natural gas enters the intermediate or distribution pressure systems for delivery to customers.

There are three resource options to evaluate when planning system expansions: pipelines, compression and storage. To solve capacity constraints, each alternative is analysed with respect to overall cost, difficulty of implementation, operational flexibility, implementation time, and other factors within the overall philosophy of system sustainment and reliability. Often, a combination of the three resource options leads to an optimal solution:

Pipelines

To increase throughput capacity, an existing pipeline can be replaced by a larger diameter pipeline (increasing the flow area and decreasing the gas velocity) or it can be twinned with a parallel pipeline. Twinning pipelines is called “looping”.

Compression

Adding compression helps to increase the average pipeline pressure, thereby providing a higher supply (or driving) pressure to move the gas. This higher pressure also increases the gas density leading to a reduction in gas pipeline velocity and generally lower pressure drop. Compressors can be added to existing compressor sites to provide additional station throughput capacity or new compressors can be added at intermediate locations on the pipeline.

On-System Storage

Storage facilities located within a service region are considered “on-system” supply-side resources. The FEU consider liquefied natural gas (LNG) storage to be an on-system storage facility. During low demand periods, natural gas is injected into the storage facility. Conversely, during high demand periods, stored gas is injected back into the pipeline system in order to maintain pipeline operating pressure and increase system capacity without having to install throughput capacity from pipelines or compressors. Since the FEU can call upon these resources when necessary, system security and reliability increase through the use of these on-system storage facilities. Another benefit of the FEU's LNG facilities is the ability to provide customers with the potential to buy LNG for fuel use.

5.1.1.2 System Capacity Planning Considerations

Supply-side system resources are identified using computer models of the pipeline systems to carry out hydraulic analyses. Computer simulations allow various "what if" scenarios to be evaluated and compared against one another. In determining the need for transmission system expansions, the FEU consider the following:

- Optimizing resource capacity additions to meet demand requirements over a 20-year planning period.
- Correlating actual billed consumption information against temperature to determine the expected demand under design temperature conditions.
- Planning capacity additions to meet firm transportation demand. Interruptible demand is not considered when identifying system improvements to sustain Core demand. System improvements identified for Core demand provides opportunities for interruptible customers during off peak conditions.
- Designing transmission systems to meet peak demand. Core demand varies on an hourly basis and typically exhibits a morning peaking period between 6 and 10 am and an evening 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. Transmission systems are designed to meet this peak demand condition.
- The amount of line pack within a transmission system determines whether it should be designed to meet peak day or peak hour conditions. As demand increases and pressure in the pipeline is drawn down, the amount of gas "packed" in the pipeline (i.e. line pack) is reduced. Pipeline length and operating pressure determine the amount of line pack available in the system. Typically, longer, larger diameter systems operating at higher pressures with high line pack are designed to peak day conditions; conversely, systems with lower amounts of line pack (due to factors such as lower pressures and smaller volumes) are designed to meet peak hour loads.
- Long lead times are needed for large infrastructure projects. This is due to regulatory reviews, public consultation, conceptual design, and detailed engineering and construction schedules.

EEC activities lead to an overall decrease in annual consumption but may or may not affect peak demand. Some types of EEC activities may lead to an increase in peak demand. Set-back thermostats, for example could potentially reduce yearly gas consumption but lead to concentrating gas demand at specific times during the day, while new on-demand water heaters are likely lead to a reduction in total annual gas consumption but potentially at the requirement of shorter periods of higher consumption. Other end-use trends may lead to either a levelling or an increase in peak demand.

Many EEC measures are expected to lead to a decrease in peak demand. Adding insulation to houses will smooth energy requirements (by retaining heat) but peak demand may go up or down depending upon the BTU rating of the equipment. High efficiency furnaces provide the same level of comfort and heating as an older furnace but at reduced gas loads. When these factors are taken into account, it becomes apparent that the effect of EEC and shifting end-use trends on peak demand cannot be predicted without knowing the specific details of equipment installations. The FEU believe that a reasonable approach to consider the effect of EEC and changing end-use trends assumes that these effects offset one another in the Reference Case peak demand forecast and otherwise should be captured within the expected potential range of peak demand variation using high and low demand sensitivities. This approach explains why the recommendations in this section for system capacity related resources are not replaced by demand-side measures, thus addressing Section 44.1(2)(f) of the *UCA*.

5.1.2 Regional Transmission System Capacity Planning

For capacity planning purposes, the FEU is split into three main transmission systems and a number of smaller transmission laterals. The three main transmission systems are:

- FortisBC Energy Vancouver Island (FEVI): encompassing customers served on Vancouver Island, the Sunshine Coast, Squamish and Whistler.
- Coastal Transmission System (CTS): encompassing the Fraser Valley and surrounding cities, Metro Vancouver and North Vancouver.
- Interior Transmission System (ITS): encompassing communities from the Kootenays, Okanagan, Salmon Arm, Kamloops, Osoyoos, etc.

Each of the three main transmission systems are discussed in further detail below. For each system, the FEU discuss:

- Existing major system infrastructure.
- Demand and capacity balance, which determines approximately when demand in the region will reach the ability of the system to deliver natural gas during peak conditions, thus identifying when system constraints will occur.
- Peak demand forecast sensitivity, or the extent to which higher- or lower-than-expected peak demand over the forecast period will change the timing of any identified system constraints. Constraints that occur further out in the planning period are generally subject to greater timing uncertainty than constraints that occur in the nearer term.

- System expansion alternatives. These are the infrastructure options that exist for solving identified system constraints. The options for constraints that occur in the near term are presented in more detail than those that are further out in the planning period.
- The impact of new demand for natural gas as a transportation fuel (CNG and LNG) on the expected timing of system constraints and consideration of alternative solutions.
- The impact of potential large, new industrial loads on the expected timing of system constraints and consideration of alternative solutions.

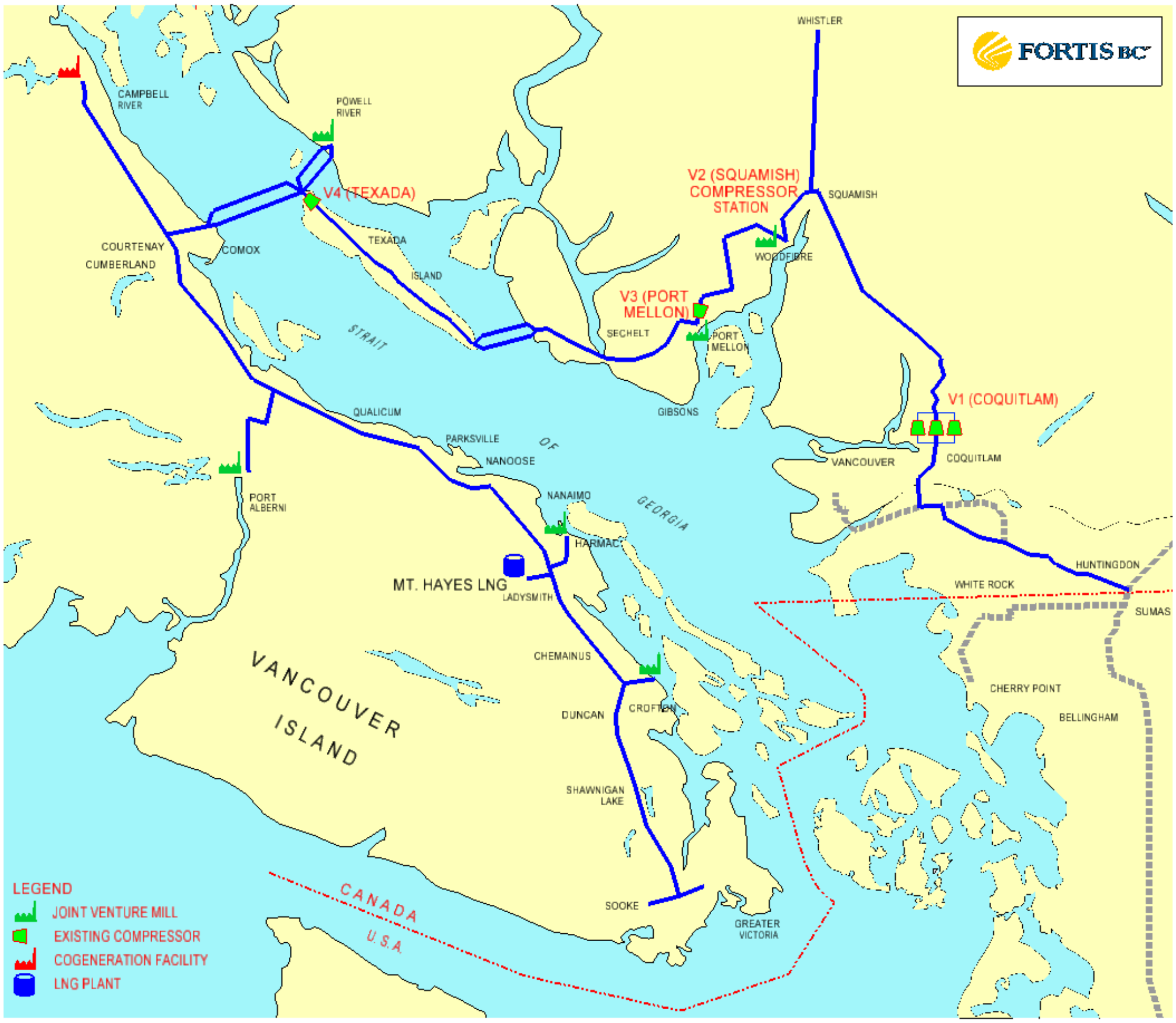
The FEU examine all of these factors to identify the expected timing of both system constraints and the need to develop formal solutions that may require further expenditure applications to the Commission. As these constraints approach in time, changes in the planning environment and new information may emerge that could impact the timing of the constraints or the alternative solutions being considered. Such changes will be presented in future LTRPs or in any required applications to the Commission. A common recommendation for constraints that are further out in the planning horizon is to continue to examine the demand and capacity balance and the potential alternative solutions.

5.1.2.1 FEVI Transmission System

A potential capacity constraint has been identified on the FEVI Transmission System late in the planning period for which both operational and infrastructure solution options exist. This system serves Vancouver Island, the Sunshine Coast and feeds the communities of Squamish and Whistler. It consists of 626 km of high pressure pipelines including three twinned marine crossings of the Georgia and Malaspina Straits, three compressor stations, and the Mt. Hayes LNG storage facility in Ladysmith. Natural gas for FEVI customers is delivered from upstream sources on Spectra's Westcoast Pipeline system to the Huntingdon-Sumas trading point. From Huntingdon, FEVI contracts for transportation capacity across the FEI Coastal Transmission System (CTS) to the start of the FEVI system at Eagle Mountain in Coquitlam. The Mt. Hayes LNG storage facility has improved system reliability and enabled significant operational flexibility of the combined FEI CTS and FEVI systems.

Figure 5-1 shows the layout of the FEVI transmission system including the location of the Mt. Hayes LNG storage facility, compressor stations, major industrial customers and locations of distribution networks.

Figure 5-1: Layout of the FEVI Transmission System



FEVI Demand and Capacity Balance

The FEVI transmission system needs to serve the natural gas capacity requirements for the following customers:

- FEVI Core[69] residential and small commercial customers located on Vancouver Island and the Sunshine Coast, in Squamish (for FEI) and in Whistler (for FEW);
- Pulp and paper mills represented by the Vancouver Island Gas Joint Venture (VIGJV);
- BC Hydro for its Island Generation (IG) Plant, pursuant to a long term Transportation Service Agreement; and

69 All FEVI customers are considered Core customers except for the Vancouver Island Joint Venture Mills and the Island Generation Plant.

- Forecasted expectations for demand from customers using natural gas as a transportation fuel.

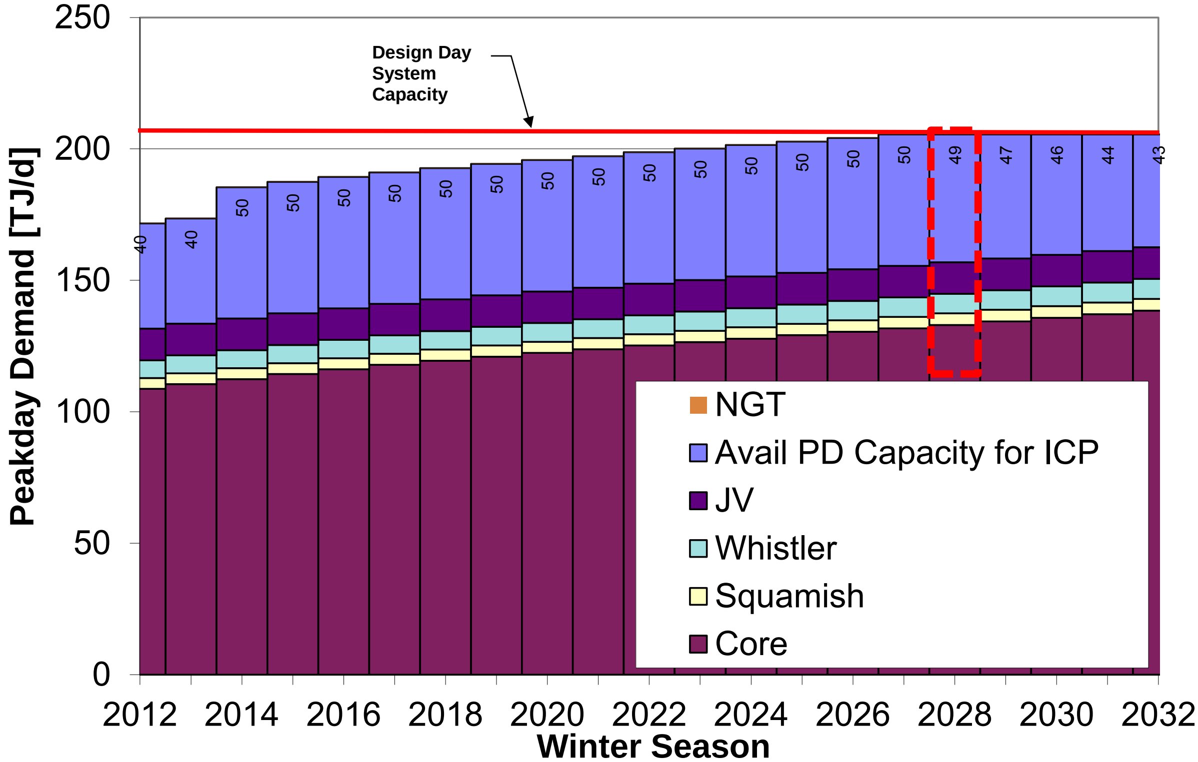
Peak demand for FEVI's Core customers is presented in Section 3.4.1 and Appendix B-1. Current contract demand requirements for IG are 40 TJ/d from November 1, 2012 to October 31, 2013. For the 2013-14 winter, BC Hydro has indicated a contract demand of 40 TJ/d. Since this contract demand can be amended for the following year (i.e. for 2014-15) to a maximum value of 50 TJ/d, the FEU have analysed transmission requirements for FEVI based on the IG contract demand increasing to and remaining at 50 TJ/d from 2014 onwards. The VIGJV has recently increased its contract demand from 8 to 12 TJ/d starting in the 2012-13 winter season. For demand and capacity modelling, it is assumed that VIGJV demand is fixed at 12 TJ/d from 2012-13 onwards. Future daily demand for natural gas as a transportation fuel in the FEVI service region is determined by dividing the annual demand presented in Section 3.4.1 by 365 (days). As such, the daily demand for transportation is forecast to reach 0.04 TJ/day in 2033 in the Reference Case NGT demand forecast and is expected to be used primarily for compressed natural gas vehicles.

Prior to installation of the Mt. Hayes LNG storage facility, the FEVI system was fully subscribed and relied upon a right to call back capacity to IG from BC Hydro during design weather events in order to serve its Core market design day, that is peak demand, requirements. Construction of the Mt. Hayes LNG storage facility was completed in 2011 and the facility entered service for the 2011-12 winter season. This "on-system" storage facility optimizes the existing system infrastructure by providing significant operational flexibility, regional storage resource benefits for both FEVI and FEI, and improved system reliability.

The Mt. Hayes facility has a storage capacity of 1.5 billion cubic feet (Bcf) (approximately 1,614 TJ[70]), of liquefaction capacity of 7.5 million standard cubic feet per day (mmscfd), and a send-out deliverability of 150 mmscfd (161 TJ/d). According to the storage and delivery agreement between FEVI and FEI, as part of its primary service, FEVI retains one third of the Mt. Hayes storage (i.e. 0.5 Bcf or 538 TJ) and send-out capabilities (50 mmscfd or 54 TJ/d) for supply and system capacity needs. FEI will contract the remainder of the storage and send-out capabilities for gas supply benefits. As part of the supplemental service, FEVI can put a portion of its one-third capacity to FEI, and has done so in the past. Further capacity constraints on the FEVI system are not expected until 2028, at which time additional Mt. Hayes send-out capacity above the primary service is required. Figure 5-2 shows the peak demand and capacity balance for FEVI with 2012 base case long range forecast, Core design day demand, and daily transportation requirements for VIGJV mills (12 TJ/d, 2013 onwards) and BC Hydro's IG (50 TJ/d, 2014 onwards). Since the daily demand from natural gas vehicles is forecast to be small relative to other loads, it does not show up in the demand graph. This graph shows a capacity constraint on the FEVI transmission system by 2028.

[70] Using a conversion of ~1.076 TJ/mmscf

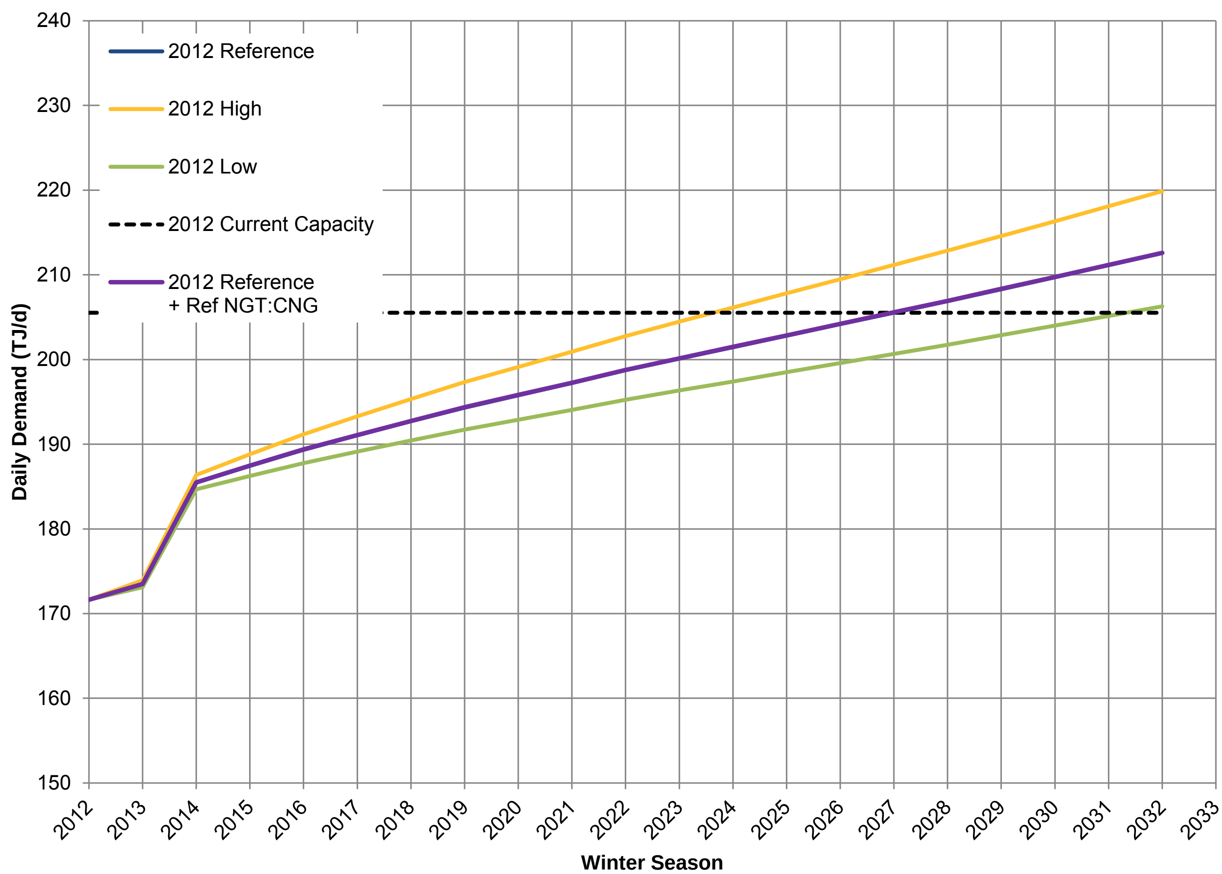
Figure 5-2: FEVI Demand-Capacity Balance with the Mt. Hayes Facility (Reference Case)



FEVI Peak Demand Forecast Sensitivity (Reference, High and Low Scenarios)

The FEVI system peak demand forecast shown in Figure 5-3 was analysed against Low and High demand scenarios. The Low and High demand scenarios were determined by taking the incremental year-over-year increase in Core demand for FEVI and multiplying this value by 79% (in the Low scenario) or 125% (in the High scenario). These values were chosen to maintain consistency with previous resource plans in which the High and Low scenarios were driven by high and low customer additions forecasts. Figure 5-3 shows that the Low and High scenarios move the FEVI capacity constraint back by three years to 2031, or advance it by four years to 2024. Note that in Figure 5-3 there is a 10 TJ/d increase in demand in 2014. This represents Island Generation's contractual right to request a firm capacity of 50 TJ.

Figure 5-3: FEVI Facility Timing Using Reference, Low and High Peak Demand Scenarios



Sensitivity of FEVI Peak Demand to Alternative NGT demand forecasts

The 2032 Reference Case demand for NGT fuel shows an approximate 0.04 TJ/d increase in demand for CNG on Vancouver Island. The FEU have also examined the capacity of the FEVI transmission system to handle higher than expected demand for NGT fuel. For the Reference Case shown in Figure 5-3, capacity analyses indicate that an additional 0.6 TJ/d could be allocated to serve the CNG market without advancing the system reinforcements from 2028. This represents enough capacity to handle a ten-fold increase in CNG demand over the Reference Case.

FEVI System Expansion Alternatives

The identified capacity constraint in 2028 (Figure 5-2) occurs six years after expiry of the FEVI - BC Hydro Transportation Service Agreement (TSA) for service to the IG. If the FEU and BC Hydro extend the TSA beyond 2022, based on current reference scenario forecast numbers, FEVI would have the following three resource options to manage forecast demand for the Core market customers and transportation requirements for the VIGJV and IG, and thus solve the capacity constraint that occurs in 2028:

Option 1: Increase Mt. Hayes Send-Out Allotment

The first option is to increase the FEVI send-out and storage allotment from Mt. Hayes to provide more on-system supply for FEVI during peak demand periods. This option is an operational solution involving the adjustment of contractual obligations between FEI and FEVI for storage and send-out services from Mt. Hayes.

Option 2: Compression Squamish V2

The second option is to maintain the current FEVI send-out and storage allotment and install a new single compressor station at V2 Squamish.

Option 3: Renegotiate BC Hydro Contract with IG

And the third option would be to renew the existing peaking agreement with BC Hydro allowing curtailment of flows to IG to meet Core market requirements.

Table 5-1 presents analysis results for the FEVI System Expansion Portfolio. The earliest date that a system expansion would be required is in 2024 for the High demand scenario. Given that an operational solution (Option 1) is available through FEI and FEVI cooperation, this is expected to be the simplest and most cost-effective solution; therefore, the FEU has not conducted further analysis of the FEVI expansion alternatives.

Table 5-1: Summary of FEVI System Expansion Portfolio and Timings

Demand Scenario	Option 1: Increase Mt. Hayes Send-Out Allotment	Option 2: Compression Squamish V2	Option 3: Renegotiate BC Hydro Contract with IG
High	2024	2024	2024
Reference	2028	2028	2028
Low	2031	2031	2031

As stated above there is approximately +0.6 TJ/d space for additional CNG customer load on the FEVI system. Addition of this 0.6 TJ/d incremental load is above any of the demand expectations forecast for CNG on FEVI, but would advance the anticipated system expansion from 2028 to 2027 (see Table 5-1). This indicates that current forecasts of growth in NGT load on Vancouver Island do not impact the capacity requirements for Vancouver Island.

Potential Large New Industrial Loads

Additions of large single customers on the Vancouver Island transmission system are evaluated on a case-by-case basis to ensure they are in the interests of customers and align with the FEU's objectives of delivering cost-effective, safe and reliable energy. As indicated in Section 2.1.1, low natural gas prices and possibly other market dynamics in B.C. have spurred interest from a range of industries in locating or expanding facilities that would use large volumes of natural gas within the province. Any required major reinforcements to serve potential new industrial loads would be evaluated as part of a formal submission to the BCUC once firm agreements regarding natural gas services have been made.

As a result of inquiries received, the FEU are exploring developing the Utilities' systems to accommodate transportation service for new, large industrial demand in various locations in their service territories. One such example in the FEVI service territory is a small-scale LNG export and processing facility (Woodfibre LNG Project) located on the FEVI system at the former Woodfibre pulp mill site near Squamish. Pacific Energy Corporation (PEC) is exploring the feasibility of constructing and operating a small-scale LNG export and processing facility. FEVI and PEC have entered into a Development Agreement for FEVI to perform development work, including a feasibility study, engineering, and obtaining the regulatory and other approvals required to expand FEVI's system to provide a firm natural gas transportation service to PEC. PEC has presently indicated that it expects to require firm transportation service from FEVI of approximately 230 MMscfd.[71]

The target in-service date of the LNG facility is April 1, 2018. This would require PEC to complete its feasibility and engineering studies and make a decision to proceed with its small scale LNG export project at the Woodfibre site by December 2015. At PEC's request, FEVI is currently assessing the feasibility of advancing the pipeline expansion to support an option of an earlier in-service date. This assessment is on-going; however, FEVI expects the earliest date it would be able to start providing service is Q4 2016, which would require PEC to make a final investment decision by June 2015.

In order to support PEC's timeline on the Woodfibre LNG Project, FEVI has developed a scope of work in the Pipeline Reinforcement Project, which outlines the system reinforcement requirements that are necessary in order to transport the additional load required by the export terminal. FEVI would need to reinforce its existing system with pipeline looping and add compression on the system to meet PEC's natural gas transportation service requirement; this infrastructure expansion would exactly match the firm transportation capacity contracted by PEC. With additional firm contract daily demand on the system, all else being equal, FEVI expects the Woodfibre LNG Project to help reduce costs for firm transportation on the FEVI system and thus provide benefits to FEVI's existing customers through lower rates.

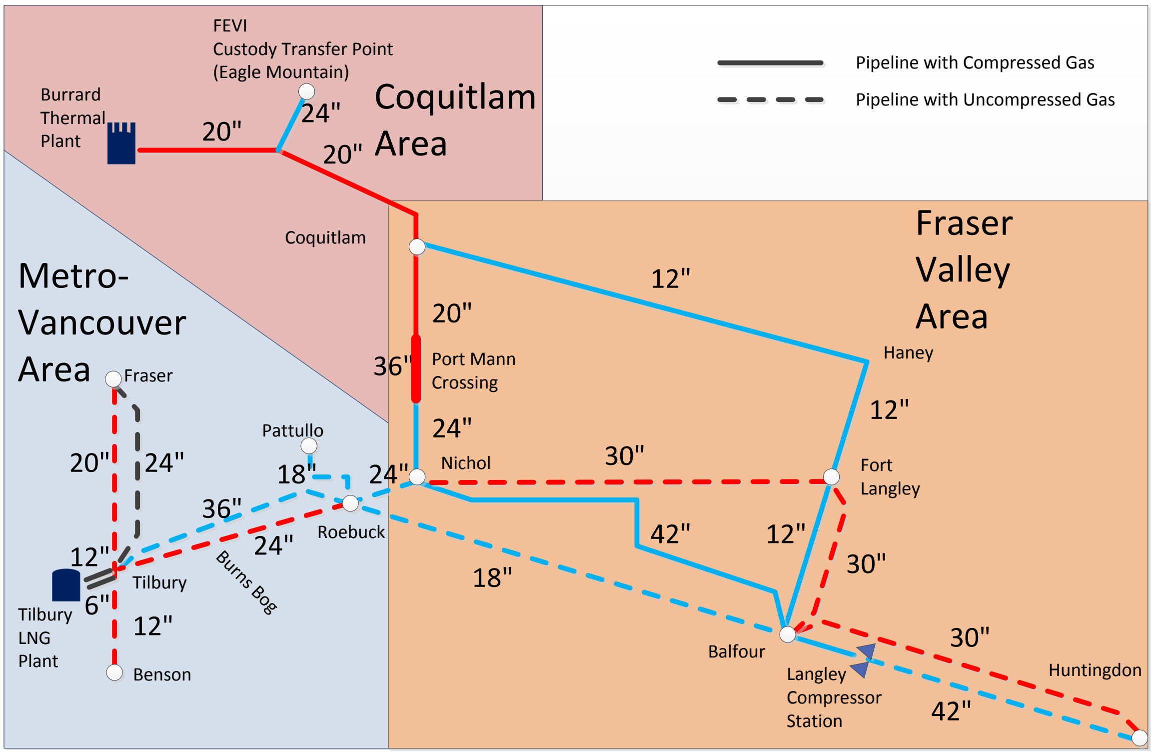
5.1.2.2 FEI Coastal Transmission System

The Coastal Transmission System (CTS) is part of the FEI transmission system and 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. There are two primary transmission-related facilities on the CTS: the Langley Compressor Station, which is used to boost pressures on the CTS during periods of high

[71] As a transportation service customer, PEC's Woodfibre project would not impact FEVI's gas supply planning as the customer would independently acquire its gas supply.

demand, and the Tilbury LNG storage facility, which is used to provide peaking gas supply during colder weather. The CTS delivers gas to the core market distribution networks in the Lower Mainland, and provides transportation service to BC Hydro's Burrard Thermal Generating Station and to the FEVI transmission system at Eagle Mountain in Coquitlam. The schematic diagram in Figure 5-4 shows the general layout of the CTS.

Figure 5-4: Schematic of the Coastal Transmission System Including the Langley Compressor Station and Tilbury LNG Storage Facility



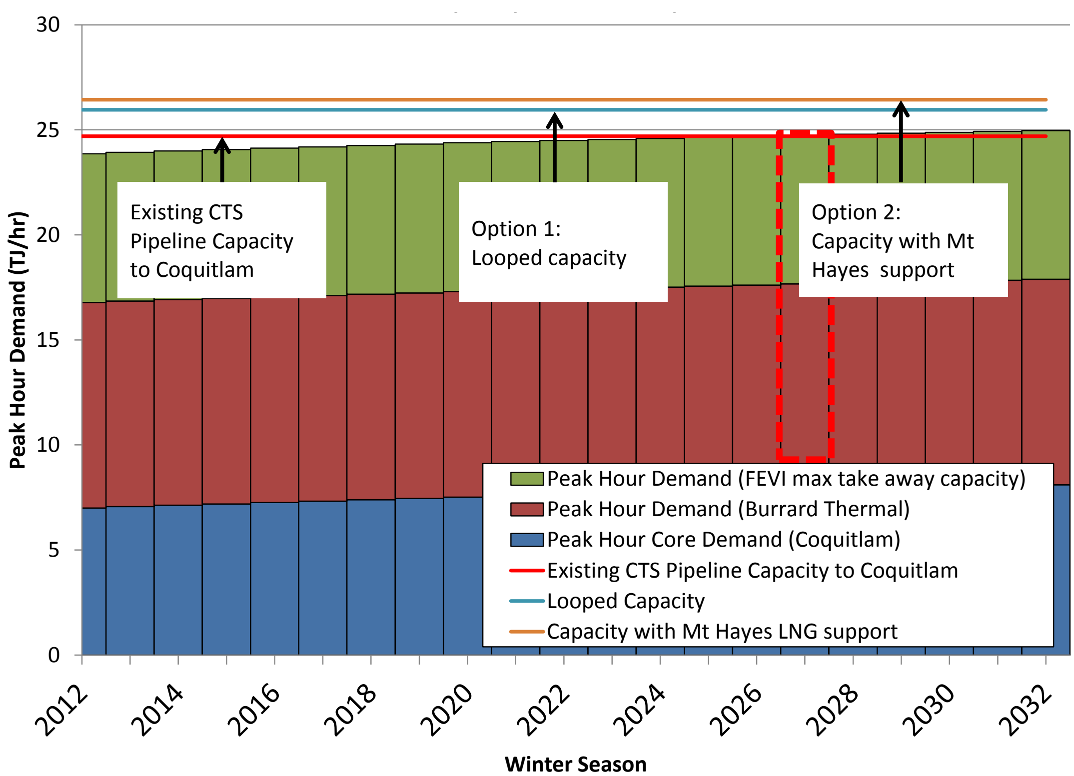
The majority of the CTS in the Fraser Valley and Metro Vancouver areas is already looped and has sufficient capacity to meet the FEU's long term forecast demand requirements. However, the Coquitlam area is primarily fed by a single pipeline running north from the Nichol valve station in Surrey towards Coquitlam. On a peak day, this flow is approximately 35% of the total peak day demand from Core customers in the Lower Mainland (including the BT and FEVI demands). A second feed to Coquitlam via the 12-inch (323 mm) transmission pipeline running east-west through the Fort Langley and Haney areas provides only 6% of the total peak day demand for the Coquitlam area. Consequently, the Nichol to Coquitlam pipeline is expected to face capacity constraints within the 20-year planning period.

CTS Peak Demand and Capacity Balance

With forecast overall growth on the CTS, the Nichol to Coquitlam pipeline has been identified as a system capacity constraint. To assess the resource requirements for the Nichol to Coquitlam pipeline, peak demand is balanced to pipeline capacity. Core demand along the Nichol to Coquitlam pipeline includes the Core demand for the Coquitlam area, FEVI demand requirements (consisting of FEVI, FEW and Squamish Core demands, and the firm transportation demands for VIGJV and IG), firm demand required to service Burrard Thermal Generating Station and the expected, or Reference Case demand for CNG vehicle fuel in the CTS service region.

With the November 2013 release of the BC Hydro Integrated Resource Plan (BCH IRP), BCH indicates that the Burrard Thermal power generation plant will be phased out of service by 2016 as other electrical system assets are brought online. From a gas capacity planning perspective, FEU is contractually obligated to reserve pipeline capacity to supply all six thermal power units at Burrard Thermal during peak demand conditions until a formal change to the contract is received. Based on this planning environment (e.g. assuming that firm gas capacity must still be reserved for Burrard Thermal) the peak demand and capacity balance for the Nichol to Coquitlam pipeline is shown in Figure 5-5.

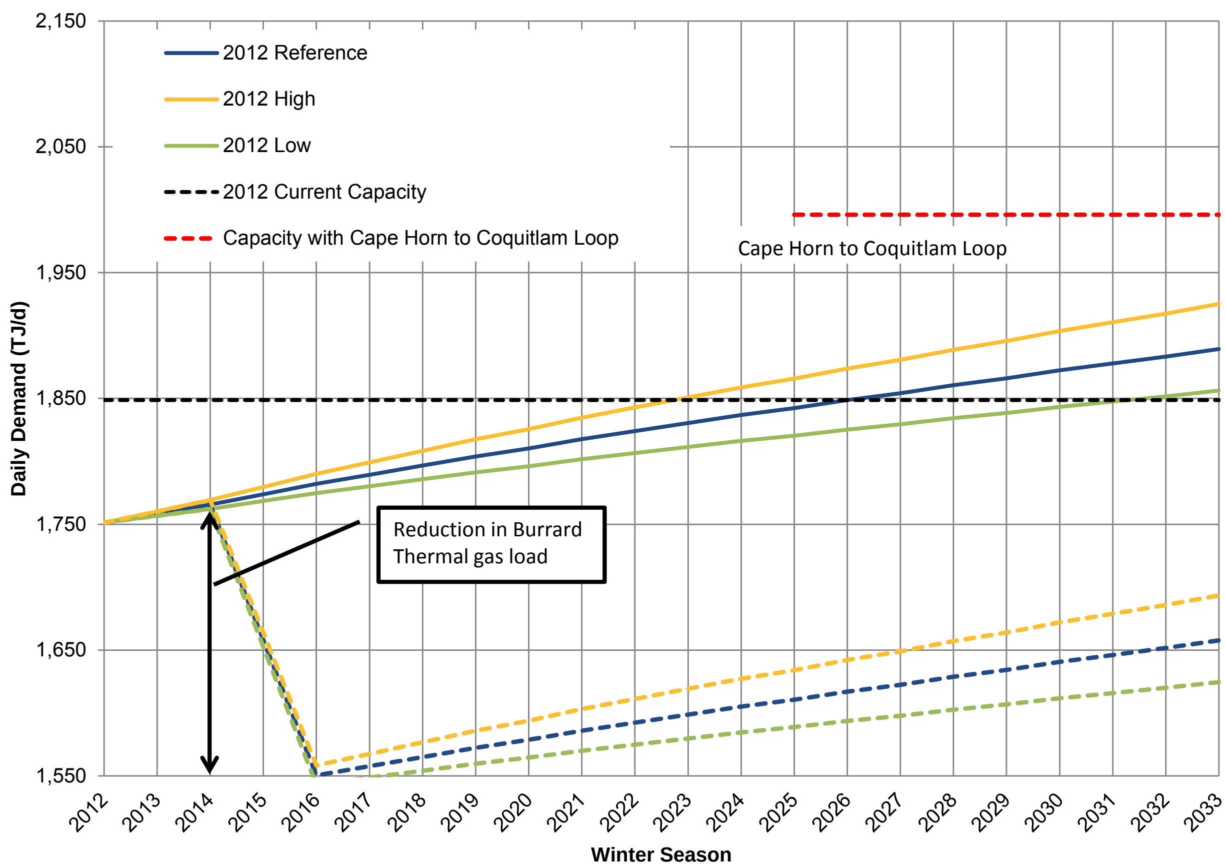
Figure 5-5: CTS Peak Demand and Capacity Curve to Serve the Coquitlam Area via the Nichol to Coquitlam Pipeline



CTS Peak Demand Forecast Sensitivity (Reference Case, High and Low Scenarios)

Reference Case peak demand for the entire CTS, shown in Figure 5-6, was analysed for Low and High scenarios by adjusting the Reference Case Core growth by 76% and 126% respectively. Again, these values were used to remain consistent with previous LTRPs in which high and low customer additions forecasts drove the peak demand sensitivities. The Low, Reference and High cases shown with the solid lines in Figure 5-6 include the current contractual firm demand for Burrard Thermal. The dashed lines in the same figure show the impact of phasing out the Burrard load from 2014 to 2016. With the inclusion of the Burrard Thermal load, Figure 5-6 shows that the Low and High cases delay the capacity constraint on the FEI CTS until 2032, or advance it forward to 2023, respectively. However, if Burrard Thermal is phased out, then Figure 5-6 shows that no capacity reinforcements are required in the 20-year planning window. In this graph, it should be noted that the Reference Case demand forecast and the Reference Case plus CNG transportation fuel demand are very close to one another.

Figure 5-6: CTS Facility Timing Using Reference Case, Low and High Peak Demand Scenarios



CTS System Expansion Alternatives

Under the current planning environment (e.g. assuming that firm capacity is still required for Burrard Thermal) Figure 5-5 indicates that the existing CTS pipeline capacity to the Coquitlam area faces a capacity constraint in 2027. Three main options have been identified to alleviate this capacity constraint:

Option 1: Loop Cape Horn to Coquitlam

A 4.5 kilometre pipeline loop running from Cape Horn (north of the Port Mann Bridge) north to Coquitlam would alleviate this constraint. Based on a 30-inch (762 mm) diameter loop, the pipeline capacity would increase to approximately 26 TJ/hr thereby providing sufficient capacity to meet the 2032 forecast Reference Case loads. However, as part of the Long Term Sustainment Plan discussed in Section 5.2, a 36-inch (914 mm) is the preferred option as it addresses both capacity and system sustainment requirements.

Option 2: Provide Mt. Hayes LNG Support

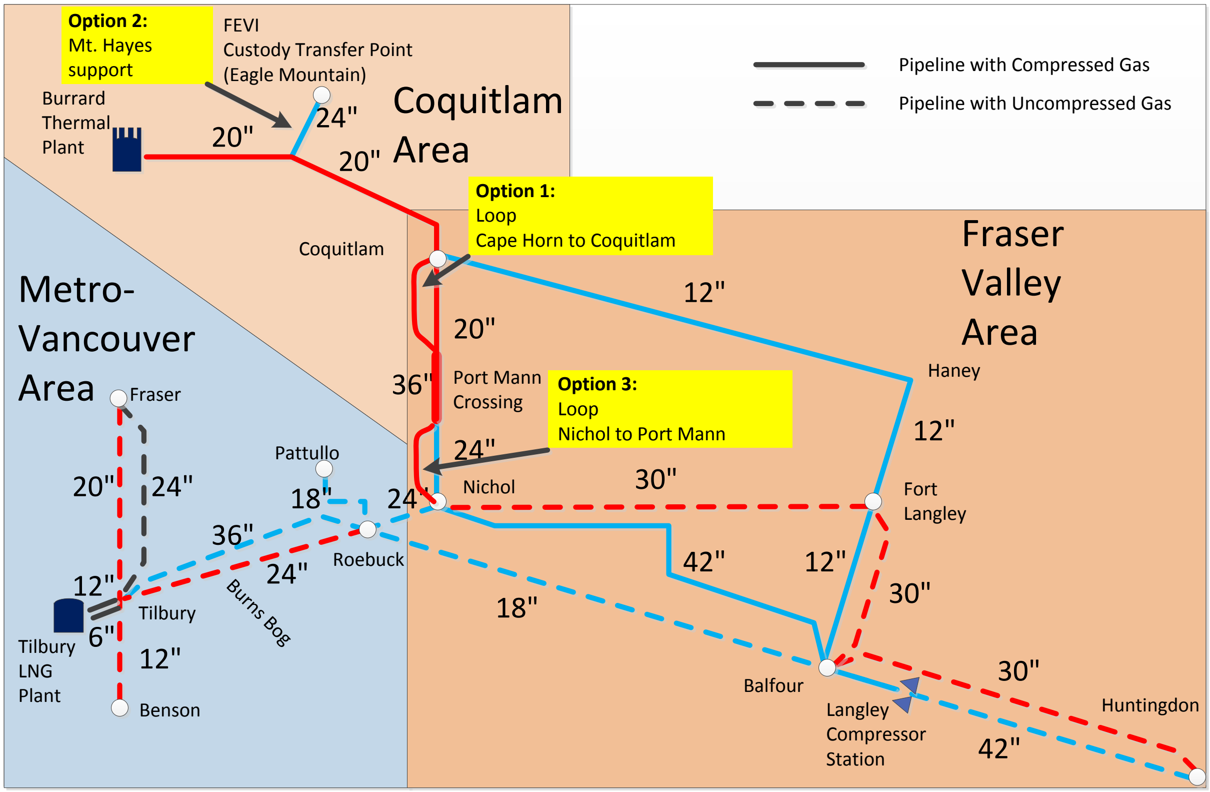
The Mt. Hayes LNG storage facility could also alleviate the capacity constraint identified on the CTS for the duration of the planning period in two ways: Firstly, the Mt. Hayes facility reduces transport requirements to FEVI across the CTS as it provides on-system supply to FEVI during peak demand periods. Secondly, FEI contracts two thirds of the Mt. Hayes storage and deliverability capacity. Delivery of FEI's peaking supplies from the Mt. Hayes storage facility is largely through displacement, which leads to a further reduction in physical transport requirements to FEVI across the constraint on the Nichol to Coquitlam pipeline. Therefore, the capacity constraint on the CTS can be deferred beyond the planning period. Unlike option 1, the use of Mt. Hayes does not fully address Long Term Sustainment concerns.

Option 3: Loop Nichol to Port Mann Pipeline

Replacing or looping the existing 24-inch (610 mm) pipeline from Nichol to Port Mann would also provide sufficient capacity to meet the 2032 forecast demand. This has the added benefit of aligning with the Long Term Sustainment Plan (see Section 5.2.2.2). This option would increase the Nichol to Coquitlam flow capacity to approximately 25.1 TJ/hr.

These three alternative options are depicted on a schematic diagram of the CTS in Figure 5-7. Since the timing of this constraint is late in the 20-year planning horizon, a more detailed analysis and decision on which of these options would normally occur closer to the timing of the constraint, with regular monitoring of peak capacity conditions to ensure the timing does not shift. However, FEI has identified that a solution for this pipeline is needed much sooner to address system sustainment issues. Section 5.2.2.2 describes the system sustainment issue and incorporates this capacity constraint in the consideration of a preferred solution.

Figure 5-7: Location of Possible Coastal Transmission System Reinforcement Options



Impact of Potential Future Demand for LNG and CNG as a Transportation Fuel

Natural gas demand for transportation consists of both the markets for CNG and LNG as vehicle fuel. Additional CNG load for transportation would be added in relatively small increments at various points on the system whereas the point source nature of additional LNG production at Tilbury may create broader system impacts and could trigger the need for suitable system reinforcements of the CTS. The demand for natural gas from transportation sector fuel customers is forecast to continue growing over the next 20 years (see Section 3.3.7); the Lower Mainland area will likely drive LNG and CNG demand growth due to increasing road and coastal marine transport demand.

Based on the FEI's natural gas demand forecast for NGT (refer to Section 3.3.7), the existing Tilbury facility can meet this demand until 2017, after which time demand is expected to outstrip the quantity of LNG available under the approved Rate Schedule 16 tariff. On November 28, 2013, the Government of B.C. issued Special Direction No. 5 to the BCUC to exempt from CPCN review an expansion of up to $400 million of the Tilbury LNG facility.[72] An LNG facility expansion is expected to be in place by mid-2016 to provide the fuel to meet expected LNG

[72] B.C. Order of the Lieutenant Governor in Council, "Direction No. 5 to the BCUC," Order in council No. 557, B.C. Reg. 245/2013 deposited Nov. 28, 2013.

demand. The FEU's long term outlook must consider the system requirements for such an expansion.

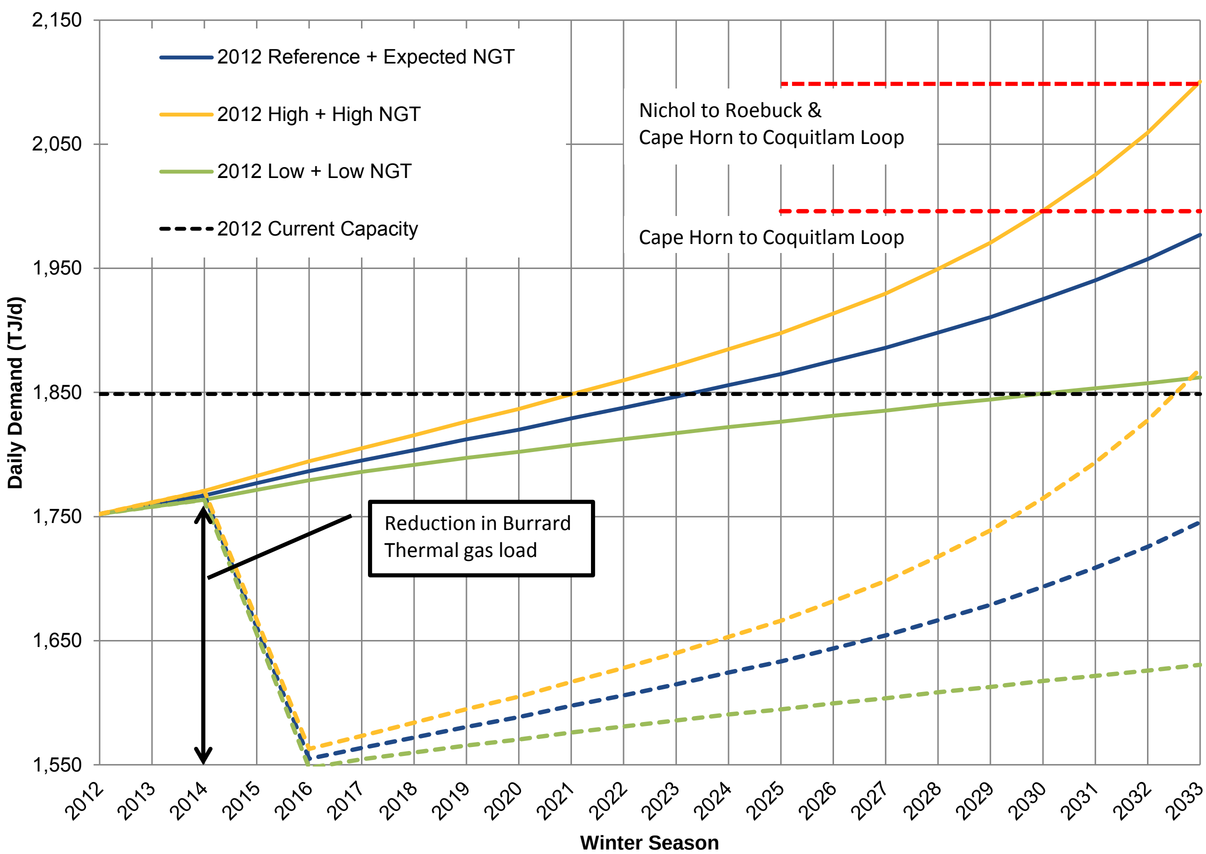
The expected level of CNG fuel demand is captured in the Reference Case peak demand shown in Figures 5-5 and 5-6. These figures show that the CNG vehicle fuel does not impact the timing of capacity-related system constraints. For LNG, however, the demand on the transmission system originates from a point source – the location of the LNG liquefaction and storage facility used to serve that demand. The FEU expects demand by LNG customers in the Lower Mainland to be served by the Tilbury LNG liquefaction and storage facility in Delta, B.C.

Figure 5-8 shows the impact of the reference, high and low case NGT forecast demand on the FEI CTS over the next 20 years with and without the Burrard Thermal load – solid lines include the Burrard Thermal firm load; dashed lines show the effect of phasing out the Burrard Thermal load; dashed red and dashed black lines indicate system capacity constraints. For this analysis, it is assumed that LNG demand grows gradually over the planning horizon and reinforcements are only installed when the total demand exceeds system capacity.

Under Reference (or expected) NGT market growth with Burrard Thermal still considered, the previously identified reinforcements of either Option 1 (looping Cape Horn to Coquitlam with a 30-inch line) or Option 3 (looping the Nichol to Port Mann pipeline with a single 36-inch pipeline) are feasible. Both options provide sufficient capacity for the 20-year planning window. However, the 36-inch pipeline replacement from Nichol to Port Mann provides the added benefit of allowing inline inspection from Nichol and the Fraser River crossing. Figures 5-5 and 5-6 depict the need for and timing of the 36-inch Nichol to Port Mann pipeline loop identified to solve this constraint. Option 2 (Provide Mt. Hayes LNG Support) could potentially be used to address the additional system constraints on the CTS created by increased demand for LNG from Tilbury. This option is not preferred as it presupposes that there is LNG send out available from Mt. Hayes on off peak days. Under the High NGT forecast, Figure 5-8 indicates that the *first* reinforcement would be advanced from 2027 to 2022 and that a second capacity reinforcement would be required in 2030. The second reinforcement has been identified to be an approximate1.6 km loop from Nichol to Roebuck with a 42-inch diameter pipeline. It is important to remember that this High NGT demand is not backed by detailed market strategies or business cases, but rather is intended only to show the impact of a potentially higher and transformational market capture rate as requested by stakeholders (see Section 3.3.7).

When the Burrard Thermal firm load is not included in the NGT analysis, both the Reference and Low NGT scenarios (dashed lines in Figure 5-8) do not need capacity reinforcement within the 20-year planning window. Conversely, the High NGT case would still require reinforcement in 2033 and would consist of one of the three options identified above.

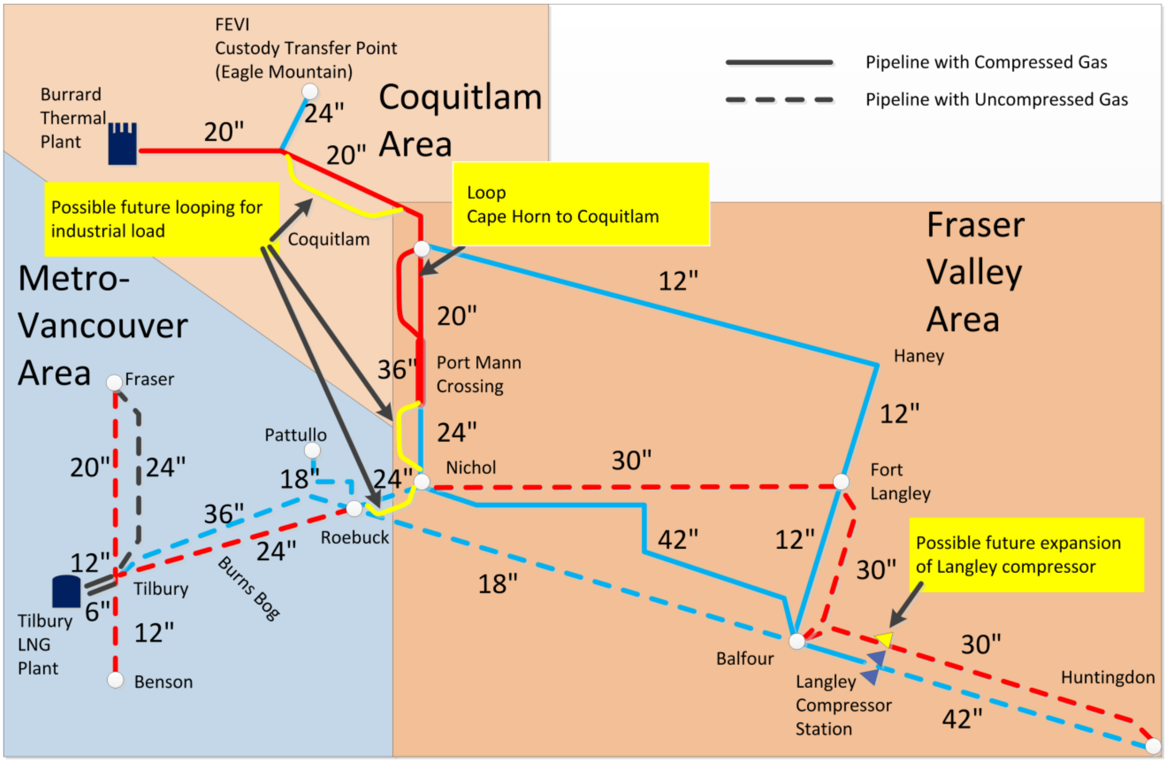
Figure 5-8: Impact of Reference, High and Low Case NGT Demand on CTS Capacity



Potential Large New Industrial Loads

Low gas prices, stability of the Canadian gas market, and existing infrastructure on the FEU CTS have increased interest to add potential new industrial load at different sites near the CTS (see also Section 2.1). Accommodating new industrial loads would require installing additional loops and/or additional compression at Langley. Figure 5-9 shows potential reinforcement loop locations in yellow lines, which were determined by examining the impact of new load in different areas of the service region. As no commitments have been made for any significant industrial load additions on the CTS, detailed analysis on timing and capacity requirements has not been carried out. However, the FEU will consider the overall effect of potential capacity increases, in conjunction with sustainment needs, when planning the infrastructure requirements on the CTS.

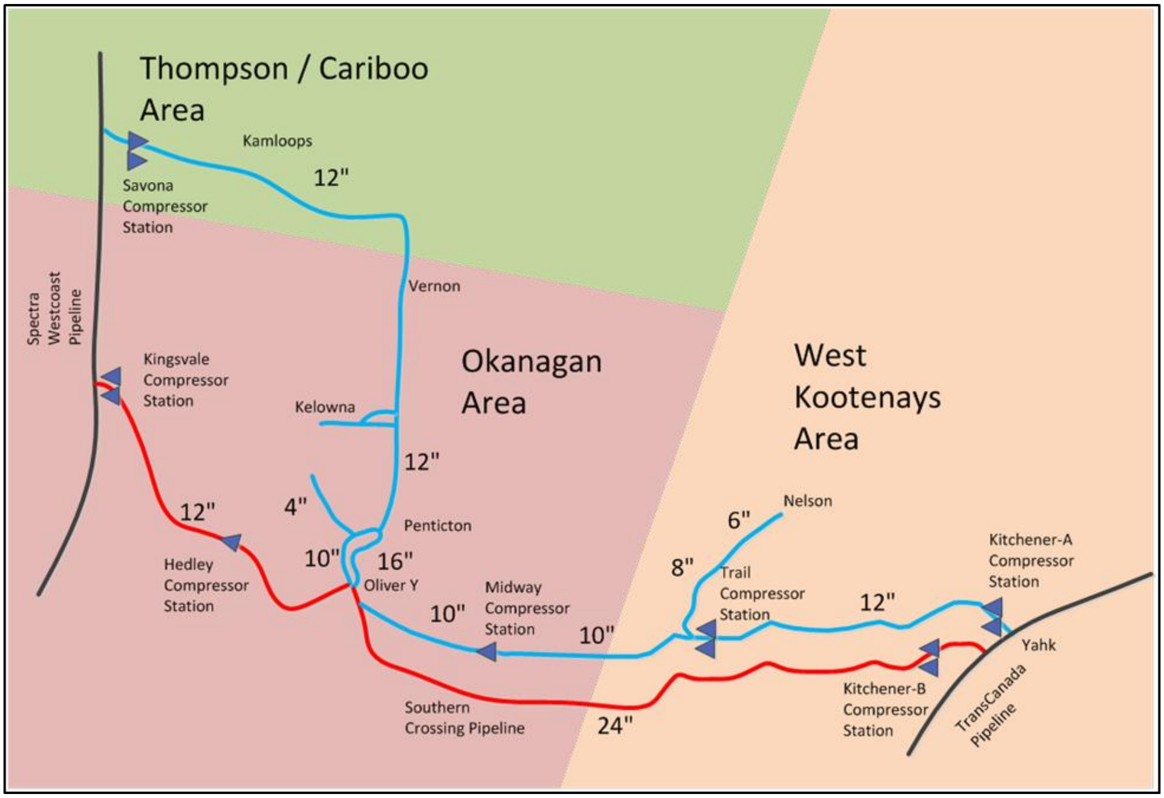
Figure 5-9: Looping Requirement Options to Meet Potential Industrial Load Growth on the CTS



5.1.2.3 FEI Interior Transmission System

The Interior Transmission System (ITS) consists of 1,515 km of transmission pipelines operating at maximum operating pressures between 4,600 kPag (669 psig) and 9,928 kPag (1,440 psig) (see Figure 5-10). Gas received from Spectra'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 winter periods, another pipeline transports gas from the SCP via Oliver-Y hub to Kingsvale for redelivery to the Lower Mainland via the Westcoast Pipeline.

Figure 5-10: FEI Interior Transmission System

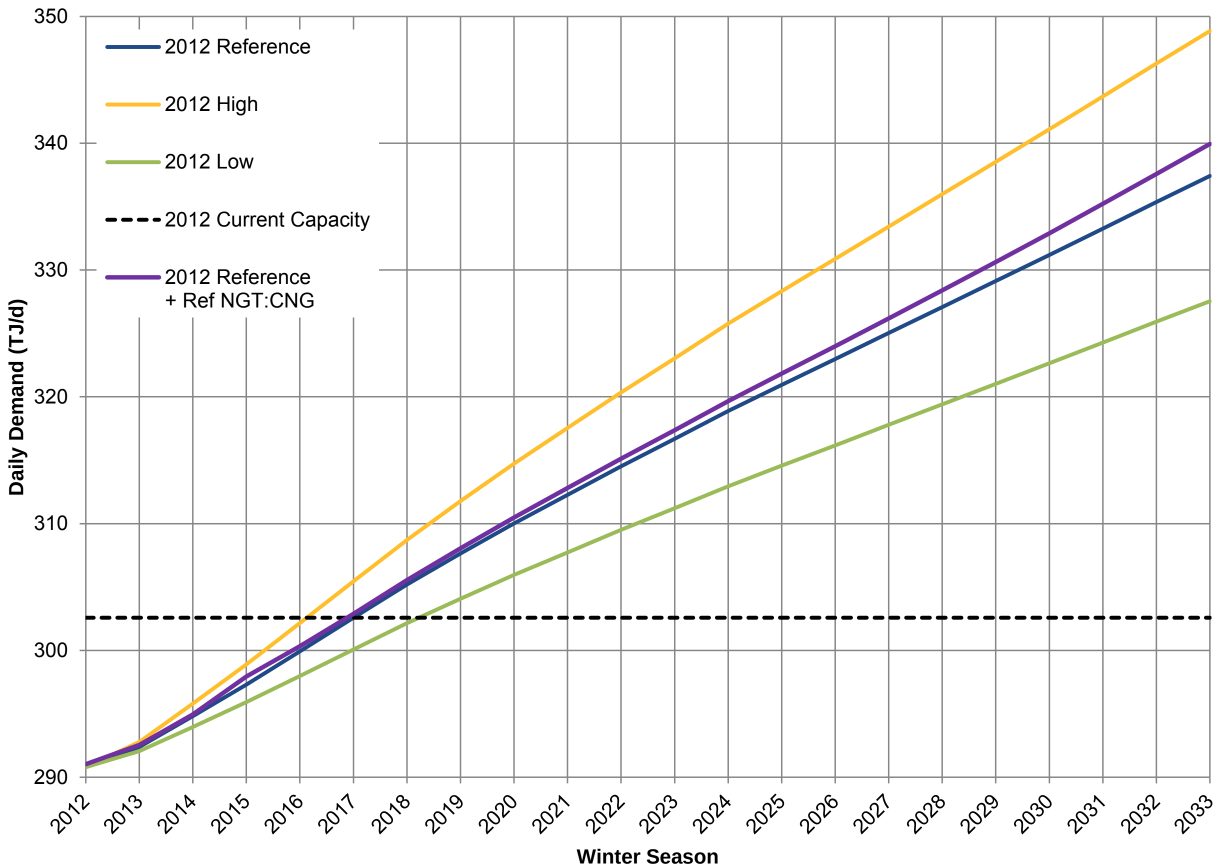


ITS Demand and Capacity Balance

Approximately 60% of the current ITS Core residential and commercial customer demand is concentrated in the South, Central and North Okanagan regions. Growth in the Okanagan region is one of the main factors driving the location of future incremental capacity additions to the ITS. Because the ITS is characterized by long pipeline lengths through a number of less densely populated areas, the system benefits more from line pack – the build-up of pressurized gas up to the pipeline MOP – than the CTS, where high volumes of gas must travel short distances to serve a large population. The ability to draw down the gas that is essentially stored in the ITS allows the FEU to plan the ITS on a peak day, rather than a peak hour, maximum flow. The current peak day system capacity for the ITS is approximately 303 TJ/d.

Since gas is delivered to the ITS from two upstream pipelines—the Spectra Westcoast Pipeline at Savona and the TransCanada Pipeline at Yahk—the ITS peak demand will reach pipeline capacity when the system capacity from both supply feeds are fully utilized. Although gas is delivered to the ITS from the Spectra Westcoast Pipeline in the west and the TransCanada Pipeline in the east, a system capacity constraint occurs in the Okanagan due to regional demand increases in the South, Central and North Okanagan regions. The Reference Case peak demand graph for this region is shown in Figure 5-11, indicating this capacity constraint occurs in 2018.

Figure 5-11: ITS Forecast Demand and Capacity Curves - Reference, High and Low Scenarios



ITS Demand Forecast Sensitivity (Reference Case, High and Low Scenarios)

Figure 5-11 shows the demand and capacity curves for the Reference, Low and High cases for the ITS serving the Okanagan region. The Reference Case demand scenario shows that demand on this portion of the ITS will exceed capacity in 2018 (2019 and 2017 for the Low and High scenarios, respectively). The reinforcement of this system to increase capacity is known as the "Okanagan Reinforcement Project", for which three potential alternative solutions have been identified. This graph also shows that expected demand for natural gas to serve CNG vehicles does not impact the timing of this reinforcement.

ITS System Expansion Alternatives

Three reinforcement alternatives have been identified to meet the Reference Case demand forecast:

Option 1 - South Loop from Ellis Creek and Additional Compression

The first alternative solution is installation of a 20-inch (508 mm) diameter pipeline loop that follows the existing pipeline right of way, running from Ellis Creek (Penticton) to north of Valve SN-10 (north of Naramata) over a distance of approximately 23 km. This pipeline looping would be accompanied by an additional compressor unit at Kitchener-B compressor station and would increase gas supply delivered from the TransCanada Pipeline at Yahk via the SCP. The high demand area between Penticton and Kelowna is predominantly served by the Savona-Oliver 16-inch (406 mm) transmission pipeline.

Option 2 - North Loop from Savona and Kelowna Lateral

The second alternative is installation of a 20-inch (508 mm) loop running from Savona to Valve SN 3-2 (East of Kamloops) over a distance of 52 km. This pipeline looping would increase gas supply delivered via the Westcoast Pipeline at Savona. In 2025, the Kelowna #1 lateral (consisting of both 4 and 8 NPS pipelines on the lateral) would have to be upgraded to a dual NPS 8 pipeline (i.e. remove existing NPS 4 and replace with NPS 8). This is to ensure sufficient inlet pressure to the Kelowna #1 Gate Station.

Option 3 - LNG Storage Facility

The third alternative is an LNG storage facility located between Westwold and Grandview Flats close to Vernon. An LNG facility located closer to the load centre allows natural gas to be moved into storage in times of low gas demand when excess pipeline capacity is available, and provides on-system delivery to the region during periods of high demand. Since a high level cost analyses indicated that options 1 and 2 were less costly than an LNG facility, only the Reference Case demand was analysed for option 3.

Figure 5-12 shows the potential locations of the three system resource expansion options on the ITS. Table 5-2 summarizes the required timing for the ITS facility additions for each resource option.

Figure 5-12: Location of Possible Interior Transmission System Reinforcement Options

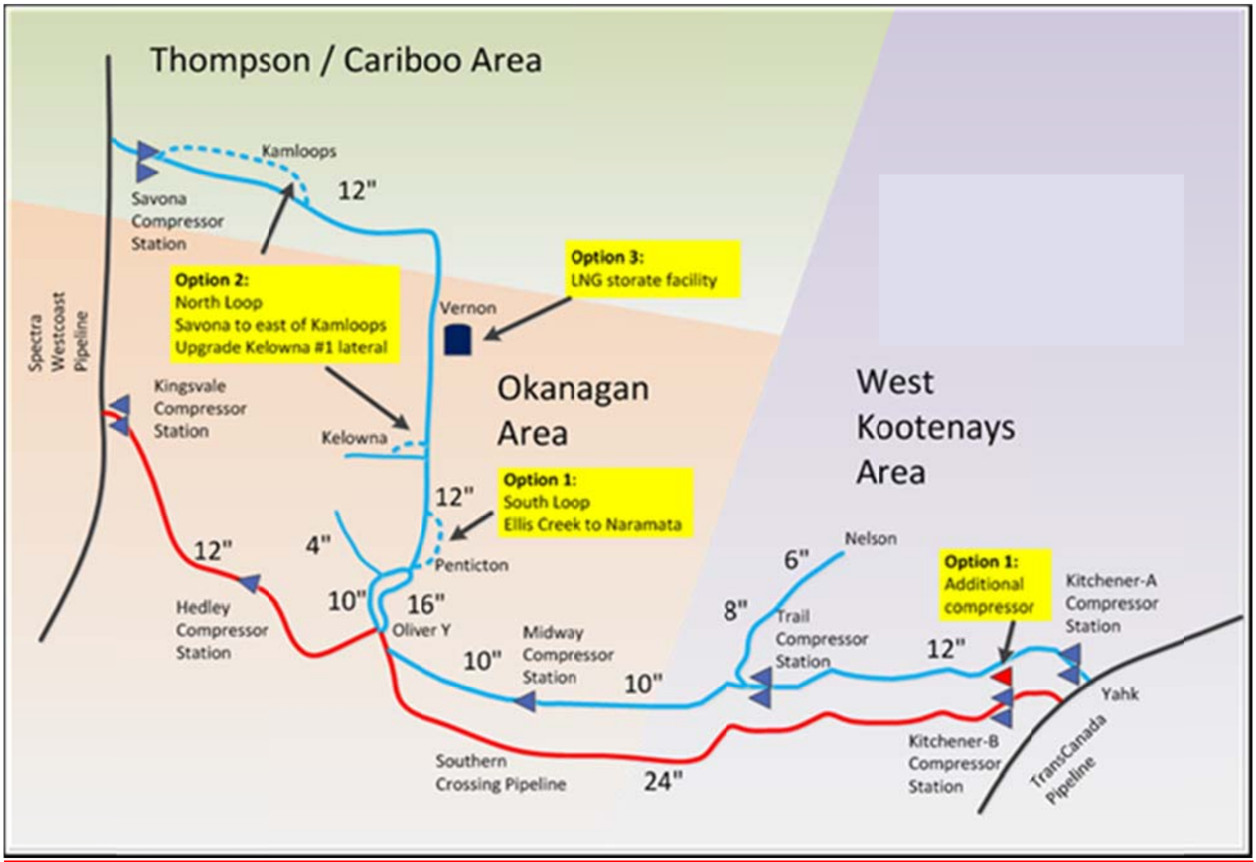


Table 5-2: ITS Resource Requirements

Option 1: South Loop	**Ellis Creek to Naramata** **23 km x NPS 20 pipeline** **3rd Compressor Unit at Kitchener-B Station**
Low	2019
Reference	2018
High	2017

Option 2: North Loop	**Savona to East of Kamloops** **52 km x NPS 20 pipeline**	**Upgrade Kelowna #1 Lateral**
Low	2019	2030
Reference	2018	2025
High	2017	

Option 3: LNG storage facility	
Low	Not analyzed
Reference	2018
High	Not analyzed

Potential New Industrial Load

Based on the 2012 FortisBC Inc. Integrated System Plan filed with the Commission in June 2011, a gas-fired power generating station was identified as one of three preferred build strategy options in the Okanagan area to meet growing peak electrical demand and avoid installing costly electrical transmission infrastructure. For the ITS, this or any other large additional industrial load that could arise would result in enough demand to drive the system reinforcement requirements described in this section (Section 5.1.2.3). The FEU would only include such new industrial demand in its peak demand forecast and conduct detailed system requirements analysis once a firm commitment is made by the customer for natural gas supply services. To date, the only formal proposal has been the gas-fired generating station mentioned above.

Potential for New LNG Demand for Transportation

Given the B.C. Government's direction to support a $400 million investment to expand the Tilbury LNG facility, the FEU's current focus is expanding the Tilbury LNG facility. However, as LNG demand for transportation grows along highway corridors to the Interior, a new LNG production and storage facility added in the Okanagan region would provide additional benefits beyond system capacity expansion. This facility could provide an LNG supply point to serve new NGT demand in the interior as well as the energy needs for remote communities such as Sun Peaks, Revelstoke and Invermere, which are located too far from conventional gas transmission and distribution systems to be supplied economically by extending pipelines. In addition, an Okanagan LNG facility could supply the potential demand from both mine haul vehicles and power generation in the East and West Kootenay regions.

Adding LNG production, storage and associated transportation and dispensing facilities to meet potential new LNG demand may impact the Interior gas transmission and distribution infrastructure. A new LNG facility would create a point source of new industrial load which could require system reinforcements unless LNG were integrated into plans if or when a system capacity expansion is required in the Okanagan area. The FEU will assess each individual opportunity carefully in consultation with its stakeholders to determine needs, requirements and an implementation strategy.

5.1.2.4 Transmission Laterals

FEI operates transmission laterals that connect to the Westcoast and TransCanada pipelines to serve communities and industrial users in north-central and southeastern British Columbia. The

Cache Creek/Ashcroft Lateral has been identified to have insufficient capacity to meet the forecast demand throughout the 20 year planning horizon.

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. Addition of a 17 km pipeline loop is required to meet current firm transportation service to the industrial customer. However, the FEU are currently exploring the possibility of further reducing this contractual demand.

5.1.3 Distribution System Capacity

By convention, the FEU 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 100 psig, and
- Distribution pressure systems operating below 100 psig.

For ease of operation and maintenance, safety to the public, and reliable service, distribution networks operate at a relatively low pressure. FEI operates its distribution networks at a MOP of 60 psig while FEVI operates its distribution networks at a MOP of 80 psig. Supply resources 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, adding a parallel pipe (a loop) or by introducing gas into the network from an alternate source (a backfeed).

Since distribution systems operate at a low pressure through relatively small diameter pipes, there is little line-pack capability for managing hourly demand fluctuations. Therefore, capacity requirements for distribution systems are based on design hourly demand.

In the 2010 LTRP, two distribution systems were identified as requiring or potentially requiring major resource additions: FEI's Metro Vancouver Intermediate Pressure System and FEI's Revelstoke Propane System. An update on these two projects is provided below.

5.1.3.1 Metro Vancouver Intermediate Pressure System

The long range strategy from the 2010 Resource Plan called for a 2.7 km loop to be installed on the Metro Vancouver IP System in 2017, followed by an additional 2.1 km installed in 2022 in order to satisfy IP capacity requirements from the Fraser Gate station. The planned improvement to the Coquitlam IP pipeline (see section 5.2.2.2) to address the IP capacity expansion from the Fraser Gate IP feed via required integrity improvements to the Coquitlam IP pipeline will also address the capacity constraints these projects were conceived to address. These options are being evaluated to determine the best selection and, if deemed feasible, will be put forward through the CPCN process.

5.1.3.2 Revelstoke Propane System

FEI operates a satellite, off-grid propane distribution system that serves residential and commercial customers in the Revelstoke area. Due to its geographic location, Revelstoke is located too far away to economically connect to the natural gas grid. Consequently, propane is transported by railcar and tanker truck to Revelstoke where it is then off-loaded into storage tanks, vapourized as needed and distributed to customers through an underground pipeline system. Core demand growth in Revelstoke is forecast to be minimal and serviceable by the pipe, storage and send-out capacity of the current system. However, plans for a large-scale ski hill and resort development could potentially double the area's load requirements in 20 years and would require FEI to expand the propane system with pipeline extensions, main looping, additional storage tanks and loading facilities. The development has been delayed though, and this delay has resulted in FEI delaying the planned expansion until 2018, pending status of the development. As part of FEI's commitment to provide safe, reliable service to its customers, current plans are to increase the capacity of Revelstoke's second vapourizer in order to provide full redundancy.

FEI has identified Revelstoke's satellite propane system as a potential opportunity to convert the community from propane to natural gas. FEI has conducted an internal pre-feasibility study on using LNG from Tilbury for a possible conversion from propane to natural gas using a satellite LNG station at Revelstoke. After converting the existing propane distribution system to enable natural gas transmission, this off-grid LNG storage facility would accept shipments from Tilbury, re-gasify the LNG and then send it into Revelstoke's distribution network. The pre-feasibility analysis indicated that there could be a benefit to customers from converting to natural gas due to a lower cost of service and potential for a sustained lower delivered commodity price. The study focused on economic estimates and evaluations however, and did not identify specific challenges associated with converting from propane to natural gas. FEI will conduct further internal studies to refine conversion costs, review land availability and the logistics of transporting LNG infrastructure, and will also consult with Revelstoke stakeholders. FEI is planning to further examine the integration of this potential LNG opportunity with an overall LNG market assessment.

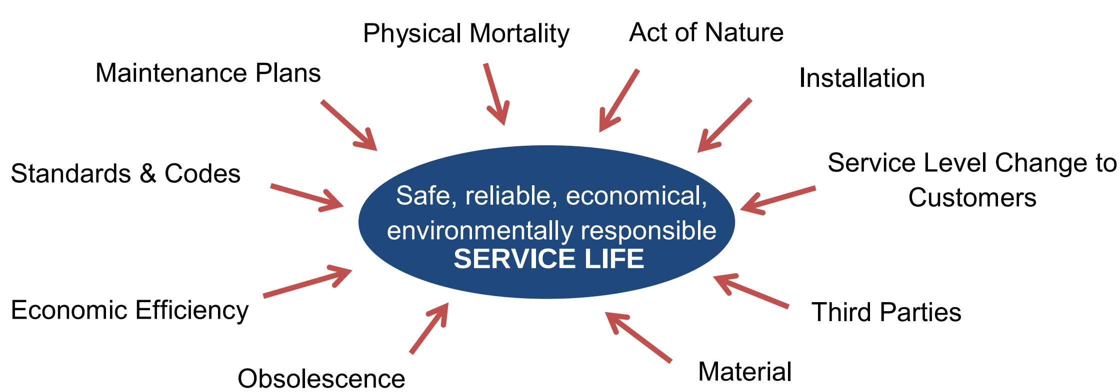
In addition to providing economic benefit to customers in Revelstoke, converting the town of Revelstoke from propane to natural gas could provide significant GHG emission reduction benefit. Based on current propane consumption levels of FEI's Revelstoke customers, the community's GHG emissions would fall by 1,995 tonnes of carbon dioxide equivalent (CO_2e) per year.[73]

5.2 *SYSTEM SUSTAINMENT*

Since the late-1950s, when natural gas was introduced in British Columbia and gas transmission and distribution infrastructure was first established, the FEU and their predecessor companies have a history of providing safe, reliable, environmentally responsible and cost-effective natural gas delivery to their customers. Today, a host of challenges confront the Utilities in addition to large, aging portions of infrastructure: ongoing safety and reliability concerns, increasing regulation, tightening scrutiny on costs, heightened stakeholder expectations, continuing environmental responsibility, avoiding rate shocks and volatility, and delivering customer value.

A number of factors (shown below in Figure 5-13) cause natural gas infrastructure to degrade over time and the FEU must continue to prudently manage emerging risks as they arise. Through normal wear and tear, external factors such as obsolescence, changes in codes and standards, economic efficiency and changes in service requirements, FEU's aging assets face an increasing rate of deterioration and are approaching the end of their expected service life.

Figure 5-13: Factors Affecting Service Life of Asset



Section 5.2 identifies some of the most pressing transmission and intermediate pipeline sustainment issues, organized by region. Additional background information is provided in

[73] This estimate is made using a current propane energy consumption of 210,000 GJ/year, a propane emission factor of 61 $kgCO_2e/GJ$ and a natural gas emission factor of 51.5 $kgCO_2e/GJ$.

Appendix D-1 and, as previously noted, distribution level assets and resource requirements are discussed in the Utilities' Five-Year Capital Plans and Appendices D-2, D-3 and D-4.

5.2.1 Approach to Sustainment Planning

Understanding how and why an asset fails and the risks associated with those failures enables development of appropriate sustainment programs that minimize costs while ensuring the ongoing safety and reliability of the natural gas delivery system. In response to the challenges posed by aging infrastructure, in 2010, FEU initiated the development of a long-term capital planning approach, or Long Term Sustainment Plan (LTSP) approach as an asset management process enhancement. The subsequent development and implementation of the LTSP approach has enabled the FEU to create and support long term asset replacement plans and capital expenditures by developing a relative risk framework that continually measures asset health and identifies specific areas of concern that require further evaluation or action. This relative risk framework provides a tool that, in conjunction with FEU's other Integrity Management Program activities, facilitates proactive decision-making on appropriate mitigating actions. This proactive decision-making tool, in turn, will assist in ensuring that asset replacements are made only where needed and supported by data, thereby reasonably minimizing the need for early asset retirements.

The FEU have been proactive in implementing the LTSP process and convening a LTSP project team that has developed:

- An enhanced understanding of asset condition and the future reliability of natural gas delivery assets;
- A sustainable methodology to identify and prioritize capital work required as much as 20 years into the future; and,
- A prioritized list of future projects and programs required to ensure the ongoing operation and maintenance of a safe and reliable natural gas delivery system at the lowest reasonable cost.

The implementation of the LTSP process has led to the identification of areas of concern from a sustainment perspective, and further analysis has enabled the creation of long-term sustainment capital plans (Sustainment Plans) for FEU's distribution and transmission assets. For each asset, the relative probability and consequence of failure is evaluated, which together reflect the level of relative risk of the asset. The relative probability, consequence and risk are expressed by means of a numerical score calculated via customized criteria evaluating possible failure modes and causes. This process uses geospatial analysis software and a custom database application to extract data from FEU's geographical information system in real-time, as well as using data from other enterprise and external systems and records. The data input into the risk assessment is objective and represents the most current available information, supplemented by manual analysis where necessary.

The risk scores derived using the above methodology and the underlying factors used to calculate the scores can be used to evaluate asset condition and pinpoint areas to be analyzed further for potential replacement or mitigating actions. These results support the decisions of asset management staff in identifying long term programs and projects, and in prioritizing those programs and projects relative to one another. Programs and projects identified are added to the FEU's capital projects and executed under sustainment management processes.

In the 2010 LTRP, the Utilities stated that they had embarked on a plan to enhance their asset management practices in order to be able to better manage the impacts of aging assets.[74] Through this exercise, the Utilities have gained a better understanding of asset condition and the impact of age, and have realized that age is not the causal factor that affects the probability of asset failure. Rather, the probability of failure is determined by the presence of threats such as corrosion or natural forces which act on the pipe. For example, corrosion is dependent on factors including coating and mitigating measures such as cathodic protection. Steel pipe that is properly coated and has effective cathodic protection has little threat of corrosion and can last virtually forever. Polyethylene pipe was expected to last 35 to 40 years when it was first installed in the early 1980s; however, samples of such pipe of this age removed from service in 2011 were tested by an independent laboratory and showed no degradation in performance. Thus, an asset's risk is dependent on the presence of threat factors which the asset management project team identified through literature, experience and expert knowledge. This approach ensures that the FEU's resources are allocated to where they are most effective at mitigating threats to pipe condition, which thereby maximizes the cost-effectiveness of each dollar spent and optimizes the service life of assets.

5.2.2 Transmission and Intermediate Pressure Sustainment Plans

Sustainment capital expenditures increased from 2010 through 2013 and are expected to continue to increase. A number of major projects have been identified as requiring further analysis and the FEU continue to gather, assess, and analyze the information needed to determine what, if any, mitigating actions are necessary. Although safety remains the primary component of assessing risk, the FEU also strives to ensure that customers pay only for projects that are required to continue the ongoing safe, reliable delivery of natural gas.

The following sections review the FEU's intermediate and transmission pipelines by region from a sustainment perspective. As noted below, sustainment issues in the Lower Mainland service area have been identified as those requiring the most immediate attention. To address these issues in a holistic manner, capacity needs and alternatives from Section 5.1 have been brought into consideration to develop the FEU's comprehensive system sustainment plans. While the LTSP process for each of the FEU's service regions looks out up to 20 years, it recognizes that the condition and risk factors associated with assets will change over time and assets that exhibit higher risk factors need more immediate attention. Therefore, rather than setting

[74] The FEU and other entities in B.C. that manage the province's energy, transportation, water and wastewater infrastructure are all faced with managing the impact of aging assets.

definitive time period boundaries for sustainment plans (i.e. a 5-year, 10-year or 20-year Sustainment Plan), the plans identify when nearer term projects are required and therefore when the costs for those projects need to be included in the five-year capital plans or, depending on the size of the projects, when CPCN applications need to be developed and submitted to the Commission.

5.2.2.1 FEVI Transmission System

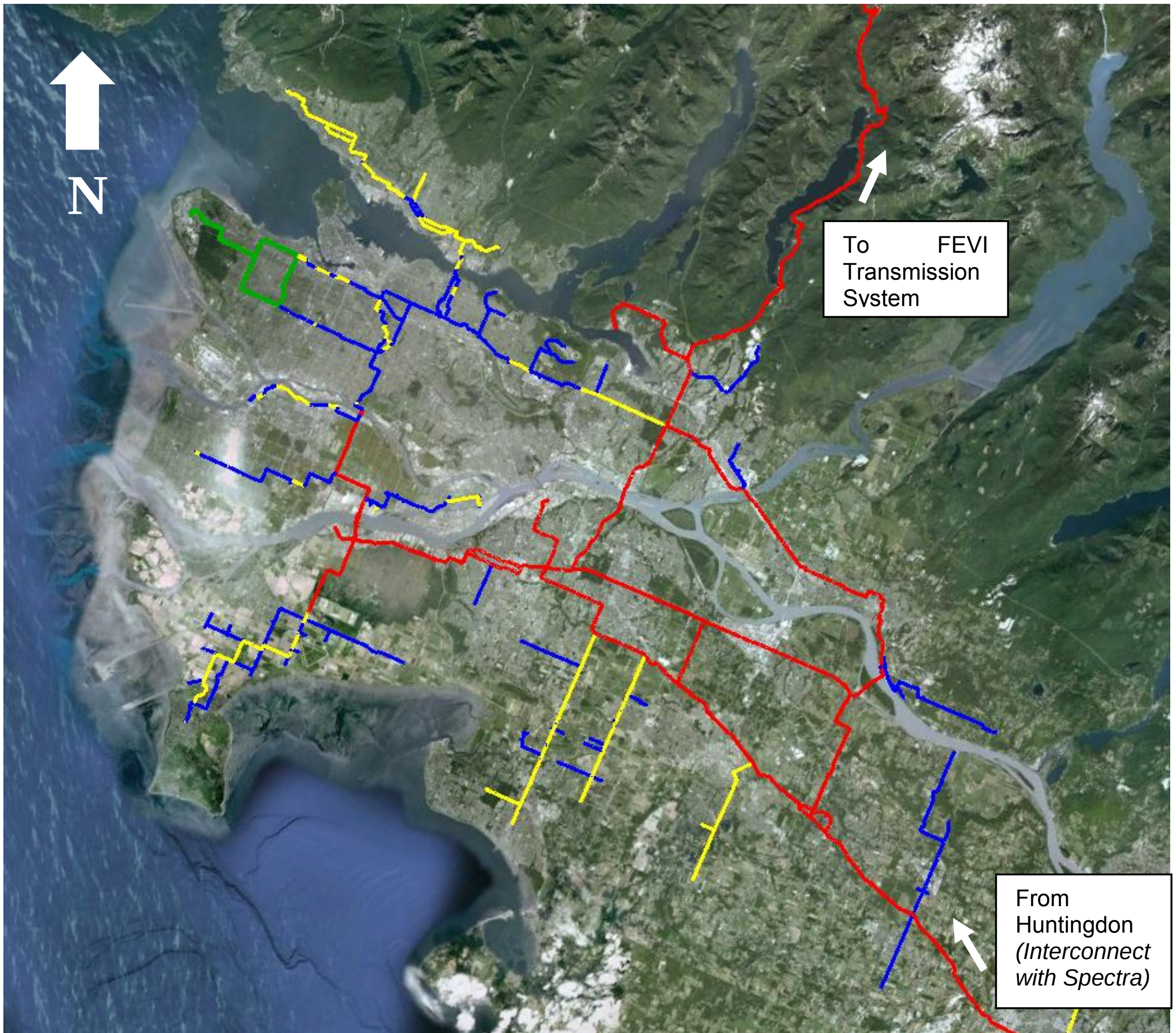
As noted in Section 5.1.2.1, the FEVI transmission system is comprised of 626 km of high pressure pipelines including three twinned marine crossings of the Georgia and Malaspina straits, three compressor stations, and the Mt. Hayes LNG storage facility in Ladysmith. As the FEVI transmission system is relatively new, and in good condition, it is not surprising that the relative risk of failure associated with this system is lower than that for certain areas on the FEI transmission system. Although the FEU continue to analyze and assess the relative risk across all of its service regions, the initial focus of detailed sustainment plans is on the Coastal Transmission System, where the relative risk is highest.

5.2.2.2 FEI Coastal and Lower Mainland Intermediate Pressure System

As noted in Section 5.1.2.2, the CTS consists of a 265km 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 (refer to Figure 5-4 for a diagram of the CTS layout). As Sustainment Plans discussed in this section include intermediate pressure pipes as well as transmission pipes, this network is referred to as the Coastal System for the remainder of this discussion. The Coastal System delivers gas to core market distribution networks in the Lower Mainland, and provides transportation service to BC Hydro's Burrard Thermal Generating Station and to the FEVI transmission system at Eagle Mountain in Coquitlam. The Lower Mainland Intermediate Pressure (IP) System is a network that delivers gas to pressure regulating stations throughout the service area, and is fed primarily from Fraser Gate and Coquitlam Gate stations with a minor feed through Patullo Station. Pressure Regulating stations then reduce pipeline pressure from intermediate pressures to distribution pressures for delivery to the Lower Mainland as shown in Figure 5-14.

The FEU LTSP team has identified a limited number of high priority sustainment issues on the Lower Mainland IP System and the Coastal System. While projects at FEU are typically identified, budgeted and executed as discrete assets, in reality, the natural gas delivery system is a series of integrated assets and changing one asset impacts others. Correspondingly, planning projects and assessing the requirements for those projects must be done at a system level instead of at the asset level. This is especially true for the complex system in the large urban environment of the Lower Mainland service area shown in Figure 5-14. Project planning for sustainment needs on the Coastal System in particular incorporates consideration of the system capacity needs and alternatives previously identified in Section 5.1.

Figure 5-14: Aerial View of the Lower Mainland Intermediate Pressure, Transmission Pressure, and a Portion of the Distribution Pressure Systems Under Consideration



Source: FEU data overlaid on Google Earth mapping

- Transmission pressure pipelines operating at 300 psi or greater
- Intermediate pressure pipelines operating at 100 psi up to 300 psi
- Intermediate pressure pipelines operating at 100 psi up to 300 psi
- Distribution pressure pipelines operating at less than 100 psi

Figure 5-14 is a diagram of the Lower Mainland with transmission pipelines indicated in red, intermediate pipelines in blue and yellow, and a portion of the distribution pressure pipeline system in green. A number of projects have been identified by FEU for the Lower Mainland system over the next five to ten years as a result of the LTSP process and are summarized in Table 5-3. In keeping with the FEU's commitment to dialogue with Aboriginal communities on an ongoing and timely basis, FEI has initiated consultation with affected communities and have engaged First Nations in the area through the system sustainment planning process.

The following projects (except for Burns Bog) will be submitted through two CPCN applications in 2014. The first CPCN will include a pipeline replacement of Coquitlam IP and a 700 meter section of Fraser Gate IP, in addition to pipeline loops of Nichol to Port Mann and Cape Horn to Coquitlam (identified in Table 5-3 as Nichol to Coquitlam); the second CPCN will include the Nichol to Roebuck pipeline loop. Although the Fraser Gate seismic upgrade project is listed below with an estimated at $3 to $4 million (therefore under the $5 million CPCN threshold), it is included here as it is an integral part of the assessment of the Lower Mainland natural gas delivery system. Additional inspection and analysis must be conducted before determining an appropriate course of action for Burns Bog.

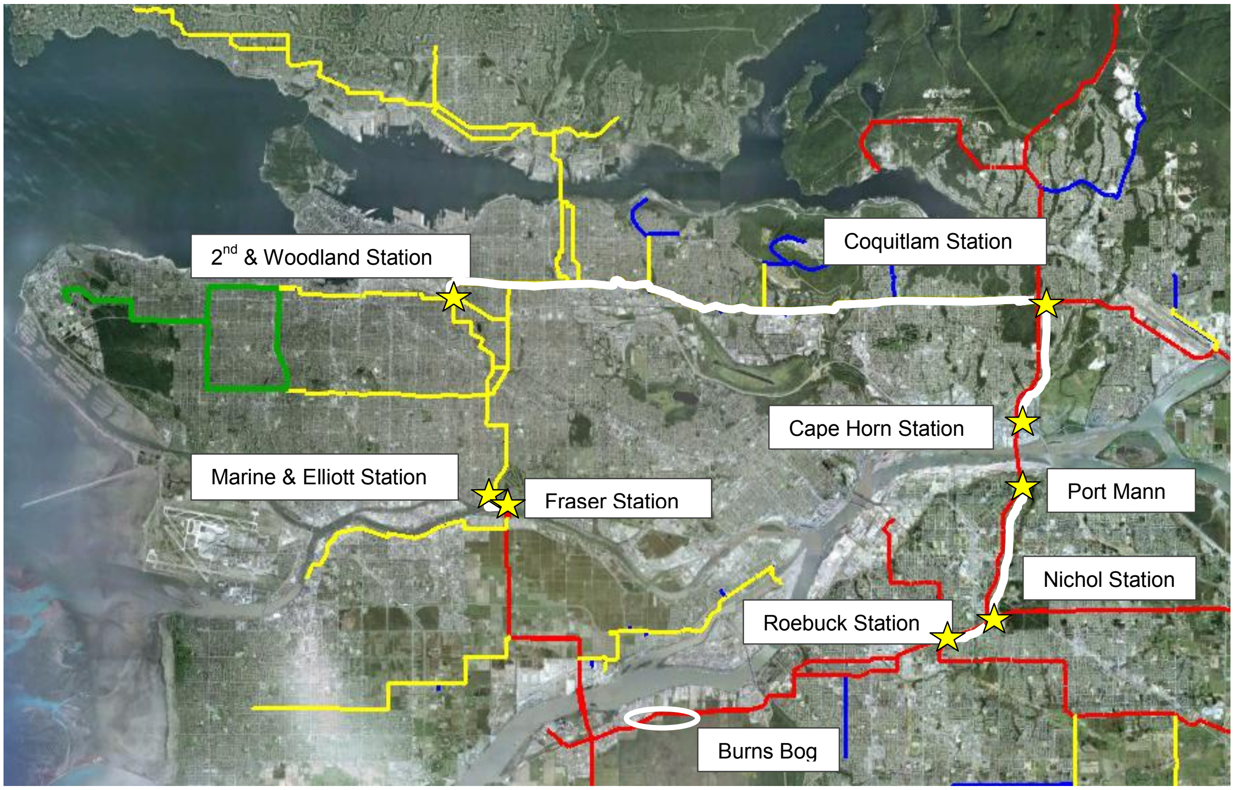
Table 5-3: Portfolio of Proposed Sustainment Projects for the Lower Mainland Service Area

Pipeline	Sustainment Issue	Proposed Solutions
508 mm Coquitlam Gate IP Pipeline	A number of leaks have been experienced on this pipeline, and subsequent investigative digs led to the identification of active corrosion on multiple sections. The leaks and corrosion are due to disbonding of a field-applied coating at the girth-welds. Based on the leak history and evaluations of the investigative digs, the pipeline has been assessed as nearing the end of its service life and requires replacement.	Replace the 508 mm pipeline—consider increasing pipe diameter to improve security of supply and to enable mitigation of seismic issues on the Fraser Gate IP pipeline (see below). Estimated cost $125 to $200 million. This replacement is linked to other projects as noted.
762 mm Fraser Gate IP Pipeline	High risk of failure from seismic movement. Analysis indicates either replacement or stabilization of 700 m of the 762 mm pipeline is required. However, Coquitlam system capacity must be improved before addressing seismic risk.	Options to enable work on seismic upgrade: • Install a temporary bypass (not technically feasible due to a railway obstruction). • Reinforce/ increase back-feed capacity through the Coquitlam 508 mm pipeline. Estimated cost $3 to $4 million. This project is only feasible with increased capacity through the Coquitlam Gate IP pipeline.

Pipeline	Sustainment Issue	Proposed Solutions
Nichol to Coquitlam	The current pipeline capacity is inadequate to supply Coquitlam Station and reinforce the Fraser Gate IP outlet.	• Upgrade the 323 mm Livingstone to Coquitlam pipeline (With a cost estimate at greater than $150 million, this option is too expensive when a more economical, practical solution exists). • Loop the 508 mm TP pipeline from Cape Horn to Coquitlam. Estimated cost $28 million; AND • Loop the 610 mm TP pipeline from Nichol to Port Mann (to be done first, see below).
Nichol to Coquitlam	In-line pipe inspections are required between Fergusson Station and Port Mann Station.	• Loop Nichol to Port Mann with 914 mm pipeline. Estimated cost $24 million. • Move the 610 mm receiver from Fergusson Station to Port Mann. Estimated cost $3 million.
Nichol to Roebuck	Analysis of risk from a security of supply perspective indicates a pipeline loop is required.	Loop Nichol to Roebuck with 1067 mm pipeline. Estimated cost $22 million.
Burns Bog	High stress on pipeline due to ground movement.	Conduct in-line inspection (ILI) and analyze data before proceeding.

Figure 5-15 below illustrates the proposed capital project locations on the Lower Mainland IP System and the Coastal Transmission System. White lines indicate sections of pipeline that must be replaced or looped and yellow stars indicate pressure regulating stations. Burns Bog appears as a white oval instead of a line since additional inspection and analysis must be conducted before determining an appropriate course of action.

Figure 5-15: Aerial View of Proposed Capital Project Locations on the Lower Mainland IP System and the Coastal Transmission System



Source: FEU data overlaid on Google Earth mapping

Additional details of the analysis and planning for the Lower Mainland Intermediate Pressure and Coastal Systems are provided in Appendix D-1. This discussion includes consideration of how the system capacity requirements for the FEI CTS (Section 5.1.2.2) are integrated into the system sustainment planning for the Lower Mainland.

5.2.2.3 FEI Interior Transmission System

An effort similar to the analysis being completed on the Coastal System is required on FEI's Interior System as the methodology developed through the LTSP process (referred to in Section 5.2.1) has identified certain areas on the Interior system that warrant further examination and planning. Initial reviews have identified areas where there are integrity issues such as corrosion and security of supply vulnerabilities. While the FEU's Asset Management team is focusing on the more immediate concerns identified on the Coastal System, examination of the Interior Transmission System is an ongoing process that will result in a long term asset replacement plan for the Interior system. These identified conditions will provide a starting point for in-depth analysis that will be conducted in the future when FEI focuses more closely on sustainment issues in the Interior. It is anticipated that a series of projects will be required for the Interior system similar to those identified above for the Lower Mainland in order to continue to provide safe, reliable and cost-efficient natural gas delivery service.

5.3 UPDATE TO THE FIVE-YEAR CAPITAL PLAN

The FEU's capital plans contain projects related both to capacity requirements and sustainment requirements, and include both transmission and distribution system projects. The projects included by the FEU in their capital plans are numerous and are therefore segmented into regular capital expenditures and major capital projects. Many of the regular capital expenditures are smaller in nature and are therefore not identified in any of the preceding discussion of long term major system capacity and sustainment needs, as is the case with many of the distribution level projects. Five-Year Capital Plans are segmented as follows:

Figure 5-16: Expenditure Categories in the FEU's Five-Year Capital Plans

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 Plans
Major Capital Plan	• Capital projects that do not require a CPCN • Capital projects that require a CPCN

Regular capital expenditures are categorized into Categories 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 are categorized into projects that do not require a CPCN and those which do require a CPCN to proceed.

While notable capital expenditures are listed below, the FEI, FEVI, and FEW Five-Year Capital Plans for the 2013-2018 period are presented in Appendices D-2, D-3, and D-4 to provide context for this Resource Plan. The FEU are not submitting these Capital Plans for the purposes of approval by the BCUC as part of its review of the 2014 LTRP. Consistent with past practice, the FEU believe that the appropriate forum for review of its capital expenditures is through its Revenue Requirements Application filings. As the FEU's Five-Year Regular Capital Plans and Major Capital Plans include all planned capital expenditures, the FEU believe that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the *Act*.

5.4 RECOMMENDATIONS FOR SYSTEM REQUIREMENTS TO MEET GROWTH AND SUSTAINMENT NEEDS

Sustaining the FEU's existing natural gas system infrastructure and planning to meet future demand growth are undertaken to ensure that planned improvements optimize operation of the system as a whole. With annual increases in forecast peak demand and potential new sources of demand from NGT and industrial sources, the FEVI, FEI CTS and FEI ITS transmission systems will all face capacity constraints within the 20-year planning period. System reinforcements are needed in the Lower Mainland portion of FEI's natural gas delivery system to address long term requirements for both system sustainment and capacity constraints. System constraints related to capacity requirements in the Okanagan region of the FEI's ITS are also looming. The FEU's LTRP recommendations to address system capacity and system sustainment needs are to:

- Develop comprehensive CPCN applications based on the Lower Mainland System Sustainment Plan, and as such, integrating the CTS long term system capacity requirements for submission to the BCUC in 2014. This work is underway and is continuing as of the date of this LTRP.
- Continue to monitor and study the system capacity constraints identified to occur in 2018 in the Okanagan region of the ITS and complete the analysis of system reinforcement alternatives in anticipation of a CPCN application to the BCUC in the next three to five years.
- Prepare detailed system sustainment plans for the FEI Interior South, FEI Interior North and FEVI service regions following completion of the project application and approval processes related to the Lower Mainland System Sustainment Plan.
- Implement the FEI and FEVI Capital Plans as approved by the Commission through the appropriate Revenue Requirements filings.

6. GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Gas supply portfolio planning and price risk management are key elements in providing secure, reliable, and cost-effective supply for customers over the long term. Gas supply portfolio planning (Section 6.1) includes the strategies and activities used by the FEU in securing gas supply and contracting for storage facilities and transportation capacity to meet Core customers' annual and peak load requirements. Price risk management (Section 6.2) includes the use of both physical and financial tools and strategies to reduce market price volatility and provide some rate stability for customers. Monitoring and understanding the natural gas marketplace and its changes and developments are necessary for effective resource planning over the short and longer term.

This section describes the FEU's gas supply and portfolio planning and price risk management, and addresses the requirement in section 44.1(2)(e) of the *Utilities Commission Act*. The LTRP is not seeking approval of the FEU's gas supply portfolio or the Companies' price risk management activities, as these approvals are sought through separate applications to the Commission. Discussion of the Companies' Annual Contracting Plans (ACPs) and Price Risk Management Plans (PRMPs) is included in the LTRP in order to provide context for the resource planning, price risk management and market price environment rather than for specific Commission approval. The impact of demand-side measures to date is inherently considered in the ACP since the short term demand forecast, on which the ACP is based, captures these recent efficiency trends. Future ACPs will likewise consider future demand-side measures, since the ACP is shorter term in nature and updated annually, thus addressing Section 44.1(2)(f) of the *UCA*.

Key factors in this portfolio planning include resource cost and availability, which are determined in the natural gas marketplace. Consequently, gas supply portfolio planning activities must also consider regional marketplace developments that will impact traditional regional gas flows and supply and demand in the region, as well as the cost and availability of regional market resources for the FEU (briefly highlighted in Section 6.1 and further discussed in Appendix A-2) in both the near and long term. At this point in time, these developments include the shale gas supply potential in northern B.C., initiatives by TransCanada Pipelines Limited (TCPL) in capturing this B.C. gas for its Alberta markets and the potential for LNG exports from B.C. to Asia. Furthermore, due to the limited gas infrastructure and resources including natural gas storage capacity in the region, the FEU must often compete with other regional utilities, such as those in Washington and Oregon, for these resources. Therefore, the FEU must continuously monitor market developments and be proactive in relevant regulatory proceedings and resource contracting to ensure effective gas supply portfolio planning for customers over the long run.

For managing price risk, physical tools such as commodity purchases and storage, as well as financial tools such as hedges, help the Companies maintain the competitiveness of natural gas and reduce the impacts of adverse market price movements on customer rates. As previously mentioned in Section 2, while natural gas prices have fallen in recent years due to the increase in supply arising from shale gas developments, market price volatility still occurs due to fluctuating supply and demand balances. Furthermore, natural gas prices are not expected to remain at their current low levels for the long term. While the focus of price risk management in the past has been primarily on short term planning, the FEU believe the current market price environment creates opportunities for longer term strategies. Going forward, these could include consideration of longer term instruments or tools that could improve long term cost certainty and help provide stability in rates as well as ensuring security of supply for customers.

6.1 *REGIONAL MARKET DEVELOPMENTS*

Significant regional changes are occurring that will impact the FEU's long term gas supply resource contracting. Section 2 reviewed the natural gas commodity market, highlighting that it is changing as a result of the development of new supply basins. Given that many of these new basins are close to traditional consuming markets in eastern North America, this change affects supply, demand, and pricing on both a North American basis, as well as regionally in B.C. In part, these broad changes are leading to new developments and proposals that seek to improve the region's natural gas transmission systems and enable increased gas flows from production areas in northern B.C. to markets in Alberta and B.C.'s west coast to support a number of LNG export proposals. More information regarding these developments, including the potential to expand FEI's gas transmission system from Kingsvale on the Spectra system to Oliver on the FEI system in the B.C. interior in order to diversify supply alternatives for major demand centres in the PNW, is provided in Appendix A-2, Regional Gas Supply Infrastructure. With limited alternatives from where supply can be cost-effectively sourced, it is critical that the FEU continue to monitor and assess market developments and plan appropriately for longer term resource contracting in order to continue to be able to meet the FEU's objectives. These developments will impact how the FEU plan and contract for resources to serve customers by meeting the objective of providing safe, reliable and cost-effective natural gas service.

6.2 *SUPPLY PORTFOLIO PLANNING*

6.2.1 Background and Overview of the Gas Supply Planning Process

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. Gas supply is also provided via the FEU's own on-system LNG storage facilities.[75] For the FEU, understanding market dynamics, including identifying regional infrastructure opportunities that could benefit customers over the long run, is critical. Competition among market participants for favourable gas pricing and for physical capacity on the regional transmission infrastructure means that utilities must always be vigilant in identifying regional developments that could negatively impact

[75] The FEI-owned Tilbury LNG storage facility in Delta, B.C. has a capacity of approximately 0.6 PJ. The FEVI-owned Mt. Hayes LNG storage facility near Ladysmith, B.C. has a capacity of approximately 1.6 PJ.

customers or, conversely, identifying opportunities that could provide benefits. The FEU are involved in helping to manage key regional issues that include ensuring the availability of regional gas supply for their marketplace as well as the development and tolling of infrastructure that facilitates the movement of supply to market (see Appendix A-2 regarding the Komie North Decision for an example of this involvement).

The FEU file an Annual Contracting Plan (ACP) with the Commission each year, in which the FEU assess the overall North American market and evaluate the regional market with respect to supply and infrastructure. 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.

While ACPs include development of gas portfolios for the upcoming gas contract year[76], they must also consider resources available and market developments over the longer term as these will ultimately impact the annual gas supply portfolio.

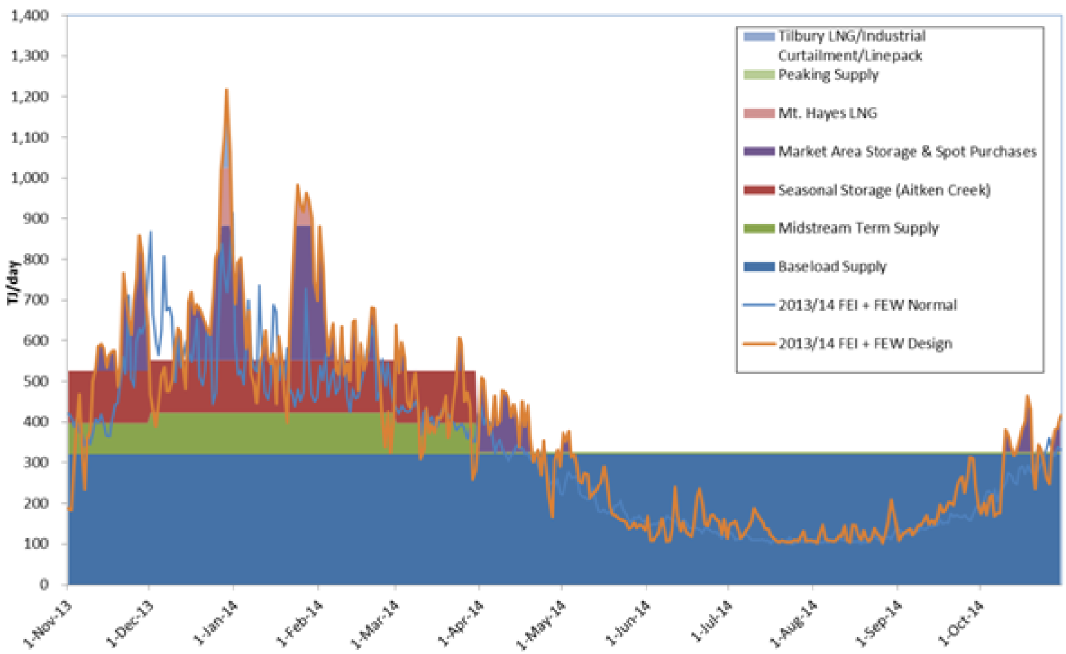
The FEU design their portfolios to provide secure and reliable daily gas supply to customers so that both forecasted normal and peak design day demand is met. Supply resources include contracted term and spot supply, gas injected and withdrawn from various leased storage facilities, and company owned on-system LNG facilities. Many of these resources are contracted for the long term if they are cost-effective and reliable, and if there are concerns with their long term availability. Over the short term, the portfolios do not change significantly from year to year. However, the portfolios can change over the long run as market changes occur and new infrastructure is developed.

The FEU continuously assess their mix of pipeline, storage and supply options in order to balance security and diversity of gas supply, while attempting to minimize the cost of the total portfolio. Contracting considerations for storage facilities are generally planned to cover a longer time horizon, such as three years or greater, due to risks with limited availability of such resources in the region as a whole. The ability of the FEU to continue to provide gas supply to Core market customers under severe winter conditions and emergencies requires contracting for a variety of resources within the portfolios. The diversity of resources also facilitates the provision of backstopping supply in the event of supply failure for those customers who have chosen to purchase their commodity supply from natural gas marketers under the Customer Choice program. For example, Figure 6-1, illustrates the forecast peak[77] and normal load for

[76] Gas contract year spans the 12 months from November 1 to October 31.
[77] For gas supply planning purposes, peak demand is defined as the design day demand, or the amount of natural gas demand that is forecast on the coldest day expected to occur over a 20 year period. Refer to Section 3.4 for additional explanation of design day demand.

FEI (including FEW) and the broad mix of resources needed to meet demand for the 2013-14 gas contract year.

Figure 6-1: 2013-14 FEI Forecasted Peak and Normal Loads vs. Resources

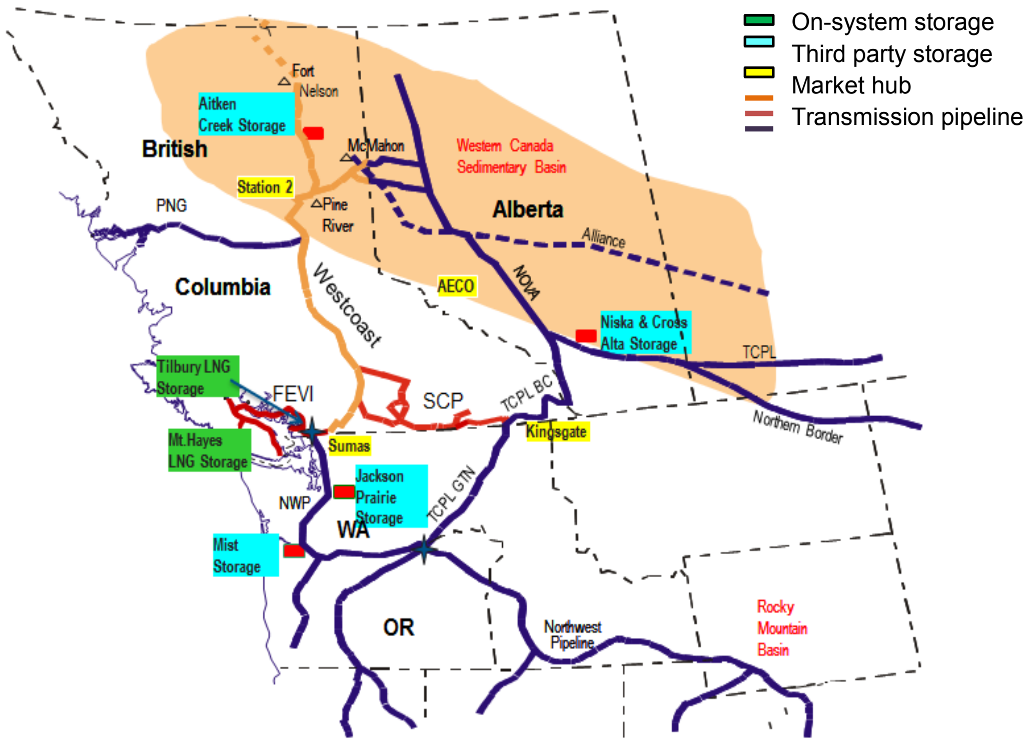


The forecast normal and peak load profiles have not changed significantly over the past few years. However, this could change in the future. A number of developments, including for example, those related to industrial growth spurred by the current low natural gas price environment, could impact the resource mix included in the portfolios. Additionally, regional developments related to potential LNG exports and increased demand from Alberta for supply from northeast B.C. could affect the development of additional infrastructure that increasingly ties northeast B.C. production into new markets. The impact of these changes may drive the need to consider a different mix of resources in the portfolios in order to ensure a continued ability to reliably meet demand.

6.2.2 Sources of Natural Gas Supply

This section describes the current sources of natural gas supply in the region and the transmission and storage assets required to bring the gas commodity onto the FortisBC system. The FEU and other utilities in the U.S. PNW access gas supply that originates from the Western Canadian Sedimentary Basin (WCSB). They also compete for a variety of storage and pipeline resources that are available in the region. Gas supply from the WCSB includes gas supply that is sourced from B.C. and Alberta that travels on Spectra's Westcoast and TransCanada's pipeline systems for delivery to various market centres. PNW utilities also access a portion of their gas supply from the Rockies basin in the U.S. although the amount of pipeline capacity that facilitates this movement is currently constrained. Figure 6-2 shows an overview of the FEU's operating region and the market supply hubs, pipelines and storage facilities located within it.

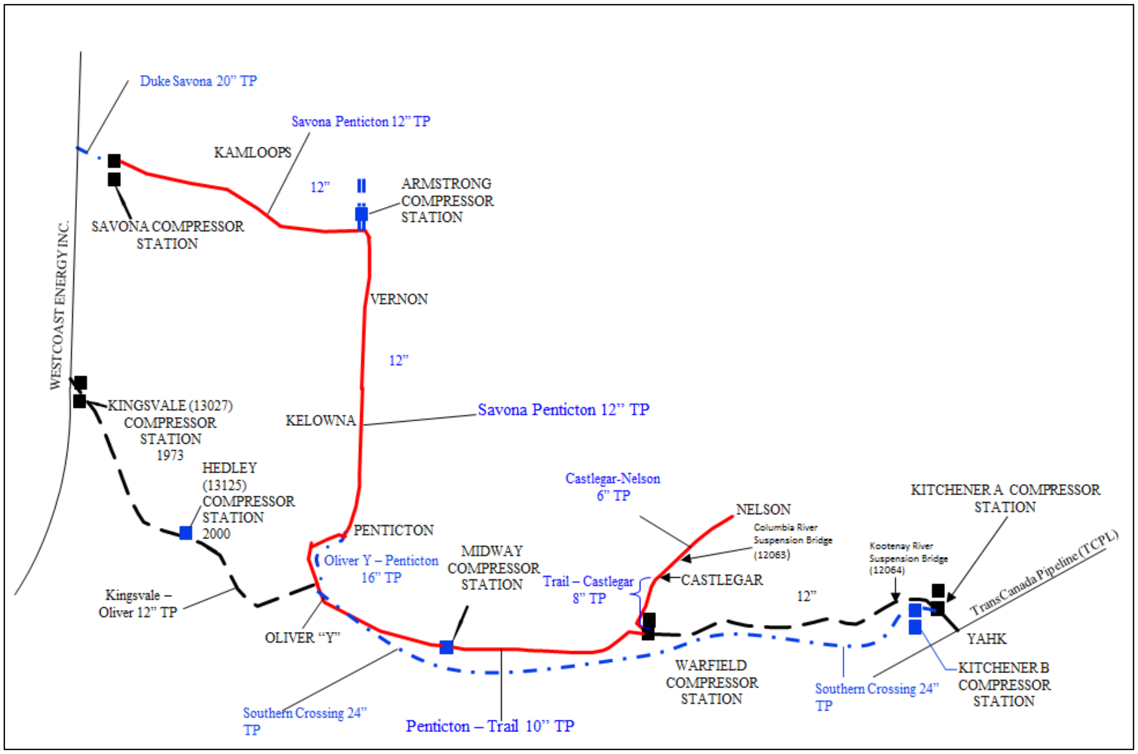
Figure 6-2: Regional Supply Resources – Pipelines, Storage and Trading Hubs



The FEU contract with third parties such as Spectra, TCPL and Northwest Pipeline (NWP) for transportation capacity in order to move supply purchased at different market supply hubs, and withdrawals and injections from storage facilities for delivery to the FEU's transmission system. Contracting for transportation on Spectra's T-North and T-South system provides the FEU with access to gas supply from northeast B.C. that is mainly purchased at the Station 2 hub, and supply that is withdrawn from the Aitken Creek storage facility. Contracting for capacity on TCPL's NGTL and Foothills BC systems allow the FEU to access gas supply from the Alberta and Kingsgate markets and storage facilities, while capacity on NWP provides access to supply from storage facilities south of the border in Washington and Oregon states. The FEU are also able to access short duration but high volume gas supply from FEU-owned and operated LNG storage facilities that are located in the Lower Mainland (Tilbury) and on Vancouver Island (Mt. Hayes).

Gas supply sourced from Alberta is transported on TCPL's Foothills BC system to an interconnecting point on FEI's Southern Crossing Pipeline (SCP) system at Yahk for delivery to various communities in the B.C. Interior.

Figure 6-3: FEI's Southern Crossing Pipeline and Interior Transmission Pipeline (TP) System



Gas supply from the SCP system can also be accessed by customers in the Lower Mainland due to the SCP's ability to connect with FEI's pipeline via a 12" pipeline that runs between Oliver and Spectra's T-South system at Kingsvale. The existing Kingsvale to Oliver and SCP lines also have the ability to flow in the opposite direction, whereby supply accessed from Station 2 can flow from west to east. This west to east movement has provided value to FEU customers and other shippers that operate in the B.C. marketplace, especially in the summer months when gas can be purchased at Station 2 and sold at Kingsgate for greater value than if resold at Huntingdon. Currently, this system has capacity constraints that restrict the amount of gas that can flow in both directions.

6.2.2.1 Kingsvale to Yahk Pipeline Constraint

The amount of gas that can be transported between Kingsvale and Yahk (in either direction) is limited by the current capacity of the Kingsvale to Oliver segment. To remove this constraint, FEI has assessed a potential to loop its 12" pipeline between Oliver and Kingsvale over a length of approximately 161 km and adding compression facilities to increase bi-directional flow between Spectra's T-South system and the Foothills BC system using the SCP. New shale gas developments in northeast B.C. are also driving infrastructure development as shippers seek ways to move new production to market. Removing the constraint on FEI's system between Kingsvale and Oliver also creates an opportunity to expand transportation services to provide improved access to markets for growing natural gas production. By removing this physical constraint on its pipeline system, FEI would be well-positioned to capture this opportunity while also providing increased long term diversity and security of supply for its customers.

6.2.3 Importance of Diversification of Gas Supply Resources

It is critical that the FEU's supply and resource portfolio incorporate a flexible variety of resources ranging from purchased term and spot gas supply, seasonal and short duration third party storage contracts, and high volume on-system resources. Accessing gas supply from a variety of locations and sources provides the Utilities with diversity within their total pool of resources, which helps mitigate locational supply disruptions while allowing for cost-effectiveness within the FEU's portfolios.

Each resource within the portfolio has different characteristics and function to meet Core load requirements. For example, while seasonal winter supply is used to meet average winter loads during each day of the winter, peaking resources such as Tilbury LNG storage are designed to be used on only the coldest days of the winter. The resources are selected based on how they meet the load profile, cost and their availability in the marketplace.

The FEU's market area storage and peaking resources are important for helping to meet forecast design peak day requirements and can include the following:

- Kingsgate and Huntingdon spot and peaking supply;
- Market area storage (Jackson Prairie Storage and Mist);
- On-system storage (Tilbury LNG and Mt. Hayes LNG); and
- Industrial supply curtailment.

The FEU and other utilities in the PNW rely heavily in the winter months on gas supply originating from northeast B.C. that is transported on Spectra's Westcoast T-North and T-South pipelines. To manage the risk of supply interruptions associated with well freeze-offs, upsets in processing plants, and potential transmission force majeure events, the FEU source gas from a wide range of producers that have supplies flowing out of the three largest plants—namely, Ft. Nelson, McMahon and Pine River plants—as well as from several smaller facilities for delivery to Station 2. In addition, in the past, the FEU have negotiated base load supply purchase deals directly at the outlet of the Fort Nelson plant in order to ensure long term supply with producers active in the Horn River basin.

The risks associated with processing and pipeline infrastructure outages or incidents are mitigated largely through seasonal and shorter duration storage resources, which include facilities located in B.C., Alberta and the PNW. In addition, the FEU's own on-system LNG storage resources are available to further provide high volume gas supply during critical circumstances.

The FEU use their storage resources to balance system loads on a daily basis, particularly during cold snaps in the winter months when intraday fluctuations can be severe. Seasonal storage facilities such as Aitken Creek provide term supply in the winter months and assist in load balancing during normal winter weather.

Market area storage facilities, such as Jackson Prairie (see Figure 6.2) in the PNW (Washington and Oregon states), provide the FEU with a valuable shorter duration balancing tool for further managing intraday load fluctuations, particularly during cooler and peak weather conditions. During extreme weather conditions, the FEU rely on the on-system LNG storage facilities at Tilbury and Mt. Hayes to provide high volume gas supply upon very short notice. Supply from these two facilities is able to reach the FEU's largest load regions within a span of a few hours due to the on-system location of these facilities. The access to high volume on-system LNG resources provides the FEU's customers with secure and reliable gas supply in the event of unplanned outages or when the PNW region undergoes a severe cold snap.

6.2.4 Long Term Supply Planning and Contracting Strategy

Due to these regional and North American gas market developments, the FEU must continue to be proactive in securing reliable and diversified gas supply cost-effectively over the long term. In order to meet these objectives, the FEU will use the following broad strategies to secure future resources:

- The FEU will continue to actively participate in pipeline infrastructure developments, tolling proceedings and other initiatives to ensure that the marketplace in B.C. offers supply liquidity and competitive pricing compared to neighbouring regional markets.
- The FEU will continue to establish key relationships with major producers that plan to develop gas supply in the Horn River, Montney and other producing regions of B.C. over the long term, including those actively involved in attempting to develop LNG exports to Asian markets.
- The FEU will evaluate opportunities within its own operating region to improve infrastructure that will provide greater access to markets, leading to better diversity and reliability within the gas portfolio over the long term.

6.3 *PRICE RISK MANAGEMENT*

The FEU operate in a marketplace characterized by volatile market prices and competing sources of energy for customers. Ensuring that natural gas rates remain competitive with other energy sources, maintaining affordable and reasonable rates for customers, and reducing market price volatility are fundamental to retaining existing load and adding economic new load. Both FEI and FEVI have developed diversified procurement strategies within their respective ACPs and, in the past, have utilized price risk management plans (PRMPs) to manage commodity price risk and facilitate competitive natural gas rates. While the cost of natural gas relative to other energy sources can be a factor that is considered by energy users, the FEU recognize that other factors are also important—such as government and public policy and GHG emissions.

The FEU's price risk management activities are aimed at protecting customers from market price volatility and helping to ensure the competitiveness of natural gas. While the competitiveness of natural gas and market price volatility have improved in recent years (as discussed in Section 2 and Appendices A-1 and A-3), there is less certainty of these conditions going forward and over the longer term. While the focus of price risk management in the past has been primarily on short term planning, the FEU believe the current market price environment creates opportunities for longer term strategies. In the future, these could include consideration of longer term instruments or tools, such as fixed price purchases or investment in natural gas reserves. Not only do these provide long term cost certainty and help provide stability in rates, but they also ensure security of supply for customers.

6.3.1 Physical Resources

The FEI (including FEW) and FEVI gas supply portfolios include diversified commodity, storage and transportation resources to maintain supply reliability and moderate commodity price uncertainty. This strategy is outlined in the ACPs (which cover a shorter time horizon than the LTRP) submitted to the Commission for review. The executive summary of the FEI-FEVI 2012-13 ACP is included in Appendix E. While ACPs include the portfolio of resources for each upcoming gas year, they also include long term resource planning, resources and contracts that extend for ten years and longer.

Volatility in natural gas prices is managed by maintaining access to liquid trading hubs, utilizing a variety of storage and transportation resources, and using different pricing structures and contract terms. The FEU consider access to appropriate natural gas infrastructure and minimizing reliance on any one price point a critical element of price risk management. The FEU diversify their gas supply portfolios to manage price risk, including taking into consideration the following measures:

- Diversifying gas pricing by purchasing at various supply hubs, including Station 2, Huntingdon, AECO/NIT and Kingsgate;
- Purchasing physical supply at daily and monthly prices;
- Procuring seasonal and market area storage capacity and deliverability from third parties. Storage provides a natural physical winter hedge by locking in the value between summer and winter gas prices for gas that will be used during the heating season. Storage also increases security of supply and reliability by significantly reducing the risk of gas well or plant upsets and by providing greater operational flexibility (day-to-day and intra-day nominations) for load balancing to meet unexpected changes in supply or demand;

- Contracting for base load supply based on the average daily load over the contract year. In the summer, any base load supply that is not needed to meet load is injected into storage so that it will be available to help meet higher demand in the winter months;
- Diversifying storage resources with different facilities and staggered contract expiry dates. The FEU contract for storage capacity at several facilities including Aitken Creek in B.C., Jackson Prairie Storage and Mist in the U.S., and Niska and TGSP (TransCanada Gas Storage Partnership) in Alberta. Storage contract terms and expiry dates are staggered to provide optionality for portfolio shaping, reduce negotiation failure risks, and alleviate the need to contract for large volumes of storage capacity, particularly during periods of high storage prices. FEI recently renewed a portion of expiring Aitken Creek capacity for ten years to provide longer term resource security and to maintain diversity in the portfolio;
- Contracting for transportation capacity with staggered expiry dates. The FEU have pipeline contracts with terms ranging between one to twenty years, however, the majority of its contracts are negotiated for terms of five years or less. Staggering expiry dates reduces the risk of having to re-contract for all or most of the required transportation capacity at once, and provides the flexibility to adjust capacity-based changes to supply and storage resources. With limited exceptions, transportation agreements currently have full or limited renewal rights upon notification as specified under the respective contracts;
- Contracting for transportation capacity to access different market hubs. The FEU have firm transportation contracts with Spectra, TransCanada (in B.C. and Alberta), NWP and SCP to diversify sourcing of supply from numerous supply hubs; and
- The Tilbury and Mt. Hayes LNG facilities are utilized to balance the load in cold or extreme weather conditions, or to provide gas supply during emergency conditions. The high level of deliverability from these facilities will greatly assist in managing price volatility at the Huntingdon marketplace while providing a secure source of on-system gas supply.

Other potential instruments or tools for managing longer term market price volatility include long term fixed price contracts or investment in natural gas reserves. Long term fixed price contracts would involve the FEU purchasing physical supply from a natural gas producer at a fixed price for a term of up to ten years. Investment in natural gas reserves would provide even longer term price protection. This would typically involve entering into a joint venture arrangement with a natural gas producer, wherein the right to a portion of the gas production is earned by paying a share of the costs to develop the gas plays. This type of transaction would not provide the same degree of price certainty as a hedging or fixed price purchase strategy but would provide cost-based supply for a longer period of time.

6.3.2 Locational Basis Risk

Locational basis risk results when the pricing at one market hub disconnects from that of other regional market hubs. The Huntingdon market hub, with its Sumas pricing, is considered to have relatively high locational basis risk, due to regional market forces that can severely disconnect prices from other market hub prices, such as AECO/NIT and Station 2, and cause high volatility in prices. Such periods of pricing disconnects occur when increased demand in the PNW region exceeds the delivery capacity at Huntingdon and causes Sumas prices to increase significantly above other prices.

The FEU are somewhat limited in their ability to reduce this basis risk due to the limited regional resources available to the PNW utilities. Key means to manage this locational basis risk include contracting for market area storage, relying on on-system LNG resources, and reducing Huntingdon supply in the portfolio when possible. The use of storage and on-system LNG resources also provides the Companies with much needed intraday flexibility, overnight withdrawals, and security of supply in the portfolio. The Mt. Hayes LNG facility has also recently reduced the need for peaking supply at Huntingdon during extreme weather, thereby reducing portfolio exposure to Sumas prices. With the availability of market area storage, the Companies are also able to cycle gas over the winter months to maintain adequate deliverability for use in times of high demand.

This Sumas price disconnection risk is not expected to diminish in the short term given the current infrastructure in place, winter demand in the region, and the potential for greater power generation and industrial demand. New infrastructure in the region that brings more gas supply to the Huntingdon and PNW I-5 demand corridor[78] could help reduce some of this basis risk over the long term. The FEU will continue to monitor developments in this regard and take appropriate measures to protect the Companies' customers.

6.3.3 Financial Hedging

Hedging strategies are another way of managing regional basis risk and price volatility. Hedging involves the use of financial derivative instruments wherein the market price for gas supply purchases is converted to a fixed price or capped price via a transaction with a counterparty such as a bank. The benefits of this approach include greater gas supply price and cost certainty and protection against rising market prices. It is important to note that hedging directly impacts the cost of gas supply while other rate smoothing mechanisms, such as the use of deferral accounts, do not directly impact gas costs but rather defer costs or surpluses for refunding to a future point in time.

In the past, hedging by the FEU has been outlined within its PRMPs and has been shorter term in nature, with hedging up to five years out. The current low market gas price environment creates the opportunity for longer term hedges, providing greater cost certainty and stability in

[78] The I–5 demand corridor includes B.C.'s Lower Mainland and Vancouver Island, Western Washington and Western Oregon.

the portfolio. The FEU will continue to evaluate such opportunities which can provide longer term price risk management.

6.4 CONCLUSION

Effective gas portfolio planning and price risk management on both a short and long term basis enables the FEU to secure cost-effective, reliable gas supply and also reduce rate volatility for customers. Given the significant marketplace developments in terms of North American gas supply, demand and pricing as well as regional infrastructure changes, the Utilities must continue to monitor changes and be proactive in assessing challenges and identifying opportunities.

Regional market developments (discussed in Appendix A-2) such as infrastructure initiatives to facilitate the movement of natural gas from B.C toward the Alberta market and west to supply LNG export projects may change traditional regional gas flows, along with supply and demand balances and pricing. By monitoring these developments and responding to changes through portfolio planning, the FEU can help ensure they continue to access cost-effective supply for Core sales customers. The FEU will continue to examine these regional developments and participate in regional project approval processes wherever they see a need to act to protect their customers' interests in maintaining secure, cost-effective supply sources and infrastructure over the long term. This includes continuing to examine potential opportunities on the FEU's own transmission and storage systems, such as expanding the FEI transmission system between Kingsvale and Oliver, in order to improve supply security and diversity for the region.

As discussed in Section 2, natural gas prices are near their lowest levels in a decade. However, market price volatility continues to be present and recent price forecasts suggest that future market prices will likely be higher as supply and demand come into a more sustainable balance. Effective price risk management can help reduce this market price volatility and is fundamental to retaining existing load and adding cost-effective new load. The FEU will continue to explore a range of price risk management activities to mitigate the impacts of price increases and volatility on customer rates in both the near and long term. The FEU will also continue to make separate applications to the Commission for approval of the risk management activities that the Companies believe are in the best interests of their customers.

7. STAKEHOLDER ENGAGEMENT

Connecting with customers, communities and other stakeholders on long range planning issues is of critical importance to the FEU. Effective stakeholder engagement provides valuable insight that can impact the energy planning process, demand forecasting and EEC program development, through to the development of an action plan for implementing the Utilities' preferred resource solutions.

When soliciting stakeholder input during the resource planning process, the BCUC's Resource Planning Guidelines encourage utilities to "focus such efforts on areas of the planning process where it will prove most useful and to choose methods that best fit their needs." For this LTRP, the FEU have improved both the scope and quality of stakeholder consultation activities. Between 2011 and 2013, the Utilities managed a number of initiatives to offer stakeholders the opportunity to participate in discussions to inform the 2014 LTRP. These activities included:

- Workshops with the dedicated Resource Planning Advisory Group (RPAG);
- Community Consultation workshops in communities served by the FEU; and
- Other activities that indirectly inform the resource planning process, including dialogue with First Nations, advisory groups, industry associations and other stakeholders.

The FEU consider stakeholder consultation for resource planning to be an ongoing process and one element of the many stakeholder activities that the Companies undertake for a range of purposes. This section summarizes the range of stakeholder consultation initiatives leading up to the 2014 LTRP.

7.1 *RESOURCE PLANNING ADVISORY GROUP*

The RPAG engages strategic stakeholders representing municipalities, government, First Nations, customers, associations and organizations in the development of the LTRP. The group consists of members with interest and experience in the resource planning process and significant industry knowledge that provide key insight and feedback to the FEU.

RPAG workshops provide a forum for discussing many broad themes, including but not limited to the following:

- LTRP process, inputs and analytical results;
- Forecasting methodologies and results;
- FEU initiatives and expectations;
- The energy and emissions planning environment; and
- Energy and emissions policy and regulation.

The FEU held seven RPAG workshops between 2011 and 2013 to review key steps in the LTRP process and discuss inputs into the 2014 LTRP (refer to Table 7-1 for meeting dates and list of major topics discussed). Engagement from attendees was in the form of questions and discussion throughout each presentation, as well as interactive sessions allowing for more in-depth discussion and feedback. The RPAG also had the opportunity to take site visits to the Tilbury LNG facility and the Waste Management CNG fuelling station, which allowed members to increase their understanding of the FEU's infrastructure and operations.

Table 7-1: RPAG Meetings and Major Topics Covered

RPAG Meeting Date	Topics Discussed
May 5, 2011	• Customer and energy demand • EEC update and planning • Energy and emissions planning environment • Future scenarios and sensitivities
January 10, 2012	• Scenario Development Workshop: scenario analysis overview and approach, critical uncertainties, scenario themes
February 9, 2012	• Site visit to Waste Management CNG fueling station • Gas supply and energy prices • Review of scenario development
May 29, 2012	• Site visit to Tilbury LNG facility • Community consultations • Asset management planning • New technologies
October 23, 2012	• End-use forecasting • Residential baseline forecast • Energy calculator • Natural gas for transportation • Renewable Natural Gas Offering
March 20, 2013	• Scenario assumptions review • Forecast results • Peak demand and system constraints • Update on EEC potential and impact on demand
November 7, 2013	• Overview of LTRP and results • Integrated results for sustainment and capacity planning • Rate impact analysis (demand scenarios, EEC savings & NGT) • Key issues and outcomes

The RPAG has been instrumental in helping the FEU to complete the 2014 LTRP. For example, in addition to identifying the critical uncertainties that led to development of scenario inputs for the end-use annual demand forecasting approach, the RPAG has provided guidance regarding the FEU's consideration of the potential market transformation of NGT activities in B.C. As resource planning is an iterative and on-going process, some of the feedback and recommendations received from the RPAG during this planning period will also be considered by the FEU in the next iteration of the resource planning process.

7.2 COMMUNITY CONSULTATION WORKSHOPS

The FEU recognize the importance of considering diverse community perspectives when planning for the future, and have established resource planning Community Consultation workshops to gather feedback from stakeholders throughout the FEU's service territories. Individuals involved in a variety of roles are invited to attend these ongoing events, including:

- Community planners/developers;
- Energy and sustainability managers and professionals;
- First Nations representatives;
- Municipal community leaders;
- Energy and sustainability non-profit organizations;
- Real estate builders and developers;
- Large businesses/manufacturers;
- Local businesses and business associations; and
- Other interested parties.

Twenty-one Community Consultation workshops were held between 2011 and 2013 in communities across British Columbia[79], with over 150 registrants. These workshops sought input on a variety of topics related to resource planning including distribution and safety, demand forecasting, the impact of demand for renewable thermal energy and EEC. The FEU presented plans to meet the future needs of customers and communities, and discussed issues affecting energy supply and demand, along with other initiatives to help meet future energy needs such as such as renewable natural gas and natural gas for transportation.

Themes that were consistently identified by stakeholders included:

- Finding solutions to reduce GHG emissions;
- New FortisBC Alternative Energy Services offerings such as district energy systems;
- NGT and biomethane;

[79] Burnaby, Campbell River, Castlegar, Coquitlam, Courtenay, Cranbrook, Duncan, Gibsons, Kamloops, Kelowna, Kimberley, Langley, Nanaimo, Powell River, Prince George, Revelstoke, Surrey, Trail, Vancouver, Vernon and Victoria.

- Programs to help customers and communities manage energy costs and emissions including EEC and High Carbon Fuel Switching;
- Advanced metering and billing options;
- Gas pricing trends; and
- Coordinating activities between utilities and municipalities.

Overall, the 2014 LTRP Community Consultation workshops facilitated the sharing of valuable long term planning information between stakeholders and the FEU. In particular, the workshops assisted the FEU in identifying energy issues or planning opportunities in municipalities throughout B.C. Stakeholders appreciated the opportunity to learn about the FEU's initiatives, make direct connections with FEU staff, and offer feedback on the Utilities' future plans. Attendees gave positive feedback on the workshop evaluation forms and overwhelmingly stated that they found the workshops both valuable and informative. The workshop discussions were robust and customer-focused, and they demonstrated that the FEU's long term planning considerations align well with stakeholder expectations.

7.3 *DIALOGUE AND ENGAGEMENT WITH FIRST NATIONS*

The FEU are leaders in developing and building mutually beneficial working relationships with First Nations communities. Understanding, respect, open communication and trust continue to be the FEU's aim when working with First Nations groups throughout the province.

The FEU work to ensure that First Nations' interests are represented in the Companies' various advisory groups. The RPAG and EEC Advisory Group both include members that represent British Columbia First Nations, which ensures that First Nations play an active role in the ongoing resource planning process. In addition, First Nations representatives from across the province—including the Lower Kootenay Band, Adams Lake Indian Band, Knucwentwecw Development Corporation, Tseshaht First Nation and Lhtako Dene Nation—have participated in Community Consultation workshops throughout the preparation of this 2014 LTRP.

The FEU's Statement of Aboriginal Principles (see Appendix F) ensures the Companies' business operations are conducted with respect for social, economic and cultural interests. One of these principles declares the Companies' commitment to dialogue through clear and open communication with Aboriginal communities on an ongoing and timely basis for the mutual interest and benefit of both parties.

To meet this objective, the FEU aim to establish an open dialogue with First Nations at the earliest planning stages to ensure that First Nations consultation and accommodation requirements are met. For example, from the outset of consideration of the Kingsvale Oliver Reinforcement Project (KORP), the FEI have maintained ongoing communications with First Nations representatives. Although an eventual decision was made in conjunction with the First Nations to temporarily defer the KORP, positive relationships and a smooth transition from an active project to a temporarily suspended project helps to ensure that the parties maintain a strong relationship. The importance of engaging First Nations "early and often" has been reiterated by First Nations representatives at RPAG meetings.

7.4 *OTHER CONSULTATION ACTIVITIES*

The FEU communicate frequently with stakeholders on issues related to resource planning through workshops, focus groups and other meetings that are not directly part of the LTRP stakeholder engagement framework. These activities seek input on a wide range of energy planning issues and solutions; feedback and dialogue from these events, although not focused solely on resource planning, have also been used to inform the resource planning process. Examples of these activities are summarized below:

7.4.1 EECAG Consultation

The dedicated EEC Advisory Group (EECAG) provides insight and feedback on a range of EEC related issues and activities. During the development of the 2014 LTRP, the FEU consulted with the EECAG for feedback on its approach to long range EEC forecasting. Specifically, the EECAG was asked to:

- Review the LTRP scenario and forecasting approach; and
- Offer feedback on the FEU's approach to forecasting EEC activities.

Feedback obtained from the EECAG helped the FEU to develop and refine its analysis of EEC potential and also identify other issues of interest to EECAG members for consideration in future LTRPs. The FEU will continue to consult with the EECAG on EEC-related issues during the next resource planning period.

7.4.2 Industry and Market Involvement

The FEU meet regularly with industry associations and other organizations such as the Canadian Home Builders' Association (CHBA), QUEST (Quality Urban Energy Systems of Tomorrow), the Urban Development Institute (UDI) and the Union of British Columbia Municipalities (UBCM) in order to share information and insight. This dialogue is mutually beneficial as it allows the FEU to stay abreast of industry trends and developments while facilitating the distribution of important information to stakeholders.

The FEU's involvement with such organizations allows the Companies to develop a more comprehensive picture of how the energy market is evolving. Participating in conferences, workshops and other engagement opportunities with these organizations has helped to position the FEU as leaders in the marketplace, strengthen the Companies' credibility, and generate a number of business opportunities.

7.5 CONCLUSION AND RECOMMENDATIONS

The FEU have a strong record of conducting effective stakeholder engagement activities, though in a new initiative for this LTRP, the FEU have consulted a dedicated RPAG planning group and hosted a number of Community Consultation Workshops to engage diverse perspectives on the FEU's planning activities across the communities that the Utilities serve. These changes adhere to the BCUC's stakeholder input guidelines and have been beneficial to the development of this LTRP. The information gained through these activities is brought into the LTRP process through informing the FEU's market research and analysis, identifying long term planning issues of concern to a number of stakeholder groups, and identifying interested stakeholders who may become more engaged in the LTRP process. The FEU recommend continuing with the RPAG and community consultation activities in order to build on the successful interest and input obtained through these initiatives.

8. 20-YEAR VISION FOR THE FORTISBC ENERGY UTILITIES

The BCUC's decision regarding the 2010 LTRP included a requirement for the next LTRP to describe a vision of the FEU in 20 years:

> *…pursuant to section 44.1(2)(g) of the UCA the Panel directs the following be included in the next LTRP: 1. [FEU] – A 20 Year Vision. This vision could describe what [the FEU] may look like in the future: its business lines, its customers, the expectations for supply and demand and the major issues it will deal with over the 20 year resource plan timeframe.*[80]

The directive lists a number of areas appropriate to be covered in the 20-year vision. This section of the 2014 LTRP has been developed in response to the Commission's directive to include a 20-year vision and thus presents a brief description of the FEU's long term vision along with the following:

- The contextual background that in part defines the FEU's 20-year vision for the LTRP in response to this directive,
- The challenges inherent in defining a 20-year vision and the limitations thereof, and
- Those components of a 20-year vision as listed by the BCUC within their directive and for which information is available to the FEU to include.

The FEU's long term vision is to be B.C.'s trusted energy provider for safe, reliable and cost-effective natural gas delivery services to their customers, and to be a healthy, growing contributor to B.C.'s economy and to the well-being of B.C.'s communities. As such, the FEU have examined a broad range of future potential conditions under which it must realize this vision. The FEU's approach has been to identify a set of resources to acquire that will meet the range of potential futures analysed rather than to attempt to predict a most likely future and plan only to that future, since the likelihood of correctly predicting the future is low.

8.1 CONTEXT AND LIMITATIONS FOR THE FEU'S LONG TERM VISION

The BCUC's directive to include a 20-year vision in the next LTRP was made at a time when the FEU were developing service initiatives to provide renewable thermal energy solutions complimentary to the Utilities' natural gas services. Since that time, the Commission has undertaken a review of the regulation of renewable thermal energy solutions and determined that it considers the Companies to be natural gas utilities only and that they should not provide renewable thermal energy solutions[81]. As a result, some items that the Commission contemplated for the 20-year vision are no longer appropriate for FEU's 2014 LTRP. For example, the FEU's consideration of renewable thermal energy services is limited to the

80 BCUC Terasen Utilities 2010 Long Term Resource Plan Decision, February 1, 2011.
81 BCUC AES Inquiry Report, Dec. 2012.

potential impact that such services provided by third parties may have on demand for natural gas, rather than being included as a new initiative undertaken by the FEU.

Another important limitation to describing the FEU's long-term vision is the degree of detail that can be included. The Commission's directive was made at a time when the outlook for natural gas supply resources and long term gas price forecasts was different than it is today. The 20-year vision directive does not appear to have contemplated the government's shifting emphasis on energy policy from GHG reductions within B.C. to the development of natural gas resources, use and exports for economic development, job creation and global emission reductions. A long term vision cannot be made so specific that it does not allow for such changes in the planning environment.

The FEU have attempted to address the items outlined by the Commission for inclusion in its 20-year vision without being so specific that it quickly becomes outdated as changes in the planning environment occur. In addressing the Commission's directive for the inclusion of a 20-year vision, the remainder of this section discusses how the LTRP has addressed:

- market transformation,
- the relationship between GHG reductions and demand,
- the FEU's forecasted contribution to B.C.'s GHG reduction targets,
- the potential impact of new technologies and market conditions on demand for natural gas,
- new initiatives,
- B.C.'s energy objectives,
- B.C.'s Natural Gas and LNG Strategies,
- the impact of long term demand variations on customer rates, and
- key drivers impacting the need for resources.

8.2 *MARKET TRANSFORMATION*

There are three areas of market transformation that have been incorporated into the LTRP analysis that the FEU can discuss: transformation of the market for natural gas as a transportation fuel (NGT), a range of assumptions about how much renewable thermal energy demand might replace natural gas demand in each of the future scenarios, and market transformation of energy efficiency technology that is inherent in the EEC potential analysis.

NGT

Sections 3.3.7 and 3.4.2 discuss the impact of varying levels of NGT market transportation on customer demand for natural gas from 1% to 30% of the applicable market over 20 years.

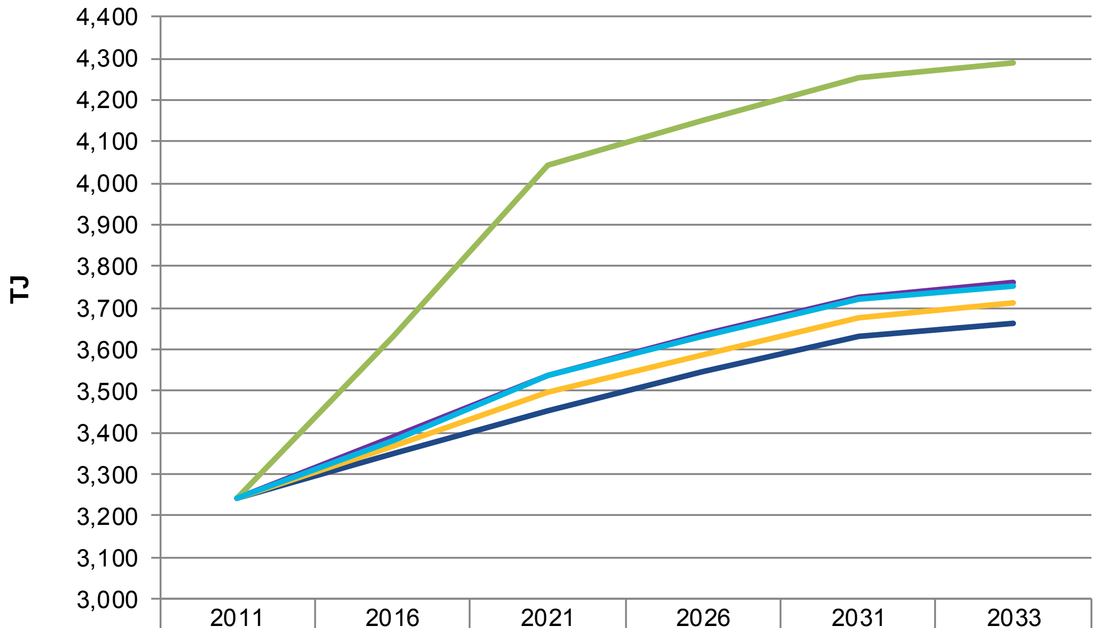
While capturing 30% of the market over 20 years is reasonably possible and has been examined in the high NGT demand scenario, the FEU have included a more modest 15% market capture for B.C. in the Reference Case demand scenario. The impact of these alternative scenarios on infrastructure needs has been analysed and discussed in Section 5.1.

Renewable Thermal Energy

Renewable thermal energy solutions such as geoexchange systems, waste heat recovery systems and solar thermal systems can displace both existing and future expected demand for natural gas. While the FEU do not offer these services to their customers, the potential for other third party service providers to do so creates a risk to the FEU's annual demand profile and thus to the FEU's revenue expectations. The LTRP has addressed this risk by including varying levels of displacement of natural gas demand by renewable thermal technologies in each of the annual demand scenarios presented in Section 3 (see Figure 3-6). The highest level of displacement is included in the lowest natural gas demand scenario (Scenario B) while the lowest level of displacement is included in the highest natural gas demand scenario (Scenario C).

Figure 8-1 shows the renewable thermal demand profile for all five end-use scenarios over the next 20 years. In the Reference Case, renewable thermal energy systems are expected to provide 3.7 PJ of thermal energy demand. In Scenario B, where energy markets are moving toward decentralized or self-generated energy systems (refer to Section 3.3.4 for scenario details), this figure may rise to 4.3 PJ. This thermal demand represents a displacement or market shift from natural gas to renewable thermal energy sources of less than 2.0% and 2.5% respectively. While this shift may not appear significant in terms of market transformation, it is an important trend for the FEU to monitor and address as it represents a risk to the demand and revenues from residential and commercial customers. This highlights the need for FEU to invest in other load building initiatives such as NGT and to seek new industrial customers. With today's limited but growing market penetration of renewable thermal energy systems, the FEU will continue to monitor thermal energy demand in order to gauge its impact over time on the Utilities' natural gas load and system capacity.

Figure 8-1: Renewable Thermal Demand



	2011	2016	2021	2026	2031	2033
Reference Case	3,240	3,349	3,452	3,545	3,631	3,664
Scenario A	3,240	3,388	3,536	3,634	3,725	3,760
Scenario B	3,240	3,630	4,041	4,150	4,251	4,290
Scenario C	3,240	3,368	3,495	3,588	3,676	3,710
Scenario D	3,240	3,382	3,535	3,631	3,719	3,753

Energy Efficiency Technologies

The impact of introducing and implementing programs that shift the market adoption of energy efficient technology has been addressed in the Companies' CPR and subsequent long term EEC planning analysis presented in Section 4.2. Figure 4.3 shows the results of that analysis by scenario. Although the FEU have not identified the extent of market transformation that will occur for each measure or technology, the analysis results do represent an estimate of the amount of energy efficiency that can be achieved by the Companies over the planning horizon.

Industrial Demand

In Section 3.3.9, the FEU discuss the potential for new industrial customers and load resulting from the current relatively low gas price environment. The FEU continue to receive interest from potential industrial customers and believe that adding industrial load will benefit all customers. While new industrial load could substantially increase both annual and peak demand, the FEU does not have sufficient information to estimate how industrial markets might transform over the planning period and will continue examine these opportunities on a case by case basis.

8.3 *RELATIONSHIP BETWEEN GHG EMISSIONS AND DEMAND*

The BCUC has indicated that it would like to see a discussion of the relationship between demand and GHG emissions within the 20-year vision for the FEU in addition to the contribution that the FEU's initiatives may have on emission reduction targets. The FEU have presented the GHG emissions associated with the 20-year annual demand scenarios in Section 3.5. For residential, commercial and industrial demand, GHG emissions associated with each of the forecast scenarios is provided in Figure 3-24.

8.4 *FEU'S FORECAST CONTRIBUTION TO B.C.'S GHG TARGETS*

Another item the BCUC identified as part of a 20-year vision discussion is the FEU's contribution to B.C.'s GHG targets. Outlined in Part 1(2) of the province's *CEA,* B.C.'s energy objectives include taking demand-side measures to conserve energy, encouraging efficient energy use, fostering the development in B.C. of innovative technologies that support energy conservation and efficiency, encouraging switching from one kind of energy to another that decreases provincial GHG emissions, and reducing B.C.'s GHG emissions. The FEU's EEC activities, NGT initiative, RNG offering and Switch 'N Shrink program are all important activities that help to meet these goals. The contribution of each of these areas to B.C.'s energy objectives is described below. The FEU note that B.C.'s energy objectives apply to the province as a whole and do not identify any sector-specific allocations. As a result, there are no government-mandated GHG emission reduction targets for the Utilities' customers to attain.

GHG Reductions from NGT Initiatives

The range of forecast annual demand for NGT use has been analyzed and is discussed in Section 3.3.7. Figure 3-23 illustrates the effect of increased natural gas use for transportation on the potential to reduce B.C.'s GHG emissions for each of the three NGT demand scenarios. In the Reference Case, B.C. would see approximately 634,000 tonnes of GHG emissions removed from the atmosphere in 2033. This is the equivalent of taking over 132,000 passenger cars off of B.C.'s roads or avoiding consumption of nearly 270 million litres of gasoline.[82]

The Companies expect their NGT solutions to capture a significant opportunity for emissions reduction in B.C.'s transport sector while providing an important source of load growth on the FEU's systems (shown previously in Figure 3-13). This will result in a more cost-effective and efficient utilization of the natural gas distribution system with benefits to all FEU customers while also furthering the province's natural gas strategy for transportation and GHG emission reduction goals.

[82] Based on one passenger vehicle emitting 4.8 metric tons of CO_2e per year. U.S. EPA, "Greenhouse Gas Equivalencies Calculator: Calculations and References," 2012, http://www.epa.gov/cleanenergy/energy-resources/refs.html#vehicles.

GHG Reductions from EEC Activities

The FEU provide analyses of the Companies' contributions to B.C.'s energy efficiency and conservation objectives in Section 4 of this LTRP. Different levels of EEC activity in the end-use forecasting scenarios have varying impacts on natural gas demand, and consequently, corresponding GHG emission reductions. Figure 4-3 shows the estimated GHG reductions associated with the Reference Case and the lowest and highest demand scenarios (Scenarios B and C) and shows the extent to which the FEU contribute to B.C.'s energy conservation and efficiency objectives over the 20-year planning horizon. It should be reiterated that the figure shows the reductions from FEU activity that meets the B.C.-specific definition of demand-side measure. The largest estimated GHG emissions reductions are associated with the Reference Case scenario at nearly 670,000 tonnes of avoided CO_2e per year.

GHG Reductions from RNG Offering and Switch 'N Shrink Program

FEI's RNG Offering and the FEU's Switch 'N Shrink program offer additional opportunities to reduce the province's GHG emissions. Although the total contributions to the province's GHG targets is small, these programs remain strategically important to offer the FEU's existing and potential customers additional avenues to reduce their carbon footprint and also heating costs for Switch 'n Shrink customers. Based on selling the biomethane supply from all currently approved RNG project contracts, the program is estimated to account for 20,165 tonnes of avoided CO_2e by 2020, which is 0.1% of the province's reduction target for that year.

Projecting the 2012 Switch 'n Shrink data over the next eight years to 2020, the program may see an estimated 27,000 tonnes of avoided CO_2e by 2020 or 0.1% of the province's 2020 GHG target. This projection assumes that the number of program participants remains constant throughout this time period.

Contribution to B.C.'s GHG Targets

Using a 2007 baseline year, B.C.'s GHG emissions targets are reductions of at least: 18% by 2016, 33% by 2020 and 80% by 2050. With base year emissions reported as 64.9 $MtCO_2e$ in the province's 2010 GHG Inventory Report[83], B.C.'s future target emission levels are:

- 53.2 $MtCO_2e$ in 2016, which amounts to an emissions reduction of 11.7 $MtCO_2e$;
- 43.5 $MtCO_2e$ in 2020, which amounts to an emissions reduction of 21.4 $MtCO_2e$; and
- 13.0 $MtCO_2e$ in 2050, which amounts to an emissions reduction of 51.9 $MtCO_2e$ from the 2007 baseline.

Below, the FEU provide an estimate of the extent to which the Companies' activities contribute to B.C.'s GHG emission reduction objectives over the planning period through the most

[83] http://www.env.gov.bc.ca/cas/mitigation/ghg_inventory/pdf/pir-2010-full-report.pdf

significant GHG-reducing activities—the Companies' EEC and NGT initiatives.[84] The milestone years that the FEU have used to present the annual demand forecast, EEC energy savings estimates and NGT demand forecast do not entirely align with the GHG target dates set out in B.C.'s energy objectives and the *Greenhouse Gas Reduction Targets Act*. However, the FEU provide a comparison of the FEU's contribution to B.C.'s GHG reduction targets in Table 8-1 in the closest years for which comparable data is available.

Table 8-1: Comparison of FEU's Contribution to B.C.'s GHG Targets

GHG Reductions Required to Meet 2016 Interim Target	Expected GHG Emission Reductions in Milestone Year 2016 ($MtCO_2e$)		
	Reference Case	Scenario B	Scenario C
11.7 $MtCO_2e$	EEC - 0.082 NGT - 0.032	EEC - 0.081 NGT - 0.032	EEC - 0.032 NGT - 0.032
	Total - 0.114	**Total - 0.113**	**Total - 0.064**
GHG Reductions Required to Meet 2020 *GGRTA* Target	**Expected GHG Emission Reductions in Milestone Year 2021 ($MtCO_2e$)**		
	Reference Case	**Scenario B**	**Scenario C**
21.4 $MtCO_2e$	EEC - 0.212 NGT - 0.083	EEC - 0.203 NGT - 0.042	EEC - 0.101 NGT - 0.099
	Total - 0.295	**Total - 0.245**	**Total - 0.200**
GHG Reductions Required to Meet 2050 *GGRTA* Target	**Expected GHG Emission Reductions in Milestone Year 2033 ($MtCO_2e$)**		
	Reference Case	**Scenario B**	**Scenario C**
51.9 $MtCO_2e$	EEC - 0.672 NGT - 0.634	EEC - 0.585 NGT - 0.042	EEC - 0.398 NGT - 1.268
	Total - 1.306	**Total - 0.627**	**Total - 1.666**

Based on the information in the table above, in the Reference Case, the FEU expect to contribute 1.0% of the province's 2016 interim GHG emissions target. By 2021 (the nearest milestone year for which data is available), the FEU expect to contribute 1.4% of the province's 2020 emissions target and by 2033, the Companies expect to contribute approximately 2.5% of the province's 2050 target. No data currently exists to estimate the FEU's contribution to the province's GHG target after 2033.

[84] References to GHG-reducing activities in this section refer to emissions reductions at the provincial level.

8.5 *POTENTIAL IMPACT OF NEW TECHNOLOGIES AND MARKET CONDITIONS ON DEMAND*

The FEU have incorporated a range of annual demand, end-use forecast scenarios for commercial, residential and industrial demand discussed in Sections 3.3.2 through 3.3.6. The FEU do not attempt to specify what technology innovations or market changes occurred in each scenario, as the purpose of the end-use forecasting methodology is to model a range of directional impacts on demand that could be caused by changing market trends, policies or technologies. The FEU further examine the impact of market and technology trends favourable for natural gas use by modelling the impact of NGT demand on overall annual demand in Section 3.3.7 and the impact of potential large new industrial demand in Section 3.3.9. The impact of new technologies on peak demand is discussed in Section 5.1.

The end-use forecasting methodology has also provided the opportunity for the FEU to examine technology and market trends that favour declining annual demand (see Figure 3-6 for the full range of annual demand forecasts). The FEU believe that this range of forecasts from declining demand to demand growth—largely from transportation and industrial customers—represents a reasonable range of potential future demand scenarios over the next 20 years for which to plan.

8.6 *NEW INITIATIVES*

The long term potential impact of new initiatives on demand for natural gas and related resources include FEU's NGT and potential new industrial demand sources as discussed in Sections 4.3.2 and 4.3.3. The FEU continue to be vigilant for additional opportunities to develop new natural gas service initiatives that add value for customers.

8.7 *B.C.'S ENERGY OBJECTIVES*

Section 2 of B.C.'s *CEA* outlines 16 energy objectives for the Province. Of those, three are directed specifically at BC Hydro and a number of others are related specifically to electricity resources and are not applicable to the natural gas services offered by the FEU. The discussion below outlines how the LTRP has addressed the remaining B.C. energy objectives in which the FEU can play a role.

Energy objective (b) to take demand-side measures and to conserve energy:

Section 4 of the LTRP discusses the analysis of potential energy efficiency and conservation measures and Section 4.2.4 sets out a plan for implementing EEC activity that will reduce demand for natural gas during the planning period.

Energy objective (d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources:

The FEU's 2014 -2018 EEC Plan includes an innovative technologies component and, although it is being reviewed through a separate regulatory process, forms part of the long term plan set out in Section 4.2.4 for implementing EEC activity during the planning period. The FEU's NGT initiative, presented in the LTRP as an approved new initiative, also encourages the development and use of new technology that will reduce GHG emissions. The EEC Plan and Analysis are discussed in Section 4.2.

Energy objective (g) to reduce greenhouse gas emissions:

Section 8.4 quantifies the extent to which the FEU's EEC activities and new initiatives can reduce GHG emissions under different future scenarios. The FEU notes that neither the Companies nor their customers have mandated emission reduction requirements.

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

The FEU's RNG, Switch 'N Shrink and NGT initiatives are each an example of fuel switching initiatives that move customers from higher to lower GHG-emitting fuels and are discussed as ongoing initiatives that have been considered in the development of this LTRP. Of these, the NGT initiative has the highest potential for GHG emission reductions as shown in Section 8.4.

Energy objective (i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently:

The FEU's 2014 -2018 EEC Plan includes programs that encourage communities to reduce GHG emissions and use energy efficiently. Although the EEC Plan is being reviewed through a separate regulatory process, it forms part of the long term plan set out in Section 4.2.4 for implementing EEC activity during the planning period. A similar level of EEC activity is assumed to continue through the planning period. The EEC analysis and plan are discussed in Section 4.2.

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

The FEU's RNG offering is designed to encourage the collection of biogas from organic waste sources in B.C. The RNG offering is discussed in Section 2.3.2 with the supply and demand outlook presented in Appendix A-7.

Energy objective (k) to encourage economic development and the creation and retention of jobs:

The FEU have an important role to play in this objective by remaining a healthy, growing contributor to B.C.'s economy and to the well-being of B.C.'s communities as described in the long term vision presented in the introduction to Section 8. Capital investments from projects identified in Section 5 as solutions to capacity constraints or system sustainment requirements will contribute to B.C.'s economy and the communities in which the FEU operate. Further, the FEU's EEC activities have been shown to have economic and job creation benefits in addition to energy and emission reduction benefits[85].

Energy objective (n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia):

By continuing to serve B.C.'s thermal energy needs with natural gas, the FEU will help to curb increases in electricity demand that would otherwise be caused by gas-to-electric fuel switching in either new or retrofit buildings. This electric load avoidance will in turn preserve other green and renewable energy resources for export to help reduce GHG emissions within the electricity trading region and for the benefit of all British Columbians.

8.8 *B.C.'S NATURAL GAS AND LNG STRATEGIES*

This LTRP supports a number of aspects of the B.C. Government's vision to be a global leader in natural gas development. In regard to market diversification, the Natural Gas Strategy states:

> *…there are new and expanded uses of natural gas in North America and British Columbia, including transportation, fuel switching from coal to natural gas for power generation, and as a feedstock to make other products.*[86]

The FEU's NGT initiative supports the first of these uses, and the analysis of system capacity in Section 5.1 anticipates the potential for new large industrial loads. One source of new industrial load could be the use of natural gas as a feedstock for a range of products.

In regard to maintaining competitiveness, the Natural Gas Strategy states:

> *Ensure infrastructure is available to encourage investment.*[87]

Again, the FEU consider the potential for growing natural gas use in the transportation sector and for new large industrial demand within their service territory. However, to maintain a reasonable level of planning certainty, the FEU do not forecast new industrial customer additions until firm contracts have been signed.

8.9 *IMPACT OF LONG TERM DEMAND ON CUSTOMER DELIVERY RATES*

One of the FEU's central objectives is to provide customers with cost-effective delivery service. Customer demand can have a significant effect on delivery rates as increasing natural gas

[85] ICF Marbek, Conservation Potential Review 2010 FortisBC. Impact of CPR-2010 Natural Gas Savings on the B.C. Economy (2010-2030), May, 2011.
[86] B.C. Ministry of Energy and Mines, "B.C.'s Natural Gas Strategy," February 3, 2012, pg. 5.
[87] Ibid., pg. 7.

demand has a downward impact on delivery rates for all customers, all else being equal. As such, the FEU aim to increase system efficiency and optimize infrastructure use by maintaining sufficient throughput on the FEU's distribution system.

To provide context of the FEU's long term volume forecasts as they relate to delivery rates, Figures 8-2 through 8-4 provide a directional look at the potential impact of long term demand on customer rates. Using approved rates and actual volumes from 2011, the following figures include the cost of service for major capital items plus an escalation of the cost of service by a growth factor of 2% per year, divided by delivery volumes in each scenario. The figures do not consider future rate design changes and are not indicative of a detailed rate forecast--they provide simply a directional, 20-year view of FEI's delivery rates over time.

Figure 8-2: Delivery Rate Direction – All Rate Classes

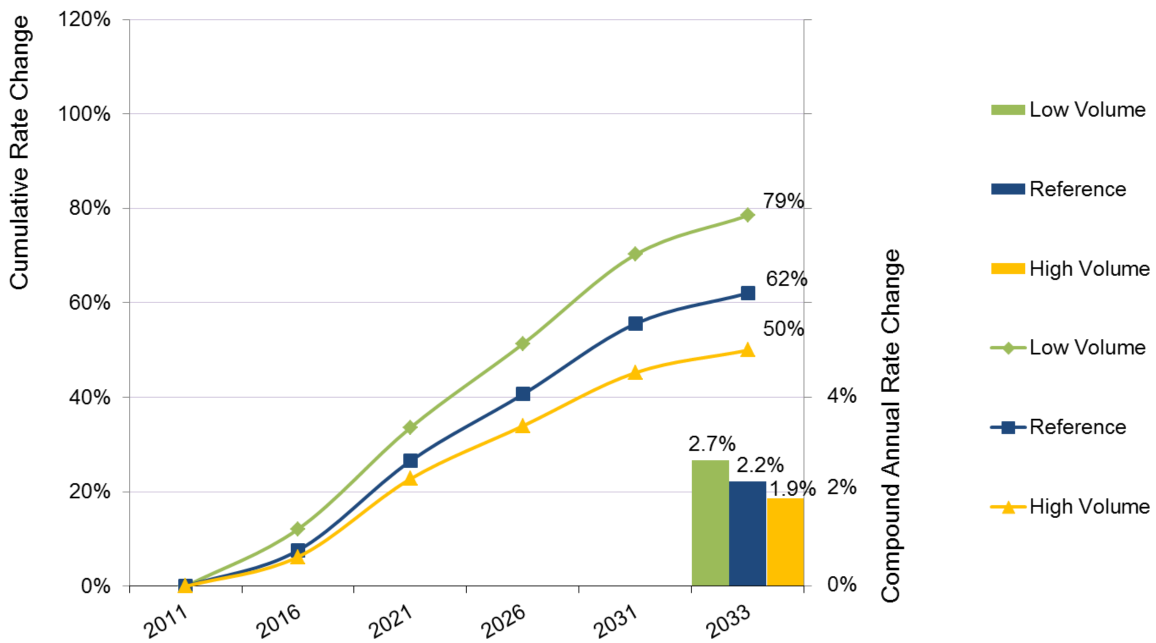
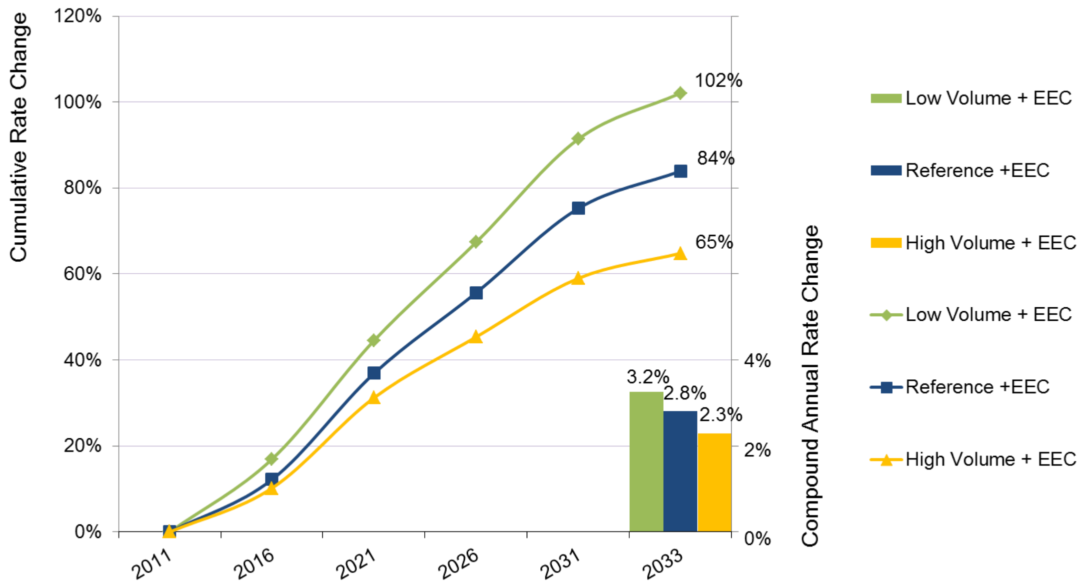


Figure 8-2 shows the delivery rate direction for the Reference Case, the lowest and highest volume scenarios (Scenarios B and C respectively). In the Reference Case, the compound annual delivery rate change is 2.2%, which amounts to a 62% cumulative delivery rate change over the 20-year planning horizon. Below, Figures 8-3 and 8-4 show the expected influence of EEC and NGT initiatives on delivery rates. In general, as the volume of gas delivered decreases, delivery rates increase as less throughput on the system results in higher delivery costs per customer. EEC programs incent customers to use less gas, causing demand for gas on the system to fall, thereby putting upward pressure on delivery rates. As such, the compound annual delivery rate change in the Reference Case of Figure 8-6 grows by 2.8%

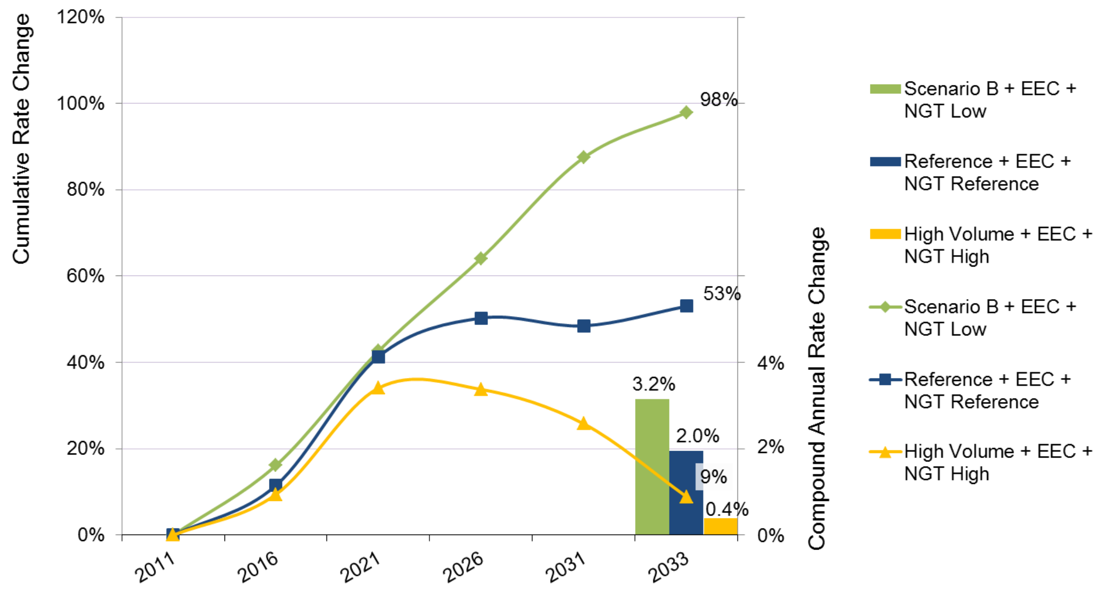
annually, which amounts to an 84% cumulative delivery rate change over the planning horizon in this simplified model.

Figure 8-3: Delivery Rate Direction – All Rate Classes and EEC



Conversely, adding NGT demand (shown below in Figure 8-4 increases total demand on the system and thus puts downward pressure on delivery rates. When adding the effect of NGT demand to the previous two scenarios, the compound annual delivery rate change falls to 2.0% and the cumulative delivery rate change over the 20-year planning horizon also falls to 53%. In sum, holding all else constant, increasing delivery volumes has a positive effect for rates. Expanding the NGT market is an important opportunity for growth on the delivery system and underscores the importance for the Companies to explore other opportunities for growth that will assist in mitigating upward pressure on delivery rates.

Figure 8-4: Delivery Rate Direction – All Rate Classes, EEC and NGT



8.10 *KEY DRIVERS IMPACTING THE NEED FOR RESOURCES*

The key drivers impacting the need for resources are the amount of natural gas demand forecasted over the planning horizon, the impact that demand will have on available system capacity, system sustainment requirements for continued delivery of safe, secure and cost-effective gas supply, and the amount and nature of demand-side activities that the FEU expect to undertake over the planning period. The demand forecast is presented in Section 3 and the amount of energy savings from EEC activities is presented in Section 4. Sections 5.1 and 5.2 present the analysis of system capacity and system sustainment requirements and the expected timing of each. The system sustainment resource requirements identified in Section 5.2 are needed regardless of the extent to which demand grows. The system capacity requirements identified in Section 5.1 may shift in terms of timing depending on how quickly demand grows, but they may also be easily integrated into system sustainment projects to satisfy both needs under all of the future scenarios examined.

The final driver impacting the need for resources is the extent to which the planning environment may change over the planning period and the nature of those changes. The FEU believe that the demand scenarios analysed in this LTRP adequately capture the range of planning environment changes that may begin to unfold by the time the next LTRP is prepared. Section 8.9 shows the importance of adding natural gas demand in new markets to help offset increases in customer rates caused by declining use per customer in other sectors, and the risk of further declines represented in the lower demand forecast scenarios presented in Section 4. Therefore, resources to conduct customer and market research, and to identify and acquire customers in new and traditional markets are among the resources that the FEU must continue to maintain over the planning horizon.

8.11 *CONCLUSION*

The context in which to provide a 20-year vision for the FEU is significantly different today than it was three years ago when the directive was issued with the 2010 LTRP Decision. Notably, the FEU were developing service initiatives to provide renewable thermal energy solutions, the outlook for natural gas supply and long term gas price forecasts was significantly different, and since that time, the Government of B.C. has placed increasing emphasis on developing natural gas resources for use and export.

In response to the Commission's directive to provide a 20-year vision, in Section 8, the FEU have explained how and where the LTRP addresses a number of items related to this vision. This section also highlights the need to monitor a small but important trend of growing renewable thermal energy demand, the extent to which FEU initiatives contribute to B.C.'s overall GHG reductions, and the how variations in demand over the planning period can influence customer delivery rates. Since decreases in demand (whether through market trends or EEC activities) place upward pressure on delivery rates while increases in demand lend to the reverse effect, the Utilities will to continue to explore opportunities for demand growth on the distribution system. Through continuing to implement the activities outlined throughout this 2014 LTRP and in this 20-year vision, the FEU will continue to strive toward becoming B.C.'s trusted energy provider for safe, reliable and cost-effective natural gas delivery service, with a positive effect on the well-being of B.C.'s economy and communities.

9. ACTION PLAN

The following Action Plan describes the activities that the FEU intend to pursue over the next four years based on the information and recommendations provided in this 2014 LTRP.

1. **Continue to monitor and analyse the energy planning environment.**

Being aware of and understanding the many factors that influence the FEU's long term analysis is critical to providing appropriate context for the analysis, results and recommendations that are made throughout the LTRP. The FEU will continue to monitor market and policy developments that may impact regional gas flows, supply, demand and pricing. In addition, the Companies will continue to monitor and examine emerging technologies and advancements in gas metering infrastructure. The FEU's research and investigations will seek to uncover any potential challenges as well as identify opportunities to improve on the secure, reliable and cost-effective energy services that the Companies provide.

2. **Continue to implement the Companies' NGT initiatives.**

The FEU will continue to implement the Companies' NGT initiatives as described in Appendix A-8 to provide an important source of load growth on the FEU's natural gas distribution system while also capturing an opportunity to assist in reducing the GHG emissions of B.C.'s transport sector.

3. **Discontinue using the traditional annual demand forecasting method for residential, commercial and industrial customers.**

The FEU will discontinue use of the traditional end-use forecasting methodology for all sectors. The Companies will update the end-use forecasting model to a 2012 base year and will continue to incorporate relevant new information in future long term forecasting work.

4. **Pursue approval of EEC funding for the 2014 – 2018 period through the FEI 2014-2018 PBR application.**

The FEU will continue to seek approval for EEC funding for the 2014-2018 period through the FEI 2014-2018 PBR application and is not seeking approval in this LTRP. That application includes consideration of the need for undertaking a new CPR commencing in 2015.

The FEU will continue to examine the potential for all forms of DSM activity to optimize the use of B.C.'s energy infrastructure by implementing programs that help meet customer energy needs while working toward B.C.'s energy objectives.

5. **Plan for and prepare CPCN applications for near-term system requirements identified in the FEU Five-Year Capital Plans.**

The high priority projects on the Lower Mainland IP System and the Coastal System for which the Utilities intend to submit CPCN applications and will be examining in the near term are the:

- Coquitlam IP pipeline replacement,
- Nichol to Port Mann TP pipeline loop,
- Cape Horn to Coquitlam TP pipeline loop,
- Fraser IP pipeline replacement, and
- Nichol to Roebuck TP pipeline loop.

As the FEU's planning efforts are undertaken to ensure that planned improvements optimize operation of the system as a whole, these system upgrade requirements have been integrated with the reinforcement options that are under consideration to meet the FEU's capacity needs. The Utilities will conduct further inspection and analysis on pipelines in the Burns Bog area before determining an appropriate course of action for this project.

6. **Expand the Tilbury LNG facility.**

B.C.'s Natural Gas and LNG Strategies aim to use LNG development to spur change in other sectors. The FEU will work toward implementing an expansion of the Tilbury LNG facility in accordance with the B.C. Government's Special Direction No. 5. Construction planning and the LNG facility expansion are expected to be in place by 2016.

7. **Continue monitoring and evaluating system expansion needs in the Okanagan area.**

The FEU have identified a constraint in the Okanagan region of the ITS as early as 2017. The Companies will continue to evaluate the three proposed reinforcement options presented in Section 5.1.2.3. In addition, the Companies will continue to monitor FortisBC Inc.'s Integrated System Plan and potential need for natural gas generation as a back-up to renewable electricity production during peak electric demand periods. Should FortisBC Inc. proceed with a gas-fired peaking generating station, this or any other large additional industrial load will result in a need to submit a CPCN for facility expansion.

8. **Protect and promote the interests of the Utilities' customers by securing a reliable, cost-effective long term gas supply.**

Fundamental objectives for the FEU are to procure a stable, secure gas supply over the long term while minimizing the cost of the annual portfolio. In order to meet these objectives, the FEU will use the following broad strategies to secure future resources:

- Manage volatility in natural gas prices by maintaining access to liquid trading hubs, utilizing a variety of storage and transportation resources, and using different pricing structures and contract terms.
- Continue to actively participate in pipeline infrastructure developments, tolling proceedings and other initiatives to ensure that the marketplace in B.C. offers supply liquidity and competitive pricing compared to neighbouring regional markets.
- Continue to establish key relationships with major producers that plan to develop gas supply in the Horn River, Montney and other producing regions of B.C. over the long term, including those actively involved in attempting to develop LNG exports to Asian markets.
- Evaluate opportunities within the FEU's own operating region to improve infrastructure that will provide greater access to markets, leading to better diversity and reliability within the gas portfolio over the long term.

Also, to protect customers from market price volatility and help ensure the competitiveness of natural gas rates, the FEU will explore opportunities for longer term price risk management strategies that may include using fixed price purchases, investing in natural gas reserves and financial hedging.

Appendix A

PLANNING ENVIRONMENT

Appendix A-1

NORTH AMERICAN GAS MARKET OVERVIEW

APPENDIX A-1 – NORTH AMERICAN NATURAL GAS MARKET OVERVIEW

1. Introduction

Significant changes have occurred in the North American natural gas market over the past few years and have directly impacted the regions in which the FEU operate. Advances in drilling technology and cost reductions for producers have led to an abundance of gas supply; despite near-term production curtailments, over the longer term, increases in shale gas production are expected to continue to rise. Low gas prices are providing opportunities for increased natural gas use, particularly in power generation, LNG export markets, and the transportation sector. Current to the time of writing in November 2013, this appendix provides an overview of the evolving natural gas market in North America including natural gas supply, demand, storage and prices.

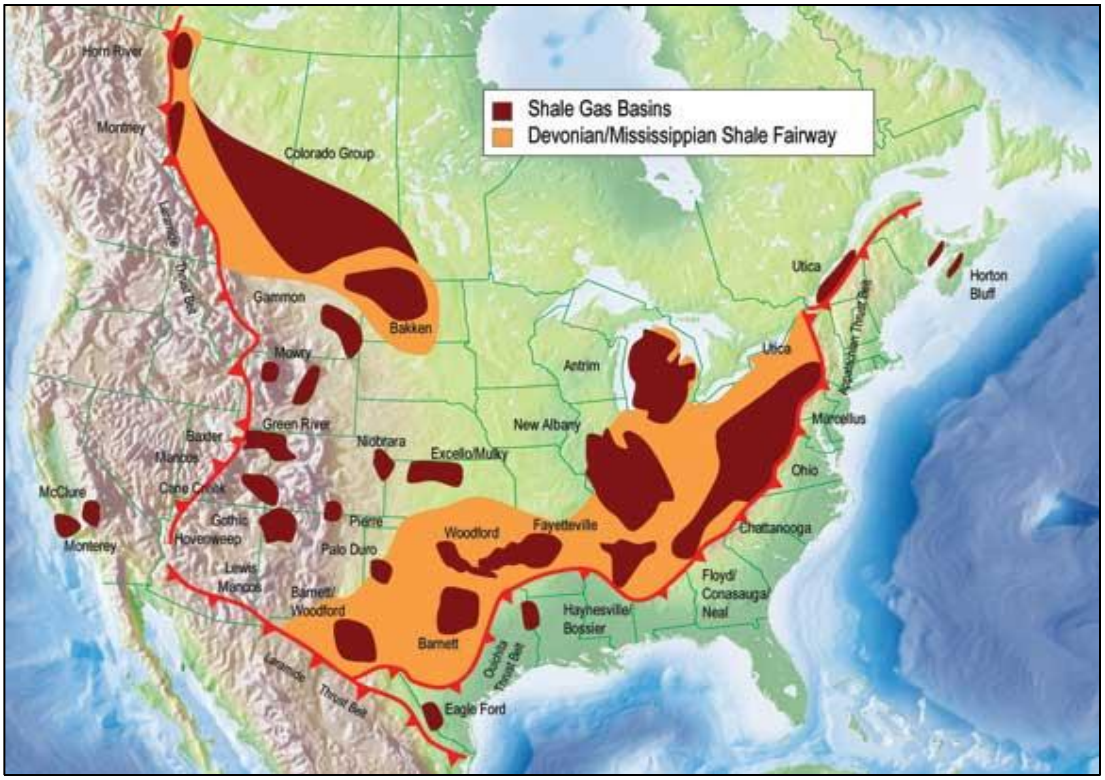
2. Natural Gas Supply

The North American natural gas market has undergone significant changes in terms of supply over the past few years. Advances in drilling technology and significant cost reductions related to unconventional gas development, in particular shale gas, have created an abundance of gas supply in North America.

2.1 NORTH AMERICAN SUPPLY RESERVE POTENTIAL

Before the proliferation of shale gas, the gas industry believed that supply in North America was dwindling and the market would become more dependent on LNG imports. However, over the past five years, advances in technology and horizontal drilling have been able to unlock previously known natural gas reserves trapped in shale deposits all across North America. Producers are able to drill more cheaply and produce more gas than ever before. Gas market analysts currently predict that North America contains over 100 years of economically recoverable supply based on current consumption levels. Not only is the gas supply abundant, shale gas supplies are located throughout North America, providing cost effective supply within close proximity to major load centres. Figure below shows the key North American shale gas regions.

Figure 1: North American Shale Gas Plays



Source: National Energy Board, Understanding Canadian Shale Gas - Energy Brief

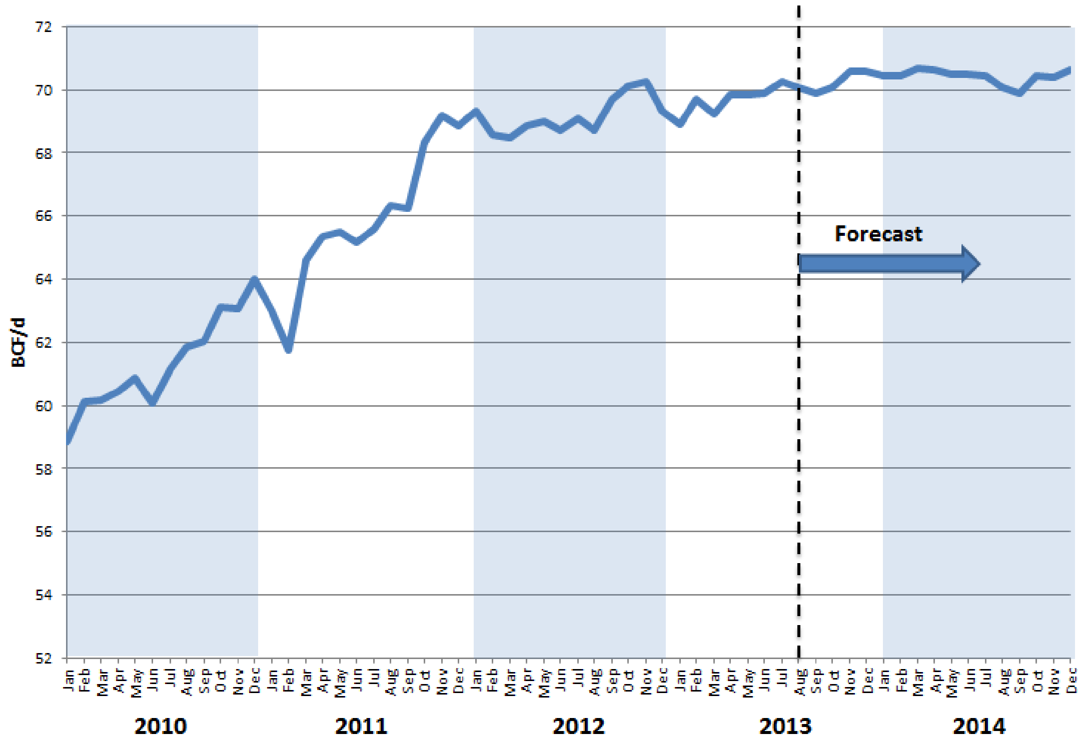
The Western Canadian Sedimentary Basin (WCSB), which extends from northeast B.C. to southwest Saskatchewan, also contains significant unconventional gas supplies and includes the Horn River, Montney, Liard, Cordova, and Duvernay gas plays. The WCSB is estimated to have 143 trillion cubic feet (Tcf) of marketable gas remaining (discovered and undiscovered) in place.[1] This was estimated to be about 87 Tcf only five years ago.[2]

2.2 U.S. PRODUCTION

During 2012, U.S. natural gas production reached record levels. Current U.S. marketed natural gas production is above the average levels experienced in 2012, 2011, and 2010, as depicted in the following figure.

[1] National Energy Board, Energy Market Assessment, 2012-2014
[2] http://www.wcsb.ca/learningcenter/thebasin.aspx

Figure 2: U.S. Natural Gas Production[3]

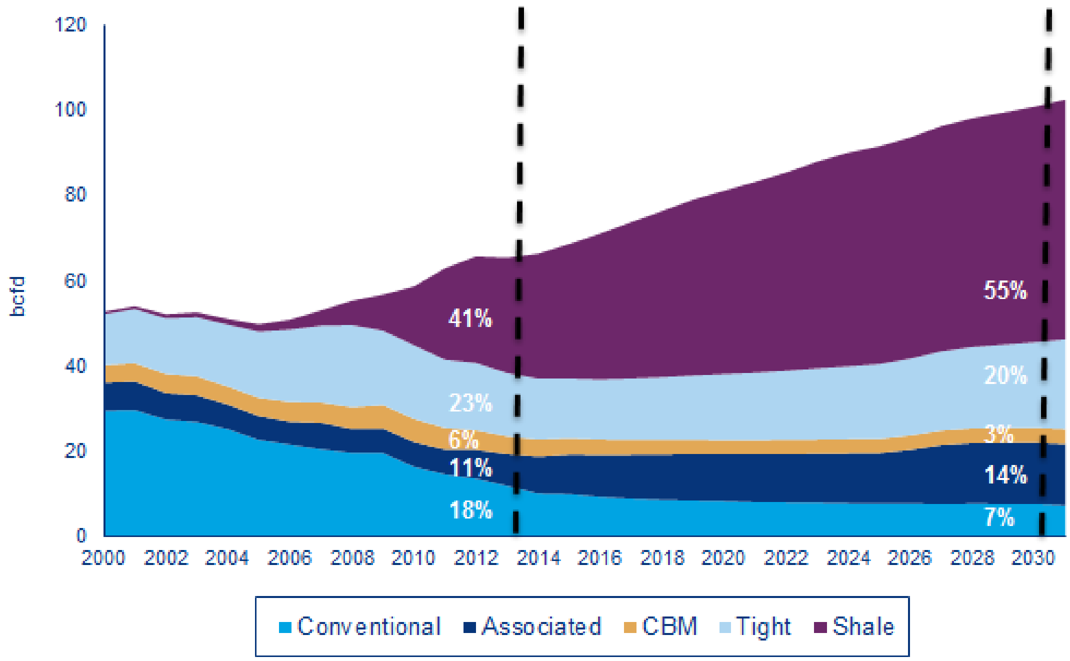


In August 2013, total U.S. production averaged about 70.1 Bcf/d in comparison to average 2012 production of 69.2 Bcf/d and 65.8 Bcf/d in 2011[4]. Despite relatively low gas prices, advances in drilling technology and efficiencies have resulted in steadily increasing production over the past few years. While supply is expected to remain high over the next few years relative to historical averages, supply growth has recently leveled off in response to low prices.

Over the long run, supplies from unconventional resources such as shales will be the single most significant contributor to growth in production and will eventually become the largest source of overall production. As of September 2013, shale gas accounted for about 41% of U.S. production. However, by 2030, shales are expected to contribute about 55% to total U.S. natural gas production, while the production contribution from conventional gas plays is expected to decline from 18% currently to about 7% by 2030.

[3] U.S. Energy Information Administration, Short Term Energy Outlook, September 2013
[4] Ibid.

Figure 3: U.S. Production by Type[5]

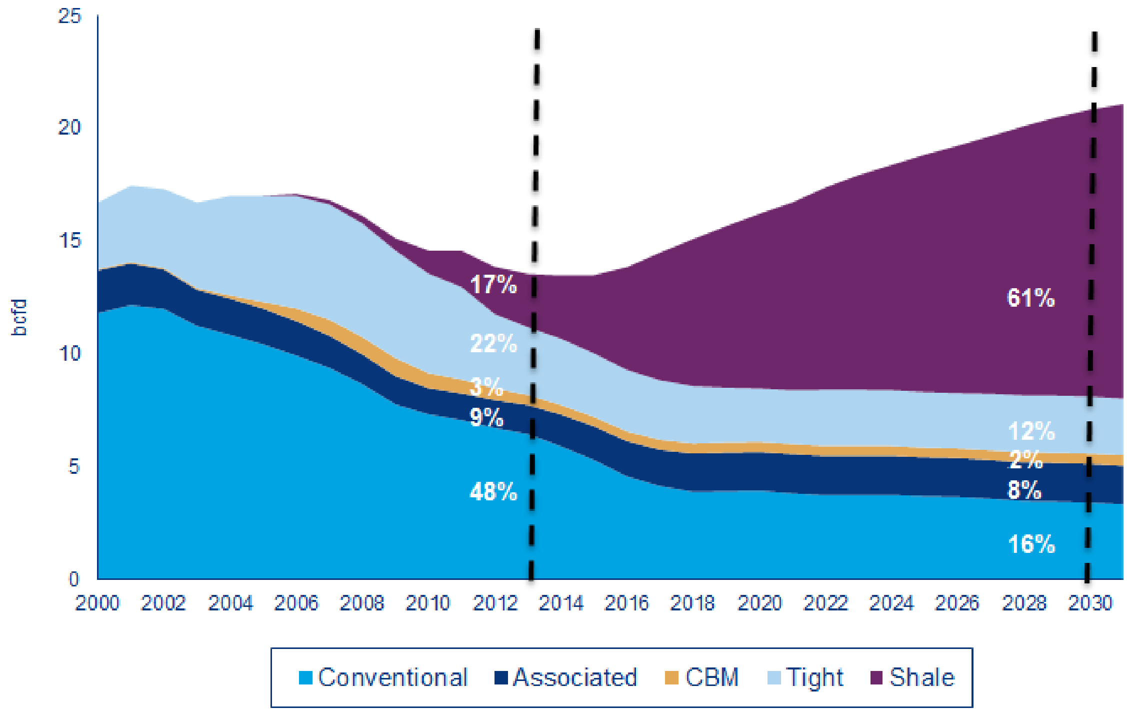


2.3 CANADIAN PRODUCTION

In Canada, the majority of natural gas supply originates from the WCSB with smaller quantities of supply originating from eastern Canada, particularly off the coast of Nova Scotia. In the short term, Canadian production is expected to remain flat, as supply growth in the Montney, Horn River, Duvernay and Liard regions is offset by declining production in Alberta. However, by 2030 production from shale gas plays is expected to make up about 61% (13 Bcf/d) of all Canadian production, as new infrastructure is built to connect supply to markets; an increase from the 17% (2 Bcf/d) that shales contribute today. Similar to U.S. production forecasts, supply from conventional sources will decrease, from 48% today to about 16% by 2030.

5 Wood Mackenzie, North America Natural Gas Long-Term View, June 2013. CBM, coal bed methane, is natural gas extracted from coal bed formations. Tight gas is a form of unconventional supply that is extracted from rock and sand formations. Associated gas supply is extracted during petroleum (oil) production. Shale gas is natural gas produced from the fractures, pore spaces, and physical matrix of rock shale.

Figure 4: Canadian Natural Gas Production Forecast[6]

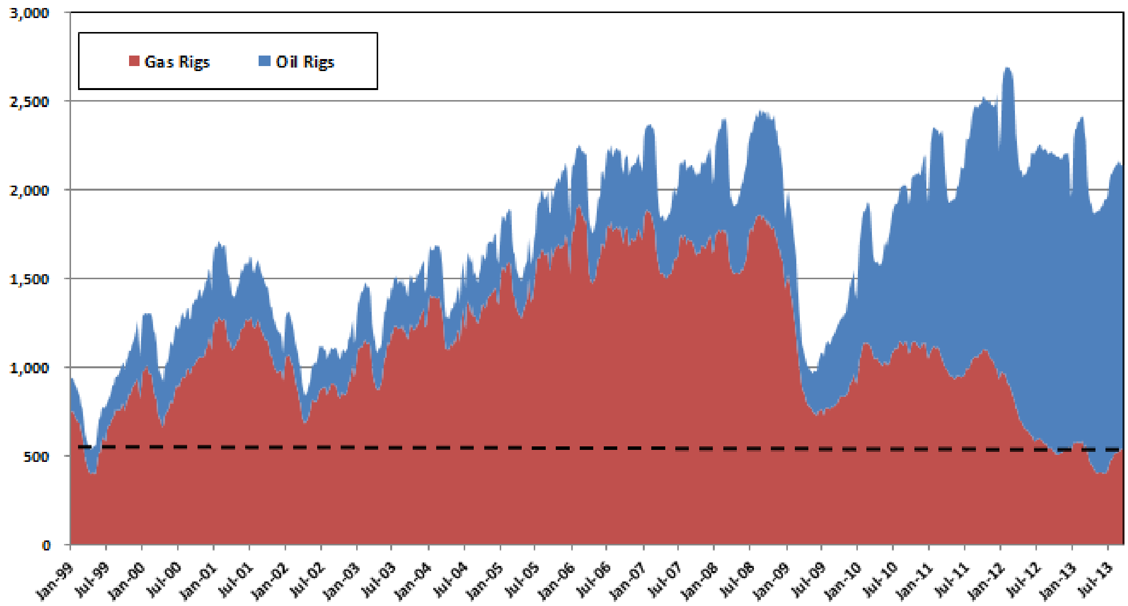


2.4 PRODUCTION SHIFT FROM DRY GAS TO OIL AND LIQUIDS RICH PLAYS

Although overall North American production levels have continued to grow, the rate of natural gas production growth has slowed as natural gas producers reduced dry gas development in response to low gas prices. Relatively higher natural gas liquids prices, which are tied to oil prices, provide incentive for producers to shift from dry gas to oil and liquids-rich drilling. The figure below shows this shift in drilling rigs from natural gas to oil over the past number of years. This shift to relatively more oil drilling is helping to rebalancing the natural gas market, as production growth has slowed while demand has and is expected to continue to increase.

[6] Wood Mackenzie, North America Natural Gas Long-Term View, June 2013

Figure 5: North American Oil and Gas Drilling Rig Count[7]



With oil and liquids-rich drilling, there is often associated gas that is produced as a by-product and this gas is also contributing to overall gas production. However, despite the supply from associated gas production, it is not expected to offset the overall reduction in dry gas production growth in the near term. Over the longer term, with increased demand for natural gas and an increase in market prices, it is expected that gas producers would return to dry gas drilling and gas supply would increase.

Many gas producers have been able to continue to produce in this low price environment due to favourable returns from liquids-rich gas production and favourable hedged prices on some of their production.

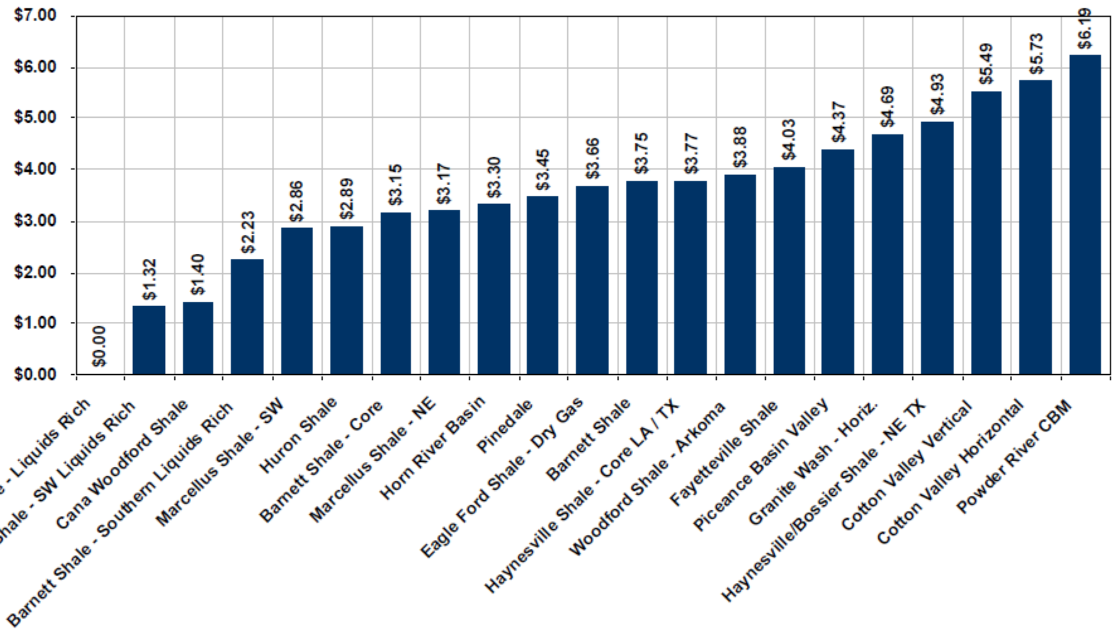
2.5 PRODUCER BREAKEVEN COSTS

The current low gas price environment is challenging some producers to recover breakeven costs for drilling and exploration of wells, particularly in dry gas regions. The figure below shows average breakeven costs, assuming an internal rate of return (IRR) of 10% per annum, for major gas plays in North America in $US/MMBtu. While dry gas plays have higher breakeven costs, gas plays that are rich in liquids have the lowest breakeven costs and therefore will attract more drilling activity, on average. The average breakeven cost is about $3.54 US/MMBtu, compared to the average breakeven cost of $4.08/MMBtu excluding the liquid rich plays. Note that the breakeven costs for many gas plays are above this average level. As a result, it is expected that current gas prices are not sustainable for an extended period of time because market prices below breakeven costs for many gas plays will force producers to either

[7] Baker Hughes Rig Count Service

reduce, shut-in production, or shift development away from gas to oil and liquids. As of the last week of September 2013, the NYMEX futures three-year price average from October 2013 to September 2016 is about $4.05 US/MMBtu.

Figure 6: North American Producer Breakeven Costs (10% IRR)[8]

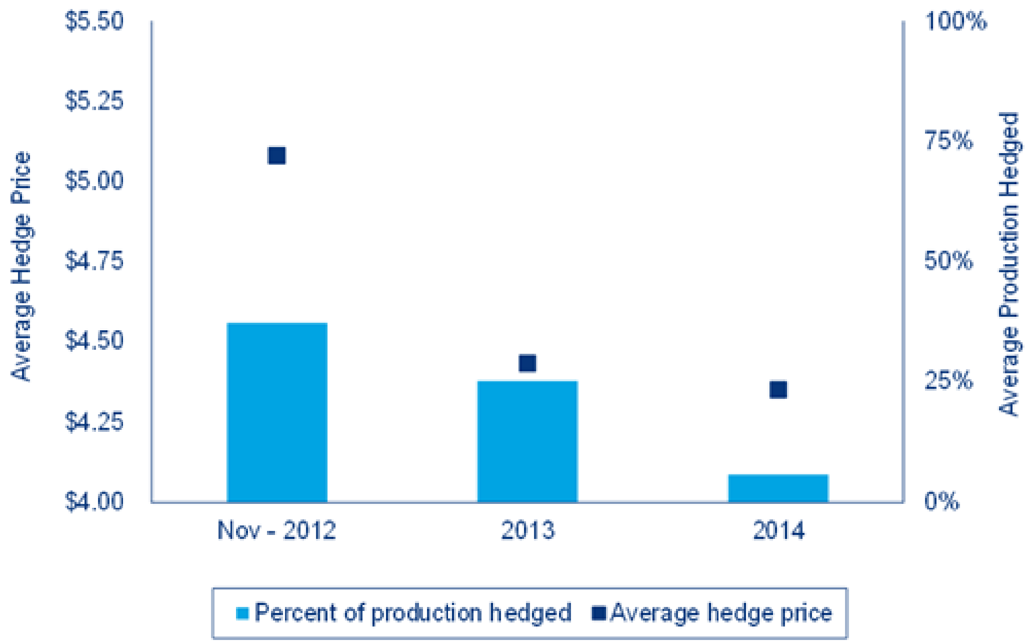


2.6 PRODUCER HEDGES

One of the reasons that some producers have continued to produce in a low gas price environment is that they still hold commodity price hedges that were implemented at prices above the current market levels. As the following figure illustrates, producers had about 30% of production hedged in November 2012 at an average hedge price of about $5.10 US/MMBtu. Looking forward, producers are only about 25% hedged at an average price of about $4.40 US/MMBtu in 2013 and about 5% hedged at an average price of about $4.30 US/MMBtu for 2014. Due to a reduced level of hedges in the future, market prices will have more of an impact than in the past on producer profit margins in 2013 and 2014. Producer bottom lines will be more impacted as producer hedges expire and some producers may find it uneconomical to continue producing in a low price environment and either elect to reduce production or shut-in production altogether.

[8] Credit Suisse, The Shale Revolution II, October 1, 2013

Figure 7: Average U.S. Hedging Levels and Hedged Prices for Surveyed Producers[9]



2.7 RECENT PRODUCER CUTBACKS TO PRODUCTION

In light of current gas prices which are lower than most breakeven costs for most dry gas plays, some producers have begun to cut back on dry gas production. Chesapeake Energy, one of the largest natural gas producers in North America, cut over 1 Bcf/d of their gas production and reduced their number of gas rigs from 47 to 24 in 2012. As well, ConocoPhillips cut back about 100,000 Mcf/d of dry gas production and Noble and Consol Energy also curtailed dry gas production in 2012 citing low prices and thin margins.

Regionally, producers in the Horn River region of B.C., such as ConocoPhillips and Encana, have announced reductions to production targets in response to current gas prices as well[10]. Additionally, Exxon/Imperial, which is the largest energy producer in the world, is keeping their Horn River production at the minimum level required to hold drilling rights in the region. Instead, Exxon/Imperial has announced shifting focus away from the Horn River and towards the more liquids-rich Duvernay and Montney regions and to oil sands production in Alberta. To support this, Exxon/Imperial completed the purchase of Celtic Exploration late in 2012 for $3.1 billion, which holds large land positions in the Duvernay and Montney regions.

The new CEO of Encana, Canada's largest natural gas producer, announced in September 2013 that the company will "develop fewer properties, bring in a new corporate structure and

9 Wood Mackenzie, North America Natural Gas Service, January 2013
10 CBC News, "Encana announces $2.9B asset sale," February 17, 2012

capital controls as well as better aligning its compensation with persistently low natural gas prices" after cutting seven per cent of its workforce in the first half of 2013 and warned for further cuts for the rest of the year[11]. Encana planned to exit a number of its 28 plays in North America to focus on top assets such as the Duvernay in Western Canada and the Tuscaloosa Marine Shale in the Southern U.S. as a shift to focus from dry gas to produce higher value crude oil and liquids rich gas in response to the low natural gas pricing environment.

2.8 SUPPLY SUMMARY

Improvements in drilling technology and the reduction in gas production costs have provided North America with an abundance of natural gas supply. Over the longer term, production, mainly from shales, in Canada and the U.S. is expected to significantly increase as presented in Figure and Figure. However, in the near term, production curtailments in response to low prices below most breakeven costs is helping to rebalance the market. This abundance of supply has spurred changes in the marketplace and demand for natural gas is expected to grow. These demand factors are discussed in more detail in the following section.

3. Natural Gas Demand

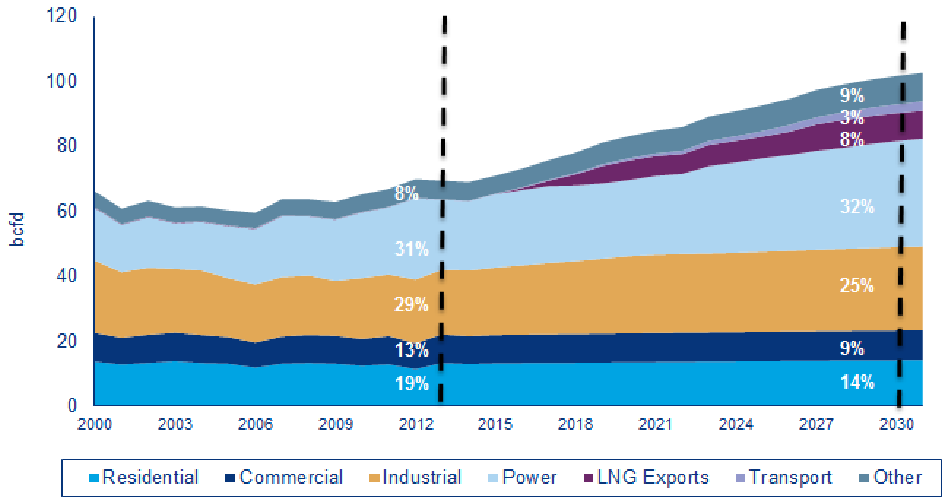
Low natural gas prices have provided incentives and opportunities for the greater use of natural gas across North America. Demand is recovering from the industrial sector, after being depressed prior to the past few years due to higher energy costs and reduced economic activity. Additionally, greater switching from coal to natural gas for power generation has occurred. The development of emerging markets such as LNG exports and, to a lesser degree, the NGT market will add to demand over the long run.

3.1 U.S. GAS DEMAND

The following figure provides a demand forecast for U.S. residential, commercial, industrial, power, NGT, other demand components (including lease, plant, and pipeline fuel), and LNG export demand out to 2030. Demand in the longer term is expected to grow steadily, with gas demand for power generation expected to be the largest contributor to overall demand in 2030 as coal-fired power plants are retired and being replaced, to a large degree, with gas fired generation. In addition, the development of the LNG export sector is expected to eventually account for about 8% of total U.S. gas demand by 2030.

[11] Calgary Herald, "Ewart: CEO lays out his vision for a smaller Encana," October 1, 2013

Figure 8: U.S. Natural Gas Demand[12]



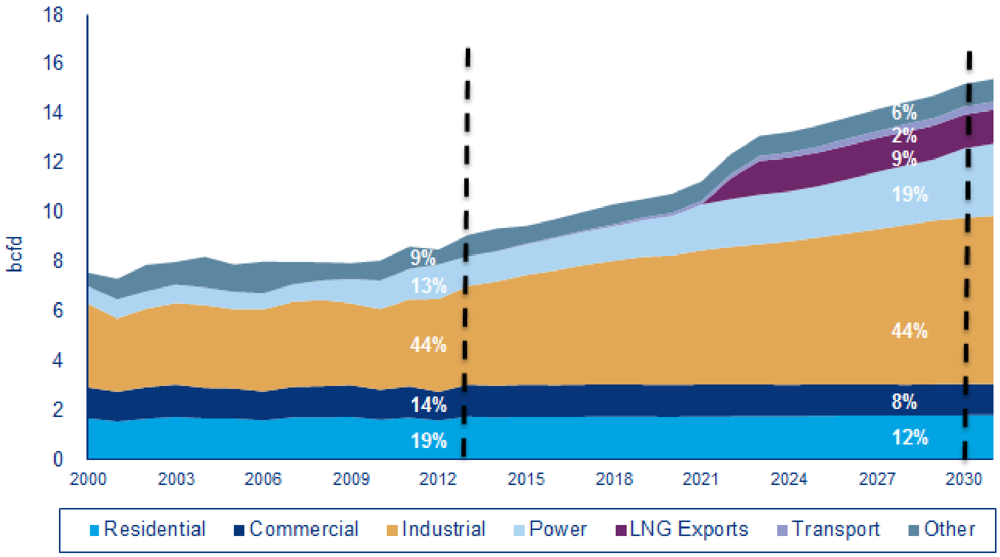
In 2012, statements made by the U.S. President promoting the use of natural gas, particularly for NGT and other transportation uses, have helped highlight the importance of natural gas in meeting domestic energy needs and favourably position natural gas for the future. In particular, on January 24, 2012, he stated in his State of the Union Address, “my administration will take every possible action to safely develop this energy [natural gas], and my administration will work with private companies to develop up to five natural gas corridors along the nation’s highways to build NGT fuelling stations”.

3.2 CANADIAN GAS DEMAND

The following figure illustrates a similar story to the U.S. for Canadian natural gas demand out to 2030. While there will be more demand attributed to power generation, the majority of the demand growth in Canada will come from the industrial sector, mainly for oil sands production in Alberta. It is expected that gas demand for LNG exports, which is discussed in detail in Appendix A-2, could grow from 0% today to about 9% of overall Canadian gas demand by 2030.

12 Wood Mackenzie, North America Natural Gas Long-Term View, June 2013. ‘Other’ demand includes gas demand for lease, plant, and pipeline fuel.

Figure 9: Canadian Natural Gas Demand[13]



The Province of B.C. has also announced its support for the development of markets for natural gas. On February 3, 2012, the Provincial Government of B.C. released two reports titled, "B.C.'s Natural Gas Strategy" and "B.C.'s Liquefied Natural Gas Strategy", which promote the use of natural gas. This includes using natural gas as an export fuel in the global LNG market, natural gas for transportation fuel, and the development of new markets for natural gas such as power generation for export to the Pacific Northwest markets.[14] The promotion of natural gas by local and federal governmental bodies positions natural gas in a favourable light and will contribute to increased natural gas demand in the future.

3.3 POWER GENERATION DEMAND

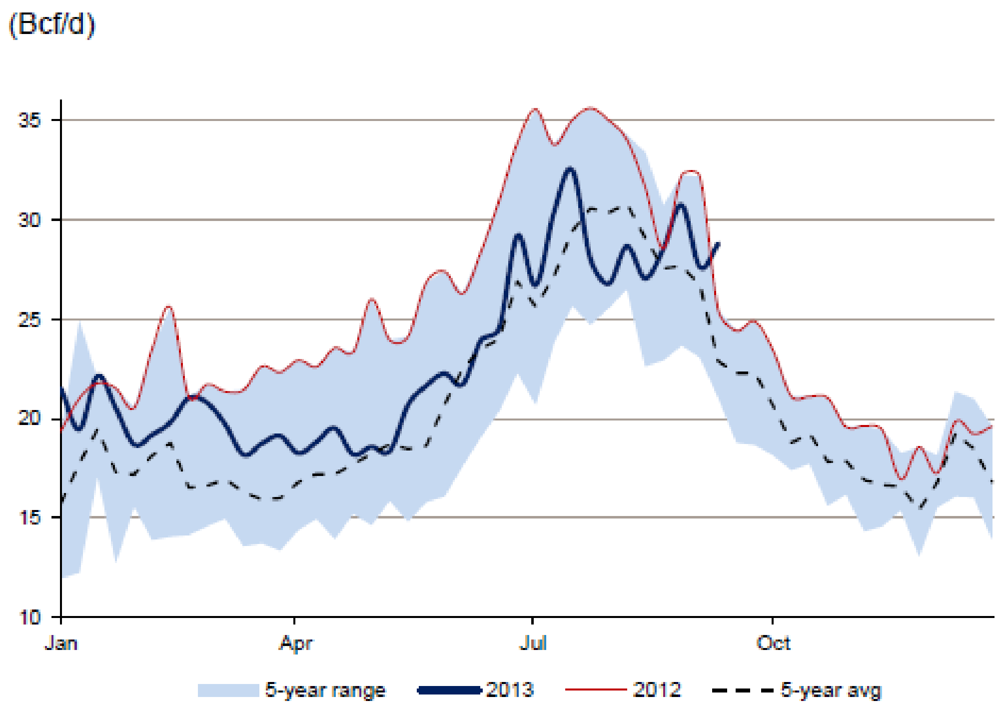
An increased focus on controlling greenhouse gas emissions (GHG) in North America will result in the retirement of older and less efficient coal-fired power plants in favour of relatively cleaner burning natural gas fired power generation facilities.[15]

In the short term, existing gas fired generation will be dispatched over coal-fired generation when gas prices remain competitive with coal prices. This is because some power generators have the ability to switch between dispatching plants that use natural gas versus those that run on coal in response to market price signals.

[13] Wood Mackenzie, North America Natural Gas Long-Term View, June 2013. 'Other' demand includes gas demand for lease, plant, and pipeline fuel.
[14] Provincial Government of B.C., "B.C.'s Natural Gas Strategy : Fuelling B.C.'s Economy for the Next Decade and Beyond," February 3, 2012
[15] U.S. Energy Information Administration, Annual Energy Outlook 2013, April 2013

The following figure illustrates this by showing U.S. natural gas demand for power generation in 2013 to date relative to 2012 and the five-year average. Due to low natural gas prices relative to coal prices, gas demand for power generation was higher for each month in 2012 than for each corresponding month over at least the past five years. On average, gas demand for power generation was the highest ever in 2012, accounting for about 30% of total power generation, compared to 37% for coal.[16] Overall in 2013, demand for power was relatively lower than in 2012 due to cooler year-to-year temperatures across most key consuming regions in U.S. and higher gas prices. However, 2012 gas demand was still higher than the five-year average and reflects the recent trend of higher dispatch rates for gas-fired power generation over coal.

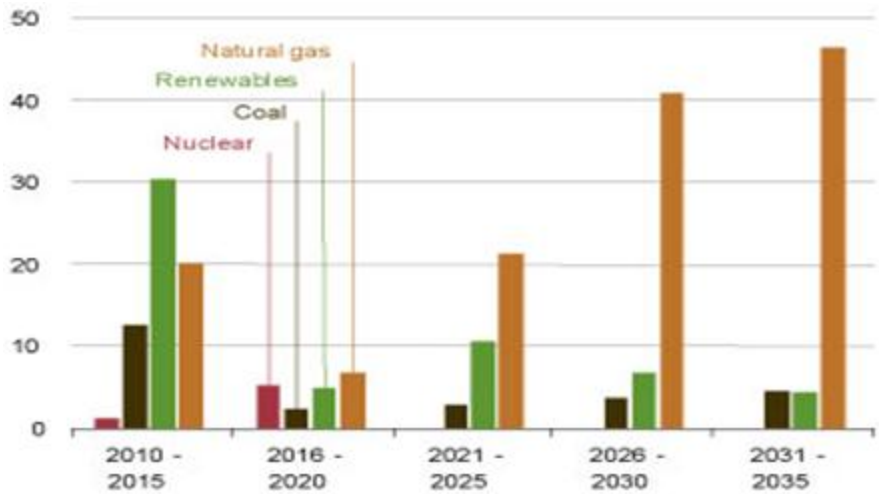
Figure 10: Natural Gas Demand for Power Generation[17]



Over the long run, the largest contributor to gas demand is expected to come from the retirement of existing coal-fired power generation. The retirement of coal-fired generation will largely be driven by environmental regulation to reduce or limit the amount of GHG emissions. Currently, gas demand for power generation accounts for about 31% of total U.S. gas demand and is expected to increase to 32% of total demand by 2030, for an increase of about 11 Bcf/d. The following Figure depicts the demand for power generation for all new capacity additions by fuel type for the period of 2010 to 2035. As presented, natural gas fired-generation is expected to make up the bulk of new capacity additions of electricity generation.

[16] Energy Information Administration, Annual Energy Outlook 2012, http://www.eia.gov/electricity/data.cfm
[17] Credit Suisse, U.S. Gas Storage, September 18, 2013

Figure 11: Capacity Additions (2010-2035) for Power Generation by Fuel Type (Gigawatts)[18]

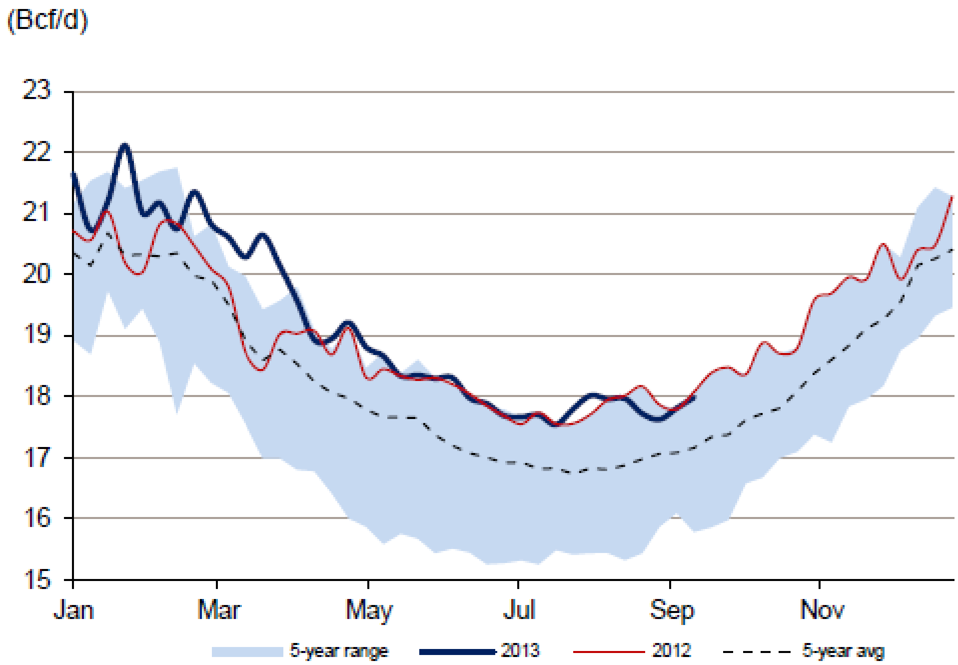


3.4 INDUSTRIAL DEMAND

Another source of demand that is increasing and is expected to continue increasing in the future in North America is demand from the industrial sector. Industrial demand continues to recover in North America as economic conditions gradually improve. Also, the competitiveness of North American industrial companies is improving for sectors such as the petrochemical and fertilizer industries due to lower gas feedstock prices. In addition to increased manufacturing, other gas intensive industries include iron and steel, cement and methanol production. The following figure shows the U.S. industrial demand in 2013 relative to 2012 and the historical five-year average.

[18] EIA, Annual Energy Outlook 2012, Market Trends, Electricity

Figure 12: Industrial Gas Demand[19]



According to estimates by analysts, there are over 120 projects in North America in various stages of development that could potentially be built to take advantage of relatively cheaper feedstock natural gas prices, with most of them in Texas and along the Gulf Coast.[20] These projects are estimated to cost up to $80 billion in new construction and expansions of existing infrastructure into 2018. An example of one of these is the project by Sasol to construct a gas-to-liquids plant that is scheduled to come online by 2018 and could add up to 835,000 MMcf/d of industrial gas demand. Other large projects include CF Industries' nitrogen fertilizer plant and Potash Corp.'s restart of its anhydrous ammonia plant in Louisiana.

Furthermore, some companies are assessing the feasibility of bringing manufacturing operations back to the U.S. from overseas to take advantage of lower gas prices. One example is the German automaker, Daimler AG, who in December 2012 stated that it would like to expand its existing facility in Detroit and chose this site over others located in Mexico and Germany.[21]

With regard to the methanol industry, Methanex, the world's largest producer of methanol, restarted its facility in Medicine Hat, Alberta in 2011. This project consumes approximately 50,000 MMBtu of natural gas per day. Additionally, Methanex is also proposing to relocate one of its Chilean methanol facilities to Louisiana which could be operational by 2014. Celanese Corp. has also said it will open a methanol production facility in Houston, Texas in 2015. These

[19] Credit Suisse, US Gas Storage, September 18, 2013
[20] Bentek Natural Gas Industry Analysis
[21] Platts Gas Market Report, January 18, 2013

developments in the methanol segment of the industry could potentially add up to several hundred thousand MMBtu per day of gas demand to the North American market if they materialize.

It is estimated that if all proposed industrial additions are built that natural gas consumption could increase by up to 6 Bcf/d in the U.S. by 2020. However, it is unlikely that all proposed industrial expansions will be built and that actual demand growth will be slower than expected due to lack of access to capital and other factors.[22]

Increased industrial gas demand is also occurring in B.C. as the FEU have experienced some fuel switching among its larger industrial customers back to natural gas. As an example, some larger cement plants, which typically each consume about 1 petajoule per year, have switched back to natural gas from other input fuels to realize cost savings from lower gas prices and tighter emissions standards. The FEU are also receiving inquiries from other industries which could lead to greater gas demand (an example of which is provided in Section 3.3.9) and additional load requirements on the FEU's systems (discussed throughout Section 5.1.2).

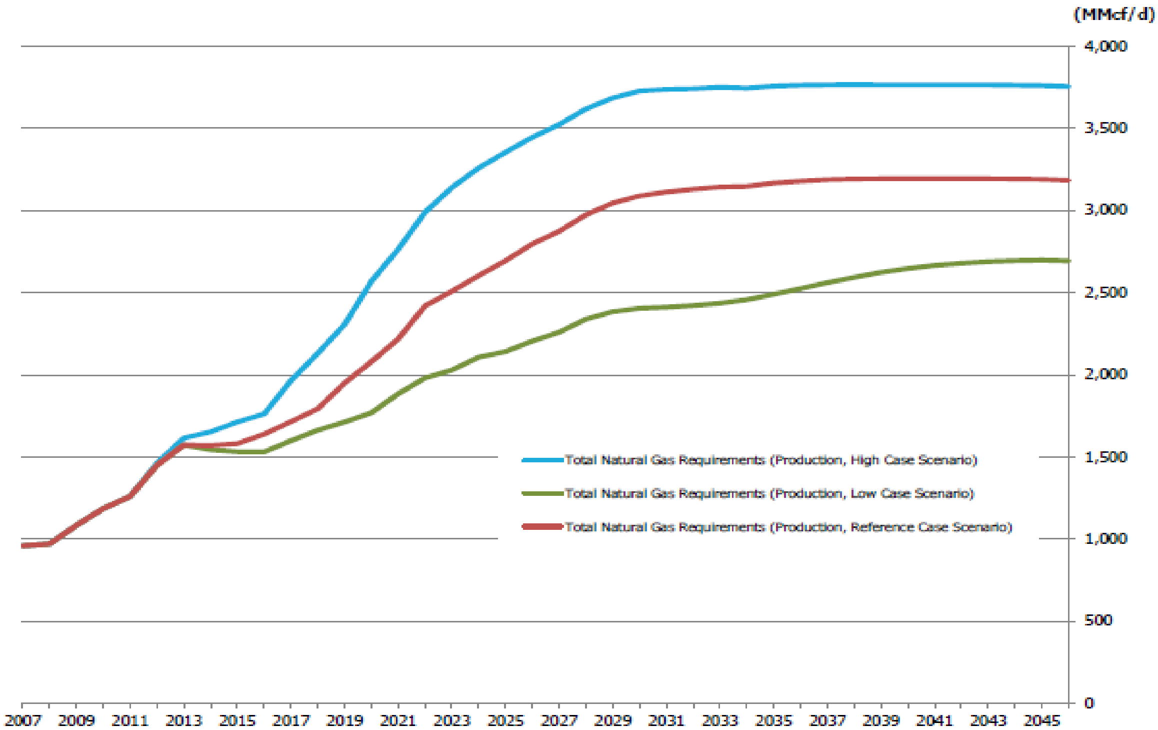
Oil Sands and Natural Gas Demand

A significant segment of Canadian industrial demand is from the oil sands of Alberta where natural gas is used in the extraction of crude oil. Key drivers that affect the development of the oil sands projects include the difference between natural gas and oil prices as well as infrastructure required to transport gas to the oil sands and carry the oil away to markets.

The following figure illustrates the natural gas required to sustain the Canadian oil sands industry to 2046. By 2046, natural gas demand from oil sands will increase two to three times from the 2011 level of 1,259 MMcf/d, to 3,183 MMcf/d in the Reference Case Scenario, or 3,753 MMcf/d under the High Case Scenario.

[22] Barclay's Natural Gas Report

Figure 13: Natural Gas Requirements for Canadian Oil Sands[23]



3.5 NORTH AMERICAN LNG EXPORT DEMAND

North American LNG exports also have the potential to provide significant demand for natural gas in the future. Countries in Europe and Asia have traditionally imported LNG from Australia and Qatar, with the imported LNG prices indexed to the crude oil prices and at higher prices than in North America.

Due to the shale gas development in North America and subsequent lower natural gas prices, the relative spread in gas prices between North America and Europe and Japan has widened over the last couple of years. The figure below from the U.S. Federal Energy Regulatory Commission (FERC) shows estimated landed world LNG prices for October 2013 delivery for various import points around the world.[24]

[23] Canadian Energy Research Institute, Canadian Oil Sands Supply Costs and Development Projects (2012-2046), May 2013

[24] The U.S. EIA defines landed prices as prices for LNG imports received at the terminal, or "tailgate," after regasification at the terminal. Generally, the reporting of LNG import prices varies by point of entry and the average prices are calculated from a combination of both types of prices. The price of LNG exports to Japan is the "landed" price, defined as received at the terminal in Japan. http://www.eia.gov/dnav/ng/tbldefs/ng_pri_sum_tbldef2.asp

Figure 14: Global LNG Spot Prices ($US/MMBtu equivalents)[25]

Many LNG export facilities have been proposed in recent years in the U.S.(Gulf of Mexico, Alaska, Oregon and the east coast), as well as in Canada (mostly on the west coast of B.C.). However, due to resource and cost constraints, it is not likely that all projects will proceed to completion.

U.S. Department of Energy LNG Report

As of September 2013, the U.S. Department of Energy (DOE) had 21 outstanding applications requesting approval to export LNG from the U.S. with a total cumulative export capacity of up to about 33.04 Bcf/d, if all are approved. However, as listed in Table, so far only four U.S. LNG export projects have received approval to export LNG to non-Free Trade Agreement countries, with a total export capacity of 6.37 Bcf/d.

[25] Federal Energy Regulatory Commission, Market Oversight, October 2013, http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf

Table 1: Non-FTA Approved U.S. LNG Export Projects

Non-FTA Approved U.S. LNG Export Projects	Export Capacity (Bcf/d)	Target Export Year
1. Cheniere Energy, Sabine Pass	2.2	2015/16
2. ConocoPhillips, Freeport LNG	1.4	2017
3. Energy Transfer Partners, Lake Charles	2.0	2018
4. Dominion, Cove Point	0.77	2017
Total	**6.37**	

Source: FEU based on U.S. Dept. of Energy

To help the DOE make a decision on these other LNG exports applications, it commissioned a study in 2012. The study commissioned by the U.S. DOE provided a comprehensive assessment on the impacts of LNG exports from the U.S., with particular focus on domestic gas prices and economic impacts. The report concluded that LNG exports would provide a net economic benefit to the U.S. economy and that the benefits would outweigh the net costs.

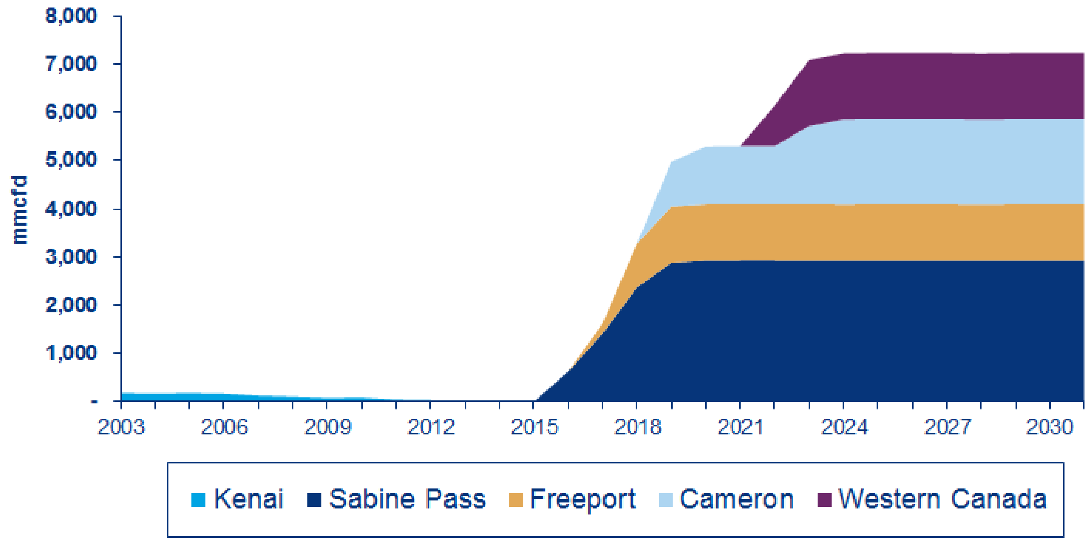
In terms of impact on domestic gas prices, the report concluded that if LNG exports reach 6 Bcf/d by 2015 then domestic gas prices could rise up by $0.33 US/Mcf. Eventually, after five years of LNG exports, amounting to a maximum of 12 Bcf/d, domestic gas prices would rise between $0.22 and $1.11 US/Mcf. The forecasted maximum price increase of $1.11 US/Mcf is assuming that LNG projects reach the maximum export capacity of 12 Bcf/d.

In all analysed cases, the DOE report concluded that the net benefits to the U.S. would increase as LNG exports would increase the overall economic output such as employment, business revenues, tax revenues, etc. Although the DOE report indicated that more LNG exports would be better for the economy, the probability that all proposed projects are approved remains low.

The following figure provides a forecast of gas demand for LNG exports from North America for various regions. Once projects are approved and built, it is assumed that LNG exports are expected to increase substantially after 2017 and eventually top out at about 7.2 Bcf/d by 2030[26]. For Western Canada, Wood Mackenzie forecasts a maximum of 1 Bcf/d of LNG exports by 2021. A detailed discussion of LNG exports from B.C. is provided in the Regional Gas Supply Infrastructure appendix.

[26] Wood Mackenzie, North America Natural Gas Long Term View, June 2013

Figure 15: North American LNG Exports[27]



3.6 NATURAL GAS FOR TRANSPORTATION

Another source of gas demand growth will come from the development of the NGT market as North American natural gas prices are expected to remain at a significant discount to gasoline and diesel prices. Conversion from tradition fuels such as diesel and gasoline in natural gas vehicles (NGV) and marine vessels to either compressed natural gas or liquefied natural gas will likely contribute to higher gas demand in the future. The largest segment of demand in the NGT industry is demand is the NGV market.

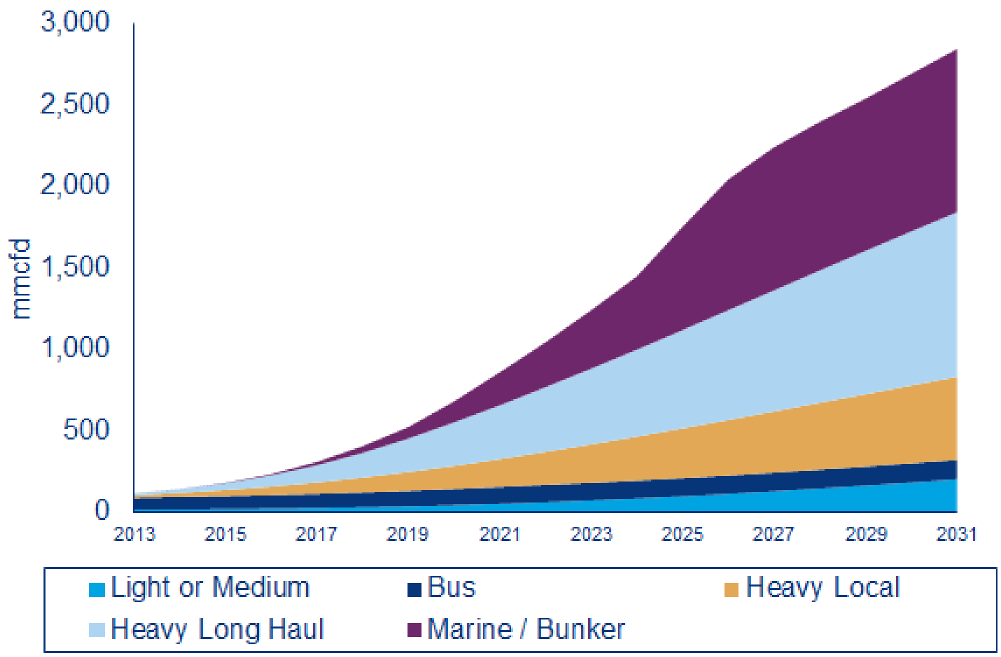
Natural Gas Vehicles

From the period 2008 to 2010, natural gas demand for NGVs rose at a rate of about 13% per year as natural gas prices were, and continue to be, more competitive over traditional fuels such as diesel and gasoline.

According to the forecast for NGT gas demand presented in the figure below, U.S. gas demand is expected to grow from about 0.1 Bcf/d in 2013 to about 2.7 Bcf/d by 2030. While significant for the NGT market, overall NGT demand is expected to represent only about 2% of total U.S. gas demand by 2030.

[27] Wood Mackenzie, North America Natural Gas Long Term View, June 2013

Figure 16: U.S. NGV Natural Gas Demand[28]



FEU and the NGT Market in B.C.

The FEU have also experienced increased demand related to the NGT market within its own service regions. This increase in demand in the NGT sector is primarily due to the FEU's ability to issue financial incentives to qualifying customers to purchase CNG and LNG vehicles as permitted under the province's Greenhouse Gas Reductions (Clean Energy) Regulation (GGRR), as discussed in Section 2.2.3.2. To date, the FEU have conducted two rounds of financial incentive funding to a number of CNG and LNG customers.

The FEU are also looking at fuel conversion in marine vessels in situations where converting to natural gas makes economic sense. In doing so, this will also allow the B.C. Government to achieve its goals of reducing GHG emissions by converting more carbon intensive fuels, such as diesel, to relatively more cleaner burning natural gas.

Although NGT demand (CNG and LNG) is expected to be a relatively small portion of the FEU's overall gas supply portfolio in the short term, there are benefits from adopting gas for transportation such as reduced operating costs for NGT customers, reduced GHG emissions, and reduced delivery rates for all natural gas customers. Appendix A-8 provides additional detail on the Utilities' NGT initiatives.

[28] Wood Mackenzie, North America Natural Gas Long Term View, June 2013

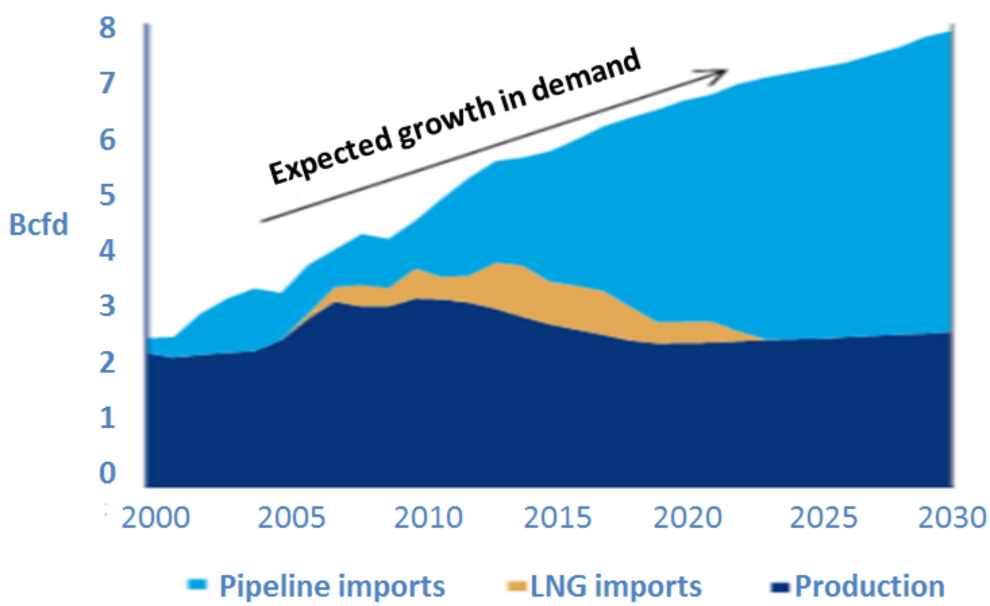
3.7 INCREASING U.S. EXPORT DEMAND INTO MEXICO

As Mexico continues its efforts to phase out oil use for power generation, gas-fired capacity is expected to increase. By 2030, total demand for natural gas in Mexico is expected to reach 7.8 Bcf/d from 5.8 Bcf/d in 2013, with 68% of the growth attributed to power generation.

Although the Mexican government has indicated shale (the Burgos basin) and deepwater gas production (the Lakach basin) projects as alternatives to satisfy upcoming demand, limited improvement is expected in the short-term from these supply sources given the capital-intensive nature of these projects. As Mexico faces challenges in meeting the growing gas demand through domestic production, it is turning to importing gas from the U.S. as a solution.

The following figure illustrates the Mexican natural gas demand up to 2030 and the various supply methods to satisfy the growing demand. By 2030, over 60% of Mexican gas demand is expected to be met by pipeline imports.

Figure 17: Mexico Natural Gas Demand [29]



In order for U.S. pipeline imports to become a secure source of gas, various pipeline projects have been in place to resolve the bottlenecks on import capacity at the U.S./Mexico border, as well as to reallocate domestic production to reducing the use of fuel oil. Current new pipeline projects, including the Los Ramones, Chihuahua and the Noroeste projects, will increase total import capacity by pipeline up to 8.3 Bcf/d, enough to satisfy domestic consumption by 2030.

[29] Wood Mackenzie, U.S. Gas Goes South: A Review of Mexico's Infrastructure, July 2013

3.8 DEMAND SUMMARY

Expectations of a lower price environment and abundant gas supply, due to shale gas development in North American, is providing incentive for the market to develop and expand uses for natural gas. Additionally, the promotion of natural gas by local and federal governments favourably positions natural gas in the future to meet environmental and energy self-sufficiency objectives.

In the short term, increased demand for natural gas is expected from industrial demand, demand related to weather, greater dispatch of natural gas over coal for power generation and demand from oil sands production in Alberta due to relatively higher crude oil prices.

Over the longer term, demand for gas is expected to increase primarily due to LNG exports, the continued increase of industrial demand, the retirement of coal-fired facilities being replaced by gas-fired power generation, and increasing U.S. import demand from Mexico. To a lesser degree, demand will also increase due to the expansion of the NGT industry. This will serve to increase gas prices above current levels and subsequently increase natural gas supply brought to market. As Goldman Sachs recently stated: "we believe that these structural changes in demand will ultimately move the market away from pricing fuel substitution and towards pricing marginal cost of production, as natural gas drilling and, ultimately, supply, will need to rise more significantly to accommodate the changes in US natural gas demand".[30]

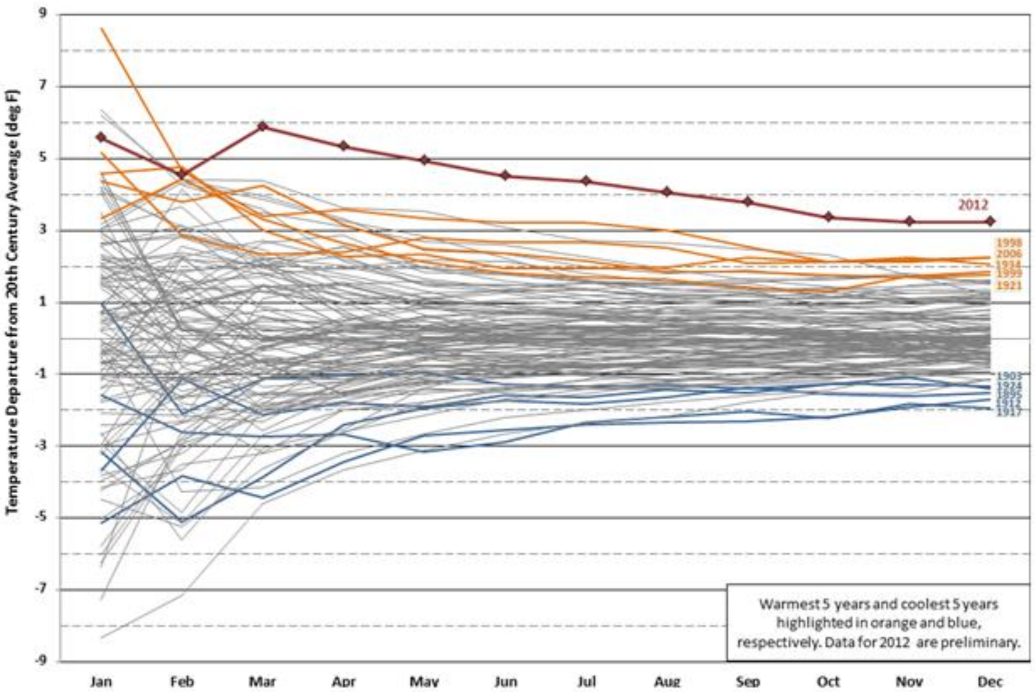
4. Natural Gas Storage Balances

Natural gas storage balances represent the amount of natural gas storage inventory levels, which will fluctuate up and down throughout the year as gas is injected into storage facilities during the lower-demand summer months and withdrawn from storage during the higher-demand winter months. In the short term, storage balances are the result of the various supply and demand factors in the gas marketplace and therefore provide a good snapshot of current market conditions. As such, storage balances influence market gas prices, particularly for the near term.

According to the U.S. National Oceanic and Atmospheric Administration, 2012 was the warmest year on record, which also included the warmest summer on record. This affected the gas market in two offsetting ways; the historically warm 2011/12 winter led to record high storage inventories exiting the winter and the exceptionally hot 2012 summer increased natural gas demand used to deploy gas-fired generation. The temperature anomalies for the contiguous U.S. are depicted in the figure below.

[30] Goldman Sachs, Natural Gas Weekly, September 11, 2013

Figure 18: 1895-2012 U.S. Temperature Anomalies[31]



Due to the exceptionally hot 2012 summer, higher gas demand for power generation helped erode the glut of storage surplus throughout 2012. However, storage inventories still entered the 2012/13 winter season at all-time high levels, or about 2% higher than the previous record on November 1, 2011.

Temperatures during winter 2012/13 averaged significantly lower than those during winter 2011/12 and weather was closer to normal winter conditions for many gas consuming regions of North America. The relatively mild start to the 2012/13 winter heating season initially kept gas storage balances near the same high levels as a year ago. However, cold weather during March and April 2013 had put storage levels in a significant deficit position to last year and a slight deficit to the historical five-year average. Since then, with higher gas production and near normal weather, the storage balances have recovered from a deficit to a surplus to the five-year average. Figure compares the U.S. degree days[32] for 2013 compared to 2012 and the five-year average. Figure shows storage balances for 2013 compared to 2012 and the five-year average.

[31] National Oceanic and Atmospheric Administration, Climate Data Center, January 2013

[32] Heating degree day is a measure of how cold a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the average of the day's high and low temperatures from the base temperature (65 degrees), with negative values set equal to zero. Each day's heating degree days are summed to create a heating degree day measure for a specified reference period. Source: U.S. Energy Information Administration glossary.

Figure 19: U.S. Degree Days[33]

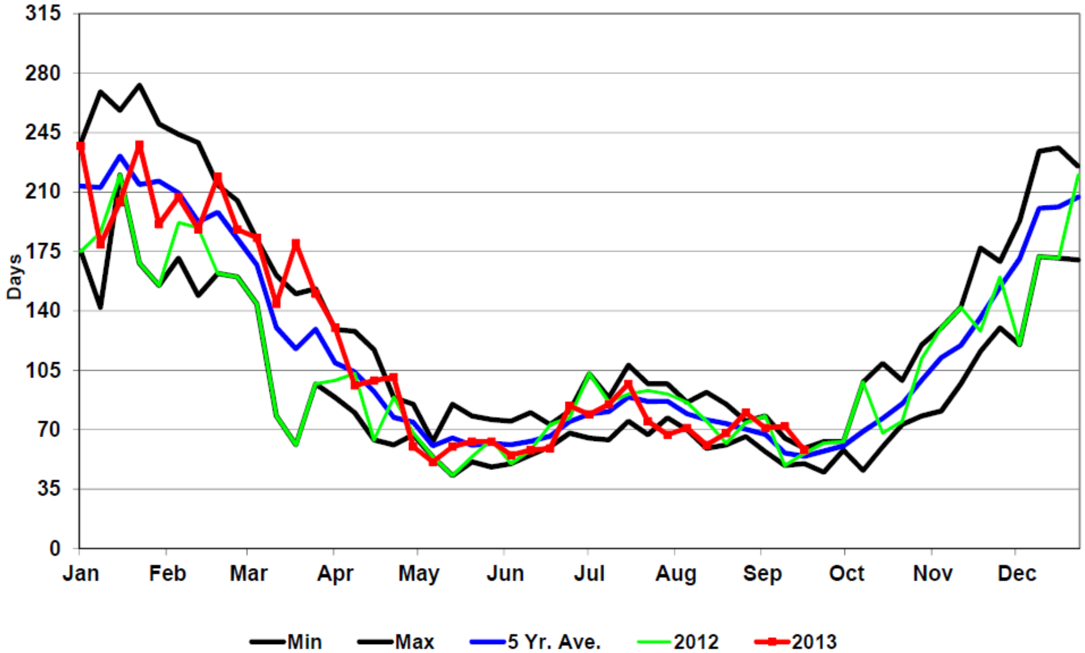
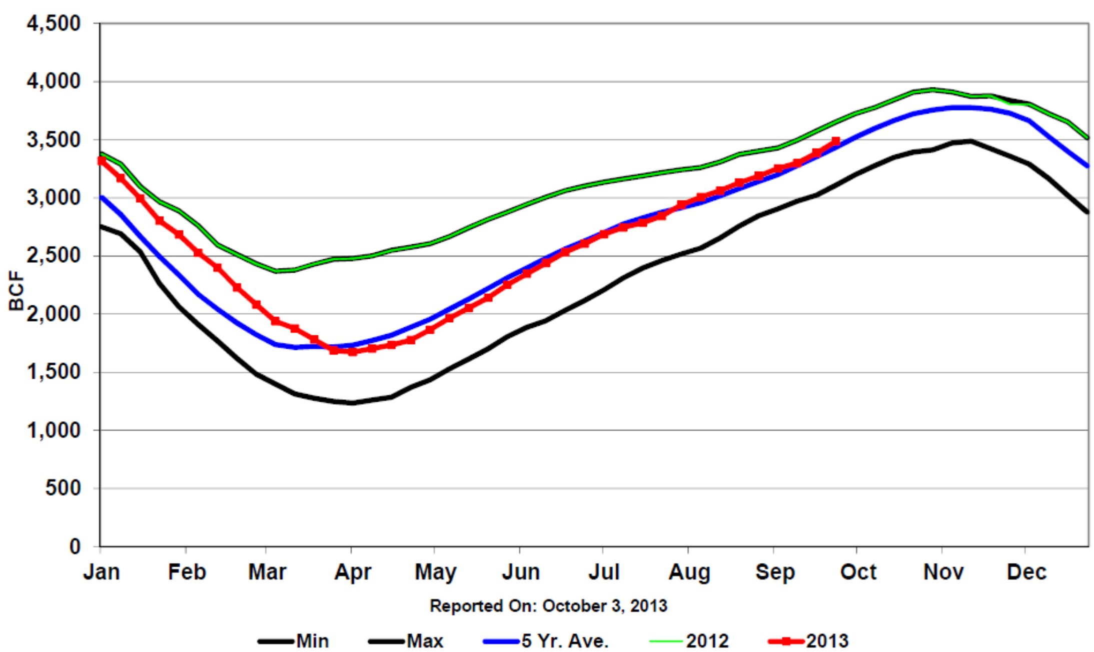


Figure 20: U.S. Natural Gas Storage Inventory[34]



[33] BMO Natural Gas Storage Charts, September 26, 2013
[34] BMO Natural Gas Storage Charts, October 3, 2013

For the week ending September 27, 2013, U.S. working gas in storage was 3,487 Bcf, which was 4.3% below last year's level of 3,642 Bcf and 1.4% above the 5-year average of 3,438 Bcf. Storage inventory levels at the end of the summer 2013 are expected to be at 3,823 Bcf, which is about 3% below the historical high storage balance of 3,929 Bcf in 2012 and 2% higher than the 5-year average of 3,757 Bcf. This highlights the significant impact weather can have on natural gas demand and storage balances, which in turn, impact natural gas prices, discussed in the next section.

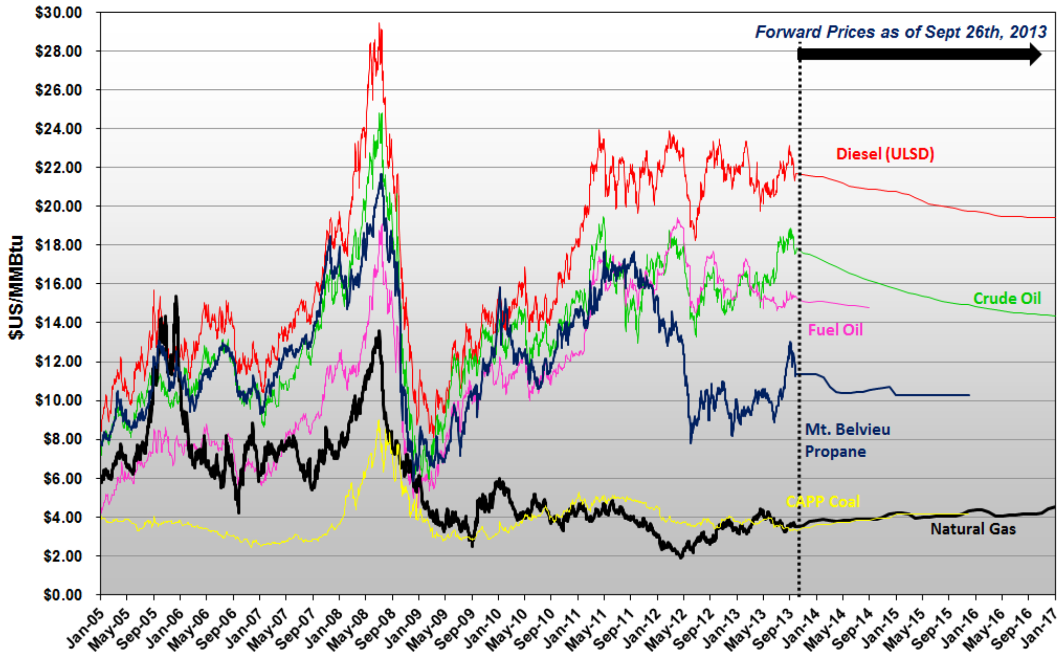
5. Natural Gas Prices

With the abundance of shale gas supply in recent years, natural gas prices have come down from the levels seen prior to 2009 where prices typically remained above $6 US/MMBtu and higher during peak demand periods (see Figure 0-19). Due to the exceptionally warm 2011/12 winter, natural gas prices reached their lowest levels in a decade in mid-2012, but have since rebounded although still remaining below $4 US/MMBtu. Furthermore, natural gas prices remain disconnected from other competing fuels, such as heating and fuel oil, which are derived from crude oil and can be used as substitutes for natural gas in certain applications such as space heating and power generation. Crude oil prices are highly influenced by global supply and demand factors and geopolitical tensions whereas North American natural gas prices have been relatively isolated from such factors and more dependent upon regional supply and demand dynamics.

Currently, Central Appalachian (CAPP) coal prices and NYMEX natural gas prices are both near the $3.50 US/MMBtu level. When natural gas prices are below the CAPP coal prices, demand for natural gas increases due to switching from coal and gas prices go up – so CAPP coal prices act as a soft cap for natural gas. The fuel switching demand mostly derives from power generators that can deploy natural gas generation in lieu of coal depending on the relative price differences between the two fuels.

The figure below shows prices (historical prompt month and futures) for various competing fuels with natural gas as of September 26, 2013. At the current time, forward natural gas prices are expected to average near the $4 US/MMBtu level. This can change quickly, however, in response to weather and supply and demand balances.

Figure 21: Competing Fuel Prices, North America[35]

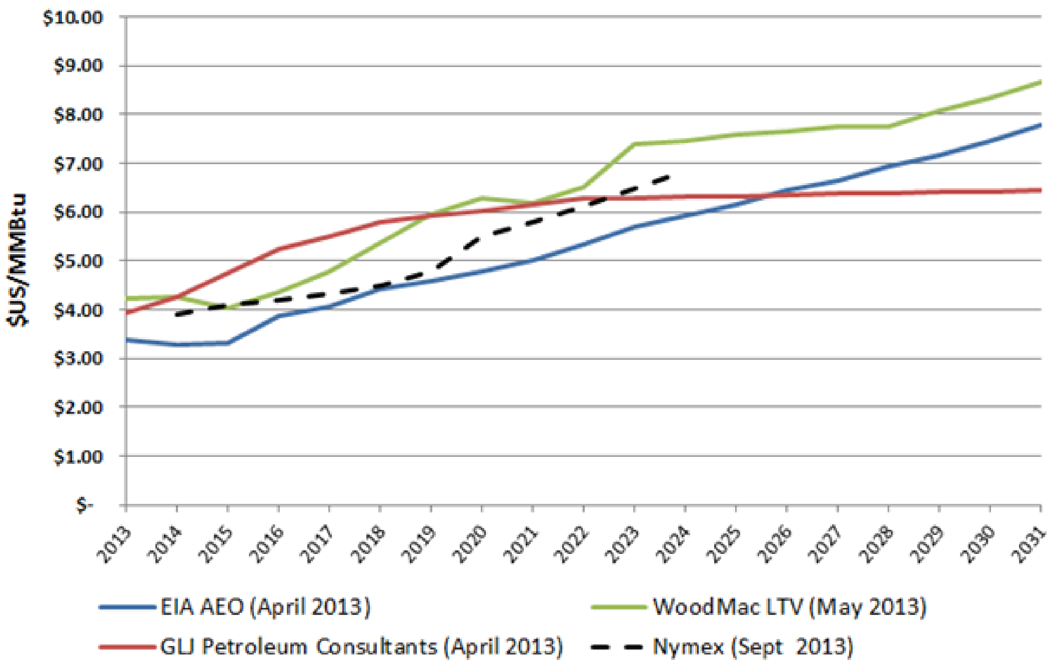


5.1 LONG RANGE PRICE FORECASTS

The following figure shows various recent long term price forecasts for natural gas based on the Henry Hub market. The current NYMEX forward curve is also provided (as of September 26, 2013). All prices are presented in nominal dollars. All forecasts show gas prices in the near term around $4.00 US/MMBtu but prices over the long run follow an upward trend due to a balancing of supply and demand and higher long run production costs. By 2020, gas prices could be in the range of $4.75 US/MMBtu and $6.25 US/MMBtu. By 2025, analysts forecast that gas prices could be in the range of $6.00 US/MMBtu and $7.50 US/MMBtu.

[35] U.S. Energy Information Administration & CME Group, September 26, 2013

Figure 22: Natural Gas Price Forecasts



Source: FEU based on U.S. EIA Annual Energy Outlook, GLJ, WoodMac Long Term View and Nymex

5.2 PRICE VOLATILITY

In addition to looking at market prices, market price volatility also provides an indication of potential prices and price movements in the future. Price volatility can be measured in one of two ways: using either observed or implied volatility.[36]

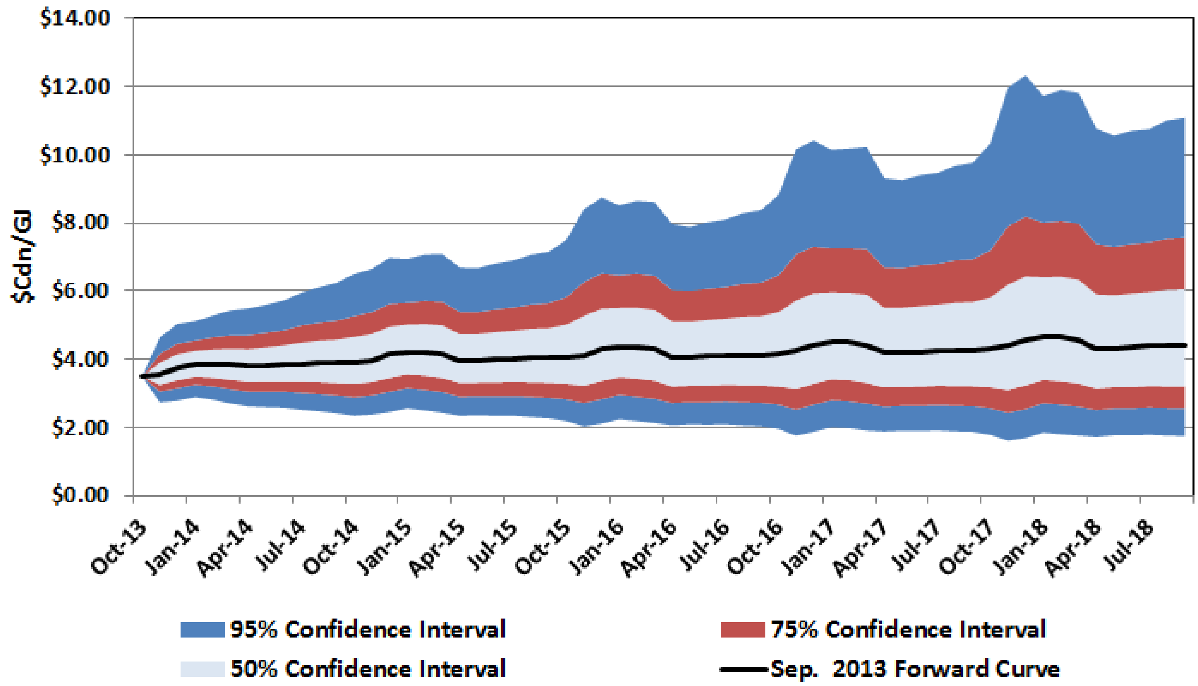
Figure below shows the forward AECO/NIT price range that is derived from the implied volatility as of September 26, 2013. The figure illustrates three confidence intervals of 50%, 75%, and 95% to provide different envelopes of potential future price movements. For example, the figure shows that for January 2018:

- The forward curve is trading at about $4.60 Cdn/GJ;
- There is a 95% probability that prices will range between $1.90 Cdn/GJ and $11.75 Cdn/GJ, for a range of $9.85 Cdn/GJ;
- There is a 75% probability that prices will range between $2.70 Cdn/GJ and $8.00 Cdn/GJ, for a range of $5.30 Cdn/GJ; and

[36] Observed volatility uses historical settled price movements over a defined period of time (such as 15, 20, 30, etc. trading days) and applies these observed changes to futures prices to model a forward curve. Implied volatility is the volatility of the price that is assumed by the market based on an option pricing model, such as Black-Scholes. This can be used to provide a probable range for natural gas prices in the future.

- There is a 50% probability that prices will range between $3.40 Cdn/GJ and $6.40 Cdn/GJ, for a range of $3.00 Cdn/GJ.

Figure 23: AECO/NIT Forward Curve and Confidence Interval Price Bands[37]

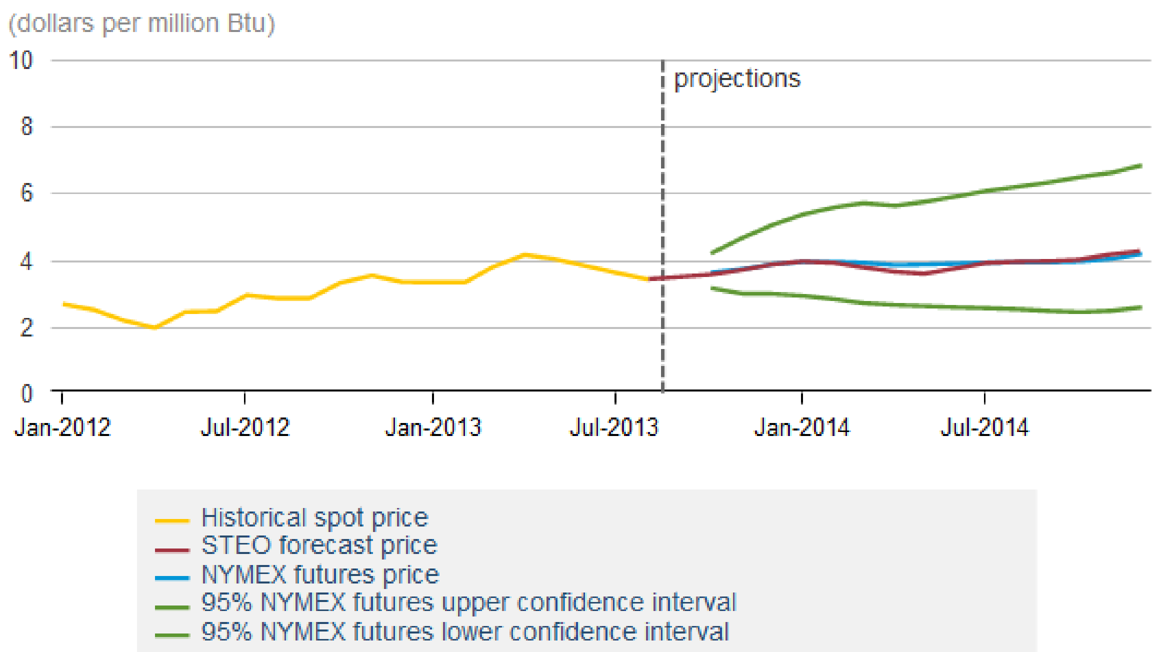


The volatility analysis provided in the figure above highlights that there is more potential for upside price movements than there is potential for downside price movements. This is consistent with the market's view that current gas prices are below the production costs for many of the shale gas plays.

Figure displays the EIA's Henry Hub natural gas price forecast and current NYMEX futures price curve as of September 2013. It also includes a 95% confidence interval forecast that provides a range of possible natural gas prices in the future. In other words, the EIA expects the December 2014 gas price to settle in between a range of $2.57 US/MMBtu and $6.85 US/MMBtu with a 95% probability.

[37] CME Group, One Exchange Corp., Goldman Sachs Group, September 26, 2013

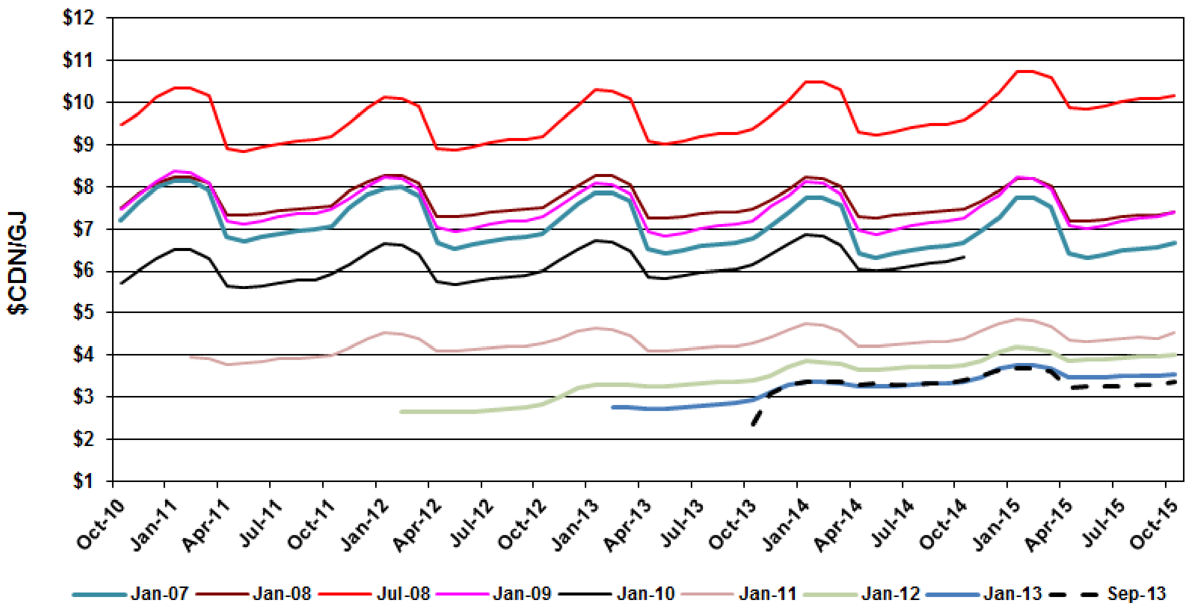
Figure 24: Henry Hub Natural Gas Price Forecast[38]



Another way of looking at price volatility is to observe changes to the forward price curve over a period of time. As the following figure illustrates, the AECO/NIT forward price curve has changed dramatically over the past number of years. The current AECO/NIT forward curve is near the lowest level in the last five years across all future terms out to October 2015.

[38] U.S. EIA, Short-Term Energy Outlook, September 2013

Figure 25: Changes in AECO/NIT Forward Curve[39]



The wide range of forecasted future prices helps to highlight key points about current natural gas prices. Firstly, natural gas forward prices, although they have increased from the lows in mid-2012 (see Figure), are still below recent historical averages. Secondly, given the costs of natural gas production (see Figure), it is not likely that gas prices will remain at these levels for a significant period of time. Furthermore, even though prices are currently low, price volatility has, and can, lead to higher gas prices in the future.

6. Summary

The North American natural gas marketplace has undergone significant changes in the last few years. The development of unconventional gas, in particular shale gas, has transformed the market from one of declining supply and requiring imports to one of abundance and lower prices than only a few years ago. This has led to increased demand for natural gas, particularly with respect to industrial and power generation, and created opportunities for the development of LNG exports and NGT markets in North America as well as the FEU's region. And while future natural gas prices are expected to rise with these new sources of demand, they are not expected to increase to the peaks seen in the recent past. This should provide both favourable returns for gas producers and reasonable costs for end users and consumers so that natural gas continues to grow in its role as a primary energy source in North America.

[39] CME Group, One Exchange Corp., September 26, 2013

Appendix A-2

REGIONAL GAS SUPPLY INFRASTRUCTURE BRIEF

APPENDIX A-2 – REGIONAL GAS SUPPLY INFRASTRUCTURE BRIEF

1. Introduction

Significant changes are occurring in the natural gas marketplace in western Canada. In a few short years, British Columbia's reserve estimates have grown significantly to reach approximately 3,000 trillion cubic feet.[1] B.C.'s natural gas potential is now considered to be second only to the Marcellus shale gas play that is being developed in the northeast region of United States. Development of this significant resource potential will bring changes that will impact traditional supply and demand dynamics as well as regional gas flows and market prices. This appendix provides background on proposed infrastructure developments that have the potential to affect regional gas supply markets in western Canada and the PNW, and hence the FEU's supply portfolio.

The prospect of developing new markets for natural gas is welcome news for producers active in the Western Canadian Sedimentary Basin (WCSB). The traditional Canadian and U.S. consuming markets for natural gas produced in the WCSB have declined steadily over the past few years. This decline is driven primarily by the development of shale gas basins, in particular the Marcellus shale gas play, that are located much closer to traditional key consuming markets in eastern North America. While increased industrial, power generation, and oil sands demand will help offset reduced demand from traditional markets, significant new consuming markets are required in order to fully develop the potential of the WCSB, including the new supply basins located in northeast B.C. Numerous LNG export projects have been announced for the west coast of B.C., which represents the most significant new market opportunity that the WCSB has seen. B.C. is poised to lead various developments relating to pipeline, infrastructure and potentially significant volumes of LNG export to Asian markets over the next few years. As a result of these changes, the FEU must continue to monitor developments and adapt the supply portfolio so that the FEU can ensure access to reliable and cost-effective supply for customers.

2. Importance of Northeast B.C. Supply for Markets in B.C.

The FEU are required to serve several major regional demand centres in B.C. that are largely isolated from each other by considerable distances and spread across a large, varied geographical footprint. Serving customers across this diverse geography and balancing daily system loads requires interconnection with third party pipelines and access to a flexible mix of supply, transportation, and storage resources.

As a matter of additional complexity, a number of factors including B.C.'s topography, location relative to North American supply basins, and winter seasonal market have limited the available infrastructure that connects the B.C. marketplace to sources of supply. As a consequence, the

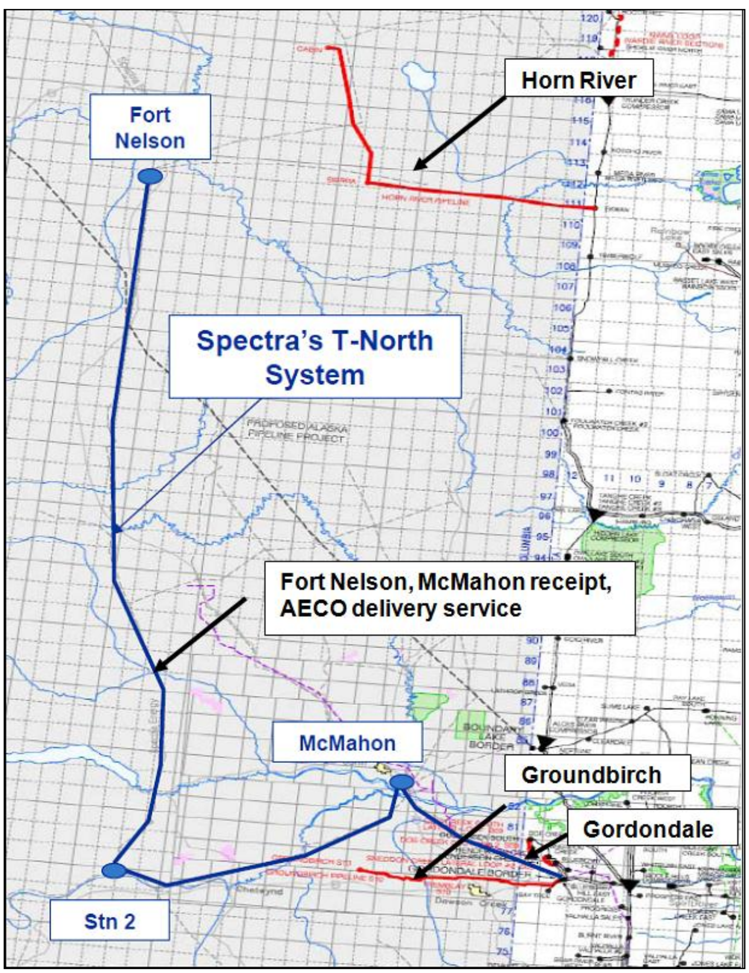
[1] B.C. Ministry of Natural Gas Development, "Study shows B.C.'s gas doubles previous estimate," News release dated November 6, 2013.

B.C. market is heavily reliant on supply originating in production basins located in northeast B.C. The majority of the FEU's current supply is sourced in B.C. and transported to the FEU's service territories via Spectra's Westcoast T-South pipeline. This reliance on northeast B.C. supply is unlikely to change significantly in the short to medium term given that only limited pipeline capacity exists to connect supply from Alberta and from the U.S. PNW.

3. Developments Affecting Northeast B.C.

In response to an increase in natural gas demand in Alberta, pipeline connectivity from supply basins located in northeast B.C. to Alberta has increased since 2010. The majority of recent pipeline expansions to the AECO/NIT market, such as the Groundbirch and Horn River Mainline pipelines by NGTL, now provide producers with the option to flow their supply directly to AECO/NIT marketplace, bypassing Spectra's T-North system. The following figure illustrates this development.

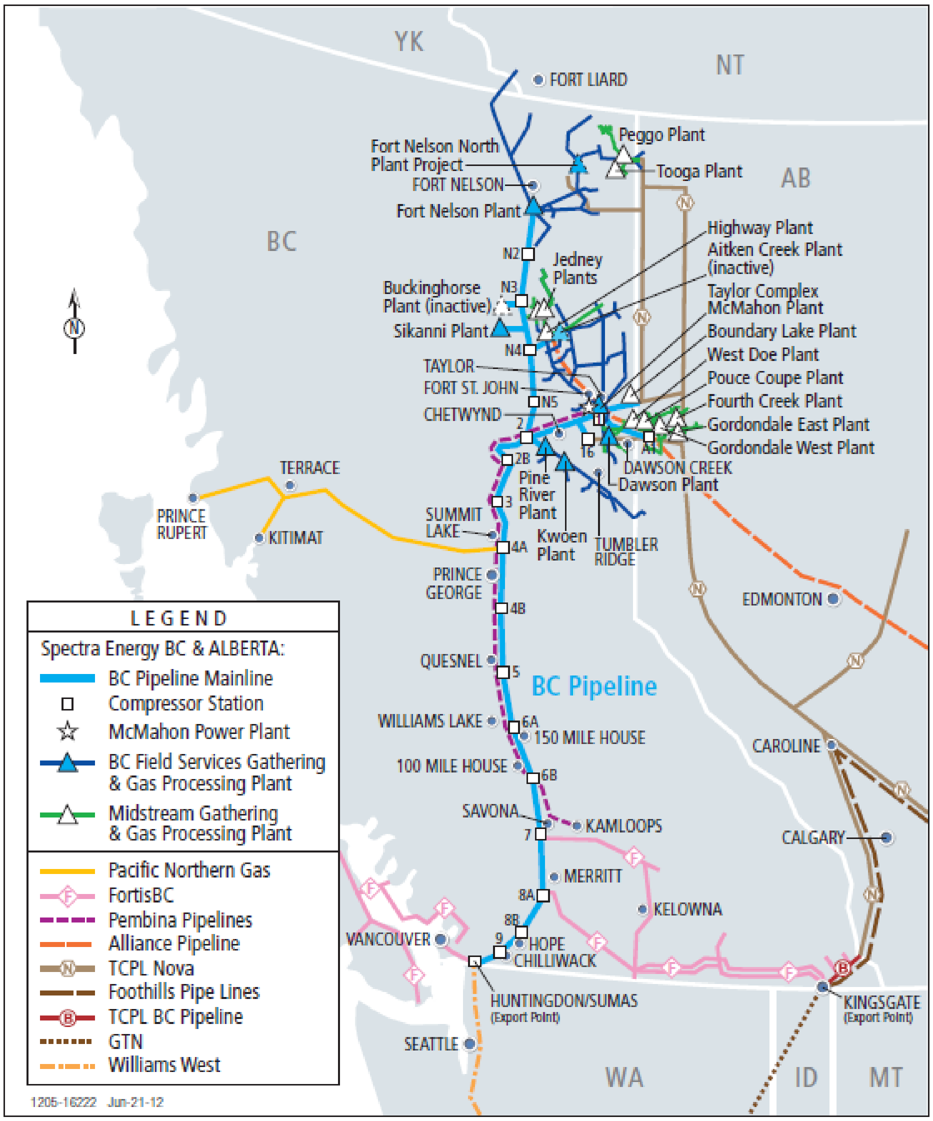
Figure 1: NGTL Pipeline Expansions into Northeast B.C.



Source: TransCanada

Future facilities additions in northeast B.C. contemplated by TransCanada Pipelines Ltd. (TransCanada or TCPL) for its NGTL system will likely accelerate this trend. Notwithstanding this development, it is possible for gas produced in B.C. to flow onto the NGTL system into Alberta and then flow back into B.C. The infrastructure connections with Spectra's T-North system at Groundbirch could flow from NGTL onto Spectra's system but requires the addition of facilities on the NGTL system. Such additions would result in increased costs to access this gas and such facility additions have not yet been completed. Figure 2 identifies the location of the major regional pipeline facilities, including those located in northeast B.C.

Figure 2: Pipeline Systems in Northeast B.C.



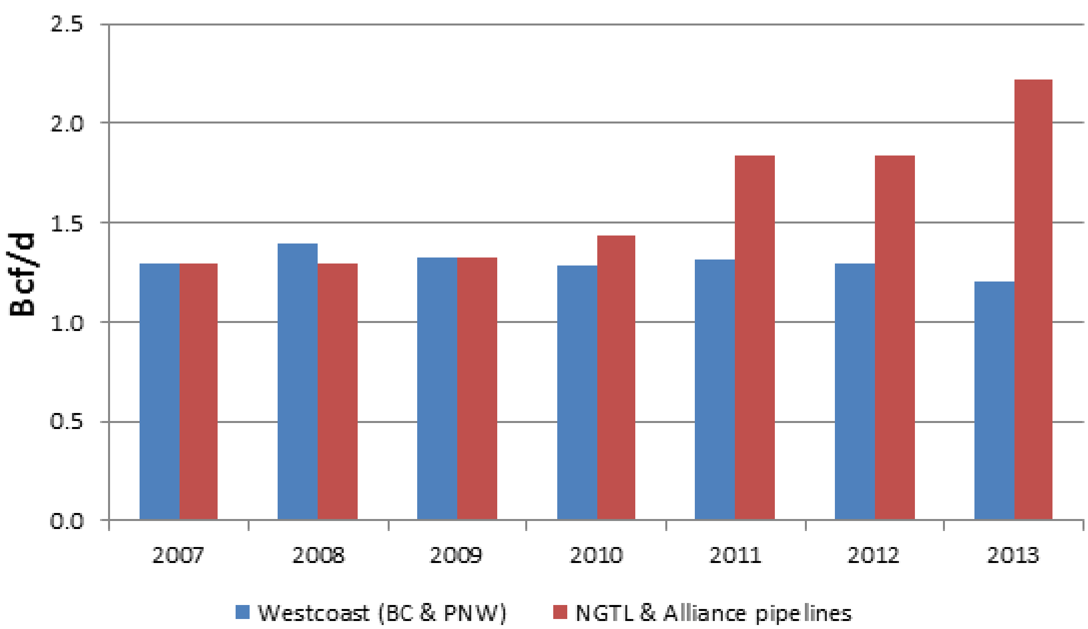
Source: Spectra Energy

Due to the significant production potential of the Montney and Horn River basins, the total production over the next few years from B.C. could significantly surpass its current level of roughly 3.5 Bcf/d. However, little of this incremental production is expected to remain in B.C.

and increasing amounts are projected to flow out of the province. Producers tend to favour Alberta and eastern markets because they provide more base load, rather than seasonal market characteristics, and are more liquid markets (i.e. markets in which there are more opportunities to buy and sell gas contracts). In contrast, downstream markets located in B.C. and the PNW are largely winter seasonal with a more limited number of purchasers, which makes them less liquid and therefore less attractive.

B.C. supply that flows on the Spectra's Westcoast system to markets in B.C. and the PNW has remained at largely unchanged levels over the past several years, while supply movement to Alberta and other eastbound markets has increased significantly (see Figure 3). For example, in 2007, the distribution between gas marketed to B.C. and the PNW as compared to Alberta and eastbound markets was almost equal, averaging around 1.3 Bcf/d. However, since 2007, gas supply to eastbound markets has steadily increased, averaging roughly 2.0 Bcf/d during the last three years, an increase of about 50%. This trend is expected to continue in the future as the need to offset declining production in Alberta rises and the increase in industrial and oil sands demand grows.

Figure 3: Increased Flows of Natural Gas from B.C. Production Areas[2]



4. B.C. LNG Exports

The most significant opportunity faced by northeast B.C. relates to the development of LNG exports. Several LNG export projects have been announced that would see the construction of liquefaction terminals on B.C.'s west coast, as well as large diameter pipelines to transport

[2] British Columbia Ministry of Energy, Mines and Natural Gas and Responsible for Housing, Production and Distribution of Natural Gas in B.C. Note that 2013 includes data for January to June 2013.

natural gas from new production basins in northeast B.C. to the liquefaction terminals. The following discussion explains how this development can be expected to impact the gas supply dynamics in B.C. and how that may impact or benefit customers.

Increasing demand for energy in Asia, particularly for natural gas, could provide a significant new market and long term opportunity for the WCSB producers. Natural gas provides Asian markets with a cleaner burning fuel source compared to coal and oil. Currently, the majority of natural gas supplies that enter Asia are imported in the form of LNG from various oil and gas production area located in the Middle East, Australia, and Russia. With significantly lower natural gas prices in North America than what Asia has typically been able to arrange for LNG imports, Asian countries are turning to North America, with B.C. facing particular interest. B.C. offers an attractive mix of proximity, market maturity, supply diversification, and political stability—benefits that are becoming increasingly valued in key Asian markets.

4.1 OVERVIEW OF LNG PROJECT PROPOSALS

Up to 13 potential LNG export projects are being considered for location on the west coast of B.C. Of these, 11 are located in the Kitimat, Prince Rupert and Kitsault region, on the northern coast of B.C., and two located on the lower coast of B.C. Of the 11 projects considered for the north coast of B.C. all, with the exception of the B.C. LNG Export Co-Op, will require substantial new pipeline infrastructure. Four of these projects have announced plans to construct new large diameter pipelines to bring supply from the new production basins in northeast B.C. A small scale LNG export proposal has also been announced for location at a site near Squamish that proposes to access supply via the FEU systems (project number 13 in Table 1 and also discussed in Sections 3.3.9 and 5.1.2.1). The LNG export projects contemplated for location in B.C. are summarized below:

Table 1: Proposed LNG Projects on the West Coast of B.C.

Project	Partners	Min Capacity (Bcf/d)	Max Capacity (Bcf/d)	Export Date	Status
1. *Douglas Channel Energy Partnership	LNG Partners, Haisla	0.13	0.25	2016	FEED initially completed - undergoing revision for internal power generation. Project status is uncertain and is currently undergoing financial re-organization.
2. Triton LNG LP	AltaGas, Idemitsu (Japan)	0.1	0.33	2017	Application submitted to NEB for 25 yr export license.
3. *Kitimat LNG	Chevron, Apache	0.7	1.4	2017	Undergoing FEED. FID expected once FEED is completed.

4. *Pacific Northwest LNG	Progress, Petronas	1.0	2.7	2019	FEED stage, undergoing government regulatory review process. FID expected in late 2014.
5. *Prince Rupert LNG	Spectra, BG Group	2.2	2.9	2021	Project Description filed with CEAA and BC EAO, awaiting environmental assessment approval.
6. *LNG Canada	Shell, Kogas, Mitsubishi, PetroChina	1.7	3.2	2020	Project Description filed with CEAA and BC EAO, awaiting environmental assessment approval.
7. *WCC LNG	Imperial Oil, ExxonMobil	1.3	4.0	2021	Undergoing project assessment and planning.
8. Aurora LNG	Nexen. CNOOC, Inpex (Japan)	1.55	3.1	2021	Application submitted to NEB for 25 yr export license. Deal to purchase Grassy Point property from B.C. government.
9. Grassy Point LNG 3	Woodside Petroleum	Expression of interest; no public project announcement.			
10. Grassy Point LNG 4	SK E&S (South Korea)	Expression of interest; no public project announcement.			
11. Elk Falls Mill, Campbell River	Quicksilver Resources	Expression of interest; no public project announcement.			
12. Kitsault Energy	Kitsault Energy	0.66	0.66	2017	Short-term 2 year NEB export license received. Application submitted to NEB for 25 yr export license.
13. *Woodfibre LNG Export	Pacific Oil and Gas Group	0.15	0.29	2018	Undergoing feasibility study and site remediation.
Total		**9.45**	**18.89**		

** Received National Energy Board (NEB) approval*

If all of the projects that have been announced publicly were to proceed, a total LNG volume approaching 19 Bcf/d would be exported. To date, only seven of these projects, the Kitimat LNG, BC LNG, Pacific NW LNG, Prince Rupert LNG, WCC LNG, Woodfibre LNG and LNG Canada, have received National Energy Board (NEB or the Board) approval to export up to 14.8 Bcf/d of LNG. A number of market analysts predict that between 1 bcf/d[3] (Wood Mackenzie)

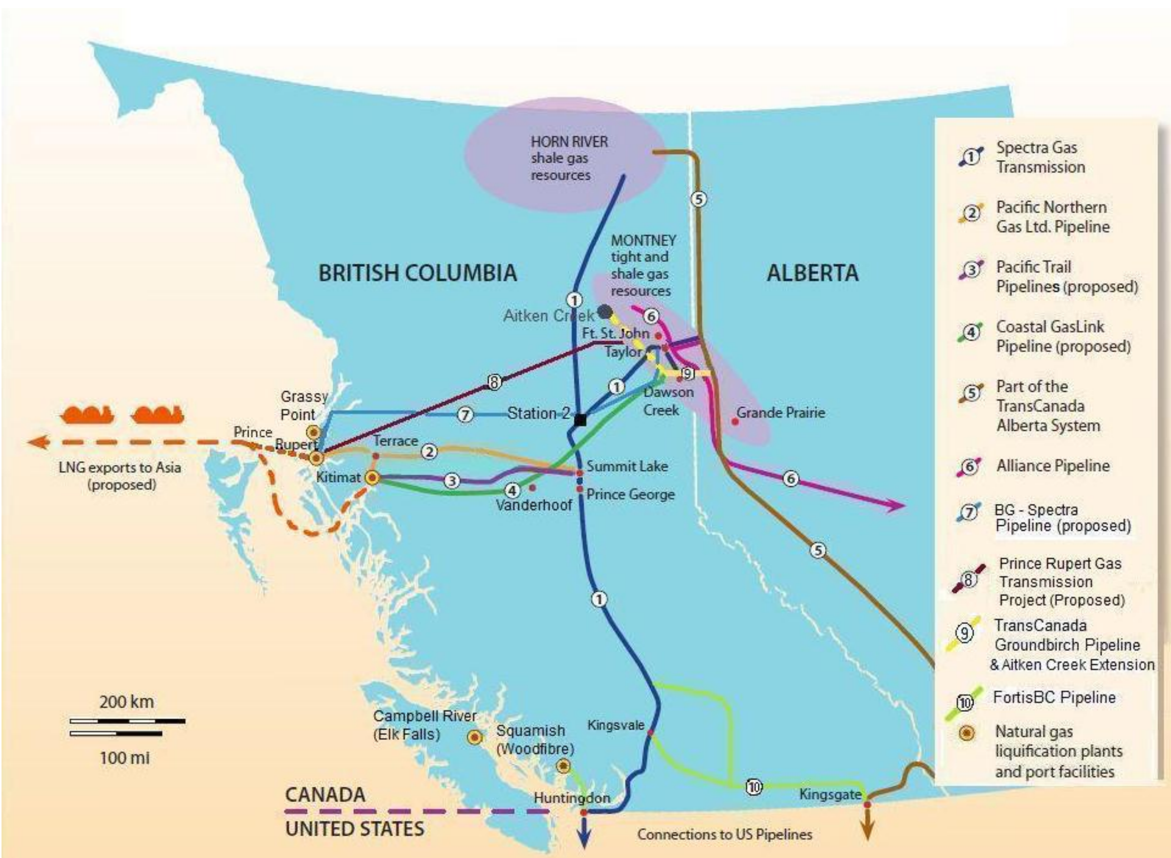
[3] The Dynamics of Western Canadian LNG Exports, Woodmac, November 2012.

and 4.8 bcf/d[4] (Goldman Sachs) of gas are likely to be exported by the end of the decade to markets in Asia.

4.2 LNG EXPORT PROJECT PROPOSED PIPELINE ROUTES

The gas supply for export projects will tie into infrastructure that either exists today or will need to be expanded in order to be able to access production from the Montney, Horn River, Cordova and Liard shale basins. Figure 4 provides a map illustrating conceptual routes for the proposed pipelines from supply sources to subsequent export terminals in the Kitimat/Prince Rupert area. Given the early stage in the project development process, final pipeline routes and their tie into existing Spectra or NGTL infrastructure may change from what has been announced publicly. Important in this context is the potential to establish an energy corridor from supply basins to the export terminals, which would facilitate construction of these pipelines. Such a corridor may also spur the consolidation of separate pipelines as a way of better managing project costs and the long-term utilization risk faced by these projects.

Figure 4: Potential Pipeline Routes in B.C. for the LNG Export Market[5]



4 Energy Outlook: Policy risks dominate the markets, Goldman Sachs, October 2012.
5 Fraser Institute Studies,"Laying the Groundwork for BC LNG Exports to Asia," Energy Policy, October 2012 and FortisBC additions based on project announcements.

4.3 IMPLICATIONS ON THE REGIONAL GAS MARKETPLACE

If the larger LNG export projects proceed with development after final investment decisions are reached, production development in the new supply basins will need to ramp up prior to actual export to new Asian markets. The effect of this ramp up process should produce incremental supply that is made available to regional market hubs such as Station 2 and AECO/NIT. In order to support this production ramp-up, NGTL is proposing to expand its pipeline system further west into northeast B.C., resulting in an integrated extension of AECO/NIT into parts of northeast B.C. In the near term, as the export market ramps up incremental supply could be brought to existing market hubs, which could result in further downward pressure on commodity prices. Lower pricing, especially at the AECO/NIT market hub, is expected to last until approximately 2018-20 when LNG exports are planned to increase substantially.

Currently, a high level of uncertainty exists as to the impact that LNG export projects will have on regional pricing for natural gas, primarily due to the uncertainty of pipeline routing and connections to traditional supply hubs. However, FEI continues to believe that these LNG export projects should significantly increase the development of production in B.C. and ensure a healthy supply picture going forward for domestic markets in North America.

5. Developments Affecting TransCanada's NGTL System

TransCanada is involved in a number of initiatives that could impact the FEU's ability to cost effectively access secure and reliable supply in the future at fair market prices[6]. These relate to TransCanada's pipeline system extensions from Alberta into B.C., involvement in B.C. LNG export projects, and TransCanada's Mainline Restructuring initiative. The FEU rely on TransCanada's NGTL and Foothills B.C. systems to transport supply to and from storage locations in Alberta and to move supply from Alberta to the FEU systems.

Komie North Decision

In October 2011, NGTL applied to the NEB for authorization to construct and operate the Northwest Mainline Komie North Extension (the Komie North Project). The proposed Komie North Project was planned to be an expansion of portions of NGTL's existing system in Alberta and a further extension of NGTL's system in northeast B.C.

The FEU intervened in this facilities application, taking issue with several aspects of the proposed extension.[7] The FEU were concerned about a number of factors: the lack of commercial contracts underpinning the proposed extension; a potential oversizing of the facilities; the impact on the utilization of existing competing facilities and competition for the development of new facilities to connect production to transmission systems in the area; and use of a rolled-in tolling methodology that would allow NGTL an unfair competitive advantage.

6 For more information on TransCanada's existing NGTL and other pipeline systems visit www.transcanada.com
7 NOVA Gas Transmission Ltd., Application for Northwest Mainline Komie North Extension (GH-001-2012), C-08-04 Evidence of FortisBC Energy Inc. (A41838) https://docs.neb-one.gc.ca/ll-eng/llisapi.dll?func=ll&objId=820525&objAction=browse&viewType=1

For the FEU, these issues create the potential to increase regional transportation costs, affect future access to gas supplies at fair market prices, and reduce the liquidity of gas commodity markets at Station 2 and at Huntingdon.

On January 30, 2013, the NEB recommended approval of the Chinchaga section of the applied for facilities in Alberta, but did not recommend approval of the Komie North section in Northeast B.C.[8] In its decision, the NEB did not accept that the Komie North section as proposed had sufficient commercial support for it to be economically feasible. The Board also took issue with the tolling treatment for the extension, noting that Spectra, who is already operating in the region where the proposed facilities were planned to be located, is required to operate under a different regulatory regime. Finally, the Board acknowledged that an approval of the Komie North extension as proposed would have unacceptable commercial impacts on other parties. It took into consideration the potential negative impacts on Spectra's existing transmission and gathering and processing facilities in northeast B.C., as well as existing shippers on this system.

At this point, the FEU are uncertain how TransCanada will respond to this decision. It is generally expected that TransCanada will attempt to reapply for the Komie North extension in the near future, addressing the key deficiencies found by the NEB, including demonstrating appropriate commercial support. TransCanada has pointed out that it interprets the decision as applying only to Komie North and that it will continue to use a rolled-in methodology in managing its NGTL system. The FEU plan on reviewing any new application to the NEB for approval of this extension in order to assess the potential impact it may create.

North Montney Project

TransCanada is planning to seek approval to extend the NGTL system from near Groundbirch, B.C., 300 km to the north. This extension is expected to be a 42-inch diameter pipe and cost approximately $1.7 billion to construct. The main purpose of this extension is to connect to the Prince Rupert Gas Transmission Project and to access north Montney production planned by Progress Energy. An interconnection with the Aitken Creek Storage facility is contemplated as part of this project. The FEU have reviewed the facilities application filed by NGTL with the NEB in order to determine potential impacts and have applied to intervene in the NEB proceeding.

Coastal GasLink Pipeline Project

In June 2012, TransCanada announced that it had been selected by Shell Canada and its partners to design, build, own and operate the proposed Coastal GasLink project. This pipeline will be used to transport natural gas from the Montney gas-producing region to LNG Canada's planned liquefaction terminal located near Kitimat. It will originate from a location near Groundbirch, B.C., where it will tie into TransCanada's existing NGTL system.

8 National Energy Board, "NEB issues recommendation regarding the Northwest Mainline Komie North Extension Project," News Release dated January 30, 2013. http://www.neb-one.gc.ca/clf-nsi/rthnb/nws/nwsrls/2013/nwsrls02-eng.html

The pipeline is expected to cost approximately $4 billion to construct and be placed in service by 2020. It is planned to be 650 km long, 48 inches in diameter, and provide an initial capacity of more than 1.8 Bcf/d and capable of being expanded to flow 5 Bcf/d.

At this point, TransCanada has indicated that it does not plan to connect this pipeline to any part of the Spectra system and permit a receipt or delivery location, even though it will cross Spectra's T-South system between Station 2 and Summit Lake.

NGTL claims that the Coastal GasLink will also provide options for other shippers to access gas supplies through an interconnection with TransCanada's NGTL System and the AECO/NIT market hub. NGTL plans on contracting for a portion of the capacity of this pipeline from the current termination of the NGTL system at Groundbirch in northeast B.C., to a point near Vanderhoof, B.C. This will allow NGTL to effectively extend the NGTL system to near Vanderhoof and roll the cost of the TBO (transportation by others)[9] arrangement into the existing NGTL System. NGTL has not yet planned on offering any receipt or delivery points other than at its origin near Groundbirch and at its terminus near Vanderhoof.

The FEU is monitoring progress on the development of the TBO and plans to actively participate in the review of NGTL's application to the NEB for the proposed TBO arrangement with Coastal GasLink in order to understand and mitigate the potential impact it may create for the FEU's future resource contracting.

Prince Rupert Gas Transmission Project

In January 2013, TransCanada announced that it had been selected by Progress Energy, a subsidiary of Petronas of Malaysia, to design, build, own and operate the proposed Prince Rupert Gas Transmission Project. This pipeline will be used to transport natural gas from the north Montney gas-producing region near Fort St. John, B.C. to Pacific Northwest LNG's planned liquefaction terminal located in Port Edward, near Prince Rupert, B.C. The pipeline is expected to cost approximately $5 billion to construct and be placed in service by late 2018. It is planned to be 750 km long, 48 inches in diameter, and provide an initial capacity of more than 2 Bcf/d and capable of being expanded to flow 3.6 Bcf/d.

As discussed earlier (North Montney Project), TransCanada also plans a major extension of the NGTL system from Groundbirch into the north Montney region in order to provide the Pacific Northwest LNG project access to supplies from both the Montney basin and from the AECO/Nit market hub. The Prince Rupert Gas Transmission Project would tie into the southern end of this extension. TransCanada foresees this pipeline being a dedicated merchant line and therefore does not plan to connect it to any part of the Spectra system at this time.

9 A TBO, or Transportation by Others, agreement is an arrangement between pipelines whereby one pipeline becomes the shipper on another pipeline system. The agreement occurs when a pipeline needs to lease space on another pipeline to obtain additional market access for its customers.

Mainline Restructuring Decision

On March 27, 2013 the Board released its Mainline Restructuring Decision, or more formally the "Business and Services Restructuring Proposal and Mainline Tolls for 2012 and 2013". In its decision, the Board denied most aspects of TransCanada's application.[10]

The FEU intervened in this application as part of the Western Export Group (WEG) taking issue with several aspects of the proposed application. WEG was primarily concerned about the proposed extension of the NGTL system to include Foothills and a portion of the Mainline which if approved would result in toll increases for all NGTL shippers. The FEU, as part of WEG, supported certain changes to services and pricing arrangements that involved providing increased discretion to price interruptible and short term firm service.

In its decision, the NEB denied the proposed service extension of the NGTL system, the reallocation of accumulated depreciation, and aspects of the proposed treatment of service costs. However, the Board did acknowledge that TransCanada's Mainline is in an unprecedented position and Mainline tolls have increased substantially over a short period of time as a result of throughput declines related to increasing levels of competition in the Mainline's supply and market areas. The Board found that tolls cannot continue to increase each year in response to throughput declines. As a result, the Board approved multi-year fixed tolls at levels that should be competitive and provide TransCanada with a reasonable opportunity to recover its Mainline costs. The Board set fixed multi-year tolls for the Mainline system at $1.42/GJ, compared to a 2013 toll of $2.58/GJ that would result from TransCanada's existing tolling methodology. The Board also approved the establishment of a deferral account that is to be used to capture any under recovery of costs, and noted that an accumulation of deferred costs in this account would be addressed in a future proceeding. The Board denied any intervener proposals to disallow costs from the Mainline's rate base or revenue requirement and recognised that its recommendation to set multi-year fixed tolls increases TransCanada's business risk related to throughput. As a result, the Board authorized an increase in the Mainline's return on equity, increasing it to 11.5 percent on an equity ratio of 40 percent. The Board also approved a number of other proposals that would give TransCanada greater discretion on how it prices services on its system, which provides an incentive for TransCanada to increase profitability if annual net revenue is higher than forecast.

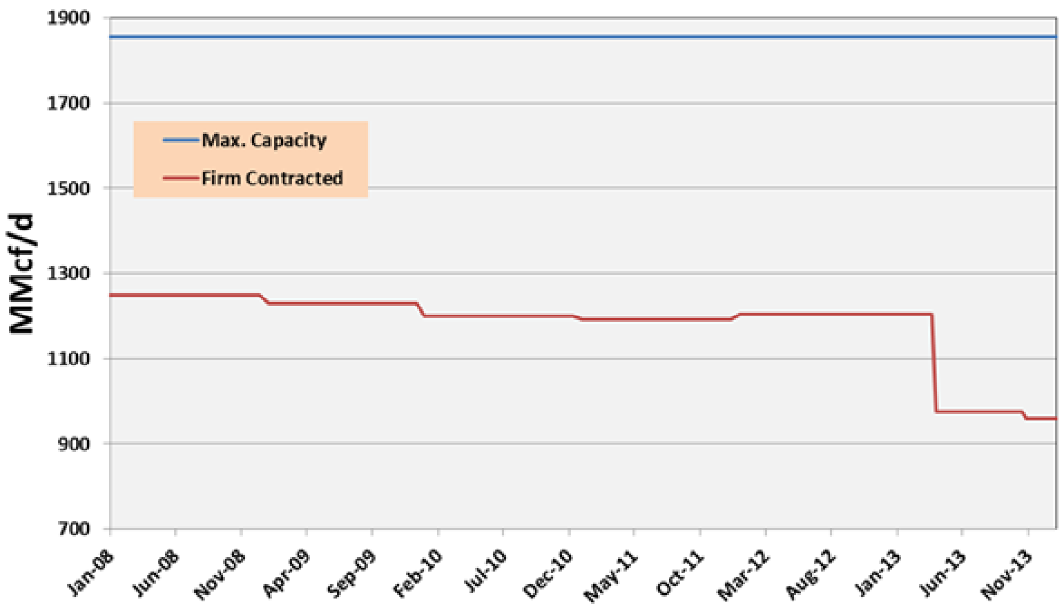
In conclusion, the NEB observed that the future of the Mainline depends on how TransCanada is able to respond to the changes to its business environment, and that in its decision, the NEB has provided TransCanada with the tools it requires to achieve positive outcomes for its investors and customers, and that TransCanada must now use those tools to construct a viable future. To date, TransCanada has not provided significant public comment about this decision and the FEU are uncertain how TransCanada will respond.

[10] TransCanada, "TransCanada Statement Regarding NEB Decision on Canadian Mainline Restructuring Proposal," March 27, 2013. http://www.transcanada.com/6268.html

6. Developments Affecting Spectra's Westcoast System

Firm contracting levels on Westcoast T-South system (Station 2 to Huntingdon) continue to hover around the 50% contracted level, which is down significantly from levels near 70% in the recent past[11]. The majority of contracted pipeline capacity on the Westcoast T-South system is now held by FEI and the PNW utilities. Figure 5 sets out the firm contracting levels on the Westcoast T-South pipeline since 2008.

Figure 5: Contracting Levels on the Westcoast T-South Pipeline to Huntingdon[12]



The Westcoast T-South system flows at maximum levels during cold or peak weather events. The lack of firm transportation contracting means that more supply to the Huntingdon market hub will flow via interruptible transportation during key demand periods in the winter. As interruptible transportation is subject to cuts when pipeline use reaches maximum capacity (which it does during peak load in the winter), this will reduce supply reliability at the Huntingdon market hub and increase the potential for price disconnections. An additional issue this contracting trend creates is higher tolling costs for firm shippers which, in turn, increases costs for natural gas customers. In response to these issues, FEI has reviewed, and will continue to assess, the level of Huntingdon supply that should be included in its gas supply portfolio.

These developments are critically important for FEI given its dependence on Spectra's Westcoast pipeline transmission system in B.C. for the delivery of the majority of its natural gas supply requirements. It is important for this system to remain competitive with other regional infrastructure development proposals to ensure continued and cost effective access to natural gas supply at Station 2 from northeast B.C. The expansion of current markets, such as

[11] For more information about the existing Westcoast pipeline system please see https://noms.wei-pipeline.com/
[12] Spectra Energy

Kingsgate and Huntingdon, that support gas to flow south via Spectra's Westcoast system will provide the FEU with access to cost effective supply over the long term in B.C. This has led Spectra to successfully offer the T-South Enhanced Service (which utilizes a portion of the FEU's system), and the opportunity to develop the Kingsvale to Oliver Reinforcement Project (KORP) which is an alternative to meet the needs of new base load markets that are emerging in the Lower Mainland and PNW.

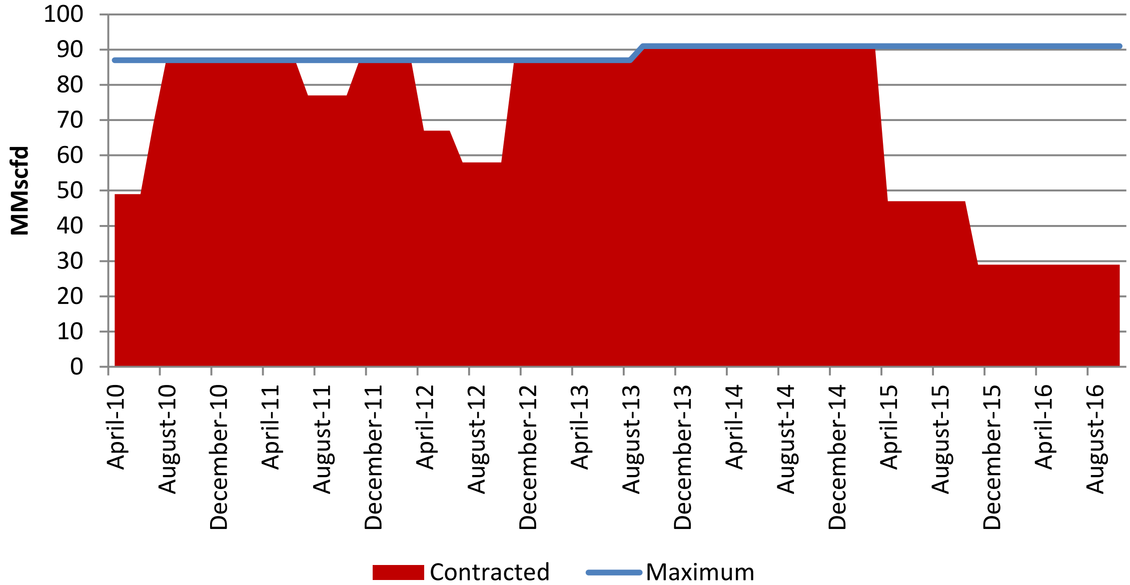
T-South Enhanced Service

Spectra Energy and FEI entered into an agreement effective May 2010, whereby FEI provides firm transportation service to Spectra Energy from Kingsvale to Kingsgate using FEI's system, including the Southern Crossing Pipeline (SCP) and FEI's contracted capacity on TransCanada's Foothills system. This arrangement allowed Spectra Energy to put forward a new service offering on its Westcoast transmission system (T-South Enhanced Service) allowing T-South shippers to transport gas from Station 2 to either Huntingdon or Kingsgate.

The T-South Enhanced Service has been a success and continues to deliver significant benefits to FEI customers. The T-South Enhanced Service was recently extended to October 2016 and FEI made available to Spectra a total maximum volume of 91 MMscfd, an increase from the original 87 MMscfd. This increase in volume will increase the overall benefits to FEI customers from both the revenue received from Spectra Energy for the SCP capacity and the T-South toll reductions from the Service. FEI customers are estimated to receive accumulated financial benefits of approximately $50 million from 2010 to 2016.

The overall T-South Enhanced Service is now fully contracted until March 2015. Below, Figure 6 illustrates the historical and current contracting levels of the T-South Enhanced Service from initial offering in May 2010, through to the extension end date of October 2016. It should be noted that the Service was contracted by a cross-section of the market, including producers, marketers and Local Distribution Companies (LDCs).

Figure 6: Spectra T-South Enhanced Service Contracted Levels (MMscfd)[13]



Kingsvale Oliver Reinforcement Project

FEI has been investigating the potential to expand its transmission system in order to provide an alternative solution to meet potential load growth in the Lower Mainland and PNW.

The Kingsvale to Oliver Reinforcement Project (KORP) consists primarily of a 161 km, 24-inch expansion project from Kingsvale to Oliver, B.C. The reinforcement would further integrate and expand service using available capacity on FEI's Southern Crossing Pipeline (SCP) and Spectra's T-South capacity. FEI could offer up to 300 MMcfd of additional capacity to transport Alberta gas to the Lower Mainland-PNW market. The pipeline would be bi-directional with the capability of transporting over 300 MMcfd of gas west to east to Kingsgate.

New base load markets are emerging on the south coast of B.C. with potentially significant incremental base load demand. FEI is aware that several project developers are assessing pipeline alternatives to the south coast, which include a focus on supply diversity from B.C. and/or Alberta. These markets are anticipated to drive the need for additional regional infrastructure. Gas-fired generation facilities and existing end use markets looking for alternatives to meet future load growth or add supply diversity to their portfolio are also ideal candidates to support KORP. For example, Puget Sound Energy has included the KORP within its recent Integrated Resource Plan submission as a potential resource option.

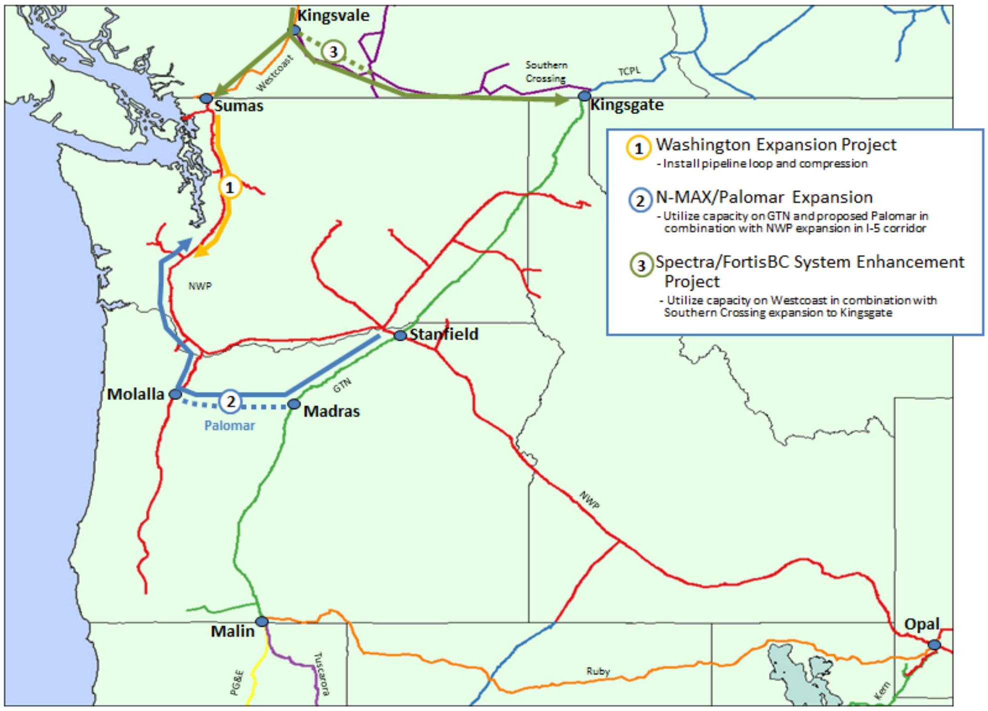
Given the project development progress to date, FEI is in a position to respond quickly to a potential market request for future service.

[13] Spectra Energy

7. Developments in the Pacific Northwest

Two other pipeline expansions in the PNW region are also under consideration by other parties. These projects may impact gas flows and pricing dynamics within the region. A map of the projects is provided in the following figure.

Figure 7: Potential U.S. Pacific Northwest Infrastructure Projects



Source: NWGA

Washington Expansion Project

In October 2013, Northwest Pipeline (NWP) issued a news release seeking expressions of interest from shippers for incremental Sumas/Huntingdon to Seattle pipeline capacity (Washington Expansion Project) on its system with service contemplated to be available as early as November 1, 2015. This expansion capacity is primarily tied to a request from Oregon LNG to develop the Washington Expansion Project to provide 0.75 Bcf/d of firm transportation service from Sumas to an interconnect with the proposed Oregon Pipeline near Woodland, Washington, to serve its proposed LNG terminal near Warrenton, Oregon. To meet the requirements of this facility, NWP would need to add additional pipeline and compression facilities to the existing NWP system in the state of Washington.

In response to the non-binding expression of interest, NWP received bids totalling approximately 1.4 Bcf/d with half of volume directly tied to the Oregon LNG project. It is expected that some form of expansion will likely occur in the next five years, however, at lower capacity than the initial bids received. If the NWP Sumas south expansion were to proceed, an expansion on systems upstream of Sumas would likely be required, which could support an expansion on T-South or a combination of KORP/T-South.

N-Max/Palomar Expansion Project

NWP is working with the current Palomar pipeline project sponsors, NorthWest Natural and TransCanada Gas Transmission Northwest (GTN), to develop the Cascade (eastern) section of Palomar in conjunction with an expansion of the existing NWP system. The Cascade section of Palomar would consist of a 106-mile, 30-inch diameter pipeline that would run from GTN's mainline in central Oregon to a NW Natural/NWP hub near Molalla, Oregon, enhancing delivery capacity to the I-5 corridor. Palomar would be a bi-directional pipeline with an initial capacity of approximately 300 MMCF/d, expandable up to 750 MMCF/d. It would be linked to an expansion on the existing NWP system to deliver gas to other markets along the I-5 corridor. At this time, there is no publicly available information regarding the timing or commercial structure of this project.

8. Summary

The development of shale gas basins located close to traditional key consuming markets, particularly in eastern North America, has led to a decline in demand for natural gas from the WCSB. However, new markets such as increased industrial, power generation and oil sands demand may play a role in sustaining the potential of the WCSB and developing new supply basins, particularly in northeast B.C. A number of proposed LNG export projects from B.C.'s west coast to Asian markets may offer the biggest potential for new market opportunities. These developments are likely to impact traditional supply and demand factors, market prices and gas flows in North America. The FEU continue to monitor regional gas supply developments and adapt the Utilities' portfolio to provide customers with access to a reliable and cost-effective long term energy supply.

Appendix A-3

COST COMPETITIVENESS OF NATURAL GAS AND ELECTRICITY

APPENDIX A-3 – COST COMPETITIVENESS: NATURAL GAS AND ELECTRICITY

1. Introduction

The competitiveness of natural gas with other sources of energy, such as electricity, is an important factor in helping to determine the future demand growth of natural gas within B.C. With the development of shale gas in recent years, North American and regional natural gas prices have fallen from highs of over $10.00/GJ in 2008 to under $4.00/GJ in 2013 (see Section 2.1 and Appendix A-1 for more details). On the other hand, average electricity prices for residential consumers in B.C. have been increasing gradually since 2008 and are expected to continue to increase in the future. Therefore, on an operating cost basis, the competitiveness of natural gas versus electricity has improved in recent years. However, upfront capital costs should also be considered when assessing energy competitiveness as this factor adds to the FEU's challenge in attracting new customers.

This appendix provides an overview of the cost competitiveness of natural gas versus electricity in order to provide some context for the environment in which the FEU operate. It examines competitiveness from both an operating cost as well as capital cost perspective and provides information for each of FEI, FEVI and FEW. The focus is on the primary uses of energy for which natural gas and electricity compete: space and water heating.

1.1 BURNER TIP RATES AND ELECTRIC EQUIVALENTS

The figures presented in this appendix show natural gas rates compared to electric equivalents on a per unit basis. The natural gas rates are presented as burner tip rates, which are the rates paid by residential consumers for each of the Utilities and include the carbon tax. Therefore, the burner tip rates include all commodity, midstream, fixed basic and delivery charges or costs. In FEVI's case, the current burner tip rate is based on the rate freeze mechanism that has been in place for several years.

The natural gas burner tip rates are compared to electric equivalents. These electric equivalents are based on BC Hydro rates which have been adjusted for various appliance efficiencies in order to provide a direct comparison to natural gas. For example, when looking at space heating for new customers, the electric equivalents include adjustments to the BC Hydro Step 1 and Step 2 rates of 90%, which is representative of the efficiency of a new gas furnace.

Starting October 1st, 2008, BC Hydro introduced the residential inclining block (RIB) rate, a two-step structure designed to encourage electricity conservation. The RIB rate includes a base Step 1 rate for electricity consumption up to 1,350 kWh per bi-monthly billing period and a Step 2 rate for any consumption above the Step 1 rate. Before beginning the comparison of natural gas burner tip rates and electric equivalents, an overview of differences in upfront capital costs is necessary.

2. Upfront Capital Costs Differences

There are significant differences in the upfront capital costs between natural gas and electric equipment or appliances which impacts the competitiveness of natural gas. However, it is often not the end user that makes the decision regarding energy sources installed in the home, which add to the FEU's challenge.

Builders and developers are the primary decision makers regarding which energy source and equipment are used in new construction. As builders and developers do not pay operating costs, they tend to be more influenced by capital costs alone. Capital costs related to natural gas equipment—such as furnaces, ducting and hot water tanks—tend to be costlier than those for electric equipment, such as electric baseboards and hot water tanks. A builder or developer also typically strives to maximize the useable square footage available from a development to maximize the return on investment. Capital cost savings and the ability to sell more useable living space incents developers and builders to install electricity equipment over natural gas equipment in new developments. The upfront capital cost difference for installing natural gas equipment has been identified by the American Gas Association as the "primary impediment to natural gas use in residential and commercial buildings if service can be made available."[1]

Table 1 provides an example of the upfront installation (capital) cost difference associated with natural gas versus electricity for a space heating furnace and hot water tank in new construction for FEU customers. The difference in upfront capital costs between gas and electricity means that over the life of the appliance, the operating cost advantage of natural gas over electricity must be at least $9.93/GJ for space heating and $5.67/GJ for hot water heating for the equipment change to be economic for the consumer.

[1] American Gas Association. Squeezing Every BTU: Natural Gas Direct Use Opportunities and Challenges, pg. 32. This report is attached in Appendix A-4.

Table 1: Capital Cost Difference for Space and Water Heating – Natural Gas vs. Electricity[2]

	Space Heating	Water Heating
Capital costs for natural gas	$9,000	$2,000
Capital costs for electricity	$4,320	$1,023
Upfront capital cost premium for natural gas compared to electricity	**$4,680**	**$977**
Annual difference in capital costs[3]	$446.68	$113.32
Annual maintenance costs	$50.00	$0.00
Total annual difference in capital and maintenance costs	**$496.68**	**$113.32**
Energy consumption per year (GJ)	50 GJ	20 GJ
Difference in cost between natural gas and electricity over measureable life ($/GJ)	**$9.93/GJ**	**$5.67/GJ**

While there will be differences in capital costs due to the cost of the equipment, annual operating and maintenance costs, life of the equipment, size of the home and energy consumption, this information is intended to provide a general representation of capital cost differences. The cost competitiveness for each of FEI, FEVI and FEW based on space and water heating applications is provided in the following sections.

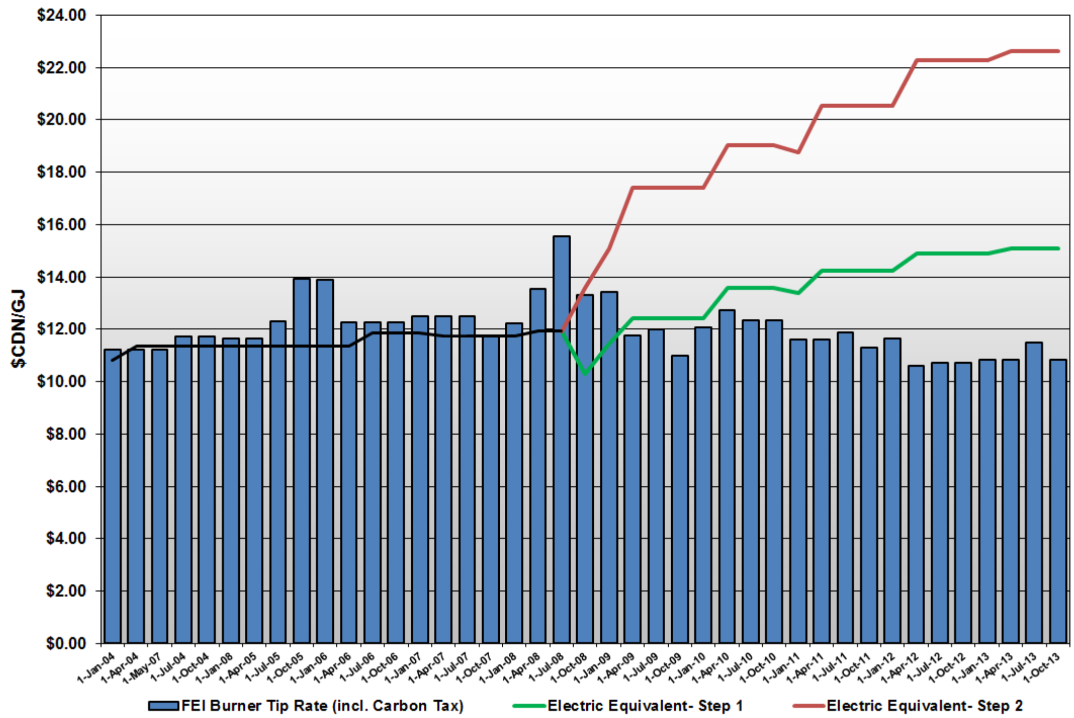
3. FortisBC Energy Inc.

3.1 SPACE HEATING

The two figures below present a historical view of the competitiveness with space heating for FEI. As shown in Figure 1 below, FEI's burner tip rate absent the capital costs (indicative of a customer that already has appliances installed) have been above the average rate and Step 1 electric equivalents prior to 2009. Since that time, FEI's burner tip rate has been below that of the electric equivalents.

2 Assumptions based on new construction of a 3,000 sq. ft. home in the Lower Mainland.
3 Represents difference in capital costs per year, assuming a stream of equal annual payments with an interest rate of 6% and measurable life of 17 years for a space heating furnace and 13 years for a hot water tank.

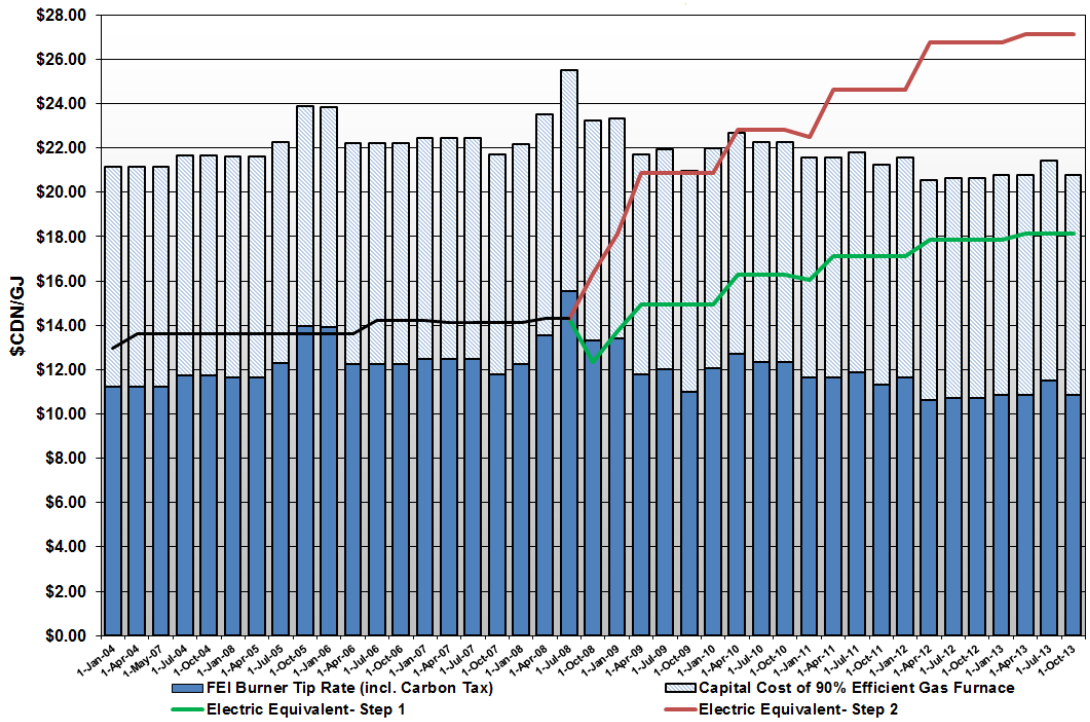
Figure 1: FEI Existing Space Heating – Burner Tip Rate vs. Electric Equivalents[4]



However, the inclusion of the upfront capital costs (from Table 1) associated with the installation of a gas furnace (indicative of a customer that directly incurs the upfront capital costs of installing gas over electric appliances) reduces the competitive position of natural gas against electricity. From January 2004 to about January 2010, FEI's burner tip rate plus the capital cost of about $9.93/GJ put the total cost per GJ above the Step 2 electric equivalent. From July 2010 to present, FEI's burner tip rate plus capital cost is above the Step 1 electric equivalent rate but below the Step 2 electric equivalent rate. Therefore, it is a more economic option to use natural gas for residential customers with larger home sizes and who consume more energy for space heating (i.e. those who would incur the Step 2 electricity rate). However, for residential customers with smaller home size and consume less energy for space heating (i.e. those who would therefore incur the Step 1 electricity rate), it is a more economical option to use electricity.

[4] The Step 1 and Step 2 electric equivalents have been adjusted using a 75% efficiency to represent the average efficiency level of all existing space heating customers.

Figure 2: FEI New Space Heating – Burner Tip Rate and Capital Cost vs. Electric Equivalents[5]

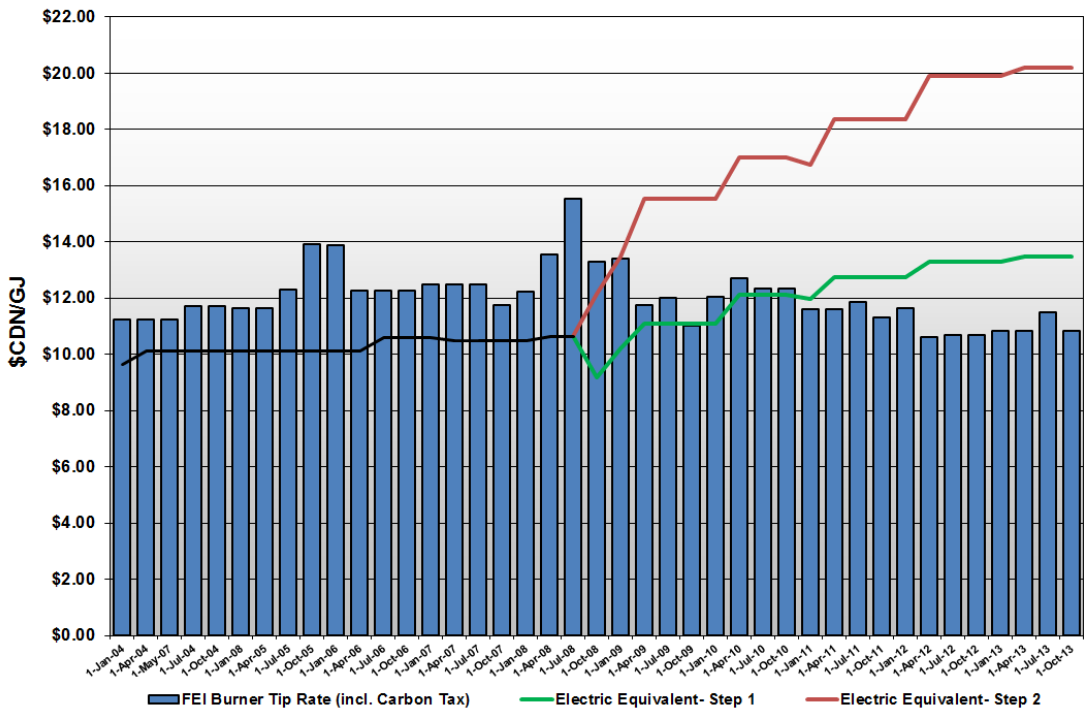


3.2 WATER HEATING

The attraction and retention of hot water heating load is even more challenging for FEI than attracting and retaining space heating load since natural gas water heaters operate at a lower efficiency and electric water heating typically makes more use of the Step 1 electricity rate. Figures 3 and 4 below present a historical view of FEI's competitiveness in the water heating market. Figure 3 shows the comparison without capital costs, which is indicative of a customer that has existing water heating equipment and therefore the expenditure of the energy equipment has already been incurred.

5 The Step 1 and Step 2 BC Hydro RIB rate electric equivalents have been adjusted using a 90% efficiency to represent the average efficiency level of a new gas fired furnace.

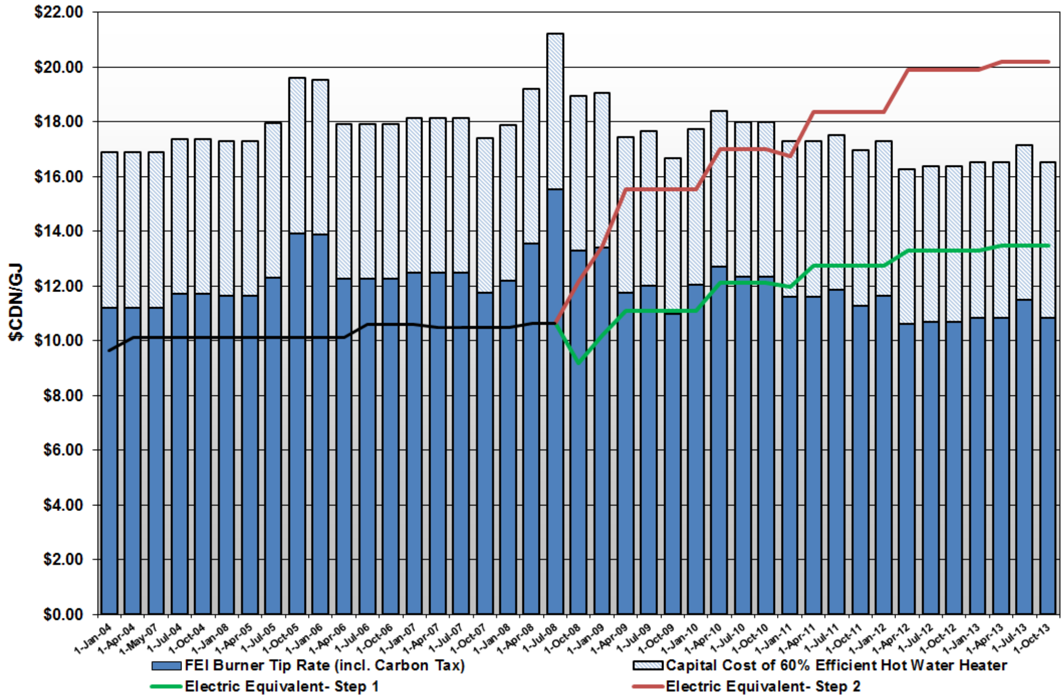
Figure 3: FEI Existing Water Heating – Burner Tip Rate vs. Electric Equivalents[6]



Illustrated in Figure 4, the inclusion of the upfront capital costs associated with the installation of a gas hot water heater dramatically reduces FEI's competitive position against the electric equivalents. From January 2004 until approximately January 2011, FEI's burner tip rate plus the capital cost of about $5.67/GJ put the total cost per GJ above both the Step 1 and Step 2 electric equivalents.

6 The average efficiency for a gas fired hot water heater is assumed to be 60% while the average efficiency for an electric powered water heater is assumed to be 90%. When comparing gas and electric powered hot water heaters, the ratio of 60% / 90% = 67% relative efficiency of a gas fired water heater relative to an electric water heater is used.

Figure 4: FEI New Water Heating – Burner Tip Rate and Capital Cost vs. Electric Equivalents[7]



Although until recently, with the increase in BC Hydro electric rates, FEI's burner tip rate plus capital cost have totalled below the Step 2 electric equivalent, it still remains significantly above the Step 1 electric equivalent. Since most residential customers would incur the Step 1 electricity rate for hot water heating, it is a more economic option for customers to use electricity when installing a new water heater.

3.3 SUMMARY

The results presented above for space and water heating show that, historically, electricity costs have compared favourably to natural gas when capital costs are taken into consideration. It is only recently, in the context of the lowest natural gas commodity prices in a decade that the price competitiveness of natural gas has improved. However, if the higher natural gas commodity price forecasts of industry experts materialize (as presented in Appendix A-1), FEI's current price competitiveness in certain applications with electricity will again be eroded.

[7] The average efficiency for a gas fired hot water heater is assumed to be 60%, while the average efficiency for an electric powered water heater is assumed to be 90%. When comparing gas and electric powered hot water heaters, the ratio of 60% / 90% = 67% relative efficiency of a gas fired water heater relative to an electric water heater is used.

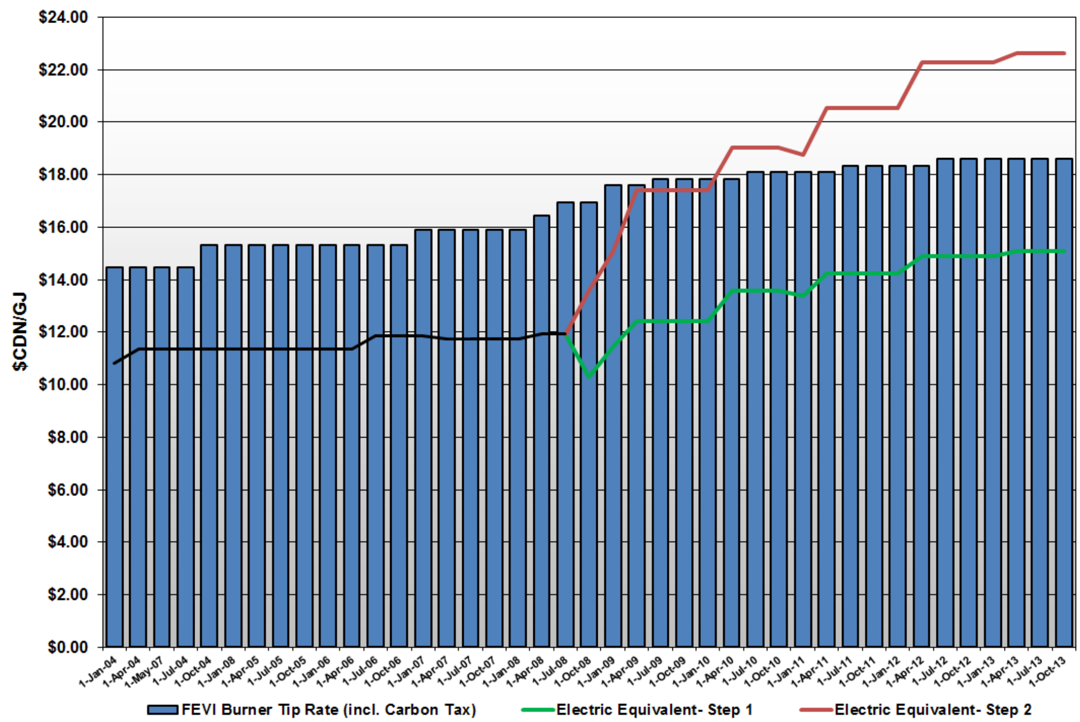
4. FortisBC Energy (Vancouver Island) Inc.

Due to FEVI's higher cost of service relative to system throughput, its per unit natural gas rates are significantly higher than those for FEI. FEVI's residential bundled variable rate has been held constant under the rate freeze mechanism for a number of years. Since FEVI's natural gas rates are set higher than market based rates due to a higher cost structure, it is less competitive in comparison to electricity than FEI.

4.1 SPACE HEATING

The two figures below present a historical view of the competitiveness with space heating for FEVI. As shown in Figure 5, FEVI's burner tip rate absent the capital costs (indicative of a customer that already has appliances installed) have been persistently above the average rate and Step 1 electric equivalents.

Figure 5: FEVI Existing Space – Heating Burner Tip Rate vs. Electric Equivalents[8]

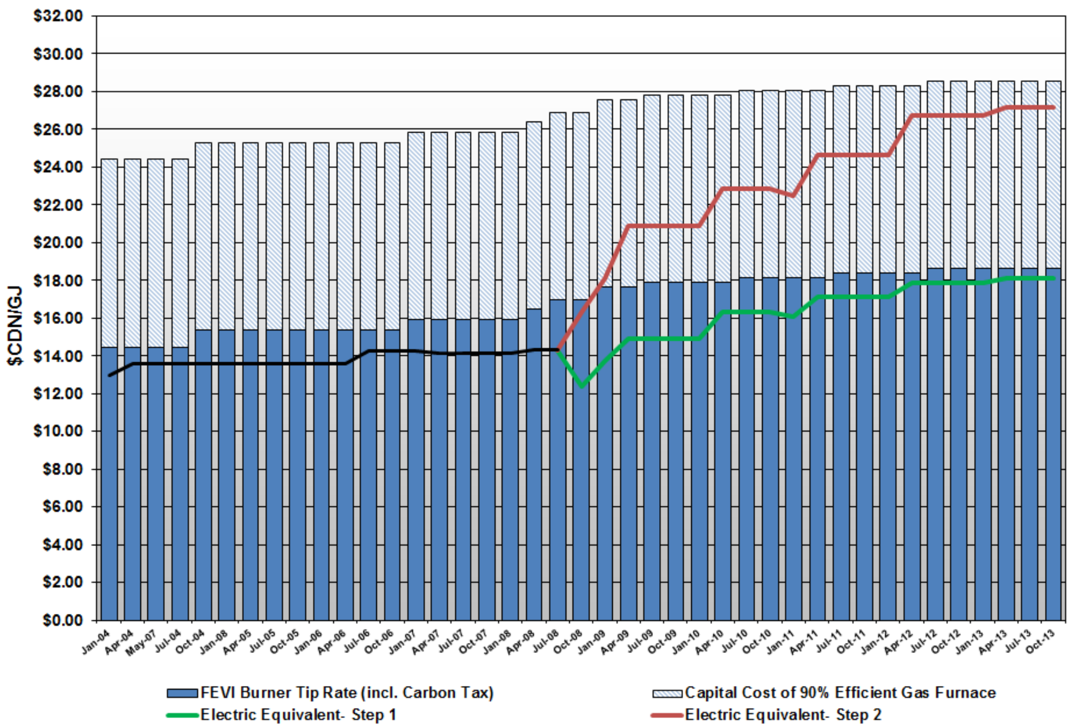


The inclusion of the upfront capital costs (from Table 1) associated with the installation of a gas furnace (indicative of a customer that directly incurs the upfront capital costs of installing gas over electric appliances) reduces the competitive position of natural gas against electricity. As illustrated in Figure 6, from January 2004 to present, FEVI's burner tip rate plus the capital cost of about $9.93/GJ put the total cost per GJ above the Step 2 electric equivalent. Higher total

[8] The Step 1 and Step 2 electric equivalents have been adjusted using a 75% efficiency to represent the average efficiency level of all existing space heating customers.

costs of installing gas over electric indicate to the consumer that electricity is the more economical option.

Figure 6: FEVI New Space Heating – Burner Tip Rate and Capital Cost vs. Electric Equivalents[9]



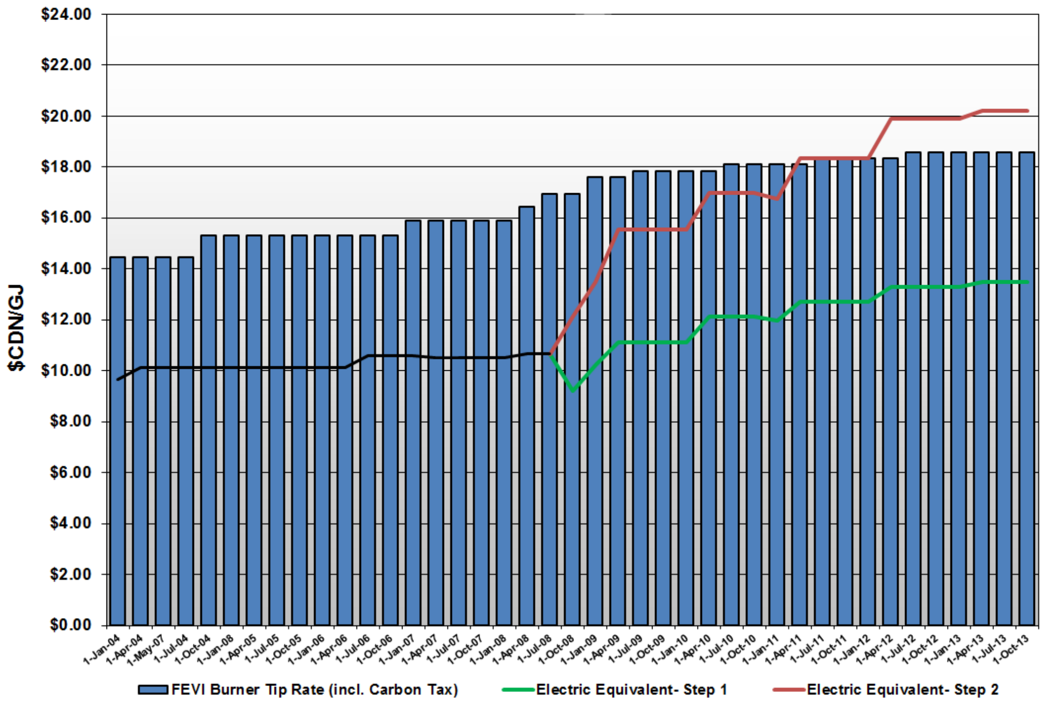
4.2 WATER HEATING

The attraction and retention of hot water heating load is even more challenging for FEVI than attracting and retaining space heating load since natural gas water heaters operate at a lower efficiency and electric water heating typically makes more use of the Step 1 electricity rate. Figures 7 and 8 below present a historical view of FEVI's competitiveness in the water heating market.

Figure 7 shows the comparison without capital costs, which is indicative of a customer that has existing water heating equipment and therefore the expenditure of the energy equipment has already been incurred.

9 The Step 1 and Step 2 BC Hydro RIB rate electric equivalents have been adjusted using a 90% efficiency to represent the average efficiency level of a new gas fired furnace.

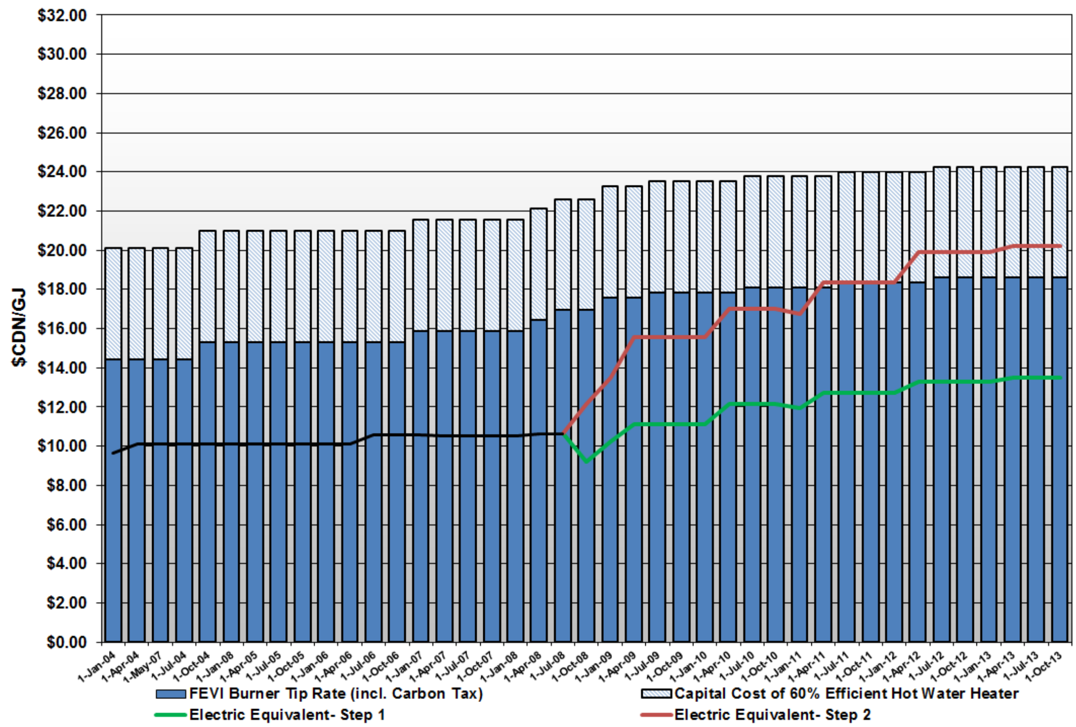
Figure 7: FEVI Existing Water Heating – Burner Tip Rate vs. Electric Equivalents[10]



As illustrated in Figure 8, the inclusion of the upfront capital costs associated with the installation of a gas hot water heater dramatically reduces FEVI's competitive position against the electric equivalents. From January 2004 to present, FEVI's burner tip rate plus the capital cost of about $5.67/GJ puts the total cost per GJ above both the Step 1 and Step 2 electric equivalents,

[10] The average efficiency for a gas fired hot water heater is assumed to be 60%, while the average efficiency for an electric powered water heater is assumed to be 90%. When comparing gas and electric powered hot water heaters, the ratio of 60% / 90% = 67% relative efficiency of a gas fired water heater relative to an electric water heater is used.

Figure 8: FEVI New Water Heating – Burner Tip Rate and Capital Cost vs. Electric Equivalents[11]



4.1 SUMMARY

The results presented above for space and water heating show that, historically, electricity costs have compared favourably to natural gas when capital costs are taken into consideration. FEVI will likely continue to be challenged with respect to competing with electricity for space and water heating even in the current low gas price environment.

5. FortisBC Energy (Whistler) Inc.

FEW was converted from propane to natural gas throughout 2009 and was fully converted to natural gas in 2010. With higher delivery cost than FEI, due to its low customer base relative to pipeline infrastructure, FEW is also challenged with respect to electricity used for space and water heating. The four figures below show FEW's burner tip rate in comparison to new and existing space heating customers and new and existing water heating customers.

[11] The average efficiency for a gas fired hot water heater is assumed to be 60%, while the average efficiency for an electric powered water heater is assumed to be 90%. When comparing gas and electric powered hot water heaters, the ratio of 60% / 90% = 67% relative efficiency of a gas fired water heater relative to an electric water heater is used.

Figure 9: FEW Existing Space Heating – Burner Tip Rate vs. Electric Equivalents[12]

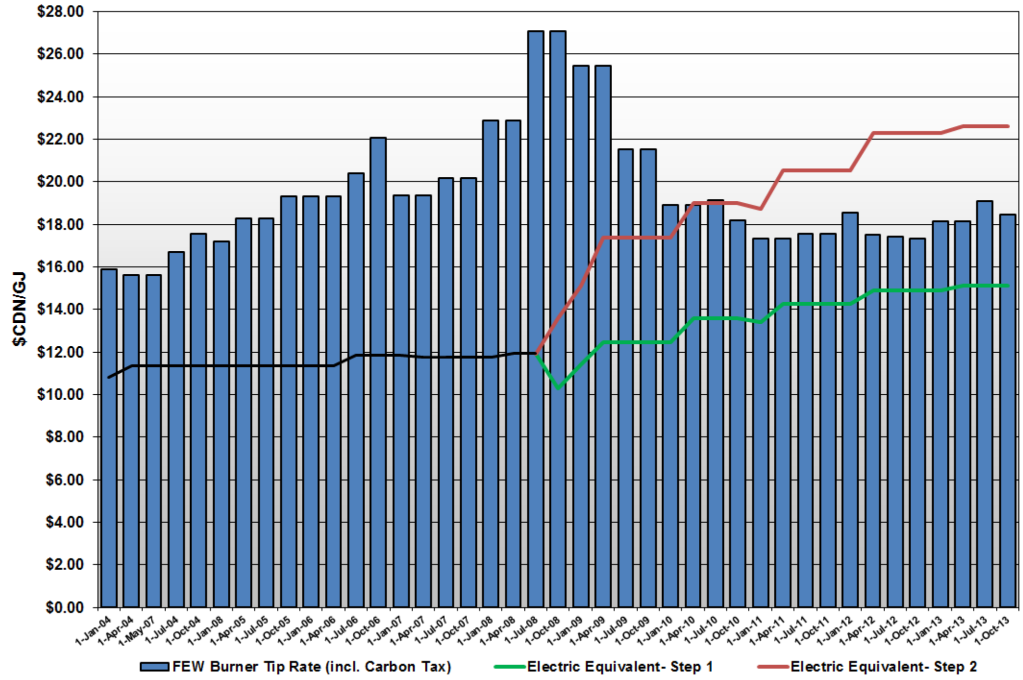
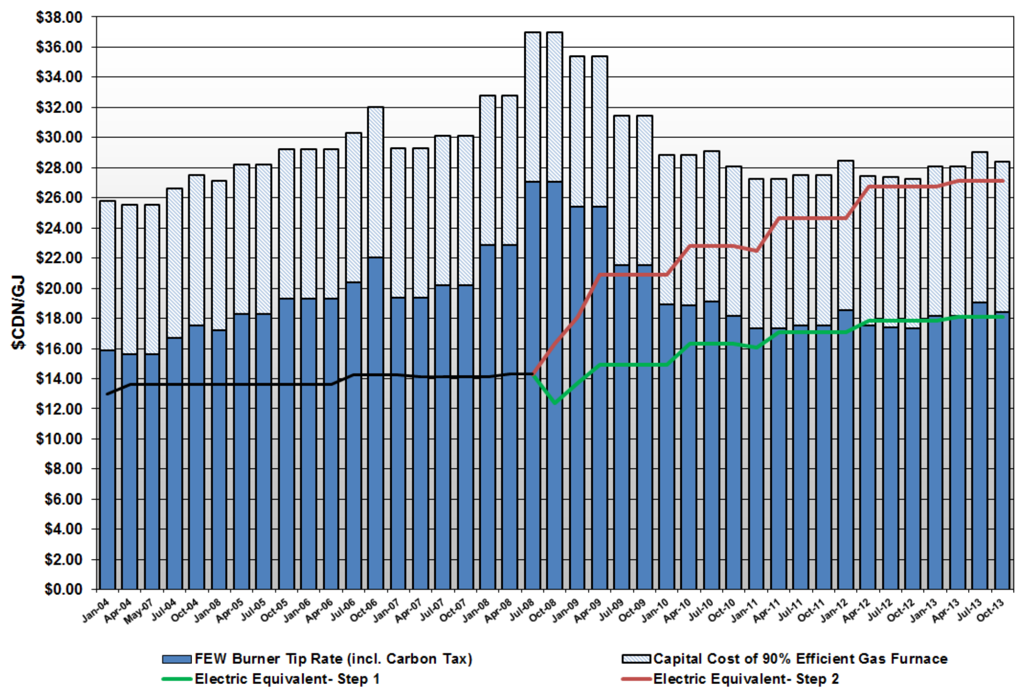


Figure 10: FEW New Space Heating – Burner Tip Rate and Capital Cost vs. Electric Equivalents[13]



[12] The Step 1 and Step 2 electric equivalents have been adjusted using a 75% efficiency to represent the average efficiency level of all existing space heating customers.

[13] The Step 1 and Step 2 BC Hydro RIB rate electric equivalents have been adjusted using a 90% efficiency to represent the average efficiency level of a new gas fired furnace.

Figure 11: FEW Existing Water Heating – Burner Tip Rate vs. Electric Equivalents[14]

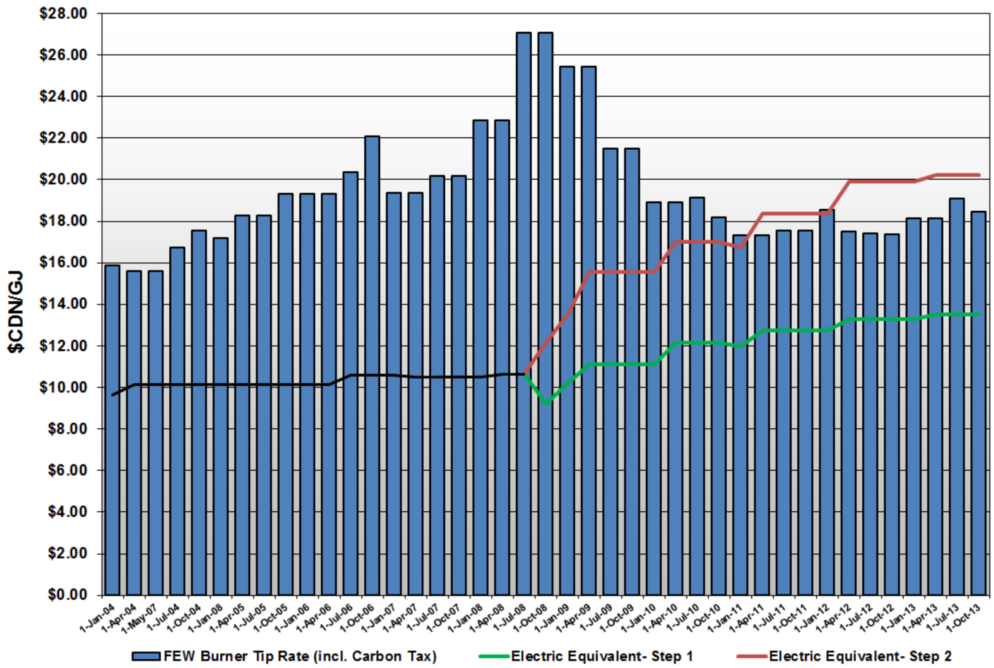
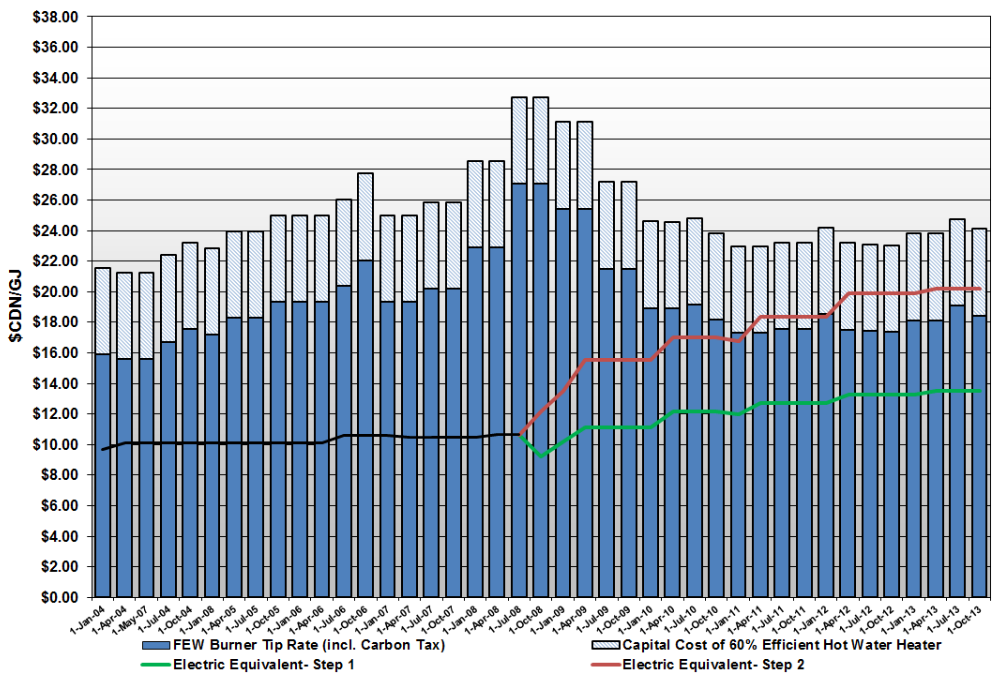


Figure 12: FEW New Water Heating – Burner Tip Rate and Capital Cost vs. Electric Equivalents[15]



[14] The average efficiency for a gas fired hot water heater is assumed to be 60%, while the average efficiency for an electric powered water heater is assumed to be 90%. When comparing gas and electric powered hot water heaters, the ratio of 60% / 90% = 67% relative efficiency of a gas fired water heater relative to an electric water heater is used.

[15] Ibid.

6. Conclusion

The current low priced gas environment has improved the competitiveness of natural gas over electricity, but only on an operating cost basis. With the higher upfront capital costs of natural gas installations and appliances negatively impacting the competitive position of natural gas relative to electricity, FEVI and FEW face an even greater challenge due to their higher burner tip rates relative to FEI.

The FEU cannot predict if the current relative operating cost advantage of natural gas service will improve in the future. Certainly, this could happen if the increases in electric rate outpace the increases in natural gas market prices. However, there is a high degree of uncertainty to the extent that this could happen.

As discussed in Section 2.1 and Appendix A-1, it is widely accepted that current market prices are not sustainable and future increases are likely. Current market price forecasts indicate that natural gas prices could be close to $6.00 US/MMBtu within five years, as supply and demand becomes more balanced.

Second, there is uncertainty regarding the level of electricity rate increases over the next five years as this is not only driven by BC Hydro's costs but also by the provincial government. In the past, while BC Hydro has issued forecasts of large general rate increases, the originally anticipated rate increases have not materialized. The provincial government's 2011 review of BC Hydro and its public statements about the intention to control or reduce future rate increases have added more uncertainty to the magnitude of future rate increases. This review has also impacted the manner to which increases would be applied to the Step 1 or Step 2 rates. Recent news has indicated that BC Hydro customers could be facing a 26% rate increase by 2016[16] though it is uncertain how large or when any rate increase might take effect.

Third, there is some level of uncertainty regarding the future of the carbon tax in B.C. The Pembina Institute—an organization that advances sustainable energy solutions through research, education, consultancy, and advocacy—has suggested that the carbon tax should rise to $200 per tonne of carbon dioxide equivalent if the government is serious about addressing climate change.[17] The current price of carbon in B.C. is set at $30 per tonne, or approximately C$1.50/GJ; although the current B.C. government has confirmed that it will maintain the current tax rate for five years,[18] the future of B.C.'s carbon tax remains uncertain, particularly if or when a new government is formed.

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[16] CBC News, "BC Hydro forecasts 26% rate increase by 2016," September 11th, 2013.
[17] Vancouver Sun, September 16, 2010.
[18] http://www.leg.bc.ca/40th1st/4-8-40-1.htm

Appendix A-4

NATURAL GAS DIRECT USE: SQUEEZING EVERY BTU

Squeezing Every BTU

Natural Gas Direct Use Opportunities and Challenges

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January 2012

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Contents

Executive Summary

Natural gas is a critical component of today's energy mix. In 2011, natural gas will be used in more than 70 million households and businesses, serving more than 40 percent of the direct energy needs of the nation's homes and buildings. Natural gas will fuel almost one quarter of electricity generation. Industry will rely on natural gas as fuel for manufacturing and as a feedstock to create fertilizers for use by farmers. It is environmentally superior to coal and petroleum, producing low pollution and half the greenhouse gas emissions of other fossil fuels, and provides the foundation to unlock the potential of renewable solar and wind energy. Natural gas is available and local. The vast abundance of North American gas holds the potential for more than 100 years of energy. Natural gas is domestic, abundant, and cost effective. It is central to the nation's energy future.

Direct-Use refers to natural gas consumed directly used in appliances for space conditioning, water heating, cooking, and clothes-drying. In contrast, some consumers use natural gas indirectly by consuming electricity generated with natural gas. However, generally the natural gas distribution system is considerably more efficient than electricity since it avoids the significant losses associated with electricity generation, transmission, and distribution, which amount to nearly half the energy used in homes and commercial businesses.

The direct use of natural gas provides a cost-effective and resource-efficient choice for consumers and offers one more option in the suite of greenhouse gas emissions reduction strategies. And direct use makes financial sense as a consumer fuel choice. A household with natural gas usually spends less on heating, cooking, and drying than one using any other fuel. A recent AGA analysis showed that a household with natural gas for these appliances on average spends almost 30 percent less than a household with all-electric appliances, and leads to 37 percent lower greenhouse gas emissions.[1]

Potential Benefits of Natural Gas Direct Use

- Lower consumer energy bills
- Increase productivity of energy supplies
- Reduce energy imports
- Fewer pollutants and greenhouse gas emissions
- Reduce new electric power requirements
- Provide enhanced domestic energy security
- Safe and reliable

[1] American Gas Association. "A Comparison of Energy Use, Operating Costs, and Carbon Dioxide Emissions of Home Appliances." 2009. http://www.aga.org/Kc/analyses-and-statistics/studies/demand/Documents/0910EA3.PDF

Despite the range of benefits, many remain unrealized. Some consumers do not have access to natural gas, and sometimes it is financially prohibitive for utilities to extend service to them without outside assistance. Consumers also tend to incur higher upfront costs when purchasing and installing natural gas appliances, thereby limiting natural gas as a consumer option, despite the cost-effectiveness of using the fuel over the long term.

Current policies also prove constraining. Some appliance and building codes and standards designed to improve energy efficiency may do the opposite because they do not take into account the far superior efficiencies of the upstream natural gas delivery system. Rules and policies that ignore these efficiencies can inhibit the use of natural gas applications through higher purchase and installation costs compared with other energy sources. And other constraints are less fair-market oriented. Electric utilities sometimes propose incentives to builders to forego natural gas equipment installations in new construction, or offer lower service rates to consumers in all-electric homes, further impeding natural gas market penetration.

<u>Limits and Constraints on Natural Gas Direct Use</u>

- Appliance first cost – Gas appliances and supporting equipment often incur higher installation and up-front costs compared to alternative fuel applications.

- Misaligned builder and consumer interests – Incentives for builders to construct at the lowest-cost are often not aligned with consumers' long-term economic interests or the nation's environmental and energy security.

- Perverse incentives – Electric utility service rates and non-rate based financial incentives designed to inhibit natural gas service installation and promote aggressive fuel switching away from gas.

- Inconsistent approach to energy policy, codes and standards – Policymakers and consumers lack a holistic and comprehensive perspective of energy use. Many energy policies, regulations, and codes and standards developed using a site-based approach to energy measurement limit natural gas and its advantages.   A full-fuel-cycle approach, which incorporates all upstream energy efficiencies and emissions, would acknowledge and leverage the advantages of the natural gas delivery system.

To achieve the full potential of direct use means reversing the counterproductive trends and removing the barriers to customers to access natural gas. The potential benefits exist in the short and long term. Converting an inefficient household to natural gas heat can provide immediate savings today. Over longer periods, as the electric and natural gas systems evolve, the integration of natural gas appliances and distributed energy technologies into an advanced *smart energy* grid offers new pathways to increase efficiency, achieve carbon reduction goals, and optimize natural gas resources.   New policies should support goals oriented to the public good, but policies must also be good for customers, presenting them with the best available options that also support public policy goals.

Policy Recommendations

- Develop and incorporate full-fuel-cycle analysis into energy policy, regulations, and energy efficiency metrics.

- Provide consumers with best available information on comparable energy options through the use of enhanced appliance and equipment labeling.

- Encourage government agencies, state public utility commissions and utilities to jointly innovate policies and regulations that provide better alignment of costs and benefits over the life cycle of consumer equipment.

- Research and development programs and investment focus should include natural gas delivery and end-use technology to fully maximize the value of natural gas resources.

There are ample and extensive opportunities for direct use of natural gas in the industrial and transportation sectors as well. This includes applications for combined-heat-and-power (CHP), distributed generation, and efficient industrial thermal processes like direct-fire water heating. These remain important options to consider in any comprehensive energy policy.

Squeezing Every BTU studies and details all of these issues. Its purpose is to explore the market and policy-related issues surrounding natural gas direct use, as well as how it can be used to maximize economy-wide energy efficiency and reduce greenhouse gas emissions. The study aims to provide an overview of the key benefits and advantages of direct use, and describes the critical constraints that limit direct use as a consumer option and energy policy tool.

1. Advantages of Direct Use

Summary

Natural gas—in particular natural gas used for direct consumption in homes and businesses for heating, cooking, and other applications—is a cost-effective and reliable fuel source with many benefits. Among the many benefits to society and consumers:

- Natural gas usually provides the lowest-cost fuel option for consumers.
- Natural gas provides one of the most efficient, lowest-carbon energy delivery pathways to consumers.
- To fully realize the environmental benefits of the direct use of natural gas requires a comprehensive assessment of appliance and fuel options based on a full-fuel-cycle analysis of energy consumption and environmental impact.
- There exists significant potential for natural gas to enhance efficiency and reduce emissions from homes and businesses, especially as a substitution fuel in homes that rely on electric resistance appliances for heat or hot water.
- Natural gas can enhance energy security as a substitute for fuel oil, especially in the Northeast.
- The abundance of North American shale gas bolsters domestic natural gas supplies, which stabilizes prices and is good for consumers.
- New end-use technologies such as distributed generation and combined-heat-and-power can help maximize the benefits of this resource and make significant contributions toward broader public goals of grid reliability, energy efficiency and emissions reductions.

1.1 Introduction

Natural gas offers energy, environmental and security benefits generally unmatched by competing fuels. Each year, natural gas passes through approximately 2.4 million miles of pipeline, 86 percent of which comprises smaller distribution mains and services that reach approximately 70 million customers nationwide. Utility companies, which install and maintain this distribution system, serve primarily residential and commercial consumers, and a smaller number of industrial entities. The *Energy Information Administration, EIA*, reported about 65 million residential and 5 million commercial gas utility customers in 2009, and 144,000 industrial or other customers. The focus of this paper will be on the residential and commercial sectors.

Direct use refers to natural gas consumed by appliances in these sectors, as opposed to using gas to generate electricity that is used by those same applications. Consumers in homes and businesses use natural gas mainly for thermal energy in four primary end uses: space heating, water heating, cooking, and clothes drying. A small amount of gas also serves natural gas space cooling in the commercial sector. The majority of gas, however, is used for space and water heating *load*, the energy requirements to serve the consumer's need. Approximately 95 percent of gas demand in the residential sector is tendered for space and water heating, and about 65 percent in the commercial sector. Natural gas serves about two-thirds of the energy requirements for these applications today.

Natural gas provides not only convenience and affordability, but also environmental benefits. Comprised primarily of methane, natural gas produces the lowest full-fuel-cycle greenhouse gas emissions of any combusted fossil fuel—this includes the higher global warming potential of methane and its impact on emissions. In addition, gas use results in significantly fewer pollutants, emitting none of the mercury and far fewer nitrogen and sulfur oxides that is found in other fuels. Natural gas is a readily abundant and domestically available resource, which helps ensure stable prices. About 90 percent of the natural gas consumed in the United States is domestically produced, a share that has been increasing in recent years as new shale resources are added to the natural gas reserve base. Almost all of the remainder is imported natural gas from Canada. When natural gas is used in lieu of petroleum products, it can reduces crude oil imports from overseas and helps strengthen the energy security of the United States. It is traded and distributed under an established and well-tested regulatory framework. Also, many gas technologies have proven reliable over a century of development, both those used for transmission and distribution through the pipeline network, and those used in end-use applications like electric generation and direct-thermal combustion.

Direct-use applications capitalize on these benefits, relying on a distribution system that, when evaluated along the entire energy value chain, delivers the most useful primary energy to the customer with the fewest system losses relative to other systems of energy delivery. Thus direct-use can help increase the productivity of the nation's energy supplies and increase economy-wide energy efficiency. Furthermore, fueling more homes and businesses directly with natural gas can help reduce new electric power requirements by easing demand on the electric power grid while reducing the need to construct expensive new electricity generating plants. Direct-use technology is here today and affordable. Policymakers and regulators should establish energy policies that acknowledge that the direct use of natural gas provides a key option to help realize cost-effective efficiency and emissions goals.

These advantages, and the relative merits of direct use of natural gas compared with competitive fuels, are highlighted in Table 1 (page 9). The table is designed to summarize the qualitative attributes of each fuel choice that are available to residential and commercial customers. Each row denotes an advantage or attribute of a given energy source; columns represent energy options, including distillate fuel oil, propane and electricity. Electricity is further subdivided by primary generation source: coal, coal with carbon capture and sequestration (CCS), solar/wind, a new nuclear plant, or a new gas plant (other primary sources such as biomass are not included due to the relatively small place in the market they currently occupy). A checkmark indicates where that fuel option offers a specific advantage.

Table 1
Natural Gas Direct Use Advantages to Other Fuels
Checkmark given for each advantage an energy source provides.

				Electricity (by Generation Fuel)				
	Direct Use Natural Gas	Heating Oil	Propane	Coal	Coal CCS	Solar / Wind	New Nuclear	New Gas
Cost effective	● +			●				●
Resource efficiency	● +					●	●	● -
Resource availability	●			●	●	●	●	●
Enhances energy security	●			●	●	●	●	●
Lowers carbon emissions	●		●		●	●	●	●
Reliable / proven technology	●	●	●	●		●	●	●
Regulatory certainty	●	●	●					

*Coal CCS = a new coal plant with carbon capture and sequestration.

The following advantages denoted in Table 1 are discussed more in the subsequent sections of this report:

Cost effective – Natural gas is the most cost-effective home heating fuel available. Fuel oil and propane are tethered to crude oil prices, which continue to rise, and expenditures for electricity for heating purposes are greater than natural gas on average. More details can be found in Section 1.2.

Resource Efficiency – The combined efficiencies of the natural gas production, gathering, processing, transmission, and distribution systems are the highest of any fuel. When gas is delivered to homes and businesses, the source-to-site efficiency is three times greater than that of electricity, and higher still than propane and heating oil. The full-fuel-cycle efficiency, which includes the entirety of the energy value chain, displays significant efficiency advantages and lower greenhouse gas emissions relative to other energy sources. See Section 1.3.

Lowers Carbon Emissions – Households using natural gas for heating, cooking and drying applications emit the lowest greenhouse gas emissions of any fuel when evaluated on a full-fuel-cycle basis. More details in Section 1.4.

Resource Availability – The development of techniques to extract shale gas has transformed the North American natural gas resource base to one of increasingly abundance. When considering home fuels, the availability of the primary resources is important, as is the availability of generation capacity in the case of electricity. While oil remains abundant, it is not a domestic resource. Renewables are theoretically infinite in supply, and nuclear has no immediate fuel constraints, but higher levelized costs of energy restrict solar, wind and nuclear investments. In addition, new EPA regulations are expected to hinder development of new coal-fired power plants. Thus natural gas is more accessible than all of these resources. More details on the natural gas resource base are found in Section 1.5.

Reliable Here-Now Technology – All options should be considered as the nation's energy demand grows and emissions and climate-related targets are imposed. The potential for renewables, nuclear and other forms of energy to meet these goals is significant. However uncertainties and costs associated with these must be weighed against the availability of natural gas and its direct use as a tool to also serve the nation's growing energy needs, while adhering to environmental goals. See Section 1.6 for more.

Enhances Energy Security – Natural gas has the potential to replace petroleum-based fuels with a domestically produced energy resource. The fuel oil market represents one of these opportunities. For more see Section 1.7.

The purpose of Table 1 and the following subsections is to provide a general picture of the various attributes offered by each consumer fuel option. Some of these advantages, of course, are dependent on local and regional factors; relative fuel benefits vary by geography. Regional differences in fuel prices and the electric generation mix changes the relative advantages, sometimes away from natural gas. An electric system with a less carbon-intensive generation mix—such as in the hydroelectric-intensive Northwest—means that natural gas may not always be the preferred solution for greenhouse emissions reductions. However, natural gas has a cost advantage in many regions for most applications, and proves far superior as a greenhouse gas reduction tool in many areas. These variations should be acknowledged and embraced as part of any reasonable energy policy.

The following subsections describe in more detail the relative advantages of natural gas and direct-use applications.

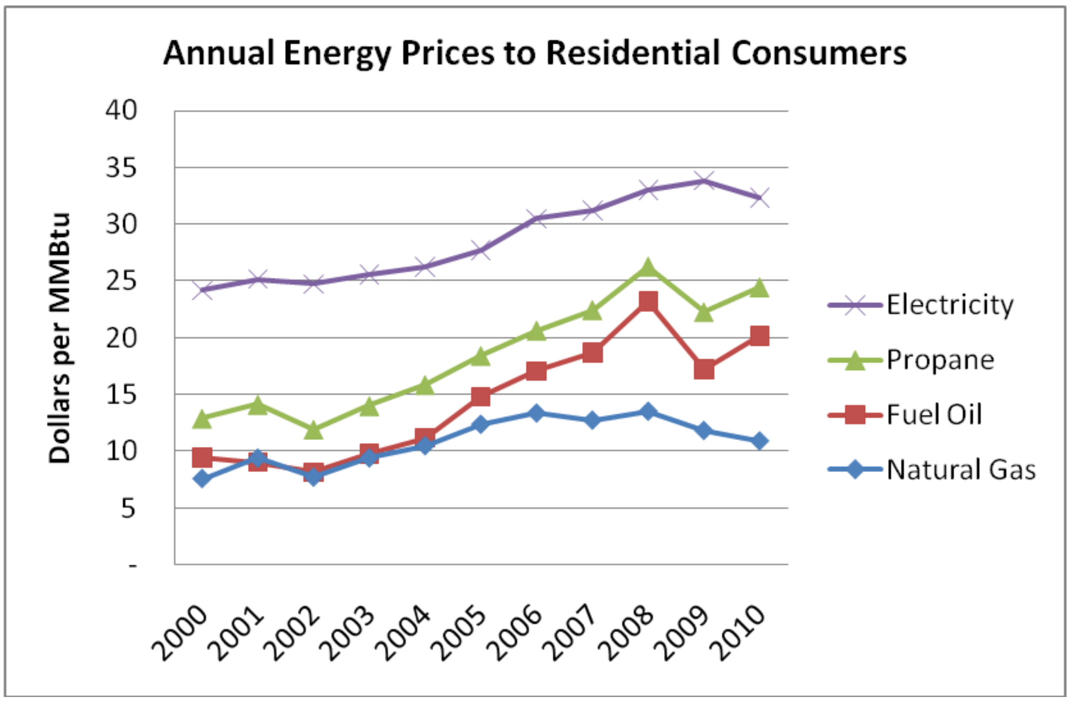
1.2 Cost Effective Fuel Option

Currently, the price of natural gas is the lowest of the four principal energy options available to residential and commercial consumers. According to an analysis by the American Gas Association, using natural gas can save homeowners 30 to 45 percent on their energy bills. This section describes the changes in delivered fuel prices during the last decade, including today's prices, and presents a comparative analysis of homeowner utility bills for a typical new household using the four principal fuel types available.[i]

The cost of all energy forms has risen during the last 10 years. Electricity prices have steadily increased, and propane and fuel oil have shown marked cost increases over the same period. Natural gas has also increased and has been subject to the same volatility that befell many commodities during the run-up and subsequent crash in commodity prices during 2008. Figure 1 illustrates the changes in prices for these fuels over the last decade, and highlights the relative stability and low price of natural gas relative to the other fuel options.

- *Electricity* has traditionally been the highest cost energy source on an energy equivalent basis. The average price for electricity delivered to homes was $32.33 per million British Thermal Units (MMBtu) in 2010, rising 34 percent since 2000.
- *Fuel oil*, which is linked to crude oil prices, had an average price of $20.15 per MMBtu in 2010, rising 113 percent since 2000.
- *Propane*, which is also linked to crude oil but to a lesser extent natural gas prices as well, had an average cost of $24.43 per MMBtu in 2010, rising 90 percent since 2000.
- *Natural gas* has the lowest cost per unit energy of the fuels presented here. Natural gas costs residential customers $10.90 per MMBtu, rising 44 percent since 2000.

Figure 1
Natural Gas Remains the Least Cost Fuel for Consumers



Source: EIA

What do these energy prices mean for consumer energy bills? Consumers will use different amounts of energy depending on their energy source and the number of appliances installed. To estimate the impact prices have on consumer energy bills, AGA conducted an analysis of the energy profile of a typical new home with space heating, water heating, cooking, and clothes drying, using each of the four fuels above. The site-based consumption estimates for the appliances, all of which were assumed to meet the federal minimum efficiency standard, were then multiplied by the fuel's average energy price in 2010 to estimate consumer expenditures per year for those applications. The final expenditures for these end uses in a typical home are listed in Table 2.[ii]

To summarize the results of the study:

- The annual site-energy requirement is 107 MMBtu per year for and average natural gas and propane household, 109 MMBtu for an average fuel oil household, 53 MMBtu for the average all-electricity household (with an air-source heat pump).
- The average natural gas household spends $1,275 per year for fueling these appliances.
- An electricity household incurs, on average, $1,793 in expenditures for an electric heat pump, resistance water heater, cooktop and stove, and dryer. The expenditures are 40 percent higher than the natural gas household.
- A fuel oil household spends $2,252 operating a furnace and water heater. Cooking and clothes drying are assumed to be electric. These expenditures are 77 percent higher than natural gas. [iii]
- Consumers with propane spend on average $2,596, which is 103 percent greater than a natural gas household.

Table 2: Estimated Annual Energy Bill for Typical New Household (2010$)

	Natural Gas	Electricity	Oil	Propane
Space Heating	$887	$1,062	$1,542	$1,806
Other	$388	$731	$710	$790
Total	$1,275	$1,793	$2,252	$2,596

For space heating, water heating, cooking, and drying applications.

For more details on the study and the assumptions made for each household, the full report can be accessed at: http://www.aga.org/Kc/analyses-and-statistics/studies/demand/Pages/Comparison-Energy-Use-Operating-Costs-Carbon-Dioxide-Emissions-Home-Appliances.aspx

Regional price differences can change the relative benefits of natural gas compared with other fuel options. But natural gas out performs electricity and other energy options in most areas of the country. That said, appliance first-cost issues can prevent consumers from realizing the low-cost benefits of natural gas. The purchase and installation of a natural gas furnace and water heater is typically more expensive than an electric counterpart. This constraint is discussed in more depth in Section 2.2 on page 31.

1.3 Greater Resource Efficiency

Energy efficiency remains one the easiest and most effective ways to reduce energy consumption and mitigate greenhouse gas emissions. Of the various forms of energy available to residential and commercial consumers, the natural gas distribution system remains one of the most energy efficient. That is, the energy required to produce, process, transport, and distribute usable energy is less along the natural gas distribution system compared with other energy options, including electricity. This is called *source-to-site* energy consumption or efficiency. When the upstream energy consumption is combined with the energy consumed at the point of use, the higher *full-fuel-cycle* energy efficiency of natural gas makes it a superior choice for energy and emissions reductions. When energy usage is viewed using this holistic, comprehensive approach, the relative efficiencies of the natural gas distribution system stand out relative to other forms of energy. Once these efficiencies are considered, the substitution of gas for less efficient forms of energy – in particular, electric resistance heat – can help achieve environmental and energy efficiency goals.

The following subsections describe the energy value chain of natural gas, electricity, fuel oil, and propane, and present a case for why a full-fuel-cycle approach is necessary to fully realize the potential for energy and emissions reductions. The full-fuel-cycle discussion is followed by a subsection on electric system losses, quantifying the amount of energy lost to waste heat from the production and delivery of electric energy. Finally, the last subsection describes how direct use may be one method for mitigating some of these losses as well as promoting the reduction of electric resistance heating, one of the most inefficient uses of electricity when evaluated along the *full-fuel-cycle*.

1.3.1 Energy Value Chain Efficiencies and the Full Fuel Cycle

The energy value chain is the process by which an energy source is produced and delivered to consumers. While each fuel has a unique value chain, there are many common elements. The energy value chain can be divided into six stages:

- Fuel extraction
- Processing
- Transportation
- Conversion
- Distribution (including electric long-distance transmission)
- End-use

Through the analysis of a given fuel's energy value chain, we can better understand the energy consumed and the emissions from our energy choices. Each stage for each fuel has a unique physical process associated with it, and the energy efficiencies associated with this process can vary even within an industry. The physical extraction of coal from the ground might vary depending on the type of coal mined, where it is mined, and the distance the coal must travel until it is consumed. The same is true of natural gas; differences between conventional and unconventional gas production, distance to market, and varying geologies affect each of these stages. The efficiencies listed in this report consider these differences and reflect aggregated industry averages.

Defining Measures of Energy Consumption

Site (point-of-use) measure of energy consumption reflects the use of electricity, natural gas, propane, and/or fuel oil by an appliance at the site where the appliance is operated, based on specified test procedures.

Full-fuel-cycle measure of energy consumption includes, in addition to site energy use, the energy consumed in the extraction, processing, and transport of primary fuels such as coal, oil, and natural gas; energy losses in thermal combustion in power-generation plants; and energy losses in transmission and distribution to homes and commercial buildings.

Source: National Academy of Science

Table 3 details the individual efficiencies of each stage of the energy value chain. Each percentage represents the proportion of usable fuel exiting that stage. For example, natural gas processing is assigned a value of 96.9 percent. That is, for every 1,000 methane molecules entering this stage, 969 molecules move into transportation. The remaining 31 molecules (or 3.1 percent) are lost as fuel consumed or inefficiencies in the system. The cumulative efficiency represents the total energy delivered to the consumer prior to end use. The exact value of this, denoted in the last column of the table, is the product of the efficiencies from each preceding value chain stage.

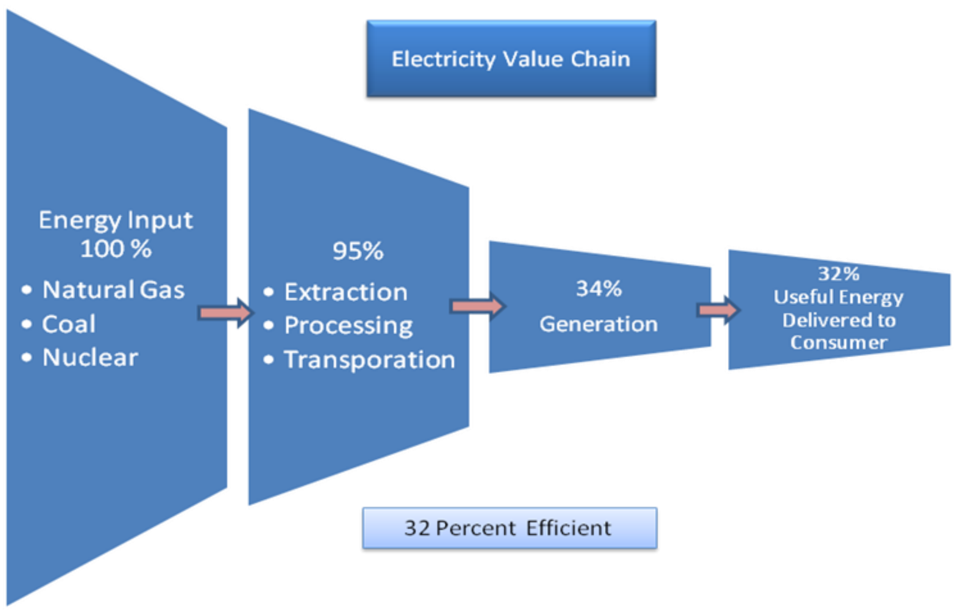
Table 3: Energy Value Chain Efficiencies

Value Chain:	Extraction	Processing	Transportation2	Conversion	Distribution	Cumulative Efficiency
Natural Gas	97.0%	96.9%	99.0%	--	98.8%	**91.9%**
Oil	96.3%	93.8%	98.8%	--	99.3%	**88.6%**
Propane	95.9%	95.3%	98.6%	--	99.2%	**89.3%**
Electricity:						
Coal-Based	98.0%	98.6%	99.0%	32.7%	93.8%	**29.3%**
Oil-Based	96.3%	93.8%	98.8%	31.7%	93.8%	**26.5%**
Natural Gas-Based	97.0%	96.9%	99.0%	42.1%	93.8%	**36.7%**
Nuclear-Based	99.0%	96.2%	99.9%	32.7%	93.8%	**29.2%**
Other[3]-Based	--	--	--	56.0%	93.8%	**49.7%**
Electricity Weighted Average[4]	--	--	--	35.8%	--	**31.9%**

Source: Gas Technology Institute

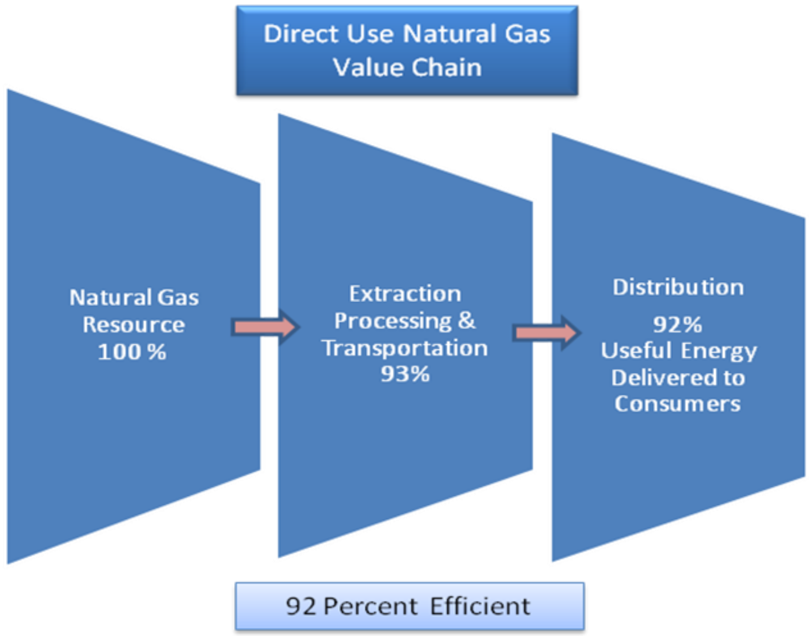
The electricity sector, on aggregate, produces and delivers energy to consumers along a value chain with the greatest inefficiencies. As Table 3 indicates, most electric system losses occur during the conversion (generation) stage, where a primary fuel is used to power electromechanical generators. Electricity is then generated and the excess heat energy not utilized for work is discarded. The efficiencies at this stage vary depending on the type of turbine and fuels utilized. Conventional steam turbines powered by coal or nuclear typically operate within a heat rate efficiency range between 32 and 33 percent; advanced combustion turbines may reach efficiencies of 37 percent. Natural gas advanced combined-cycle turbines, which use a combination gas turbine engine connected to a steam turbine, can achieve efficiencies greater than 50 percent. Renewables like wind and solar have no primary energy conversion losses. The average conversion efficiency used in this analysis is aggregated based on the average mix of fuels in the nation's electricity generation portfolio. When the efficiencies from the electricity value chain are aggregated and weighted by share of U.S. generation mix, an "average" efficiency of 32 percent is assigned to the electricity sector. That is, on average only one third of all energy used to generate and transmit electricity is actually delivered to the end-use consumer.

Figure 2 Electricity Source-to-Site Economy Wide Average Efficiency



The natural gas distribution system, by contrast, has significantly fewer energy losses. Natural gas delivered directly to consumers is a much more efficient energy delivery system, with significant implications for efficiency, economics and the environment. As a result, direct-use may be a more attractive option than electricity for direct-heating applications; natural gas use in homes and business could offset electricity usage and new generation requirements, while reducing emissions, saving energy, and optimizing energy resources. Again, this relies on an accurate, economy-wide measurement of energy consumption and environmental impacts and a comprehensive evaluation of energy impacts. A full-fuel-cycle approach is one such methodology.

Figure 3: Natural Gas Source-to-Site Economy Wide Average Efficiency



The full-fuel-cycle methodology provides a more complete picture of energy impacts. Consider electric heat. An air-source heat pump may often achieve site efficiencies more than 300 percent; heat pumps achieve these plus-100 percent efficiencies because they *move* heat from a colder environment to a warmer one, instead of directly warming the air, and therefore are unburdened by fuel-combustion related energy loss. By itself, a heat pump presents consumers with an attractive option: a heat pump operating at 300 percent efficiency seems more appealing than a natural gas furnace at 90 percent. However, this efficiency ignores upstream energy losses. When the full-fuel-cycle efficiencies are aggregated, the electric system efficiency on average operates around 32 percent prior to use. This changes the equation and comparison between fuel types. A minimally rated electric air-source heat pump operates at a 79 percent full-fuel-cycle efficiency, not 225 percent, for a minimally rated 7.7 HSPF air-source heat pump. In comparison, natural gas furnaces operate at a 72 to 88 percent full-fuel-cycle efficiency.

Table 4 summarizes the average energy usage per year for a new household for space heating, water heating, cooking and clothes drying (data from the same AGA analysis referenced earlier).[2] Site and full-fuel-cycle efficiencies are included. The results show that natural gas operates with higher full-fuel cycle efficiencies than any other major consumer fuel source. Natural gas use in primary residential appliance applications uses 121 MMBtu per year on a full-fuel-cycle basis. Electricity by contrast uses 167 MMBtu per year when measured on a full-fuel-cycle basis, despite having site-energy consumption that is more efficient than natural gas. Both oil and propane for the same applications were higher than natural gas, 136.3 and 124.5 MMBtu respectively.

[2] The study assumes that electric applications are used for cooking and clothes drying within fuel oil households.

Table 4: Average Household Energy Usage per Year for a New Household (MMBtu)

	Natural Gas	Electricity	Oil	Propane
Space Heating	74.3	31.5	74.3	74.3
Water Heating	25.4	16.6	29.1	25.4
Cooking	3.3	1.8	1.8	3.3
Clothes Drying	3.8	3.3	3.3	3.8
Total Site Use	**106.9**	**53.2**	**108.5**	**106.9**
energy losses	14.1	113.5	27.8	17.6
Full-Fuel-Cycle Use	**121.0**	**166.7**	**136.3**	**124.5**

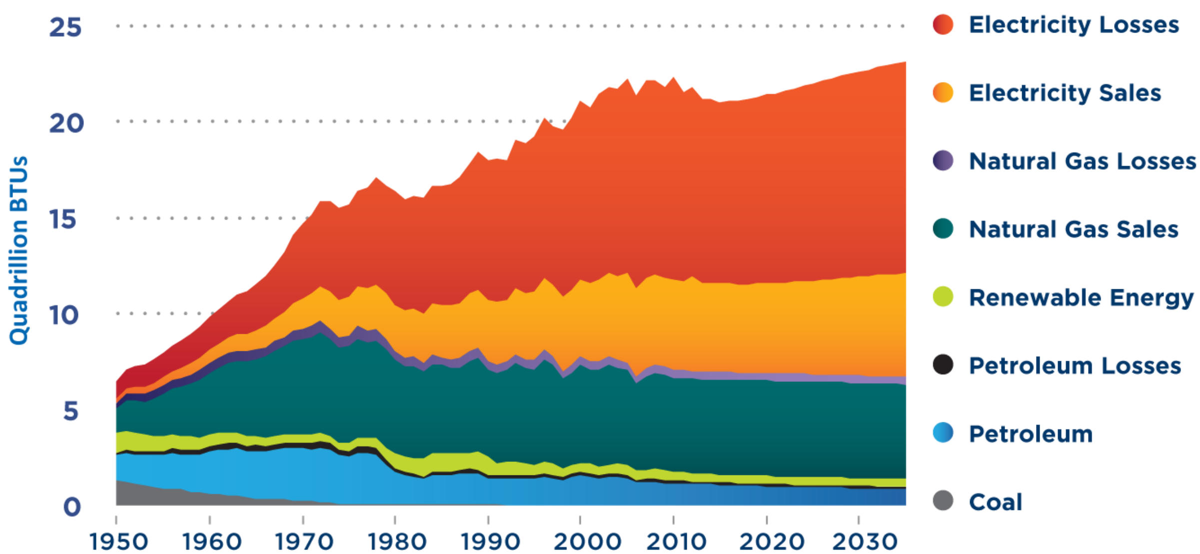
Losses include energy used or lost in extraction, processing, conversion, transportation, and distribution of energy
Full-fuel-cycle is sum of site use and energy losses

In sum, the full-fuel-cycle method of measuring energy usage across the energy value chain is the most comprehensive and accurate way of determining a fuel source's total energy and environmental footprint. Such a measurement conclusively demonstrates the benefits of the direct use of natural gas, but it has larger applications. In terms of optimizing available energy resources, considering strategic energy decisions, and formulating national policies and regulations that will actually increase energy efficiency and reduce emissions, a full-fuel-cycle methodology must be incorporated. What is more, to the extent that building energy codes and standards, appliance standards and labeling, and home and building energy rating systems are based on the full-fuel-cycle measurement, energy efficiencies and emissions reductions will improve even more significantly.

1.3.2 Mitigating Electrical System Losses

Nearly all of the growth in energy usage in the residential and commercial sectors during the last three decades is due to increased electricity consumption. New electric appliances and devices have driven this growth, despite improvements to appliance, equipment, and building shell efficiencies. New demand drives greater electricity sales, in turn engendering greater electrical system losses. As described in the last section, due to electricity generation and transmission nearly two-thirds of the primary energy in the electric system is lost to waste heat. The share of electric waste heat has grown to a sizeable portion of total energy consumed. When compared alongside other energy forms, electric system losses today now represent *half* of all energy used in the residential and commercial sectors.

Figure 4
Residential Sector Energy Consumption



Source: U.S. Energy Information Administration (EIA)
*Electricity losses refer to electrical system losses including heat lost to generation, transmission, and distribution.
*Coal and petroleum losses approximately account for less than 1% of total energy consumption

Today electrical system losses represent the single largest share of energy consumption in the residential and commercial sectors. To illustrate, Figure 4 shows residential energy consumption by primary fuel and electricity, including losses. In the chart, data from 1950 to 2009 are based on historical data reported in the EIA *Annual Energy Review*; projections for the years 2010 through 2035 rely on the EIA Annual Energy Outlook (AEO) 2011 Reference Case scenario. When aggregated, the change in residential energy consumption is telling.

Forty years ago, in 1970, electricity sales represented 11 percent of all the energy consumed in the residential sector, and electrical system losses accounted for about 26 percent. By 2010, electricity sales doubled to 22 percent and electrical system losses grew to 47 percent. This growth trend in electricity sales—and losses—is projected to continue. The AEO 2011 projects total electricity consumption is to grow at nearly 1 percent per year from now until 2035, growth driven by the myriad electronic devices available to consumers: televisions, audio players, microwaves, toaster ovens, coffee makers, computer speakers, air purifiers, battery chargers, vacuum cleaners, and so on.[iv] Meanwhile, natural gas consumption grew until 1970 and has since remained flat. Few major new natural gas appliances have been introduced into the market, or are expected too, and existing natural gas equipment has become more efficient over time. Consumption has remained flat, and the AEO projects this horizontal trend out through 2035.

There is significant opportunity for direct use to help stem some of this electric energy growth and, consequently, mitigate electric system losses. Electric resistance heating is one of the most inefficient energy technologies available and is prevalent in the home heating market today. It is also one of the least expensive, particularly on a first-cost basis. Thus, home builders and buyers focused on initial cost are often pushed toward this lower efficiency, higher emitting option. Alternatively, the direct-use of natural gas in lieu of older electric furnaces and resistance water heaters can help to avoid electric system losses, lower greenhouse gas emission, and increase overall energy resource efficiency.

About 20 percent of residential electric sales are used for space heating, water heating, cooking and clothes drying applications; in 2010 these end-uses used 1,020 trillion BTUs of electricity. But this is only part of the full energy picture. The waste heat associated with electric generation and transmission was twice as high: 2,175 trillion BTU in 2010. The total primary energy consumed was 3,195 trillion BTU.[v] There is a diverse set of appliances that serve these applications, including appliances that rely on electric resistance. It is within these resistance applications that we find significant potential for energy efficiency improvements.

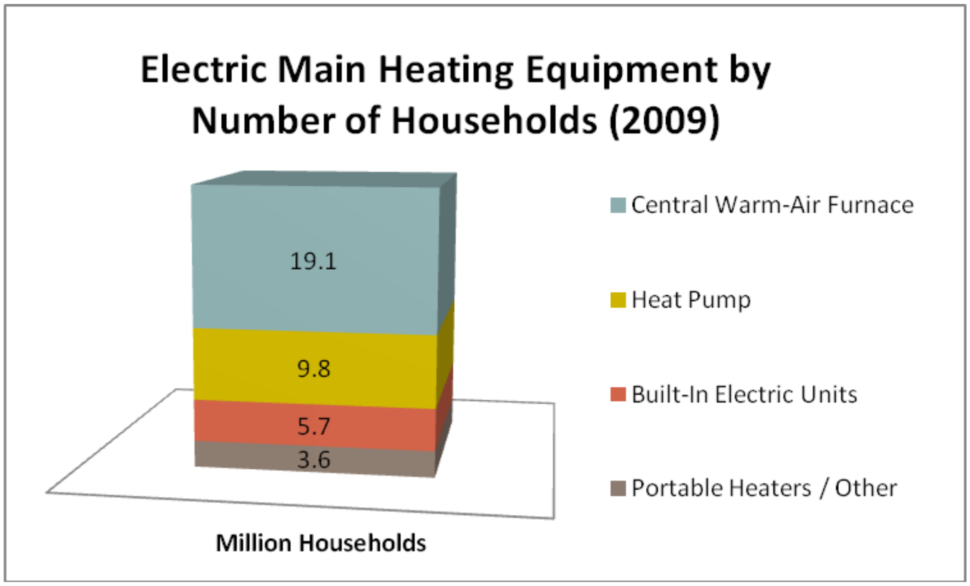
1.3.3 Low-Hanging Fruit for the Gas Industry - Electric Resistance

Electric resistance heating represents one of the least efficient forms of space and water heating, as measured on a full-fuel-cycle basis. Most electric heating relies on a resistance heating element: coiled wires acting as resistors that convert electrical current into heat. Most electric space heating appliances or equipment, such as furnaces and baseboard heaters, use a resistance heating element, although there are many air-source heat pumps on the market today as well, which are significantly more efficient than resistance furnaces and baseboard heating. Electric water heaters almost universally rely on electric resistance as the primary heating element.

Strictly speaking, from the perspective of household energy consumption, resistance heat is an efficient use of electric energy. Electric furnace and water heater efficiencies can approach nearly 100 percent, as nearly all the electric energy is converted to usable heat. Technology has maxed out any possible efficiency gains. Upgrading resistance heaters will offer only marginal efficiency gains, if any. Better insulation around the furnace, piping, or heating ducts can make incremental gains in efficiencies; however, this class of technology is fundamentally limited in terms of energy efficiency improvements. New options are needed instead. A heat pump offers significantly higher efficiencies, and for many consumers this option is viable and cost effective. And when the full-fuel-cycle measurement is considered, natural gas furnaces also offer marked improvements in energy efficiency.

The size of the electric resistance heating market is substantial. About 38 million households in 2009 used electricity for space heating, and about half of these residences utilize resistance furnaces. For water heating, about 45 million households used electricity; resistance water heaters are ubiquitous in this market.[vi] Within the commercial sector, approximately 1.2 million buildings (32 percent) use electricity for primary space heating, and one quarter of these report using resistance furnaces, according to a 2003 survey. Approximately 1.9 million buildings (55 percent) use electricity for water heating in the same survey.[vii]

Figure 5: About half of all electric home use electric resistance furnaces for space heating.

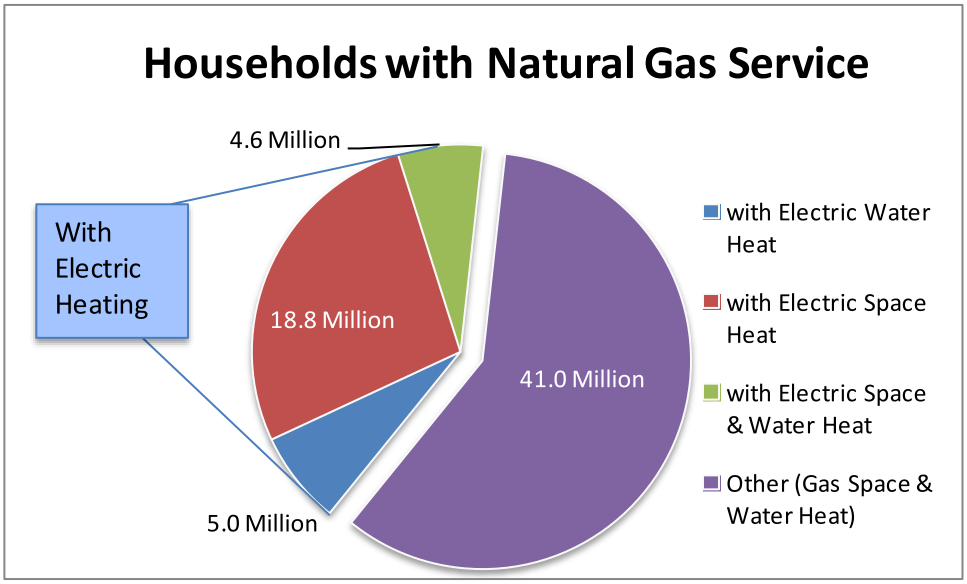


Source: EIA

Direct use of natural gas is both an energy solution for many of these consumers and a means toward efficiency and emissions improvements. The substitution of electric resistance space and water heating appliances and equipment with direct-use natural gas counterparts can improve energy efficiency, reduce greenhouse gas emissions, and decrease customer energy bills. However, conversion of these households and buildings is difficult. The first cost of natural gas appliances and the build out of supporting infrastructure may be prohibitively expensive. Furthermore, consumers might resist the notion of changing primary fuels in their household, in part because conversions can be difficult. Or perhaps they have a preference for electricity. Whatever the case, conversion opportunities are likely limited in all-electric markets.

However, there are many households and buildings with natural gas service that instead use electric resistance heaters for space and water conditioning. These households, for instance, may have an electric resistance water heater, but a natural gas furnace for space heating. Many conditions that would limit potential conversions, such as resistance to gas or costs for infrastructure build-out, do not apply here. Therefore, customers with gas service but electric equipment represent the *low-hanging fruit* of efficiency improvement opportunities. Installing natural gas service in a household must be economically feasible for a utility, so a household or building with existing gas service reduces the upfront costs of installing a new natural gas appliance. These customers are also likely to have a familiarity with natural gas, both as a fuel enjoyed, but also because of a consumer relationship with their local distribution utility. These points of leverage can help expand and accelerate natural gas conversion potential.

Figure 6: Approximately forty percent of households with natural gas service use electricity for space or water heating.

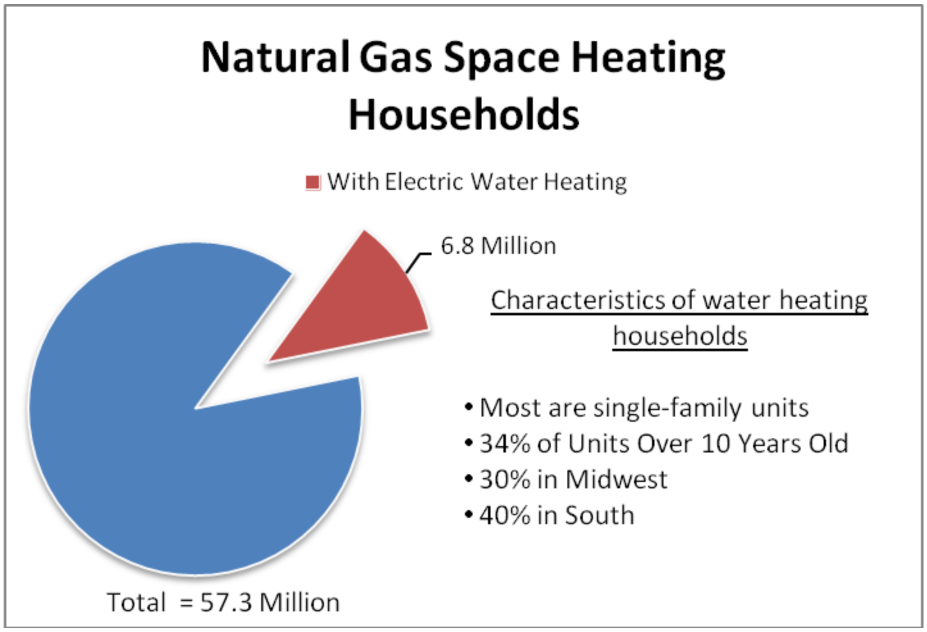


Source: EIA RECS 2009

Nearly 70 million households enjoy natural gas service in the United States. However, a significant portion does not use natural gas for their primary heating applications. In 2009, according to the most recent data collected as part of the Energy Information Administration "Residential Energy Consumption Survey", about 28 million or 40 percent of households with natural gas service instead use electricity for space heating, water heating, or both (see Figure 6). These households may use natural gas for cooking, for example, but have opted instead for an electric appliance for their heating needs. And this snapshot follows a trend of increasing numbers of electric heating appliances in gas households. The same dataset shows that the number of gas households with electric heating increased 4 million since 2005 (24 million to 28 million), despite the total number of gas customers are staying relatively constant. A closer look at the data indicates that while households with natural gas service have adopted both electric space and water heating applications over this period, much of increase was in electric space heating applications.

The most likely conversion opportunities are natural gas consumers who also use energy intensive electric resistance equipment. The prime example would be households with natural gas space heating *and* electric water heating. Based on the most recent EIA RECS data from 2009, approximately 57 million households use natural gas as their main space heating fuel. A significant portion use an electric resistance water heater, about 12 percent or 6.7 million households (this is up from 6.2 million or 11 percent of total households with natural gas main space heating in 2005).[viii] Gas service is already present to serve a gas furnace or boiler, so proper piping and adequate ventilation equipment are more likely to have been installed, thereby lowering conversion costs. Substituting an electric resistance water heater for a gas storage or tankless model would lower total energy used and could decrease greenhouse gas emissions. Furthermore, and probably most important, customers would decrease their water heating bill by half.[ix]

Figure 7



Source: EIA RECS 2009

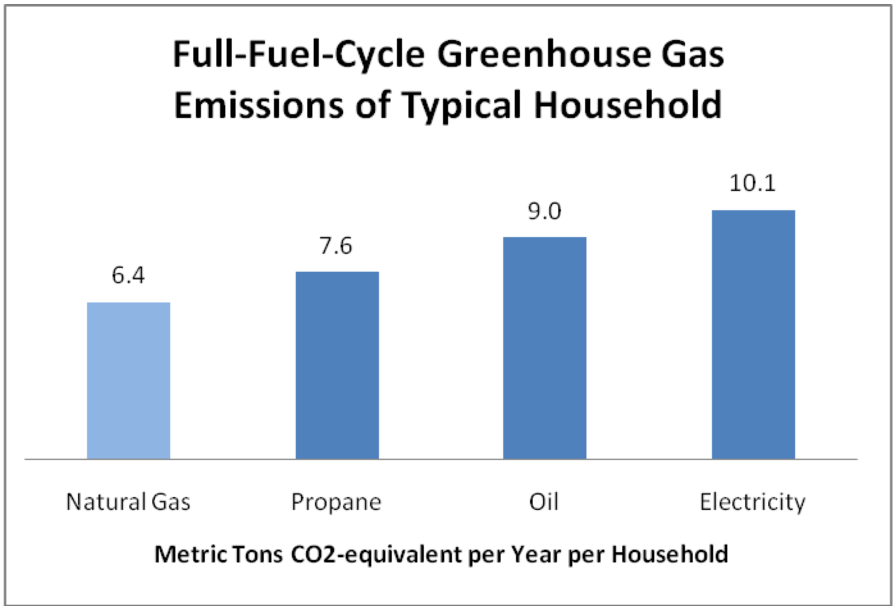
More information about appliance installation and operation costs can be found in Section 2.2.

Natural gas direct-use applications offer a pathway toward enhancing energy resources and circumventing electricity losses. There are many households and businesses with aging HVAC and water heating equipment that should be upgraded to more efficient equipment where possible. And in those instances in which natural gas is installed as the replacement fuel, the energy savings and emissions-reduction potential are significant. Efficiency programs, incentives, policies and regulations designed to reduce energy and greenhouse gas emissions should consider the amount of energy lost to electric system losses and the potential for direct use to mitigate these losses.

1.4 Reduce Environmental Impacts

Mitigating greenhouse gas emissions and reducing pollutant emissions remain salient policy issues in today's political sphere, and both can be achieved by using natural gas directly in households and businesses instead of other fossil fuels. Natural gas produces the fewest greenhouse gas lifecycle emissions of any available fossil fuel, while also producing very low levels of sulfur dioxides, nitrogen oxides, and fine particulate matter—and no emissions of mercury.

Figure 8



Source: AGA

The relative greenhouse gas intensities for a typical household in a year were estimated in the AGA paper, "A Comparison of Energy Use, Operating Costs, and Carbon Dioxide Emissions of Home Appliances," and are illustrated in Figure 8. Based on that paper, the average full-fuel-cycle greenhouse gas emissions of a typical natural gas household's energy use is 44 percent less than the equivalent energy from electricity. This includes combusted and fugitive or leaked methane emissions. Similarly, the natural gas household modeled emitted 27 percent less greenhouse gases than a household using distillate fuel oil, and 16 percent less than one using propane.

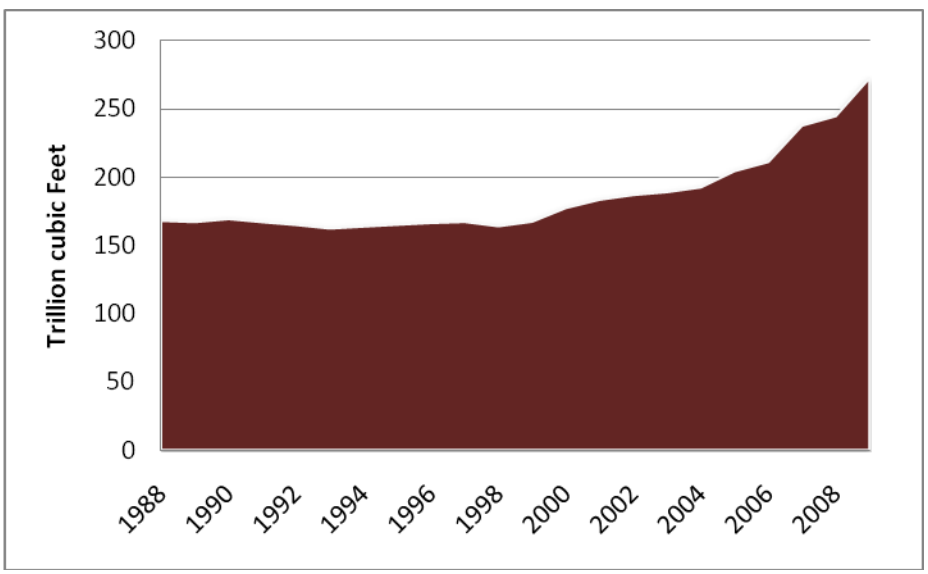
It is also important to note that the costs associated with these emissions reductions are commensurably less compared to other carbon mitigation alternatives. A study by McKinsey & Company in 2007 found that the installation of high-efficiency appliances generates a return on investment for the carbon mitigation achieved. In McKinsey's model, new and retrofitted HVAC systems in homes, when combined with a move toward natural gas and away from carbon intensive electricity and fuel oil, resulted in a negative cost (positive benefit) per ton of carbon reduction achieved. The study notes that HVAC accounts for 34 percent of residential GHG emissions annually, or 600 megatons, and represents 19 percent (360 megatons) in the commercial sector. The study elaborates on the mitigation potential: "installing more efficient HVAC systems and improving building shells could abate 160 megatons of CO_2 per year by 2030." In addition to efficiency improvements, the study notes that "switching from [liquefied petroleum gases] or fuel oil to natural gas, which burns more efficiently, could abate 12 megatons annually by 2030, with two-thirds of the amount in the Northeast." In the commercial sector, the McKinsey model calculates a 45 megaton abatement potential; switching to natural gas represents a 7-megaton abatement opportunity if substituted for fuel oil or LPG.[x] Therefore, not only is there significant carbon savings potential, but also these strategies can be pursued with a net economic benefit to consumers.

1.5 Abundant, Domestic Supply of Fuel

Natural gas today is a widely available, increasingly abundant, domestically produced fuel. Technical innovation has opened access to unconventional resources like coal seams, tight sands, and shale formations. Advances in production are lowering costs, making once previously uneconomical or inaccessible sources now profitable to producers and available to consumers at stable, affordable prices. Furthermore, new supplies and a reliable supply portfolio – which includes domestic production, gas in underground storage, imports from Canada, and liquefied natural gas – help keep prices stable during times of peak demand.

The exploration and production of natural gas has accelerated rapidly over the last five years, and the recoverable gas resource base has grown tremendously. Proved domestic reserves are now at the highest levels in 40 years and outlooks suggest more than 100 years of available natural gas supply at today's production levels. There still exist many questions and concerns over the environmental impacts of procedures to access these unconventional resources, in particular the hydraulic fracturing process. However, the fact remains that there is an abundant energy source that can play a key role in the nation's energy mix well into the future.

Table 5: Domestic Dry Gas Reserves



Source: EIA

The extent of the new resources is significant. The *Energy Information Administration* (EIA) released new estimates of the available natural gas resource base in the United States for year-end 2009. The results show a tremendous increase in available gas reserves, up 11 percent since the previous year and the highest levels since 1971. The technically recoverable volumes of gas increased more than 500 Tcf in one year—to 2,620 Tcf in 2009. Shale development is the driving force behind this substantial growth, although some growth came from conventional onshore and tight sands production as well.

U.S. marketed production of natural gas has been steadily increasing, largely because of the development of shale. Over the past year alone, domestic daily dry gas production has grown about 7 percent to 60 Bcf per day. In 2000 shale gas share of production was virtually zero. Today, shale accounts for 25 percent of gas produced in the United States and in its "2011 Annual Energy Outlook", EIA projects shale gas comprising 46 percent of all natural gas production by 2035.

This growth will help support new demand expected during the next few years and over the coming decades. Shale gas development can enable the use of natural gas for electricity generation, as a transportation fuel, and as a direct fuel in homes and businesses. The safe and environmentally sound production of this resource can enable long-term access and use of domestically produced natural gas.

1.6 Available Here and Now

The energy landscape today is fraught with uncertainty. Electricity markets, investors, utilities, and regulators see a disjointed and unclear energy policy pathway that has delayed long-term investment in new electric generation capacity. Many nuclear power plants are inching closer to retirement and for environmental reasons coal-fired power plants are not being built, yet consumer demand for electricity continues to grow. That means new generation capacity will have to be installed over the coming years and the nature of new electric generation capacity will be determined by a number of uncertain factors. In this context, the direct use of natural gas offers a "Here-Now-Available" cost-effective solution to help ease electric load requirements and reduce the need for new generation capacity.

Table 6

Cumulative Unplanned Electric Generation Capacity Additions and Costs (by 2035) (Gigawatts installed)

	Current Policies /1	Carbon Constrained Policies /2	Total Overnight Cost in 2009 (2008 $/kWh)
Nuclear	6.3	62.0	$3,820
Gas Combined Cycle	60.9	54.7	$648

1/ - EIA Annual Energy Outlook 2011 Reference Case
2/ EIA Analysis of American Power Act 2010.

For instance, there are concerns about the impact upcoming EPA regulations on the electricity sector will have on electricity costs and grid reliability; however the full details about the regulations and implementation dates are not yet established so the potential impacts are still hard to gauge. Another factor shaping energy decisions is the possibility of a greenhouse gas reduction regime, its possible reach, and whether EPA is tasked with regulating carbon dioxide emissions from power plants. Or Congress could develop an alternative scenario in which it mandated a broader "Clean Energy

Standard," which, in addition to renewables, could include nuclear and natural gas as compliance options for meeting less carbon-intensive electric generation.

The high cost of installing new capacity and the uncertainty surrounding these costs present additional challenges. Table 6 shows the unplanned electric generation capacity additions and the total overnight cost for a new nuclear plant and a natural gas combined-cycle plant. Two possible cost scenarios are also shown, one for business as usual and another assuming a carbon policy.

The first column represents current governmental policies as reflected in the Annual Energy Outlook 2011 reference case. Natural gas combined-cycle generation capacity is projected to grow 1.2 percent per year. The total overnight costs for nuclear averages $3,820/kWh.[3] Gas combined-cycle technology is the least expensive electricity option available at $648/kWh.

The second EIA scenario illustrates the effects of a carbon constraining policy on the economy by assuming passage of the American Power Act of 2010 (APA 2010), which was designed to regulate greenhouse emissions through a market-based regime.[xi] The result of the carbon price modeled in this scenario, unsurprisingly, was a significant increase in less carbon-intensive electricity generation capacity: renewable and nuclear power generation capacity additions increase 1.3 percent per year and 0.4 percent per year respectively from 2008 to 2035. This in turn pushes up costs overall for new generation capacity.

The direct use of natural gas offers a cost-effective solution to ease electric capacity constraints and reduce the need for new generation capacity. For example, replacing electric resistance water heaters with natural gas water heaters could help regulators to achieve energy efficiency and demand-side management goals.

Some states are already leading the way with policies to utilize natural gas water and space heating applications to enhance energy efficiency and conservation programs. Pennsylvania offers one example. The state public utility commission has considered using fuel switching as a cost-effective tool to reduce electricity demand. In 2008, the state legislature passed and the governor signed into law Act 129, which set forth goals for reducing energy consumption and demand.[xii] The legislation amended the state Public Utility Code to require the implementation of an energy efficiency and conservation program. One component of this program would incentivize electric customers to switch to natural gas in order to reduce the electric system constraints and lower costs. A working group that convened to discuss and study fuel switching programs recommended to the PUC that fuel switching, while it shouldn't be mandated, should be made available to electric distribution companies and their stakeholders when considering the best means of achieving energy efficiency and conservation goals. At least one utility has begun taking advantage of this program by offering rebates to electric customers to incent switching to natural gas water heaters, furnaces, or both.

[3] No interest is included in the cost, as if the plant were built "overnight."

1.7 Energy Security

Use of natural gas provides another tool to enhance U.S. energy security by offsetting the dependence on petroleum products in key markets. Instability in the Middle East, coupled with growing demand from developing countries like Brazil, China and India, has tightened the supply-demand balance of global crude oil markets, in turn increasing prices and volatility and driving up consumer costs. More than 50 percent of total U.S. crude oil imports originate from countries belonging to the Organization of Petroleum Exporting Countries (OPEC), which, to varying degrees, face political instability, thereby putting the United States at risk of uncertain petroleum supply and price shock.

The majority of petroleum in the United States is used for transportation fuels, but a substantial portion of petroleum products are distillate fuel oils and kerosene used in homes and businesses for space and water heating. In 2009, about 6.9 billion gallons of distillate fuel oil were sold to residential and commercial customers, the equivalent of 620 million barrels of crude oil or about 13 percent of total oil and petroleum products imported to the United States each year.[xiii] But residential and commercial fuel oil usage has been declining in recent years and is expected to continue. The EIA Annual Energy Outlook 2011 projects heating oil consumption declining in the Northeast at 1.6 percent per year over the next 25 years, a result of higher petroleum prices and more stringent emissions standards.

A measured approach of increasing efficiency and incentivizing switching distillate fuel oil to non-petroleum based energy sources like natural gas and electricity, when these alternative options are available, can help reduce oil imports and ease the strain of tightening crude oil markets. It will also help reduce greenhouse gas emissions.

However, limited natural gas pipeline infrastructure in parts of the Northeast severely hinders natural gas utilization, so petroleum products and electric resistance heating are generally used instead. The cost of extending main and service lines to these areas is often prohibitive, as customer density rates are too low to be economically justifiable.

Still, limited conversions and new gas installations are taking place. AGA conducts an annual Residential Natural Gas Market Survey and in 2008 companies responding to the survey said that 14 percent of new customer additions were homes converted from another fuel to natural gas. Fuel oil represented 33 percent of these conversions, and 29 percent converted from electricity. The remaining 38 percent were unable to identify the previous heating fuel present in the converted household.[xiv]

From a policy perspective it is important to understand what impact an optimum conversion program could have on natural gas supplies. So, assuming a limiting case scenario where every home in the Northeast was converted to natural gas, what would be the estimated amount of natural gas required to serve them and what effect would that have on supply? Approximately 8.2 million housing units heat with fuel oil in the United States and 6.6 million reside in the Northeast. The consumption of heating oil per household during the 2010-2011 winter in the Northeast was projected to be 708.1 gallons, or 98.2 MMBtu, based on the EIA Short-Term Energy Outlook (Dec 2010). If each of the 6.6 million fuel oil households converted to natural gas, the volume of natural gas required would be about

825 Bcf, or about 3 percent of total U.S. natural gas consumption in 2010. This equates to 3.7 Bcf per day of new natural gas demand during the winter heating season. Given the recent increases in shale gas production, which has boosted overall natural gas dry production 6 percent in 2011 over 2010 levels, the fuel required to serve the heating needs of these households appears very manageable.

1.8 Distributed Generation and Clean Energy Technologies

Distributed generation (DG) technologies, in particular those supported by the natural gas distribution system, can play a key role in cost-effectively meeting future energy needs. DG technologies, which include combined-heat-and-power (CHP) applications, can reduce capital costs, enhance grid reliability, increase energy efficiency and drive greenhouse gas emissions reductions. Smaller scaled DG technologies, geared especially toward residential and commercial markets, can also offer modularity and flexibility, in contrast to today's central generation paradigm. And as the electric and natural gas markets continue to evolve, the potential for DG to integrate the natural gas system into the electric "smart grid" remains significant.

DG technologies are at various stages of maturity and market adoption. Some new gas-based technologies are still under development and not yet widely available, while others are more time-tested. Large-scale CHP applications, for example, have been used in the industrial and large commercial sectors for years. Its availability offers a near-term opportunity.

CHP, or cogeneration, is the simultaneous production of useful thermal and electrical energy from a single fuel source, thus CHP serves both on-site generation requirements and provides energy for heating, cooling and process applications. CHP operates at higher efficiencies than conventional electricity production, which reduces operating energy costs. And because electricity is generated onsite, a CHP unit can enhance power reliability, especially if the consumer is connected to the electric grid. Natural gas is the primary fuel for existing CHP. In 2011, 71 percent of CHP installations utilized natural gas.

The key constraint of many DG and CHP technologies is the upfront purchase and installation costs, which often prevent achieving viable project economics. Lower operating costs offer consumers a payback on this initial upfront investment, but CHP is typically limited to consumers with large thermal and electric loads so that the payback period is short enough to make the project economically viable.

Therefore, industrial and large commercial customers traditionally have been the primary market for CHP. Today, 82 gigawatts of installed CHP serve almost 4,000 industrial and commercial facilities. Manufacturing facilities, chemical production plants, petroleum refineries, and paper mills comprise much of the industrial CHP installed capacity, and about 12 percent of the total CHP capacity is used in the commercial / institutional sector such as universities, hospitals, and prisons.[xv]

In addition to cogeneration, there are a number of potential or existing distributed energy technologies that can operate on natural gas:

- **Fuel Cells** produce electricity and heat using an electro-chemical reaction. Fuels vary from pure hydrogen to fossil fuels, including natural gas. Fuel cell type, size, and efficiency vary tremendously. The cost of fuel cell capacity (kW) is currently about 7-10 times that of a combined-cycle combustion turbine.[xvi] Fuel cell units are available for large-scale commercial applications, and while smaller-scale commercial and residential units are currently being explored and tested, they are not yet widely adopted.
- **Gas Turbines –** These are mid- to large-scale turbines that operate in the 50 kW to tens of MW range. These turbines are typically used in cogeneration scenarios for industrial processes.
- **MicroCHP** represents cogeneration on smaller scales, typically the 1-5kW electric load range, which suits the thermal and generation load needs of residential and small commercial consumers. Net metering[4] would be typically required for full savings to be realized.
- **Microturbines** are similar to their larger gas turbine brethren, but operating in the 25-500 kW range instead of MW. They are fueled by natural gas, diesel, propane, or hydrogen. Microturbines can achieve higher efficiencies if the waste heat from generation is re-appropriated for secondary use. Because of their large size, they are mostly suited for larger scale commercial and small industrial applications.[xvii]
- **Reciprocating Engines –** These engines range in size from a few kW to over 5 MW and are mostly found in large commercial and industrial sites, but can be used in the residential sector for in multi-family units and for small scale residential backup generation.[xviii]

The benefits of distributed generation technologies are significant, but depend on the technology and how it is used. In a report on fuel cells the Rocky Mountain Institute captured many of the benefits, listed below. These represent a generalization of the value consumers, utilities, and society may derive from DG technologies.[xix]

- **Electrical energy value** – the economic value of the electrical energy produced by the system.
- **Thermal energy value** – the value of waste heat recovered from the unit.
- **Option Value** – added value of a generation option that can avoid over-building of central-generation capacity for an area.
- **Deferral Value** – the economic value of deferring new transmission and distribution capacity in a high-cost area.
- **Engineering cost savings** – reducing the economic costs to electric distribution utilities by reducing costs in the operation and maintenance of T&D systems.
- **Customer reliability value** – the value of increased reliability power.
- **Environmental value –** lower emissions provide added value under regulatory regimes that restrict certain pollutants and drive generation costs higher.

As consumer technology choices advance, direct-use natural gas serving these distributed generation technologies can add value for the consumer and the utility. Thoughtful public policy should ensure that

[4] Net metering policy allows for consumer credit for excess distributed-generated electricity fed back into the grid.

consumers are presented with cost-effective energy options while supporting infrastructure build-out and improvement to enable these options.

2 Disturbing Trends and Constraints

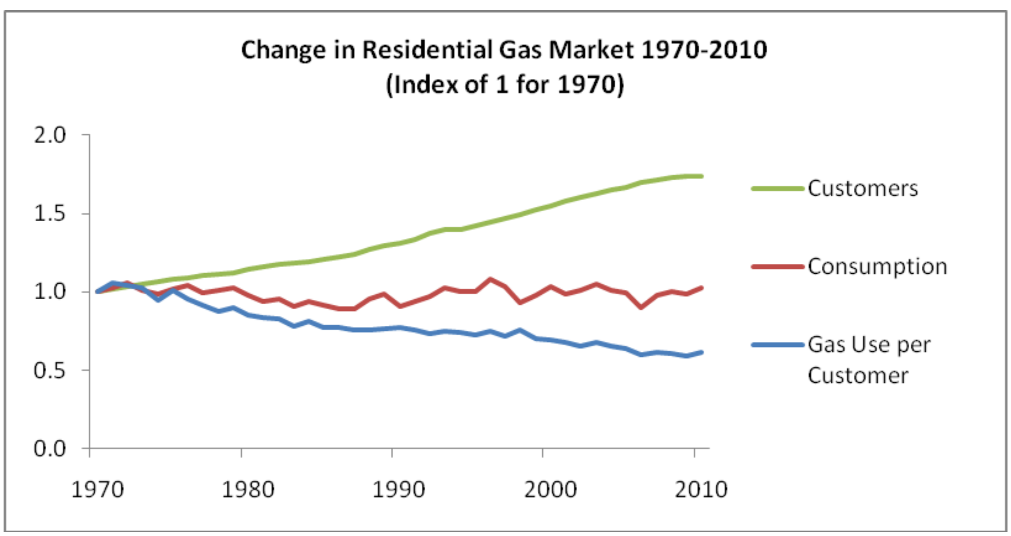
Summary

Natural gas efficiency has improved over the last 40 years, which partly explains why natural gas consumption remains flat despite a growing customer base. In addition, in recent years the installation of natural gas in new homes has slowed, the result of a combination of market factors, especially first-cost issues, regulatory constructs, and economically perverse incentives from competing energy sources.

2.1 Introduction

Over the last three decades, the residential and commercial natural gas markets have been shaped by two opposing trends: customer growth and the decline in gas use per customer. These trends have counterbalanced, leading to virtually no increase in the amount of gas consumed in the residential sector. Since 1970, natural gas use per customer has declined 39 percent on a weather-normalized basis. In contrast, electricity use per customer has increased 63 percent during the same period.

Figure 9



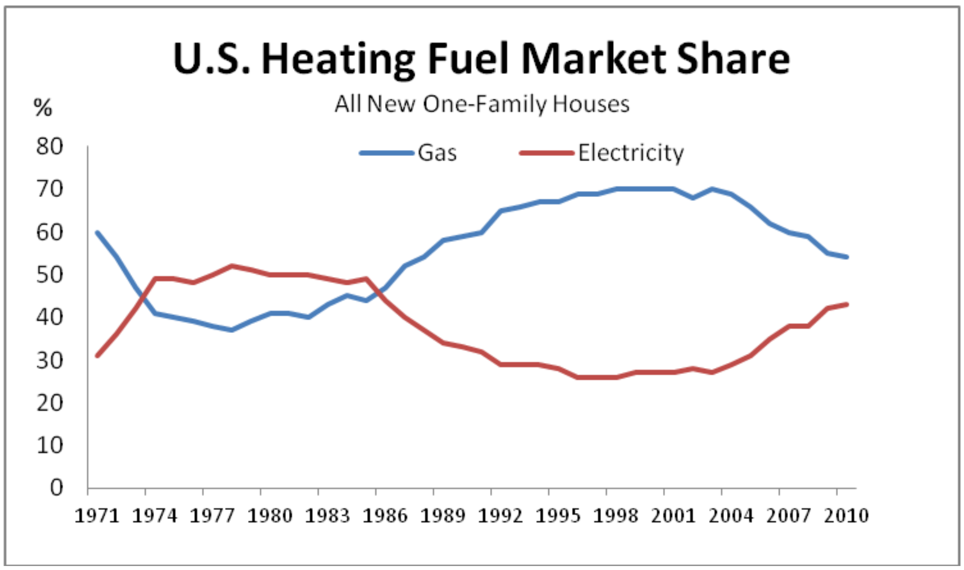
Several factors have driven the declining use per customer trends:

- Increased efficiency in space heating equipment and building shells.
- Historical increases in natural gas costs and price volatility.

- Population migration to warmer climates

For most of the past several decades, natural gas has been the preferred fuel for primary space heating in new homes. However, in recent years the natural gas share of the new home market has slipped. Figure 10 shows trends in the home heating fuel market for newly constructed single-family homes. For the United States as a whole, gas share (data includes natural gas and propane) of the new home heating market has been shrinking over the last decade. In 2010 gas share of single-family new home construction was 54 percent, down from the peak of 70 percent in 2003. Meanwhile, electricity has filled the gap left by gas. Electricity share has grown over this same period and in 2009 was 43 percent, up from its low point in 1998.

Figure 10



Source: US Census Bureau

Higher natural gas prices and increased volatility from 2000 to 2008 contributed to the decline in natural gas market share. Additionally, competing electric applications have contributed to the erosion of natural gas market share. New air-source and ground-source electric heat pumps can maintain their efficiencies and operate in colder climates, leading to competition in traditionally gas-only areas.

Regionally, the trends show some differences. In the Northeast, the gas share of the new home heating market has undergone significant growth over the last 10 years. Households once served by fuel oil have switched to propane and natural gas. Conversely, the South shows the opposite. The share of gas installations, which a decade ago was evenly paired with electricity, now represents only one-third of the market. In the West and Midwest, gas installations have declined as well; trends there are similar to the national view depicted in Figure 10.

In addition to changes in technology and prices, other key constraints have hindered customer adoption of natural gas. The remainder of this section is will describe these constraints and trends, including:

- **First cost** purchase and installation of gas equipment and appliances.

- **Misaligned incentives** of building contractors and end-use consumers.
- **Economically perverse incentives** from electric utilities in the form of monetary incentives to consumers and builders.
- **Inconsistent site-versus-source standards** in regulatory and programmatic approaches to measuring energy consumption in efficiency, appliance standards, and green building programs.

2.2 First Cost Impact

The first-cost impact of installing natural gas equipment on consumers and builders is a primary impediment to natural gas use in residential and commercial buildings if service can be made available. In general, the cost to purchase and install a natural gas appliance is higher than an electric appliance. This creates an upfront cost impact on consumers and builders who might want a natural gas appliance because of its operating cost and comfort advantages. However, because of resource constraints or merely preference, consumers may opt instead for the lower-cost alternative and not choose natural gas.

There are a number of key consumer decision points when evaluating first cost. Appliance size and efficiency, the ease of installation, and the availability of gas service (the proximity to a gas main or service line) all factor into the upfront cost calculation. Higher efficiency appliances generally incur higher costs, and the cost of a building retrofit is generally higher than new construction. Appliances with condensing units, which re-appropriates the appliance's waste heat to increase its efficiency, are more expensive. These units often cannot be accommodated in older homes without additional ventilation equipment and construction due to building code requirements, so the cost of retrofit is often higher than the cost of new construction, where architectural plans can be altered to accommodate the installation. If new natural gas service is required for the appliance, installation costs can increase even further.

This difference in upfront cost between new construction and retrofit installation costs has significant implications on appliance code standards. Appliance standards mandate minimum efficiency requirements on manufacturers. Before an appliance standard is enacted, the proposed standard, or rule, must be accompanied by a technological feasibility assessment and an economic justification. For the rule to be economically justified, the mandated improvement in efficiency must create savings through lower operating costs for enough consumers over the lifetime of the equipment in order to pay back the higher upfront expense. This cost calculation changes depending on whether the equipment is installed as part of a new construction or a retrofit. Since retrofits, on average, are more expensive than those in new construction, consumers who wish to convert to natural gas, or replace an older unit with a higher-efficiency model, must incur these higher costs or switch instead to an alternative energy source. As a result, natural gas may be pushed out of markets where it could offer the greatest advantage in emissions reductions, which is the point of the appliance standard in the first place.

2.2.1 Water heaters

Natural gas water heaters are typically more expensive than electric water heaters with similar load and efficiency requirements. AGA conducted an analysis of minimum- and high-efficiency gas and electric storage water heaters that compared the installation and operating costs of four types of water heaters over their useful lifetime. The analysis uses data on efficiency, installed costs, and average lifetimes of residential water heaters from the U.S. Department of Energy Technical Support Document (TSD) on water heaters, and annual usage data from an EPA Energy Star residential water heater Final Criteria Analysis.[xx] It shows that a consumer's operating expenses over the lifetime of a minimum-efficiency natural gas water heater are half that of a minimum-efficiency electric storage heater.[xxi]

In the analysis, the average installed cost for a minimum-efficiency gas water heater is $1,079, about two times the $569 cost of minimum-efficiency electric water heater. Higher-efficiency units have a corresponding price premium and the price relationship between equipment of both fuel types remains consistent. The average installation cost for a high-efficiency gas storage water heater rated 0.65 EF is $1,591, more than twice the average cost of $711 for an electric resistance water heater. Table 7 details the prices for these water heaters.

Table 7: Water Heater Installation and Total Costs ($2009)[xxii]

Storage Water Heater Type		Site Efficiency (EF)	Installed Cost	Yearly Energy Cost	Life (Years)	Total Cost
Gas	Minimum efficiency	0.59	$1,079	$284	12	$4,487
	High-efficiency	0.65	$1,591	$251	12	$4,603
Electric	Minimum efficiency	0.90	$569	$563	14	$8,451
	High-efficiency	0.95	$711	$533	14	$8,173

Blue box indicates a price advantage; the red box indicates a price disadvantage. The high-efficiency electric storage water heater has a lower installed cost than a gas unit, but has twice the total lifetime cost when operating expenses are included. Based on data from the DOE Technical Support Document for Water Heaters (2009).

But a natural gas water heater costs less to operate than an electric water heater. Using average annual usage data from the TSD and annual fuel prices reported by DOE in the federal register, the average annual energy cost for a minimum-efficiency natural gas water heater is $284, compared with $563 for a minimum-efficiency electric water heater (assuming $11.21 per Mcf for natural gas and 11.54 cents per kilowatt-hour for electricity).

The lifetime operating costs for a natural gas storage water heater is so much lower than electricity, in fact, when the operating costs are added to the upfront cost, natural gas represents the lowest *total*-cost option. The total cost of a minimum-efficiency natural gas water heater is $4,423, or 47 percent lower than the $8,303 for a minimum-efficiency electric water heater. A similar analysis for high-efficiency units (the natural gas water heater is rated 0.65 EF [energy factor]; the electric 0.95 EF) shows the gas unit costs 43 percent less than the electric version. The average installation, operation, and total costs of gas and electric appliances for both minimum standard site-efficiency and high-efficiency options are laid out in Table 7.

2.2.2 Space Heating Systems

Comparing replacement natural gas and electric space heating systems also shows that natural gas space heating appliances typically have higher upfront costs but lower operating costs. A recent AGA analysis of replacement HVAC equipment concluded that, compared with an electric heat pump, a natural gas furnace, on average, costs more for its purchase and installation, but costs less to operate, resulting in lower overall costs for the lifetime of the equipment.[xxiii]

The analysis presents a cost assessment of two equipment replacement scenarios. The first scenario evaluates the cost of a natural gas furnace for space heating and an electric air conditioner for cooling. The second scenario evaluates the costs of a stand-alone electric heat pump, which can serve space cooling and heating requirements. (Because of the heat pump's dual capability, the installation and operating costs of the natural gas furnace in the first scenario must include an air conditioner to make the cost comparison analysis equitable with the electric heat pump.) All of the equipment performance ratings are set at the federal minimum-efficiency standard and operate on an 18-year lifecycle. The results are shown in Table 8.

Table 8
Replacement Natural Gas Furnace and Electric Heat Pump Life Cycle Comparison

	Scenario 1: Natural Gas Heat, Electric Cooling			Scenario 2: Electric Heat & Cooling
	Natural Gas Furnace	Electric Central Air Conditioning	Total for Both Systems	Electric Heat Pump
Appliance Cost	$809	$1,761	$2,570	$2,483
Installation Cost	$782	$489	$1,271	$455
Average Annual Fuel Cost	$797	$252	$1,049	$1,262
Annual Maintenance & Repair	$42	$131	$173	$122
Life Cycle Cost - NPV			**$19,053**	**$19,467**

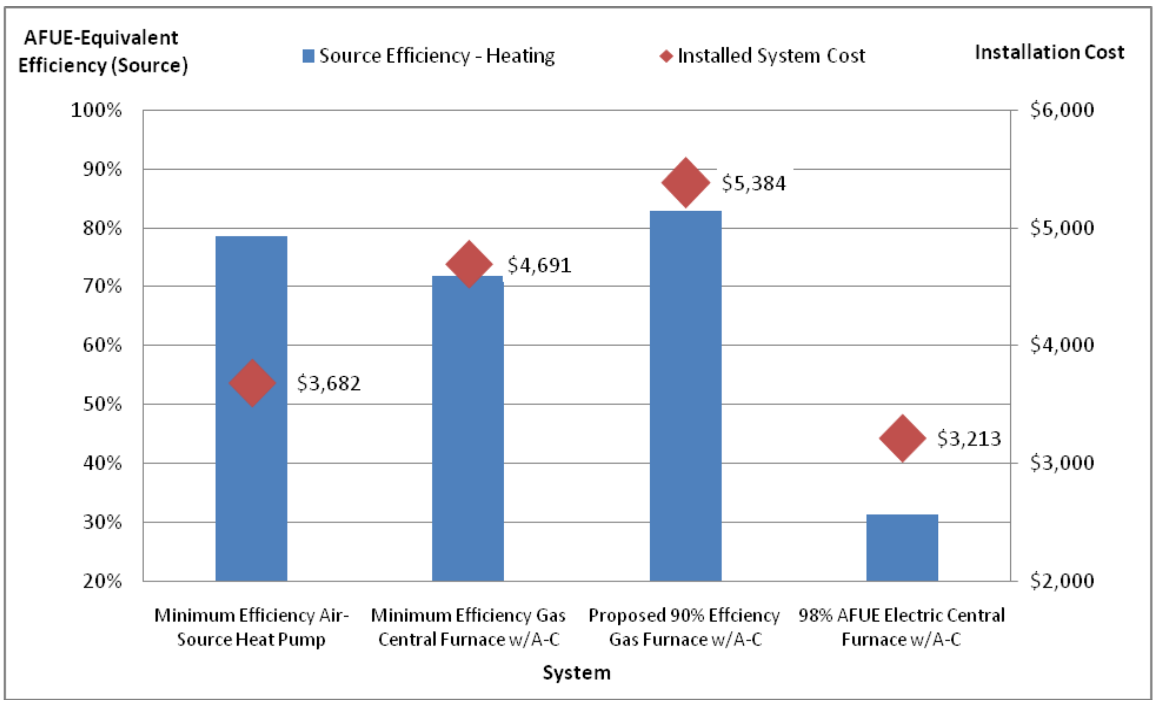
Source: AGA Financial and Operational Information Series, based on analysis of DOE Technical Support Document.[xxiv]

The natural gas furnace plus the air conditioner has an average combined appliance and installation cost of $3,841, while the less expensive electric heat pump costs $2,938, or 23 percent less than the furnace-air conditioner combination.

However, over the lifetime of the equipment, the reduced operating expenses of the gas furnace-air conditioning system makes up for the higher upfront costs. On average, a consumer will pay $1,049 annually for natural gas and electricity expenditures. By contrast, the average cost to operate a heat pump is 20 percent higher, totaling $1,262 annually. When all expenditures are factored in over the lifetime of the equipment, including repair and maintenance costs, the cost advantage for the natural gas system is $680, or about three percent. Any decrease in natural gas price, or increase in the price of electricity, makes this comparison more favorable for gas.

But how well do these different systems perform in terms of source efficiency? AGA evaluated a range of space heating appliance options to compare the relative source efficiencies and the costs of purchasing and installing these systems. The analysis included a minimum-efficiency air-source heat pump, a minimum and a high-efficiency natural gas furnace, and an electric resistance central furnace. Installation costs for the systems were taken from the DOE Technical Support Documents for natural gas furnaces, air conditioning units and electric heat pumps, as well as installation costs from the NREL Retrofit Measure Database for electric central furnaces. The analysis included new construction and replacements; therefore, the installation costs reported here are slightly different than the costs shown in Table 8, which were for replacements only.

Figure 11
Efficiencies and Installed Costs for Central HVAC Systems



Source: DOE Technical Support Document.
Note that *installed system cost* encompasses equipment purchase and installation and represents a weighted-average representative sample of households including new construction and replacement. As a result, the cost data differs somewhat from Table 8, which shows costs for replacements.

Figure 11 illustrates the differences in the installed cost and equivalent source energy efficiency of the different HVAC systems. The electric furnace (rated efficiency of 98%-AFUE) enjoys the lowest installation costs; however it has the lowest source heating efficiencies as well (32%). A minimum efficiency air-source heat pump has an installation cost of $3,682 as well as higher source heating efficiencies compared with a minimum-rated natural gas furnace. A minimum-efficiency gas furnace on average costs $4,691. The 90% efficient gas furnace had the highest source efficiency, but also the highest installed system cost of $5,384.

2.3 Builder Decision and Resistance to Gas Use

The builder decision to install a natural gas appliance, or suite of applications, is primarily driven by three principal factors:

- Natural gas availability
- Economic impact on the builder
- Consumer preference

Typically a gas utility will extend service to a new customer if the associated costs fall within the parameters (lengths of line, revenue test, return on investment, etc.) set by the utility and regulators. If the cost of extending service exceeds those parameters, the gas utility may require that the customer make a contribution in aid of construction (CIAC) to cover the revenue shortfall. Since a builder is unlikely to make this contribution, the responsibility rests with the customer. This added cost often deters the customer from switching to natural gas.

If natural gas service can be made available, the economics of installing a gas application will drive the builder decision process. The following factors often limit and inhibit the natural gas installation into a household:

- **Higher first cost for gas appliances** may incent a builder to choose a non-gas application unless the consumer demands a gas appliance or the added value of gas in a household to the builder is not demonstrably greater than the cost of installing gas.

- **Larger architectural footprint** within a structure is typically required for natural gas. Natural gas appliances and equipment tend to be physically larger than electric equipment. With floorspace at a premium in buildings, bigger rooms and more floor area to accommodate gas equipment negatively impact available square footage in the household. Generally the lower the square footage available in a household, the lower the asking price.

- **Equipment requirements**, such as ventilation equipment and in-house piping, adds additional cost for a natural gas installation.

Builders are increasingly reluctant to use gas equipment because of the higher costs unless the consumer demands the appliances. Unfortunately, most of the homes today are starter homes, and these buyers prefer the lower cost of the electric home.[xxv] A builder will receive no payback on the investment of a natural gas appliance. Therefore, the motivations of a builder to choose natural gas are not aligned with the consumer.

2.4 Economically Perverse Incentives

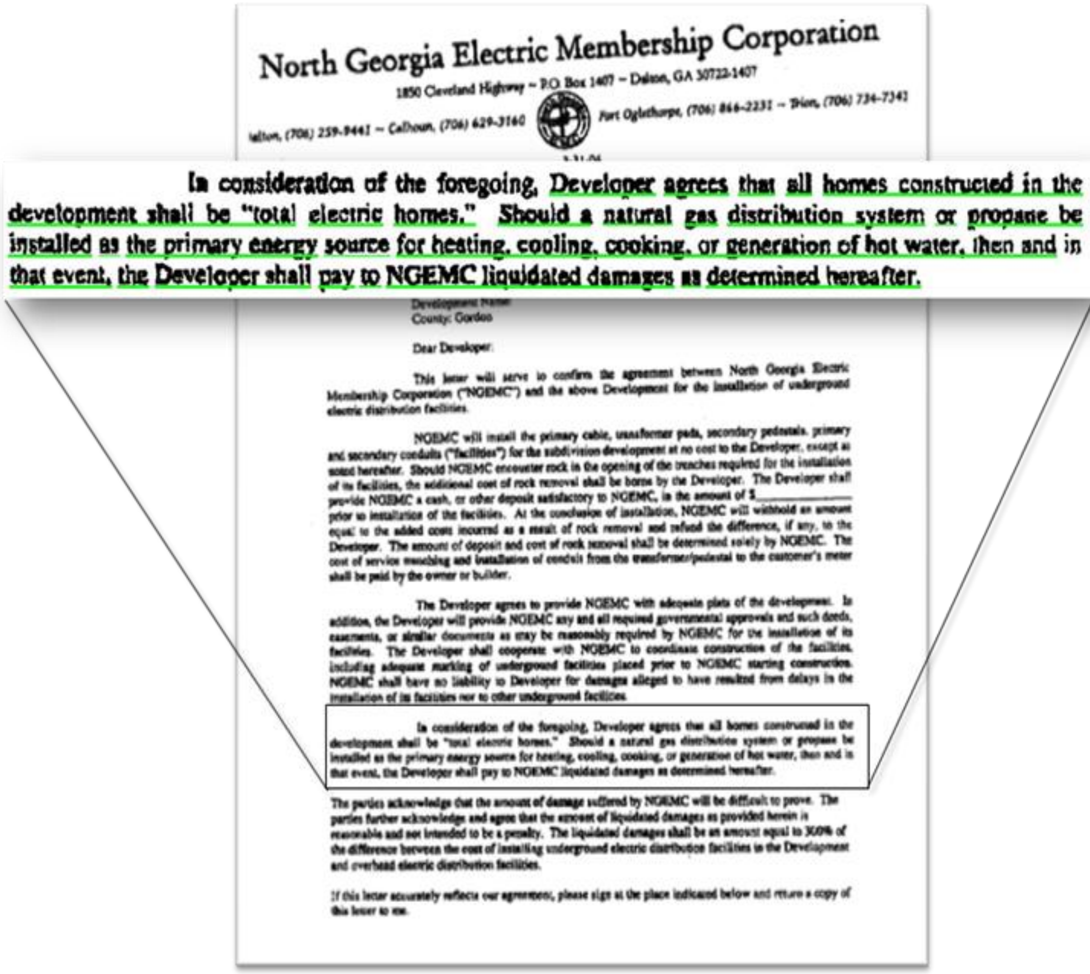
Natural gas markets face competitive pressures from other energy providers. For example, electric utilities sometimes provide economically perverse incentives to discourage natural gas use. These incentives can take the form of lower service rates for all-electric consumers, rebates to consumers to replace natural gas equipment with an electric appliance, and service fee waivers to builders that choose an all-electric installation.

There are instances where all-electric customers enjoy lower electricity rates than a customer with natural gas and electricity. The following are some examples of rate structures and schemes:

- **Discounts for all-electric customers**
  There are instances where segments of an electric utility's customer base will subsidize others in order to promote all electric homes. For example, in the wake of the 1970 moratorium on new natural gas installations, the Public Utility Commission of Ohio (PUCO) allowed an electric utility to offer discounted electric rates to customers that lived in all-electric homes. Customers with natural gas would pay higher electric rates, which in effect subsidized the discounted customers. These rates remained in place even after the gas moratorium ended. In the wake of concerns that some electricity customers were subsidizing the discounts of others and in an effort to promote greater energy efficiency, in 2007 the all-electric discount was eliminated for new customers. By 2009 the all-electric customers moved to the standard residential distribution and generation rate but still received a small discount (approximately 1.7 cents/kWh distribution discount, and 1.9 cents/kWh generation). Under pressure from customers who saw their rates rise dramatically during the winter, the utility instituted a residential generation credit (RGC) for its customers in place of the now eliminated all-electric rate cut. This new discount depended on service area and customer usage but went as high as 4.2 cents per kWh (this is in addition to the generation and distribution discounts already mentioned). The fate of the credit and discount rate is currently being decided.

- **Seasonal rates**
  For qualified customers with electric space heating or all-electric households, electric utilities may offer a seasonal rate for service that is less in the winter months relative to the summer. Consumers with an alternative energy source for space heating, such as natural gas, would not have access to these lower rates. Consequently, the higher electric rates paid by customers with natural gas heating effectively subsidize the all-electric customers that enjoy lower seasonal rates. Utilities that use seasonal charges and a declining block rate—the more energy a customer uses the less they pay—further incentivize greater electricity usage, adding additional competitive pressure.

Figure 12: Letter from Electric Membership Corporation to Developer Incentivizing All Electric Households.



North Georgia Electric Membership Corporation

1850 Cleveland Highway ~ P.O. Box 1407 ~ Dalton, GA 30722-1407

Dalton, (706) 259-9441 ~ Calhoun, (706) 629-3160 Fort Oglethorpe, (706) 866-2231 ~ Trion, (706) 734-7341

In consideration of the foregoing, Developer agrees that all homes constructed in the development shall be "total electric homes." Should a natural gas distribution system or propane be installed as the primary energy source for heating, cooling, cooking, or generation of hot water, then and in that event, the Developer shall pay to NGEMC liquidated damages as determined hereafter.

Development Name
County: Gordon

Dear Developer:

This letter will serve to confirm the agreement between North Georgia Electric Membership Corporation ("NGEMC") and the above Development for the installation of underground electric distribution facilities.

NGEMC will install the primary cable, transformer pads, secondary pedestals, primary and secondary conduits ("facilities") for the subdivision development at no cost to the Developer, except as noted hereafter. Should NGEMC encounter rock in the opening of the trenches required for the installation of its facilities, the additional cost of rock removal shall be borne by the Developer. The Developer shall provide NGEMC a cash, or other deposit satisfactory to NGEMC, in the amount of $________ prior to installation of the facilities. At the conclusion of installation, NGEMC will withhold an amount equal to the added costs incurred as a result of rock removal and refund the difference, if any, to the Developer. The amount of deposit and cost of rock removal shall be determined solely by NGEMC. The cost of service trenching and installation of conduit from the transformer/pedestal to the customer's meter shall be paid by the owner or builder.

The Developer agrees to provide NGEMC with adequate plats of the development. In addition, the Developer will provide NGEMC any and all required governmental approvals and such deeds, easements, or similar documents as may be reasonably required by NGEMC for the installation of its facilities. The Developer shall cooperate with NGEMC to coordinate construction of the facilities, including adequate marking of underground facilities placed prior to NGEMC starting construction. NGEMC shall have no liability to Developer for damages alleged to have resulted from delays in the installation of its facilities nor to other underground facilities.

In consideration of the foregoing, Developer agrees that all homes constructed in the development shall be "total electric homes." Should a natural gas distribution system or propane be installed as the primary energy source for heating, cooling, cooking, or generation of hot water, then and in that event, the Developer shall pay to NGEMC liquidated damages as determined hereafter.

The parties acknowledge that the amount of damage suffered by NGEMC will be difficult to prove. The parties further acknowledge and agree that the amount of liquidated damages as provided herein is reasonable and not intended to be a penalty. The liquidated damages shall be an amount equal to 300% of the difference between the cost of installing underground electric distribution facilities in the Development and overhead electric distribution facilities.

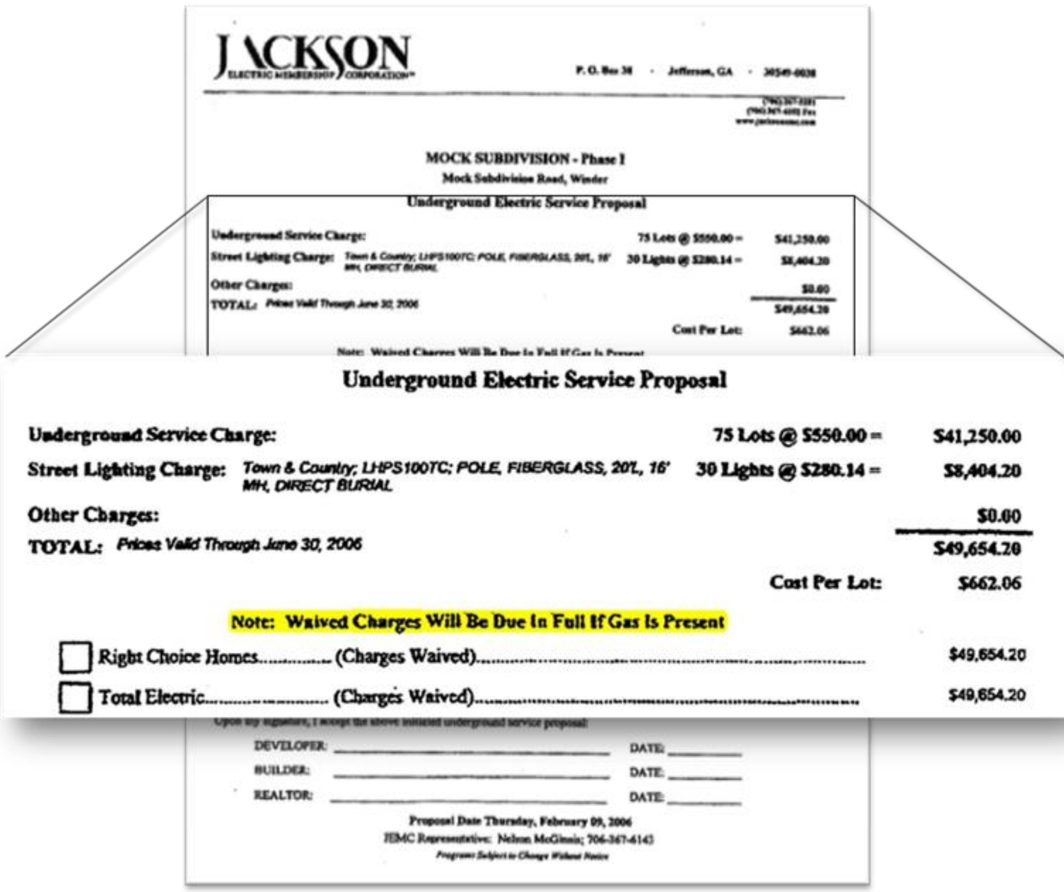
If this letter accurately reflects our agreement, please sign at the place indicated below and return a copy of this letter to me.

The developer must agree to build a household with only electric appliances in order to receive the discount

There are also financial or non-rate side incentives. These are not part of a consumer's energy rate structure, but financed using shareholder dollars. Electric companies sometimes offer discounts, rebates, tax incentives, payments to builders, and other financial incentives. The dollars to finance the incentives come from the utility's shareholder dollars—the company's profit base—and are not embedded into the regulated rate base charged to consumers. The upfront costs to the shareholders are viewed as an investment to ensure the long-term capture of an all-electric customer who will provide a long-term return on the shareholder investment.

In some cases, builders are offered direct incentives to construct homes with only electric appliances. For example, an electric service provider will offer to install electric wiring underground in a housing development, which is viewed as a premium compared to overhead wires, albeit a costly one. However, if the builder agrees to all-electric homes the service fee charges are waived, saving the builder considerable costs. If natural gas appliances are installed the builder must pay the service fee, per agreement with the electric utility. The builder now has considerable incentive to forgo natural gas appliances. Figure 12 and Figure 13 show two electric service proposals to builders as examples of these incentives.

Figure 13: EMC Electric Service Proposal


JACKSON
ELECTRIC MEMBERSHIP CORPORATION

MOCK SUBDIVISION - Phase I
Mock Subdivision Road, Winder

Underground Electric Service Proposal

Underground Service Charge:		**75 Lots @ $550.00 =**	**$41,250.00**
Street Lighting Charge:	*Town & Country; LHPS100TC; POLE, FIBERGLASS, 20T, 16' MH, DIRECT BURIAL*	**30 Lights @ $280.14 =**	**$8,404.20**
Other Charges:			**$0.00**
TOTAL:	*Prices Valid Through June 30, 2006*		**$49,654.20**
		Cost Per Lot:	**$662.06**

Note: Waived Charges Will Be Due In Full If Gas Is Present

☐ Right Choice Homes............(Charges Waived)............ $49,654.20

☐ Total Electric............(Charges Waived)............ $49,654.20

DEVELOPER: ____________ DATE: ______

BUILDER: ____________ DATE: ______

REALTOR: ____________ DATE: ______

Proposal Date Thursday, February 09, 2006

JEMC Representative: Nelson McGinnis; 706-367-6143

All Fees are waived if gas is *not* installed.

2.5 Inconsistent Approach to Energy Codes and Standards

There are many structural disincentives for natural gas in the form of building and energy codes, appliance standards, energy rating systems, and other state- and federal-level policies. Voluntary programs, compulsory codes and standards, and energy rating methodologies can be developed using either a site-based or full-fuel-cycle (FFC)-based approach to energy measurement. Site-based approaches have an inherent bias against natural gas since natural gas appliance site efficiencies are often lower than electric, despite natural gas having higher source-to-site efficiencies. Approaches that do not incorporate a comprehensive approach to energy measurement create an unequal playing field for natural gas relative to other competitive fuels and may bias towards energy sources that may overall be more energy or greenhouse gas intensive.

A FFC approach to codes and standards development would account for source efficiencies and environmental emissions from the value chain of any energy source, thus providing a more comprehensive mode of energy measurement and a more holistic perspective on fuel choice. If the goal of a policy or program is to reduce energy, minimize pollution, mitigate greenhouse gases, or other environmental- or health-related impacts, the most appropriate methodology for evaluating technology and fuel options must incorporate a comprehensive approach such as full fuel cycle. It should be employed in a manner that results in codes and standards that are technologically feasible, economically justified, and effective in reducing overall greenhouse gas emissions.

There is no single methodological approach in the development of policies, model building energy codes, energy rating systems, appliance performance standards, and other regulatory regimes. Whether a site approach or FFC approach is used depends on the program itself, and no policies currently provide guidance on this issue. The result is a varied suite of obligatory and voluntary programs of inconsistent design, leaving unrealized the full understanding of energy choice impacts, and in turn limiting the effectiveness of these many energy programs, policies and regulations.

Table 9 provides a list of voluntary and compulsory programs, categorized by those using a site or FFC approach. The remainder of this section discusses some of these programs.

Table 9: List of Programs by Energy Measurement Approach

Programs with Site-Energy Approach

- DOE Appliance Codes & Standards
- EPA Energy Star, National Energy Rating Program for Homes
- National Association of Home Builders, National Green Building Program
- Residential Green Building, Green Building Initiative
- U.S. Green Building Council, LEED Rating System

Programs with Source / Full-Fuel-Cycle Energy Approach

- DOE, Residential Retrofit Guidelines
- DOE, Federal Petroleum-Equivalent Fuel Economy Calculator
- EPA Energy Star, Commercial Buildings Program
- Green Building Initiative, Green Building Assessment Protocol for Commercial Buildings
- International Green Construction Code (IGCC) V2 Performance Path, ICC
- U.S. Green Building Council, LEED for Existing Building O&M Rating System

Programs related to the establishment of appliance minimum performance ratings are particularly influential. Minimum standards affect the floor price of an appliance’s upfront cost, which impacts consumer options and choice. However, the current standards do not properly reflect the most *cost-effective* minimum standards that result in the greatest environmental benefit. The problem is how the standards are determined. The Department of Energy is compelled under statute to determine appliance standards based on site energy. The Energy Policy and Conservation Act of 2005 requires the secretary of Energy to prescribe or amend new energy conservation standards for each type or class of identified product, and although DOE may utilize primary or source energy consumption in some analyses to determine whether a particular standard is economically justified, the final rule promulgated must determine a site-efficiency standard.[5] A site-based approach is appropriate when comparing single-fuel product types. A FFC approach is necessary to understand the energy and environmental impacts – and the market implications of a minimum standard set on these appliances – between different fueled products. In a recent study the National Academies weighed in on this subject: "Site-energy use is also the most appropriate measure for setting operational efficiency requirements for single-fueled appliances within the same class." However, the study also notes and endorses "full-fuel-cycle measure of energy efficiency as integral to supporting more explicit consideration of the impacts of energy use on the nation and the environment." A more comprehensive approach, as the National Academies supports, would better level the playing field to provide the most cost-effective consumer choices that reduce energy and environmental impacts.[xxvi]

In other programs, the energy-measurement approach is selected by the agency itself. The Environmental Protection Agency (EPA), for example, establishes its voluntary ENERGY STAR building qualifications using analytical modeling tools, or energy rating systems, to assess building efficiencies and provide a rating. EPA utilizes two energy rating systems, one for residential households and another for commercial buildings. Both rating systems rely on measuring and modeling the energy consumption of a building based on the structure's attributes, such as types of appliance and equipment installed. Buildings that perform better – use less energy – than specified thresholds qualify for ENERGY STAR, which brands the building design as energy efficient.

One reason the rating system is different for commercial buildings is the nature of the structures being rated. Residential buildings are more homogenous and are more easily comparable. Commercial buildings vary in size, shape and usage, ranging from small storefronts, to mid-sized grocery stores, to large campus institutions for corporations, hospitals and universities. Therefore comparisons between commercial buildings require the various building types to be lumped into peer groups that share similar attributes and operational characteristics.

However, many of the key differences between the two approaches are a matter of precedent. When EPA began developing the residential ENERGY STAR program, the Residential Energy Services Network (RESNET), a group of certified home energy professionals, was finalizing a comprehensive residential Home Energy Rating System (HERS), which EPA finally chose as the methodological backbone for its residential ENERGY STAR program. When EPA began the Commercial Buildings Program, it did not have a similar efficiency rating system for commercial structures, so it developed a separate national energy performance rating. One key difference between the systems was the energy measurement calculation: the residential program used a site-based approach, while the commercial side relied on source-based calculations.

[5] DOE is proposing to move from a source to a more comprehensive full-fuel cycle approach as part of these analyses.

The HERS Index scale compares a household's purchased energy consumption with the same type of household built to International Energy Conservation (IECC) 2009 code. As noted, the HERS Index was based on the site-energy consumption of the household, but over time this initial approach was found to have flaws and has since been modified. Today, the HERS efficiency rating uses a calculation that is fundamentally site-based with an adjustment factor to make more equitable the technological differences in improving efficiencies between appliances of different fuel types. The calculation also uses a correction factor to account for the efficiency of direct-energy consumption. However, there are significant problems with the HERS methodology: 1) it does not account for the ranges and differences in efficiency of using coal and natural gas for electric generation; rather an average efficiency is utilized; and 2) it does not factor in the carbon intensity of the electric generation mix. This approach does not acknowledge the full-fuel-cycle efficiencies of natural gas and competitive fuels, again limiting the ultimate effectiveness of the program.

The EPA commercial buildings national energy performance rating instead uses a source-based methodology.[6] The national energy performance rating scale is similar to the HERS index for residential structures in that it provides an external benchmark with which to compare a similar peer group of buildings and rate their energy performance. The scale is determined for each peer group by assessing a building's total energy usage relative to its operation, and how much energy do they use relative to each other on a source energy basis. The source energy basis, not incorporated into the EPA residential HERS rating, is a keystone of the EPA commercial buildings energy analysis. EPA acknowledges the superiority of this methodology, which, according to the EPA office assigned to assess energy usage in building and plants, "is the most equitable way to compare building energy performance, and also correlates best with environmental impact and energy cost."[xxvii]

There are other cases of site-based methodological approaches to assessing, modeling, and codifying home and building energy consumption and standards, as well as inconsistencies within the programs themselves. The National Association of Home Builders residential sector "Green Building Program" is designed with a site-based efficiency measurement at the heart of its energy consumption calculation. This program is also incorporated into residential activities of the *Green Building Initiative*, a non-profit organization created to promote and accelerate green building practices. However, the *Green Building Initiative* also developed the "Green Globes" tool as a guidance and assessment tool for construction and retrofits of commercial buildings. This assessment protocol and rating system utilizes a life-cycle approach, which encompasses the full-fuel-cycle, for its materials and energy consumed in the building.

In the same vein, the U.S. Green Building Council's LEED rating system for new and retrofit buildings assigns points based on the efficiency of the heating system installed, but neither penalizes nor rewards designs that consider source energy consumption and emissions. The LEED O&M rating system for existing buildings, on the other hand, uses a source-based approach.

Clearly there is no one universal methodological approach to energy measurement that will apply in all cases, nor should there be. Energy consumption exists at the heart of these programs and policies,

[6] In this case it acknowledges energy losses related to electricity generation, transmission, and distribution, but sets aside losses related to primary fuel extraction, processing, and transportation.

which are designed to increase efficiency and reduce greenhouse gas emissions. Maximizing site efficiency should not be achieved at the expense of source energy losses. Programs and policies should be designed with the most comprehensive approach feasible. A full-fuel-cycle mode is more complex and requires more data, but it is feasible. As the National Academies acknowledged in its report on appliance efficiency standards, "a [full-fuel-cycle] methodology can be developed without undue strain on DOE/EERE resources." But ultimately policies should be designed to support and achieve important public policy goals while simultaneously benefiting consumers. A thoughtful, full-fuel-cycle approach can help enable that possibility.

3 Policy Recommendations

Summary

The following policy recommendations are made to ensure that direct use of natural gas can make a long-term contribution to increasing energy efficiency and reducing overall emissions in homes and businesses. These policies should be considered in the context of overall U.S. energy policy:

- Develop and incorporate full-fuel-cycle analysis into energy policy, regulations and energy efficiency metrics.
- Provide consumers with the best available information on comparable energy options through the use of enhanced appliance and equipment labeling, including carbon footprint information.
- Encourage government agencies, state public utility commissions, and utilities to jointly develop innovative policies and regulations that provide better alignment of costs and benefits over the life cycle of consumer equipment.
- Research and development programs and investment focus should include natural gas delivery and end-use technology to fully maximize the value of natural gas resources.

The preceding chapters explored the benefits and the constraints on the direct use of natural gas to contribute to consumer and societal goals. Based on these issues, the following recommendations are suggested for consideration as part of larger domestic energy policy in order to maximize the benefits of direct use so that natural gas can contribute to greater energy efficiency and lower emissions in homes and businesses. Prudent policies and regulations are essential if consumers and society are to fully realize these benefits. As energy delivery systems evolve and the electric grid becomes more integrated with the natural gas distribution system, thoughtful policy can help to integrate new and existing natural gas technologies with current infrastructure to provide enhanced system reliability, lower costs, lower environmental impacts, and greater accessibility and choice for consumers.

Recommendations

1) Develop and incorporate full-fuel-cycle analysis into energy policy, regulations, and energy efficiency metrics.

It is imperative to consider all points of energy consumption and sources of emissions when creating policies for the cost-effective reduction of energy use, criteria pollutants, and greenhouse gases. All sources of energy and emissions along an energy value chain, from the point-of-use to the energy delivery system itself, should be fully and comprehensively accounted.

For example, energy sources such as electricity may have zero site-based greenhouse gas emissions, but, depending on the primary fuel source, may still result in significant emissions from the generation of electricity. Ignoring this can lead to unintended consequences, and policies designed to reduce energy or emissions can, in fact, preclude decreases or even lead to increases in energy and emissions. This is especially true for policies regarding consumer appliances and fuels in which interchangeable options have unequal environmental consequences.

Therefore a full-fuel-cycle analysis is appropriate. Full-fuel-cycle evaluates the energy consumption and environmental impacts (such as emissions) from energy extraction, processing, transportation, distribution and (in the case of electricity) generation, in addition to an evaluation of the final consumption of a fuel source. Energy consumption and emissions, therefore, should not be merely evaluated at point-of-use, but throughout the entire energy value chains.

Full-fuel-cycle analyses could be best integrated into energy policies, regulations, green building programs, consumer awareness and education programs, and energy codes and standards, in order to provide a better basis for comparing appliances and equipment of different fuel types. Examples of where full-fuel-cycle could be integrated include:

- Appliance minimum performance standards
- Model building energy codes and standards
- ENERGY Star qualification
- Building energy rating systems
- Consumer information, e.g. appliance labels with carbon footprint information.
- Consumer education, e.g. 'Where does your electricity come from?'

To develop an agreed-upon full-fuel-cycle methodology will require some effort. There is currently some uncertainty regarding upstream energy consumption and greenhouse gas emissions factors, in particular those of coal and natural gas extraction. In addition, there are significant regional differences regarding full-fuel-cycle analyses because of geographical variations, electric generation mix and climatic differences in appliance usage trends. However, these challenges are not overwhelming and they do not detract from the reality that a full-fuel-cycle analysis provides a more comprehensive approach to evaluating the environmental impacts of energy usage.

Prudent policy should set a course for state and federal government agencies to establish an agreed-upon full-fuel-cycle methodology that embraces the inherent regional characteristics of the full-fuel-cycle and then adopt it into the appropriate energy and environmental metrics.

2) **Provide consumers with best available information on comparable energy options through the use of enhanced appliance and equipment labeling.**

Enhanced information on appliance energy consumption and costs enables informed consumer decisions on energy choices. The EnergyGuide label, issued by the U.S. Federal Trade Commission, is commonplace on many retail consumer appliances, including furnaces, hot water heaters and heat pumps, and informs consumers of that particular appliance's energy efficiency, estimated yearly operating cost, and annual energy use.

The EnergyGuide label could be further enhanced with more information detailing the appliance's environmental impacts, in particular greenhouse gas emissions. A full accounting of these emissions would require a full-fuel-cycle analysis. While this approach is somewhat more complicated and adds to the complexity of the EnergyGuide label, it provides consumers with a carbon footprint, an important detail for many consumers making purchasing decisions. Despite the challenges and complexities, an enhanced EnergyGuide label would be a low-cost method of incentivizing better carbon choices by consumers through consistent, comparable, and verifiable information on energy use and greenhouse gas impact.

3) **Encourage government agencies, state public utility commissions, and utilities to jointly innovate policies and regulations that provide better alignment of benefits and costs over the life cycle of consumer equipment.**

There is significant potential for natural gas to cost-effectively contribute to public goals such as reduced oil dependence, greater energy efficiency, and reduced greenhouse gas emissions. Key economic constraints stand in the way, however. The higher cost of gas appliances and the added costs to extend main and service line extensions often deters customers from switching to natural gas. Measured and prudent policy and regulation can help ease these market constraints and provide a greater alignment of long-term benefits and costs.

Government agencies, state public utility commissions, and utilities should be encouraged to develop innovative policies and regulations to reduce these barriers. These policies could include the development of novel rate designs, new financing mechanisms, rebate programs, and changes to the tax code to support infrastructure build-out. Policies could include:[7]

- The leasing of utility-owned equipment to customers or providing similar financial mechanisms that allow the utility to bear the first-cost burden to relieve the customer of the upfront cost associated with natural gas.

- Deferring customer contributions in aid-of-construction for natural gas main and service line extensions by creating a regulatory liability and amortizing payments over time.

- Supporting utility infrastructure build-out as part of economic development programs through tax abatement, special pricing areas, direct contributions and others, as a way to support business development, job creation, plant expansions, and customer fuel savings.

- Providing rebate programs for customers who upgrade to high-efficiency natural gas equipment.

- Eliminating taxes on the customer contribution in aid-of-construction for natural gas main and service line extensions.

4) Research and development programs and investment focus should include natural gas delivery and end-use technology to fully maximize the value of natural gas resources.

Robust research and development plays a crucial role in technological development. In recent years, significant focus has been on upstream technological advances, especially new production techniques. But as infrastructure ages and existing home and business owners replace older appliances and equipment, there remains a need to focus on R&D for natural gas distribution and end-use technologies. R&D initiatives should include priorities to improve existing technologies and develop new solutions with the goal of maximizing the use of natural gas resources, increasing energy efficiency, reducing greenhouse gas emissions, and promoting economic growth.

A robust R&D portfolio should extend measured treatment toward distribution and end-use technology. The intent should be to develop technologies to provide cost-effective, high-efficiency, low-emitting appliances, to innovate next-generation distributed energy solutions, and to maximize the efficiency of the energy distribution system. Examples of advanced natural gas end-use technologies where R&D priority could provide significant benefit include:

- Gas fired heat pumps
- Desiccant dehumidification systems

[7] The following examples were developed by AGA and also appear in the 2011 National Petroleum Council Demand Task Group report on North American Resource Development.

- Radiant heating projects
- Combined heat and power systems
- Renewable energy backup
- Gas/electric hybrid technologies
- District heating systems and applications
- Gas/electric hybrid technologies

R&D funding to develop advanced natural gas technologies can help realize the benefits of direct-use, which can contribute to a more robust and secure energy future.

End Notes

[i] American Gas Association. “A Comparison of Energy Use, Operating Costs, and Carbon Dioxide Emissions of Home Appliances.” 2009. http://www.aga.org/Kc/analyses-and-statistics/studies/demand/Documents/0910EA3.PDF

[ii] The analysis utilized prices published Federal Register, Thursday March 18, 2010. http://www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/repaveunitcost_2010_notice.pdf

[iii] Fuel oil households are assumed to consume fuel oil for space and water heating, and electricity for cooking and clothes drying.

[iv] Of total electricity sales (and associated losses), approximately 20 percent serves space heating, water heating, cooking, and clothes drying applications. The AEO projection of this portion of electricity consumption shows flat to very moderate long-term growth, less than a percent per year from now until 2035.

[v] Energy Information Administration. “Annual Energy Outlook 2011 with Projections to 2035,” (AEO 2011). http://www.eia.gov/forecasts/aeo/
& AGA calculation of residential electricity losses based on national sales-to-losses ratio.

[vi] Energy Information Administration. “Residential Energy Consumption Survey 2009,” (RECS 2009) http://www.eia.gov/consumption/residential/ & U.S. Census Bureau, “American Housing Survey 2009,” (AHS 2009). http://www.census.gov/hhes/www/housing/ahs/ahs.html

[vii] Energy Information Administration. “Commercial Buildings Energy Consumption Survey 2003,” (CBECS 2003). http://www.eia.gov/emeu/cbecs/

[viii] RECS 2009.

[ix] American Gas Association. “A Comparison of Energy Use, Operating Costs, and Carbon Dioxide Emissions of Home Appliances.” 2009. http://www.aga.org/Kc/analyses-and-statistics/studies/demand/Documents/0910EA3.PDF

[x] McKinsey & Company. “Reducing U.S. Greenhouse Gas Emissions, How Much at What Cost?” U.S. Greenhouse Gas Abatement Mapping Initiative. December 2007. http://www.mckinsey.com/en/Client_Service/Sustainability/Latest_thinking/~/media/McKinsey/dotcom/client_service/Sustainability/cost%20curve%20PDFs/US_ghg_final_report.ashx

[xi] APA 2010 High Natural Gas Resource Case. http://www.eia.gov/oiaf/servicerpt/kgl/index.html

[xii] Pennsylvania Public Utility Commission, Act 129 Information: http://www.puc.state.pa.us/electric/Act_129_info.aspx

[xiii] Energy Information Administration. “Sales of Distillate Fuel Oil by End Use.” http://www.eia.gov/dnav/pet/pet_cons_821dst_dcu_nus_a.htm

[xiv] American Gas Association. “Challenges and opportunities in the Residential Natural Gas Market: Results of the AGA Residential Market Share Survey.” March 16, 2010.

[xv] ICF International, CHP Database

[xvi] Swisher, J.N. "Cleaner Energy, Greener Profits: Fuel Cells as Cost-Effective Distributed Energy Resources." Rocky Mountain Institute, 2002. http://www.rmi.org/rmi/Library%2FU02-02_CleanerEnergyGreenerProfits

[xvii] California Distributed Energy Resource Guide. http://www.energy.ca.gov/distgen/equipment/microturbines/microturbines.html

[xviii] Environmental Protection Agency. "Technology Characterization: Reciprocating Engines." Prepared by ICF International, December 2008. http://www.epa.gov/chp/documents/catalog_chptech_reciprocating_engines.pdf

[xix] Swisher, J.N. "Cleaner Energy, Greener Profits: Fuel Cells as Cost-Effective Distributed Energy Resources." Rocky Mountain Institute, 2002. http://www.rmi.org/rmi/Library%2FU02-02_CleanerEnergyGreenerProfits

[xx] Environmental Protection Agency. "ENERGY STAR Residential Water Heaters: Final Criteria Analysis." April 1, 2008. http://www.energystar.gov/ia/partners/prod_development/new_specs/downloads/water_heaters/WaterHeaterAnalysis_Final.pdf

[xxi] U.S. Department of Energy. Technical Support Document, November 23, 2009. Yearly Energy Cost based on DOE data and energy costs of $0.114/kWh and $1.11/therm.

[xxii] U.S. Department of Energy. Technical Support Document, November 23, 2009. Yearly Energy Cost based on DOE data and energy costs of $0.114/kWh and $1.11/therm.

[xxiii] American Gas Association, "Life Cycle Costs for Space Heating & Cooling Appliances." Financial and Operational Information Series, Volume 2011-6, June 2011. http://www.aga.org/Kc/analyses-and-statistics/fois/2011/Documents/11FOIS06SPACECONDB.pdf

[xxiv] U.S. Department of Energy. Technical Support Document. Fuel cost includes fan use of 605 kWh per year. Discount rate of 4%. Data taken from DOE technical support document. Prices for consumption from DOE long-term forecast. Gas unit = 80% AFUE, central AC = 13 SEER, heat pump = 7.7 HSPF, 13 SEER.

[xxv] American Gas Association "Challenges and Opportunities in the Residential Natural Gas Market: Results of the AGA Residential Market Share Survey" March 16, 2010. http://www.aga.org/Kc/analyses-and-statistics/studies/Benchmarking/Trends-In-Natural-Gas-Market/Documents/1003EA02.PDF

[xxvi] National Research Council. "Review of Site (Point-of-Use) and Full-Fuel-Cycle Measurement Approaches to DOE/EERE Building Appliance Energy-Efficiency Standards." National Academies Press, 2009. http://www.nap.edu/catalog.php?record_id=12670

[xxvii] "How the Rating System Works", U.S. Environmental Protection Agency http://www.energystar.gov/index.cfm?c=evaluate_performance.pt_neprs_learn

Appendix A-5

B.C.'s ENERGY AND CLIMATE POLICY

APPENDIX A-5 – B.C.'S ENERGY AND CLIMATE POLICY

Energy policy in the Province of British Columbia has been historically rooted in the four cornerstones of low electricity rates, secure, reliable supply, private sector opportunities, and environmental responsibility. In the years between 2007 and 2010, the B.C. Government took aggressive action to align the province's energy policy with a plan to address the issue of climate change. During this time, the government's plan included a number of major climate change policies such as the *Greenhouse Gas (GHG) Reduction Targets Act,* the *Carbon Tax Act* and the Carbon Neutral Government Regulation. Since introducing the *Clean Energy Act (CEA)* in 2010, B.C.'s energy policies have been largely directed at establishing a path to low carbon energy self-sufficiency. Nevertheless, with a change in government leadership and advances in technology bolstering the economic viability of B.C.'s natural gas reserves, there is renewed focus on the role that natural gas can play in the province's energy and climate future. This focus is manifested through B.C.'s Natural Gas and LNG Strategies, the GHG Reduction (Clean Energy) Regulation and Special Direction No. 5 to the BCUC. Table 1 summarizes a list of B.C.'s energy and climate policy initiatives with further details outlined throughout this appendix. A timeline of the major energy and climate policy initiatives included in this framework was presented in Section 2.2.3 of the Long Term Resource Plan.

Table 1: B.C.'s Energy and Climate Policy Initiatives

Energy	Climate Change
B.C. Energy Plan B.C. Bioenergy Strategy *Clean Energy Act (and Amendment)* • Improvement Financing Regulation • B.C.'s Energy Objectives Regulation • GHG Reduction (Clean Energy) Regulation B.C. Natural Gas Strategy B.C. LNG Strategy Special Direction No. 5 to the BCUC	*GHG Reduction Targets Act (GGRTA)* • Carbon Neutral Government Regulation • Emission Offsets Regulation *Utilities Commission Amendment Act* *GHG Reduction (Renewable and Low Carbon Fuel Requirements) Act* • Renewable and Low Carbon Fuel Requirements Regulation *Carbon Tax Act* *GHG Reduction (Emissions Standards) Statutes Amendment Act* • Landfill Gas Management Regulation *GHG Reduction (Vehicle Emissions Standards) Act* B.C. Climate Action Plan *GHG Reduction (Cap and Trade) Act* • Reporting Regulation *Local Government (Green Communities) Statutes Amendment Act* Climate Action Charter

1. B.C. Energy Plan: A Vision for Clean Energy Leadership

In February 2007, the B.C. government released the *B.C. Energy Plan: A Vision for Clean Energy Leadership*, which builds on the policies of its predecessor, *2002 Energy for Our Future: A Plan for B.C.* The Energy Plan of 2007 establishes a strategy to make the province energy self-sufficient through conservation efforts, using clean alternative energy sources, and investing in alternative technology. The plan focuses on the province's key natural strengths and competitive advantage in clean and renewable energy and outlines 55 policy actions under the themes of energy conservation and efficiency, electricity, alternative energy, and oil and gas. Of particular note are the following policy actions:

- Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
- Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
- Encourage utilities to pursue cost effective and competitive demand side management opportunities.
- Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
- All new electricity generating facilities and projects constructed in British Columbia will have net zero greenhouse gas emissions.
- Existing thermal generating power plants will achieve zero net greenhouse gas emissions by 2016.
- Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
- Ensure self-sufficiency to meet electricity needs by 2016, plus "insurance" power to supply unexpected demand thereafter.

Under the alternative energy pillar, the Energy Plan proposes to use a newly established Innovative Clean Energy Fund to focus on areas such as developing reliable power solutions for remote communities, First Nations in particular, to reduce their reliance on diesel generation for electricity, and finding ways to convert vehicles to cleaner alternative fuels.

B.C.'s Energy Plan takes a first step to incorporate transportation issues into provincial energy policy and recognizes transportation as a major contributor to climate change and air quality problems. The plan highlights that "natural gas burns cleaner than either gasoline or propane, resulting in less air pollution," thereby implying that the adoption of natural gas vehicles can play a prominent role in helping the province to reduce GHG emissions and air pollutants from the transportation sector.

2. B.C. Bioenergy Strategy

While the Province's bioenergy goals were first outlined in the Energy Plan of 2007, the B.C. Bioenergy Strategy establishes a vision that uses bioenergy to enhance B.C.'s ability to become electricity self-sufficient, foster the development of a sustainable bioenergy sector, and work toward B.C.'s climate objectives. The Bioenergy Strategy lays to groundwork to seize opportunities in converting local biomass and waste from landfills, crop residues and agricultural waste into energy.

3. Clean Energy Act

In April 2010, the Government of B.C. passed the *Clean Energy Act* (*CEA*) or *Bill 17*, which outlines 16 objectives aimed at turning B.C. into "a leading North American supplier of clean, reliable, low carbon electricity and technologies that reduce GHG emissions while strengthening [the] economy in every region."[1] These include expediting clean energy investments, protecting B.C. ratepayers, ensuring competitive rates, encouraging conservation, strengthening environmental protection, and aggressively promoting regional job creation and First Nations' involvement in clean electricity development opportunities—many of which have implications for energy optimization and GHG emission reduction solutions that the FEU can provide for its customers. The *CEA* builds on the Province's 2002 and 2007 Energy Plans and modifies a number of goals, some of which are listed below:

- Whereas B.C.'s primary objective had previously been electricity self-sufficiency, the *CEA* focuses heavily on becoming a net electricity exporter. This establishes a large role for privately-owned independent power producers.
- The *CEA* strengthens the requirement to meet new electricity demand through conservation measures from 50% to 60%.
- The *CEA* establishes a mandate to increase the required percentage of electricity generated from clean or renewable sources of energy from 90% to 93%.

While the *CEA* repackages elements of existing energy policy, it also introduces a number of changes to the way decisions about electricity supply and demand are made in B.C. One major change is a new framework that consolidates BC Hydro and the BC Transmission Corporation into one utility. The single utility, BC Hydro, is responsible for submitting its long term integrated resource plans to the government rather than to the BCUC, as BCUC oversight faces a diminished role in the utility's decisions and actions. As such, major decisions pertaining to the Province's electricity supply and generation facilities are no longer subject to the public scrutiny through the Utilities Commission process. Approval of over $10 billion in new capital projects (including the Site C dam, the Northwest Transmission Line, Smart Metering, new export

[1] Former Premier Gordon Campbell, News Release, "New Act Powers B.C. Forward with Clean Energy and Jobs," April 28, 2010. http://www2.news.gov.bc.ca/news_releases_2009-2013/2010PREM0090-000483.htm Accessed Sept. 29, 2013.

agreements, and adding new turbines to existing "heritage" dams) are thus outside the BCUC's purview and lie directly in government control.

One notable *CEA* objective is "to encourage the switching from one kind of energy source or use to another that decreases GHG emissions in B.C." Also, a new definition for 'demand-side measure' excludes electricity-to-gas fuel switching, which could likely change customer and public perception of natural gas as a clean and efficient fuel. With heavy focus by the provincial government and media on B.C.'s electricity as being a renewable energy source, there may be confusion about the role of natural gas among customers and stakeholders. Nevertheless, the *CEA* recognizes the important role that different energy types play in meeting B.C.'s resource needs by encouraging the use of natural gas, electricity and hydrogen for transport as alternatives to the higher GHG-emitting fuels, gasoline and diesel.

Clean Energy Act Amendment

By way of *Bill 30*, the *Energy and Mines Statutes Amendment Act*, in March 2012, the B.C. Ministry of Energy and Mines amended the *Clean Energy Act* to redefine the province's energy self-sufficiency requirements based on average as opposed to critical water level years. The *Clean Energy* Act's self-sufficiency provisions ordered BC Hydro to generate or buy surplus electricity at a substantial cost to ratepayers—which directly countered the *CEA's* directive to maintain low electricity rates. *Bill 30* eliminates the requirement for BC Hydro to acquire an extra 3,000 gigawatt hours per year of insurance energy by 2020 and consequently relieves some upward pressure on rates.

Improvement Financing Regulation

The Improvement Financing Regulation was introduced under the *CEA* in July 2012 to provide home owners with the ability to finance certain energy efficiency measures with no upfront cost and repaid over time on the utility bill. The regulation identifies two pilot project areas, the City of Colwood on Vancouver Island and the South Okanagan, where BC Hydro and FortisBC are respectively conducting separate on-bill financing programs. While the original pilot period is set to expire on October 31, 2014, beginning January 2014, the program will continue to be available in the Okanagan-Similkameen district and will be expanded to all of Vancouver Island and the City of Kelowna.

B.C.'s Energy Objectives Regulation

Introduced in July 2012, B.C.'s Energy Objectives Regulation modifies (in bold typeface) section 2(c) of the *CEA* to "generate at least 93% of the electricity in British Columbia, **other than electricity to serve demand from facilities that liquefy natural gas for export by ship**, from clean or renewable resources and to build the infrastructure necessary to transmit that electricity." Thus, the *CEA* redefines natural gas as a clean energy source when it is used to generate power for liquefied natural gas (LNG) facilities. Since LNG facilities consume massive amounts of electricity, this modification mitigates the pressure on BC Hydro to supply the requisite power from renewable energy sources to develop LNG exports.

GHG Reduction (Clean Energy) Regulation

As previously outlined in Section 2.2.3.3, the GHG Reduction (Clean Energy) Regulation was established in May 2012 to accelerate the adoption of natural gas vehicles in B.C. Amended in November 2013 to include mine haul trucks and locomotives, the regulation enables a utility to spend up to $62 million on vehicle and ferry incentives, up to $12 million on compressed natural gas (CNG) fuelling stations and $30.5 million on liquefied natural gas stations, for a total $104.5 million. The GHG Reduction (Clean Energy) Regulation provides significant government support for the FEI's existing natural gas for transportation (NGT) activities to convert heavy duty transport vehicles and marine vessels from higher carbon fuels to cleaner, more efficient natural gas.

4. B.C. Natural Gas Strategy

The Government of B.C. has issued strong support for natural gas and LNG development on a number of occasions. Natural gas is featured as a key sector in the B.C. Jobs Plan, which states a goal to bring at least one LNG pipeline and terminal online by 2015 and three by 2020. The Kitimat LNG Project was granted the first-ever federal license to export LNG from Canada; after receiving both federal and provincial environmental assessment approvals, a final investment decision is pending.

With the release of B.C.'s Natural Gas Strategy in February 2012, the province further entrenched its vision to become a global leader in natural gas investment, development and export. While also promoting natural gas as a transportation fuel, the Natural Gas Strategy establishes priorities to:

- maintain current markets and develop new ones;
- ensure a reliable, abundant supply;
- maintain competitiveness;
- maximize benefits of natural gas development;
- ensure environmentally responsible development; and
- build partnerships to promote development.

The Province of B.C. intends to contribute to a decrease in global GHG emissions through its LNG export strategy. However, plans for expanding natural gas development puts heavy pressure on the province's target of a 33% reduction in GHG emissions from 2007 levels as outlined in the *Greenhouse Gas Reduction Targets Act*. Meeting B.C.'s LNG development goals will see the province's annual natural gas production increase from approximately 1.1 to nearly 3 trillion cubic feet per year by 2020 (B.C. Natural Gas Strategy).

5. B.C. LNG Strategy

B.C.'s quest to boost natural gas development is further outlined in the LNG Strategy, in which the Province reaffirms a commitment to having three LNG facilities in operation by 2020 pending environmental approvals. The LNG Strategy also represents an attempt to create a new industry that is intended to bring significant investment, job-creation benefits and government revenues. The strategy is guided by three priorities:

- keeping B.C. competitive in the global LNG market;
- maintaining B.C.'s leadership on climate change and clean energy; and
- keeping energy rates affordable for families, communities and industry.

B.C. intends to differentiate itself from other LNG markets by providing LNG with the lowest lifecycle GHG emissions than anywhere else in the world. Developing upstream natural gas and an LNG export industry will remain key government priorities as the government attempts to balance responsible energy development with climate objectives.

6. Special Direction No. 5 to the BCUC

The Government of B.C. issued Special Direction No. 5 to the BCUC under Section 3 of the *UCA* in November 2013. The direction exempts from review expenditures on an expansion of the Tilbury LNG facility up to $400 million and effectively lowers the LNG dispensing rate to $4.35 per GJ. While the market effect of these recent developments is not considered in the 2014 LTRP's NGT demand forecasts, the potential effect of adding NGT load is considered in determining future system resource needs and alternatives throughout Section 5 of the LTRP.

7. GHG Reduction Targets Act

As part of the B.C. Throne Speech delivered on February 13, 2007, the government announced ambitious new targets for provincial GHG reductions. Effective January 1, 2008, the *Greenhouse Gas Reductions Targets Act (GGRTA)* enshrines in law the provincial government's GHG emissions reduction targets of at least 33% below 2007 levels by 2020, and 80% below 2007 levels by 2050; however, the legislation does not outline specific emission reduction targets for any of B.C.'s GHG-emitting sectors.

The Act also provides authority for the Carbon Neutral Government Regulation and the Emission Offsets Regulation, which were enacted in December of 2008. Under the Carbon Neutral Government Regulation, B.C.'s entire public sector has achieved net-zero GHG emissions since 2010 by measuring, reducing and offsetting GHG emissions from buildings, vehicle fleets and paper use. 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 government's commitment to a carbon-neutral public sector. B.C. is the first major jurisdiction in North America to achieve carbon neutral operations.

8. Utilities Commission Amendment Act

In 2008, the B.C. Government passed the *Utilities Commission Amendment Act (UCAA)* to encourage public utilities to pursue the following government energy objectives:

- reduce GHG emissions,
- pursue energy efficiency and conservation,
- produce and obtain electricity from clean or renewable resources,
- develop energy transmission infrastructure and capacity to meet customer needs,
- leverage innovative energy technologies, and
- take prescribed actions in support of any other goals prescribed by regulation.

The *UCAA* also provides authority for the Demand-Side Measures Regulation (DSM Regulation), which establishes rules for the BCUC to use when assessing proposed utility DSM activities. The DSM Regulation directs the Commission to consider the 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. More specifically, a public utility's DSM plan portfolio is adequate for the purposes of determining whether to accept a long term resource plan if the plan demonstrates adequacy of certain aspects of the plan portfolio including: DSM measures intended to assist residents of low-income households, inclusion of DSM measures to improve energy efficiency of rental accommodations, and inclusion of an education program for students in the utility's service area.

The DSM Regulation directs the Commission to consider a number of items in determining the cost effectiveness of the 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.

The FEU's EEC activities (outlined in Section 4) promote the efficient use of natural gas, encourage adoption of low carbon energy alternatives, reduce energy costs for customers, and support government policy to reduce GHG emissions.

9. GHG Reduction (Renewable and Low Carbon Fuel Requirements) Act

Passed in April 2008, the *GHG Reduction (Renewable and Low Carbon Fuel Requirements) Act* sets requirements for renewable fuel to be used in transportation fuel blends. The intent of this legislation is to enable B.C. to meet its commitment to adopt a low carbon fuel standard similar to that of California.

The *GHG Reduction (Renewable and Low Carbon Fuel Requirements) Act* creates the framework to introduce the Renewable and Low Carbon Fuel Requirements Regulation (RLCFRR), which was enacted in December 2009. From July 1, 2013, Part 3 fuel suppliers—fuel producers or importers—must meet annual fuel carbon intensity targets or pay a penalty. Natural gas, propane, electricity and hydrogen are considered Part 3 fuels if they are sold for use in transportation.

*S*ince the FEU sell natural gas for use in transportation applications under various rate classes, the Companies have the opportunity to claim first sale as a Part 3 fuel supplier in the province. The RLCFRR allows for generation of low carbon compliance credits based on a required carbon intensity baseline. Suppliers that are not in compliance with the mandated carbon reductions must purchase credits from others or pay a penalty. As the FEU add more CNG and LNG sales, the Companies' credits will increase as they are measured against the conventional fuel intensity baseline, which creates a potential revenue stream and benefit to customers through this deferral account mechanism. The FEU are awaiting further clarification from the Government regarding the definition of Part 3 Fuel Suppliers as it relates to natural gas for transportation.

10. Carbon Tax Act

In July 2008, B.C became the first jurisdiction in North America to introduce a carbon tax on the purchase and use of fossil fuels at the point of consumption. The carbon tax was implemented with initial tax rates set at $10 per tonne of carbon dioxide equivalent (tCO_2e) emissions and rising by $5 per tonne annually until reaching $30 per tCO_2e in July of 2012. The tax added $0.50/GJ to the cost of natural gas in the first year, rising to $1.50/GJ four years later. The carbon tax is designed to be revenue-neutral such that revenues are recycled through tax reductions and funding for other programs and initiatives. In addition, local governments and school districts that commit to carbon neutrality by 2012 (or have signed the Climate Action Charter) are eligible for the Climate Action Revenue Incentive, a grant that offsets the full amount of carbon tax paid.

The carbon tax was reviewed as part of the province's 2013 budget process and though the tax receives broad public support, it was found to have a small negative impact on B.C.'s gross domestic product. Industries with high emissions intensities such as oil and gas extraction are most impacted. As a result, through the June 26, 2013 Throne Speech, the government committed to maintaining the current carbon tax base and rate at $30 per tCO_2e for the next five years.

11. GHG Reduction (Emissions Standards) Statutes Amendment Act

The *Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act* aims to reduce GHG emissions from certain industrial operations, increase opportunities in the bioenergy sector, and enables regulation of zero and net zero GHG emissions for electricity generation. Most importantly this amendment modifies the *Environmental Management Act* to require that new natural gas-fired generation acquire and retire compliance offsets at least equal to the amount of GHG emissions that are created—which will increase the cost of new natural gas-fired generation. To date, no regulation has been enacted to bring these provisions into force. However, the 2007 BC Energy Plan also states that new natural gas-fired generation is to have net zero GHG emissions, which may be implemented through the *B.C. Environmental Assessment Act (BCEAA)*. New gas-fired electricity generation facilities with a nameplate capacity of equal to or greater than 50 MW trigger provisions under the *BCEAA* and require an Environmental Assessment Certificate to proceed. Consequently, the Environmental Assessment Office has the authority to impose a full offset requirement as part of the assessment certificate conditions.

The *Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act* also provides authority for the Landfill Gas Management Regulation, enacted in January 2009, which establishes criteria for landfill gas capture from municipal solid waste landfills. The aim of the regulation is to maximize reductions of landfill gas emissions and identify potential opportunities to increase landfill gas recovery.

12. GHG Reduction (Vehicle Emissions Standards) Act

Passed in May 2008, the *Greenhouse Gas Reduction (Vehicle Emissions Standards) Act* was intended to allow B.C. to set vehicle light-duty GHG emission standards equivalent to California's 2004 Low-Emission Vehicle II regulations. The Canadian federal government pre-empted introduction of the vehicle emissions regulation, however, with legislation that aligns Canada's standards with those established by the U.S. Environmental Protection Agency. This act also enables regulation of zero emission vehicle fleets.

13. B.C. Climate Action Plan

In June 2008, the Government of B.C. released a Climate Action Plan to provide a roadmap for the strategies and initiatives that are intended to drive the province toward reducing GHG emissions by 33 percent by 2020. The plan outlines the first phase of these initiatives and highlights a number of significant pieces of climate legislation, measures to stimulate low-carbon economic development and innovation, support for green communities, initiatives to build the value of B.C.'s forests, and the LiveSmart BC incentive program which encourages consumers to make energy-, water- and fuel-efficient decisions. The Climate Action Plan identifies actions across the economy—in the transportation, buildings, waste, agriculture, industry, energy and forestry sectors—to support B.C.'s GHG emissions reduction goals.

14. GHG Reduction (Cap and Trade) Act

The Province's *Greenhouse Gas Reduction (Cap and Trade) Act* provides the statutory basis for setting up a market-based cap-and-trade framework to reduce GHG emissions from large emitters that operate in B.C. Under authority of the *GHG Reduction (Cap and Trade) Act*, B.C.'s Reporting Regulation establishes requirements for reporting GHG emissions from B.C. facilities that emit 10,000 or more tonnes of carbon dioxide equivalent emissions beginning on January 1, 2010. In addition, facilities that report emissions of 25,000 tonnes or greater must have emissions reports verified by a third party. The Reporting Regulation is designed to facilitate a transparent reporting mechanism that can support a future cap-and-trade system.

B.C.'s cap-and-trade program was anticipated to begin on January 1, 2012; however, plans to develop the program appear to have been indefinitely stalled since 2011. Consequently, the proposed Emissions Trading Regulation and Cap and Trade Offsets Regulation are yet to be developed. The Emissions Trading Regulation would establish the rules by which emissions trading allowances are created, distributed, auctioned, traded, tracked and retired for compliance. While an existing Emission Offsets Regulation introduced under the GGTRA establishes requirements for offsets in relation to the Government's carbon neutral requirement, the Cap and Trade Offsets Regulation would establish a single standard for developing compliance-grade offsets for the province. This regulation would govern the development and recognition of emissions offsets in a manner that aligns with the Western Climate Initiative's offset design recommendations.

15. Climate Action Charter

Following a number of public declarations committing the province to becoming a climate leader (in the 2007 Speech from the Throne and the 2007 B.C. Energy Plan), local governments across B.C. signed a Climate Action Charter with the Province and the Union of B.C.

Municipalities, pledging commitment to a goal of becoming carbon neutral[2] by 2012. The Climate Action Charter recognizes that reducing GHG emissions will generate environmental and health benefits for B.C.'s individuals, families and communities, and that it is important to take collective action to share best practises to reduce GHG emissions and address the impacts of climate change. Signatories to the Climate Action Charter pledge to:

- Become carbon neutral with respect to operations by 2012 (exclusive of solid waste facilities, which are regulated under the *Environmental Management Act*);
- Measure and report on the community's GHG emissions profile; and
- Create compact, more energy efficient communities by removing barriers to taking action on climate change and encouraging infrastructure and a built environment that supports communities' needs while minimizing environmental impact.

As of September 2013, 180 out of a total 188 municipalities across B.C. have voluntarily signed the Climate Action Charter and are working to create carbon neutral, compact, energy-efficient communities.

16. Local Government (Green Communities) Statutes Amendment Act

Bill 27, or the *Local Government (Green Communities) Statutes Amendment Act*, requires local governments to include GHG emission targets, policies and actions in their Official Community Plans and Regional Growth Strategies. The act enables local communities to implement a wide range of initiatives relating to climate change, resource conservation and air quality improvements in order to help municipalities and regional districts create more compact, sustainable and greener communities. The ultimate aim of Bill 27 is to assist local governments to contribute to provincial GHG emission reduction goals.

[2] Becoming carbon neutral is a process by which interested parties measure GHG (or carbon-equivalent) emissions, reduce emissions to the fullest extent possible, and then offset any remaining emissions through purchasing credits for emission reductions achieved elsewhere.

Appendix A-6

B.C.'s NATURAL GAS AND LNG STRATEGIES

BRITISH COLUMBIA'S

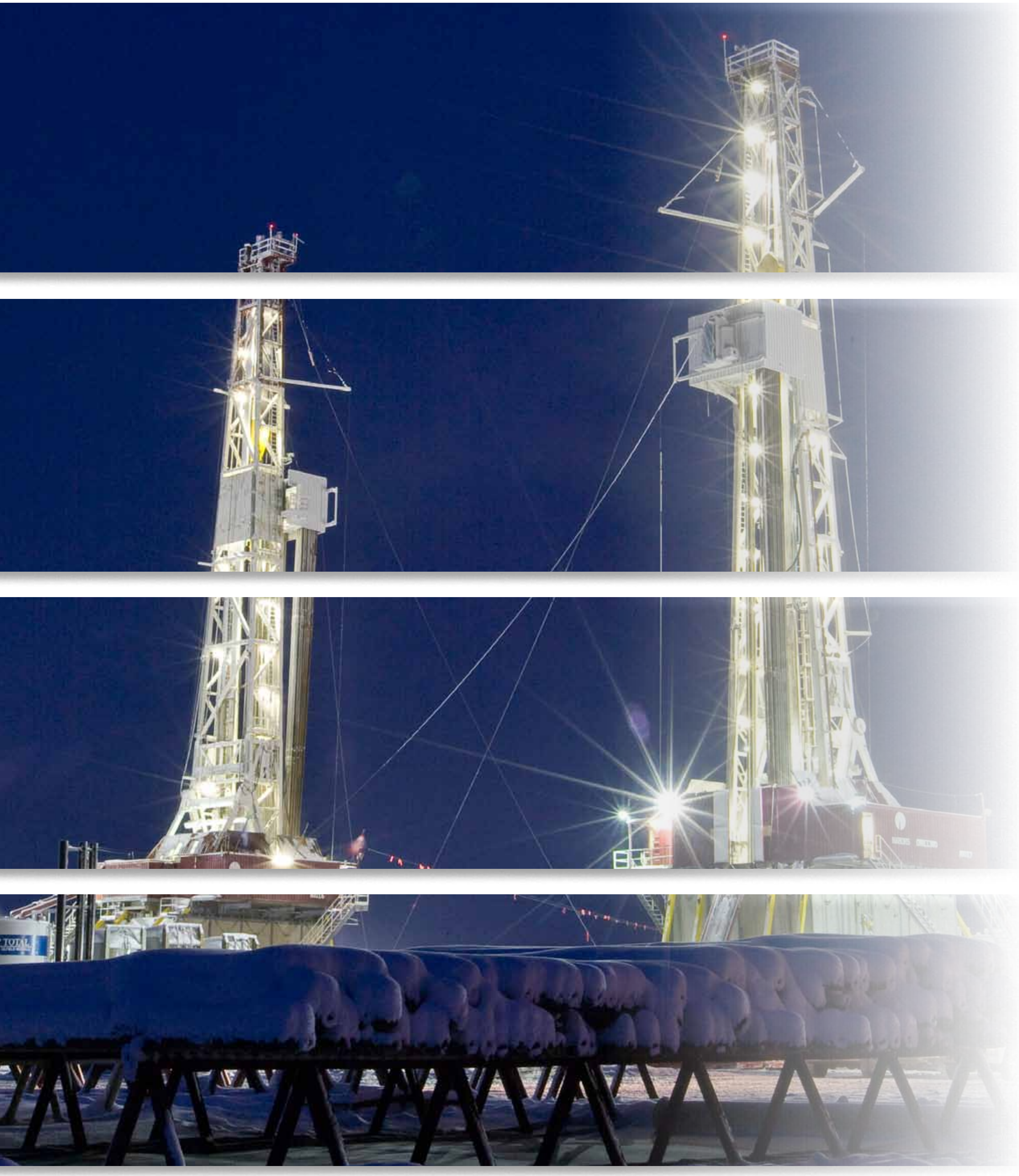
Natural Gas

STRATEGY

Fuelling B.C.'s Economy for the Next Decade and Beyond

BRITISH COLUMBIA

Ministry of Energy and Mines



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Message from the Premier

B.C. WAS BUILT ON ITS NATURAL RESOURCES and our resources continue to fuel our economy. *The BC Jobs Plan* released in September is about using our competitive advantages to benefit all British Columbians. We want to open new markets for our exports, strengthen infrastructure to get our goods to market, and work with employers and communities to help grow and strengthen our economy and create jobs in every region of the province.

The natural gas industry is an important revenue generator for British Columbia. With new, undeveloped shale gas deposits in the northeast, there is a real opportunity for growth. In partnership with First Nations and communities we can reach our goals of new investment, job creation and other economic opportunities, while protecting the environment.

Now is the time to adopt a more aggressive approach to environmentally responsible industrial development. I am confident British Columbia can create a prosperous industry that will bring local jobs to communities and economic benefits for all British Columbians for years to come.

Honourable Christy Clark
Premier of British Columbia

Message from the Minister

BRITISH COLUMBIA HAS THE POTENTIAL TO BE A GLOBAL LEADER in environmentally responsible natural gas development and export.

We are building partnerships and collaborating with other jurisdictions to ensure B.C.'s natural gas policies and programs provide efficient environmental assessment and regulatory oversight. We will advance natural gas actions and strategies to help fuel B.C.'s economy for the next decade and beyond. These will contribute to our leadership in the transition to a low carbon global economy.

Natural gas is the world's cleanest-burning fossil fuel. Over the next 20 years, global demand for natural gas is expected to rise dramatically, fuelled by rapid economic growth in Asia. With demand growing quickly, prices in Asia are up to four times higher than they are in North America. With the development of liquefied natural gas (LNG) – a shippable form of natural gas – B.C. is ideally positioned to compete for a share of that lucrative market.

Export of B.C. LNG could also significantly lower global greenhouse gas production by replacing coal-fired power plants and oil-based transportation fuels with a much cleaner alternative. In *The BC Jobs Plan*, the province has committed to having B.C.'s first clean energy-powered LNG plant in operation by 2015 and three LNG facilities running by 2020. I am confident that we can meet these bold targets.

Honourable Rich Coleman
Minister of Energy and Mines
and Minister Responsible for Housing

Introduction

Natural Gas and Our Low Carbon Future

Natural gas is the world's cleanest-burning fossil fuel. B.C. exports of liquefied natural gas (LNG) can significantly lower global greenhouse gas emissions by replacing coal-fired power plants and oil-based transportation fuels with a much cleaner alternative.

LNG development in B.C. can have lower lifecycle greenhouse gas emissions than anywhere else in the world by promoting the use of clean electricity to power LNG plants.

B.C.'s LNG industry will contribute to our leadership in the transition to a low carbon global economy.

For over 50 years, British Columbia has ranked second only to Alberta in natural gas production in Canada. B.C.'s natural gas sector employs tens of thousands and industry investment has grown from $1.8 billion in 2000 to $7.1 billion in 2010.

The natural gas industry has been a significant economic driver and revenue generator for our province. Natural gas revenue in B.C. generated $1.35 billion in 2009/10 and has been as high as $2.6 billion, in 2005/06, helping to fund vital social services such as health care and education.

The Province is planning to continue to grow the industry over the next 10 years. In the *BC Jobs Plan* released in September, the Province committed to having our first LNG plant in operation by 2015 and three LNG facilities operating by 2020, assuming all environmental approvals are in place.

B.C.'s natural gas resources contained in shale and other fine grained sedimentary rocks (also referred to as tight gas) are immense, and modern drilling technology is now making this gas accessible.

A May 2011 report from the National Energy Board and the B.C. Ministry of Energy and Mines gave a medium estimate of 78 trillion cubic feet (Tcf) of gas that could be developed from the Horn River Basin alone. Resource estimates for the Montney, Liard and Cordova basins have yet to be compiled and these will add significantly to our marketable resources.

To put this in perspective, B.C. currently produces 1.1 Tcf annually and shale and tight gas now comprise 50 per cent of this volume. A 2011 report from the BC Oil and Gas Commission confirmed that B.C. experienced a 42 per cent increase in year-end natural gas reserves over 2009. This represents the highest level of established natural gas reserves and the largest yearly increase in the province's history, continuing a 10-year trend of increases. Meeting LNG development goals will see annual natural gas production approach 3 Tcf per year by 2020.

Vision: Global Leader in Natural Gas

British Columbia can be a global leader in secure and sustainable natural gas investment, development and export.

To achieve this vision, B.C. needs to:

- Maintain current and develop new markets
- Ensure a reliable, abundant supply
- Maintain competitiveness
- Maximize the benefits of natural gas development
- Ensure environmentally responsible development
- Build partnerships to promote development

Courtesy of Nexen Inc.

Courtesy of Nexen Inc.

Developing Current and New Markets

Keep B.C. Competitive in the Global LNG Market

Demand for natural gas is growing in Asia and Europe, primarily for electricity generation and heating purposes, as well as in transportation. China and Japan are both pursuing new supply options – China to fuel its massive modernization and Japan to diversify its fuel supply. With demand growing quickly, prices in Asia are up to four times higher than they are in North America. Export of B.C. liquefied natural gas (LNG) could significantly lower global greenhouse gas emissions by replacing coal-fired power plants and oil-based transportation fuels with a much cleaner alternative. This is a great opportunity for B.C. and an important part of the *BC Jobs Plan*.

B.C. is at the forefront to develop the capacity to export LNG. The first large commercial LNG export facility in Canada is scheduled to open near Kitimat, on B.C.'s central coast by 2015[1]. Kitimat LNG has already earned federal and provincial environmental assessment approvals. It has strong support from the Haisla Nation, on whose land it is being built. In October 2011, it was granted the first-ever federal licence to export LNG from Canada.

The smaller British Columbia Douglas Channel LNG plant is seeking approval of an export license from the National Energy Board. Several other B.C. LNG projects are in the early conceptual stage of development. These LNG projects will bring about $18 billion in investment plus billions of dollars in exploration and development. These projects could also bring substantial revenue to the Province. For example, it is estimated that production from the first phase of the proposed Kitimat LNG plant could result in $90 million annually in revenue, totalling more than $1 billion by 2035.

As new opportunities like LNG emerge, the preservation of current markets will ensure industry development continues to support jobs and resource development in British Columbia. B.C. will remain engaged with the National Energy Board so the province's natural gas will continue to benefit and accommodate energy needs across Canada.

Market Diversification

Most of British Columbia's natural gas is exported. Of the three billion cubic feet per day of gas currently produced in B.C., 16 per cent is consumed within B.C., 41 per cent is exported to the U.S. through two pipeline systems and 43 per cent is delivered to other regions of Canada by pipeline.

1 Kitimat LNG partners are Apache Corporation, EOG Resources Inc., and Encana Corporation.

In addition to global market diversification, there are new and expanded uses of natural gas in North America and British Columbia, including transportation, fuel switching from coal to natural gas for power generation, and as a feedstock to make other products.

Promote Natural Gas as a Transportation Fuel

Natural gas can help reduce greenhouse gas emissions by replacing diesel in heavy and medium vehicle fleets.

Natural gas is 25 to 40 per cent cheaper than gasoline and diesel. A natural gas vehicle produces 20 to 30 per cent fewer greenhouse gas emissions compared to a gasoline or diesel vehicle.

British Columbia is home to world-leading natural gas vehicle industries, including engine and refuelling technology. To assist in transforming the market, the Province's point-of-sale incentives provide up to $2,500 off the sticker price for qualifying compressed natural gas vehicles. Investments in natural gas vehicles will lead to growth and new jobs in this local industry.

The *Clean Energy Act* provides the framework for a planned five-year, $62 million program to reduce transportation emissions for heavy duty natural gas vehicles.

Develop New Markets for Natural Gas

Natural gas has great potential in applications that could develop new industries for British Columbia. These include:

- **Gas-To-Liquids:** Natural gas can be converted into high-value liquid products like clean diesel, naphtha, or jet fuel.
- **Methanol:** Synthesized mainly from natural gas, methanol is a key ingredient in the production of plastics, plywood, paints, and permanent press textiles. It also can be used in motor vehicle fuel, solvent, antifreeze and windshield washer fluid.
- **Fertilizers:** Natural gas can be used to produce ammonia for fertilizer production.

These new natural gas-related industries could open up markets, creating new, high-paying jobs for British Columbians.

A natural gas powered school bus

Ensuring a Reliable, Abundant Supply

Shale Gas is a "Game Changer"

Shale and tight gas is natural gas produced from shale and other fine-grained sedimentary rocks.

Over the past decade, the development of horizontal drilling, and improvements to hydraulic fracturing have made abundant shale gas recoverable. This has changed the natural gas industry forever, making natural gas an abundant natural resource.

The development of shale gas resources in northeast B.C. began in 2005 and has rapidly evolved to generate billions of dollars in provincial revenue from natural gas tenure sales and royalties.

With shale gas now in play, it is conservatively estimated that B.C. has at least 100 trillion cubic feet of recoverable gas. This compares with total production of 22.5 trillion cubic feet in the province between 1954 and 2010.

Our enormous resources of natural gas will be a major contributor to our economy.

Geological Survey of Canada: Mapping shale gas host rocks

Just a few years ago, people were bracing for a shortage of natural gas in North America. Supplies of conventionally accessible gas were declining and proposals for importing LNG from overseas were being advanced. That all changed with the advent of technologies allowing for recovery of shale gas in numerous locations in Canada and the United States. This has driven down the price of natural gas in North American markets.

Despite the recent recession and low natural gas prices, development activity has remained robust in B.C., which currently produces roughly three billion cubic feet per day or 1.1 trillion cubic feet per year of marketable natural gas. However, if North American natural gas supply remains high and prices remain low, it may become difficult to maintain this level of activity.

Managing B.C.'s natural gas reserves depends on the collection, interpretation and public delivery of natural gas geoscience data. This information reduces investment risk in the exploration and development of B.C.'s natural gas resources. Knowledge of the province's resources supports a competitive royalty structure that maximizes the financial benefit to British Columbians.

B.C. needs to continually assess our geological resources to maintain an effective regulatory system that maximizes responsible, sustainable resource development.

Maintaining Competitiveness

Ensure an Effective Royalty Regime

Approximately 90 per cent of oil and gas resources in British Columbia are owned by the Province. The Province sells exploration and production rights to industry. Industry produces and markets the oil and natural gas it finds in exchange for royalty payments to the Province.

The oil and gas sector is a significant source of revenue for B.C. In 2009/10, total revenue from oil and gas, including petroleum and natural gas rights sales, totalled $1.35 billion – almost 60 per cent of total direct revenues from B.C.'s resource industries and four per cent of total provincial revenues. This helps to fund vital social services such as education and health care.

Our royalty programs help encourage oil and gas development in B.C. by providing incentives designed to meet B.C.'s unique resource challenges such as infrastructure development in remote northern locations. B.C. royalty programs are competitive with other North American programs and reflect the cost to extract the resource.

Ensure Infrastructure is Available to Encourage Investment

Ensuring adequate road and pipeline infrastructure is an essential component of maintaining B.C.'s investment competitiveness. B.C.'s innovative natural gas infrastructure programs encourage new, incremental investment that would not otherwise be carried out. The Province offers three natural gas infrastructure programs:

- **The Infrastructure Royalty Credit Program** facilitates all-season road projects and new pipeline projects.
- **The Oil and Gas Rural Roads Improvement Program** invests in the upgrade of public roads and bridges heavily used and required by the oil and gas industry.
- **The Sierra Yoyo Desan (SYD) Road project** is a public-private partnership to upgrade the SYD Road located near Fort Nelson, providing reliable year-round access to the Horn River and Cordova Basins.

Continuing and expanding these programs is vital to the development of B.C.'s emerging LNG industry. Exploring collaborative approaches to the development of pipeline infrastructure to support LNG projects is also key to ensure our natural gas reaches markets.

Amend Natural Gas Act and Regulations

The B.C. Government is reviewing the tenure provisions of the *Petroleum and Natural Gas Act* and its regulations. This is in response to significant technological advances allowing the development of unconventional natural gas resources, the implementation of the *Oil and Gas Activities Act* and emergent environmental issues.

Courtesy of Nexen Inc.

New Jobs for B.C.

The rapid expansion of B.C.'s energy sector over the past decade has resulted in a growing number of permanent, well-paying jobs for British Columbians. Over the next five years, an additional 1,000 to 2,000 job openings – mostly in the province's northeast – are expected, due to expanded natural gas exploration and production required to supply new LNG projects. Further jobs will be created to construct and operate the clean energy projects to power them.

New Skills Training

British Columbia's Jobs Plan and the BC Energy Plan have identified strategies for skills training and labour, including:

- Increasing access to skills and apprenticeship training
- Refocusing Provincial investments to meet regional labour market needs
- Improving First Nations access and outcomes in our education system

First Nations communities are an important part of the future work-force in northern regions.

The Kitimat LNG terminal alone is expected to provide 1,500 construction jobs and 125 permanent jobs. An additional 1,500 pipeline construction jobs will be required for the Kitimat to Summit Lake pipeline project. Additional LNG projects and pipelines will expand on this.

Through the Labour Market Partnerships program, the Province has funded the development of a comprehensive human resource strategy for the resource sector in northern B.C., focusing on four industries, including the oil and gas sector.

Post-secondary institutions in B.C.'s north provide a wide array of training in support of the sector. Additionally, several labour market programs include skills training for the natural resources and construction sectors in the north.

Attracting and retaining a skilled work force also requires the municipal infrastructure to support economic activity and housing. This includes schools, health, recreation and cultural facilities.

The BC Jobs Plan also calls for the creation of Regional Workforce Tables as a new platform for educators, industry, employers, local chambers of commerce, First Nations, labour and others to plan how best to align training programs with regional needs. This will inform how the Province delivers regionally based skills development programs, including $15 million to further support regional post-secondary institutions to address local labour needs.

Engaging and Consulting B.C. Communities and First Nations

Protect Health and Air Quality

Natural gas is a safe fuel. However, there are some public concerns about potential health issues as a result of oil and gas development. These concerns relate to air quality, water use, exposure to sour gas and emergency response.

The Province is conducting a health study of the oil and gas sector to address these concerns. This study includes stakeholder engagement and is expected to be complete by mid-2012. The Province is also initiating work with industries and local communities to establish an airshed monitoring association for the Peace area. In addition, regional water studies are already well underway, including work with GeoScience BC. Both of these initiatives will complement the health study.

Engage with Communities

People who live near oil and gas operations may have some concerns about how this work may affect them. The Province is working with local governments to find out what the concerns are in each community, and exploring new ways to work directly with groups and communities. B.C. is also exploring creative solutions to ensure local communities reap the benefits of natural gas development.

Continue Consulting with First Nations

Many First Nations live in areas where oil and gas development is underway. It is essential the Province consult and accommodate their interests when developing resources to open new areas of B.C. to longer-term economic certainty and stability.

To further improve the investment climate, the Province, in partnership with First Nations, will create a new Aboriginal Business and Investment Council to promote First Nations opportunities with investors and stimulate new economic prospects for communities around B.C.

Northeast British Columbia First Nations

The Province has had a long and collaborative relationship with Treaty 8 First Nations whose communities are impacted by exploration and development of oil and gas resources.

Since 1998, the Province has negotiated Consultation Process Agreements (CPAs) between the Oil and Gas Commission (OGC) and Treaty 8 First Nations. These CPAs have provided significant consultation resources directly to First Nation communities.

The Province and several Treaty 8 First Nations also have Economic Benefit Agreements (EBAs) which provide a framework for relationship building and financial benefits.

The EBAs are 15 year agreements which provide one-time up front disbursements by the Province, along with annual payments based on resource development activity within Treaty 8. Approximately $43.6 million has been provided to Treaty 8 First Nations through the EBAs. The EBAs also include a framework for an ongoing relationship between the Province and First Nations through Long Term Oil and Gas Agreements (LTOGA).

Northwest and Interior British Columbia First Nations

First Nations strongly support the recently approved Kitimat LNG terminal and connecting pipeline. The Province worked with First Nations along the pipeline route to address interests from those communities to become partners in the development. This resulted in an agreement between the Province and the First Nations Limited Partnership comprising 15 potentially affected First Nations along the pipeline route. This agreement will provide up to $35 million to the First Nations, $32 million of which is intended to assist in securing equity participation in the project.

The Kitimat LNG facility is proposed to be built on the Haisla Nation Indian Reserve at Bish Cove near Kitimat. The Haisla Nation is also a partner in the proposal to establish a smaller LNG facility through the Douglas Channel Energy Partnership.

Ensuring Environmentally Responsible Development

Oil and gas activities in British Columbia are regulated by the BC Oil and Gas Commission (OGC), a Crown Corporation and agent of the Crown. The OGC is a "single-window" regulator that works with industry, First Nations, communities and stakeholders to provide efficient and effective oversight of oil and gas activity. The OGC reviews applications and, once approved, inspects and monitors construction, operation and reclamation. The OGC is also responsible for reviewing and approving land tenure, water use, forest harvesting, waste disposal and potential heritage impacts.

B.C.'s environmental assessment process, managed by the Environmental Assessment Office, reviews major projects to ensure they meet the goals of environmental, economic and social sustainability. The assessment process considers issues and concerns to the public, First Nations, interested stakeholders and government agencies.

Natural Gas is a Climate Solution

Natural Gas is a climate solution – it is widely recognized as a transition fuel to a low carbon global economy.

We have an important role in helping to lower global greenhouse gas emissions. B.C. can make a significant contribution to global reduction targets when B.C. gas is exported to Asia as LNG and replaces coal and/or diesel as fuel for electricity production or transportation.

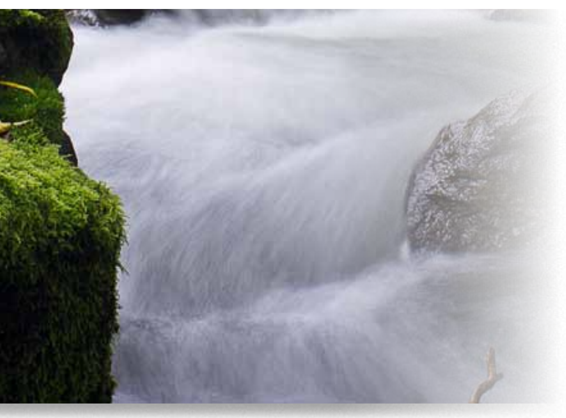
The Natural Gas Climate Action Working Group, which includes members from industry and government, is developing strategies to balance natural gas development with climate objectives with minimal economic impact. Some options include electrification of gas-fired equipment, energy efficiency measures, carbon capture and storage, and enhanced oil recovery.

One area where considerable progress is being made is with flaring – the controlled burning of natural gas that cannot be processed or sold – at oil and gas production sites. The 2007 *BC Energy Plan* committed to eliminating routine flaring by 2016, limiting flaring to short-term well testing, well work-overs, or during maintenance or emergency situations. The Oil and Gas Commission reported in 2010 that the interim goal to cut flaring in half by 2011 had already been achieved.

Another area with considerable potential is carbon capture and storage, an emissions mitigation technology that involves capturing, transporting and storing industrial sourced carbon dioxide in the pore space of rock formations deep underground. This internationally promoted measure can contribute significantly to reducing emissions.

Courtesy of Nexen Inc.





Optimal underground storage sites exist in northeastern British Columbia. Close proximity to current natural gas industry activity make these sites excellent candidates for carbon capture and storage projects.

British Columbia also has projects that are producing biomethane from landfills and biomass. The biomethane is sold either directly into the natural gas distribution network or is used to generate clean electricity.

Clean energy is an important part of LNG development in B.C. For instance, once operational the Kitimat LNG plant will be the first in the world to use clean electricity. As a result, LNG development in B.C. can have a lower lifecycle for greenhouse gas emissions than anywhere else. This will differentiate B.C. in the global LNG export market.

B.C. is a clean energy leader, supported by the *BC Energy Plan* and the landmark *Climate Action Plan* with the most comprehensive carbon price in North America under the Revenue Neutral Carbon Tax. Reaching $30/tonne in 2012, the carbon tax creates a price incentive to eliminate waste and reduce the consumption of fossil fuels. By legislation, all of the revenues must be returned into the B.C. economy through tax cuts that improve economic competitiveness and productivity. The benefits include a competitive corporate tax rate, the lowest personal income tax rates in Canada, and incentives like the Northern and Rural Homeowner Benefit.

Using natural gas efficiently in B.C. not only reduces emissions; it also reduces the cost of doing business, increases productivity and improves the standard of living that British Columbians have come to expect. Government and utilities are pursuing opportunities to increase the efficiency of buildings and industrial processes through policies and programs.

Effectively Manage Water Quality and Sustainability

Water quality and sustainability are critical to natural gas development. The Province is modernizing the *Water Act* to keep drinking water safe. This Act will consider industry's use of water, current groundwater protection and evaluate hydraulic fracturing operations to ensure sustainable water management.

B.C. also has a regulatory framework to manage water use for natural gas development. The *Oil and Gas Activities Act* and associated regulations, which were brought into force in 2010, were designed to encompass the technologies now being employed in natural gas development, including hydraulic fracturing and the use of water. The Act and regulations will continue to be monitored to ensure that they are effective, community concerns are addressed and industry's need for water is met. A B.C.-led New West Partnership (involving B.C., Alberta and Saskatchewan) working group has been established to develop and share information on best practices related to water use in shale gas development.

As a first step to address First Nation and public concerns, B.C. requires mandatory disclosure of the hydraulic fracturing fluids injected into the subsurface by industry. A public disclosure registry for hydraulic fracturing additives was launched in early 2012. The FracFocus.ca registry provides British Columbians with additional information about hydraulic fracturing and water management in shale gas development.

Continue Managing Boreal Caribou

Approximately 1,300 Boreal Caribou live in northeast British Columbia, members of a population believed to be in decline. This may be due to habitat loss, fragmentation of the herd, alteration of their habitat and increased predation.

Boreal Caribou are listed as 'threatened' under the federal *Species at Risk Act*, are provincially red-listed (Threatened to Endangered) and are identified as Priority 1 under the BC Conservation Framework.

The Province is taking action to slow this decline and ensure Boreal Caribou are maintained in British Columbia for future generations. The Province has developed an implementation plan to manage Boreal Caribou.

The plan balances habitat protection and management of Boreal Caribou with oil and gas development. Actions supporting the implementation plan include establishing areas where oil and gas tenures will not be offered for a minimum of five years, establishing management practices for activities that are proceeding within certain caribou habitat areas and collaboration with industry on funding habitat restoration and research into Boreal Caribou and their habitat.

Building Partnerships to Promote Development

Collaborate with Other Jurisdictions

Under the *Canadian Constitution Act*, provincial governments are responsible for natural resources within their jurisdictions and the federal government is responsible for natural resources in the territories and has authority in other areas affecting the natural resource sector, such as international trade, transportation and external relations. As a result, government policies and programs affecting natural gas development result from an integrated and sometimes overlapping set of authorities.

Canada's federal, provincial and territorial ministers responsible for energy and mines meet annually to discuss and take collaborative action on issues of common interest.

In 2011, energy ministers agreed on a pan-Canadian energy framework with a shared vision for Canada as a recognized global leader in secure and sustainable energy supply, use and innovation.

Within this framework, there are three key initiatives relating to B.C.'s Natural Gas Strategy:

1. Diversifying international export markets and attracting investment for the energy sector.
2. Improving the alignment of federal-provincial regulatory systems.
3. Building on past energy efficiency accomplishments.

British Columbia, Alberta and Saskatchewan launched the New West Partnership in 2010, creating an economic powerhouse of nine million people. This ambitious agreement creates Canada's largest interprovincial barrier-free trade and investment market. An energy memorandum of understanding was signed by the three provinces in 2010, establishing a collaborative framework to strengthen and expand the region's energy sectors.

The Province is also working with the federal government to achieve greater efficiencies in environmental assessments of major projects. For example, the BC Environmental Assessment Office and the National Energy Board signed an Environmental Assessment Equivalency Agreement in 2010, which specifies that where a proposed project requires both a B.C. Environmental Assessment Certificate and approval under the *National Energy Board Act*, the assessment completed by the National Energy Board is considered equivalent to the B.C. process.

To further streamline regulatory processes and to provide investment certainty, B.C. recommended in November 2011 that the federal *Environmental Assessment Act* be amended to include an option to eliminate the need for a separate federal environmental assessment of projects where a provincial environmental assessment is required. The "one project – one environmental assessment" would replace two overlapping review systems with a single system that is rigorous, comprehensive, efficient and timely. Many major natural gas development projects are subject to National Energy Board review; however, for those projects subject to separate provincial and federal environmental assessments, the one project – one assessment approach offers greater efficiencies without reducing environmental standards or the rigour of the review process.

Pacific Northwest Economic Region (PNWER)

PNWER is a regional non-partisan U.S.-Canadian forum dedicated to encouraging global economic competitiveness and preserving the world-class natural environment of the region. Its member jurisdictions are British Columbia, Alberta, Saskatchewan, the Yukon Territory, the Northwest Territories, Alaska, Washington, Idaho, Montana and Oregon. It is recognized by both the American and Canadian federal governments as the model for regional and bi-national cooperation because of its proven success. Energy is a key topic at PNWER conferences and workshops, where delegates share information on best practices, new policies and technologies, and resource development and infrastructure projects.

Pacific Coast Collaborative

With a combined population of 52 million and a GDP of $2.5 trillion, Alaska, British Columbia, California, Oregon and Washington are poised to emerge as a mega-region and global economic powerhouse driven by innovation, energy, geographic location and sustainable resource management, attracting new jobs and investment while enhancing an already unparalleled quality of life.

On June 30, 2008, the leaders of the five jurisdictions signed the Pacific Coast Collaborative Agreement, the first agreement that brings together the Pacific leaders as a common front to set a cooperative direction into the Pacific Century. Out of this agreement was born the Pacific Coast Collaborative – a formal basis for cooperative action, a forum for leadership and information sharing, and a common voice on issues facing Pacific North America.

Summary of Actions/ Strategies

Keep B.C. Competitive in the Global Liquefied Natural Gas (LNG) Market

1. Coordinate permitting and approval processes among agencies to ensure timely project construction.
2. Contribute to trade missions and other marketing initiatives that demonstrate government support for LNG exports.
3. Invest in critical infrastructure to power future LNG facilities in balance with the need to keep electricity rates affordable for the people of British Columbia.
4. Ensure the availability of sufficient clean and renewable electricity to make possible the development and operation of an LNG industry.
5. Explore collaborative solutions for natural gas pipeline development.

Current Markets:

1. Remain engaged with the National Energy Board on proposals that effect access to current markets.

Promote Natural Gas as a Transportation Fuel

1. Work to introduce a regulation under the *Clean Energy Act* to advance a proposed natural gas vehicle program.
2. Work with the business community, fuel suppliers and natural gas producers to increase the use of natural gas in the transportation sector.

Develop New Markets for Natural Gas

1. Attract investment for new value-added projects to B.C. by providing a stable, supportive development framework.
2. Encourage value-added industries through innovative government programs that reward industry for creating new applications for B.C.'s natural gas.
3. Promote the use of high efficiency natural gas electricity generation in export markets, and in specific markets in B.C., to meet the demand for capacity.

Ensuring a Reliable, Abundant Supply

1. Improve B.C.'s resource estimates by completing resource assessments of the Montney Play, the Liard Basin and other significant areas.
2. Identify, evaluate and provide the geological and hydrological context for surface, subsurface, and deep saline water resources in Northeast British Columbia.
3. Conduct regional, basin-scale studies directed at enhancing the understanding of the geological framework that hosts British Columbia's oil and gas resources.
4. Investigate, evaluate and promote new conventional and unconventional natural gas opportunities to increase investment and encourage exploration.
5. Continue to host the BC Unconventional Gas Technical Forum to facilitate information sharing about development activities and technical advances in the industry.

Ensure an Effective Royalty Regime

1. Monitor and evaluate B.C.'s royalty system and recommend expanded or new programs, as necessary, to make sure the province remains highly competitive.

Ensure Infrastructure is Available to Encourage Investment

1. Continue to offer the $120 million royalty credit allocation through the Infrastructure Royalty Credit Program, to enhance industry capital planning and investment in emerging or under-explored areas.
2. Continue the Oil and Gas Rural Road Improvement Program to target investments in public road infrastructure required for natural gas development.
3. Complete improved road access investments that will enable development of the Horn River Basin and Cordova Embayment shale gas areas.
4. Explore collaborative approaches for pipeline infrastructure development to ensure B.C.'s gas is available to supply LNG export plants.

Amend Natural Gas Act and Regulations

1. Amend the *Petroleum and Natural Gas Act* and regulations to improve and update administration for Crown-owned natural gas subsurface resources.

Summary of Actions/Strategies

New Jobs for B.C.

Skilled Workers:

1. Promote greater use of the Employment Skills Access program, which provides free skills training at public post-secondary institutions across the province for entry or re-entry into the labour market.
2. Implement a Northeast Regional Workforce Table, as outlined in the *BC Jobs Plan*.
3. Provide leadership to the post-secondary system to support the education and training needs of the natural gas development sector.
4. Create a Labour Market partnership to develop strategies that address the natural gas sector's future needs.

Engaging and Consulting B.C. Communities and First Nations

Health and Air Quality:

1. Develop and implement a three-phase health study of oil and gas development.
2. Work with communities and industries to develop and implement an airshed monitoring association.
3. Complete and publish scientific studies on water resources in the northeast.

Engaging Communities:

1. Work with communities and stakeholders to develop a "made in B.C. approach" to local engagement.
2. Work with communities to support job development and service sector opportunities, including an evaluation of current grant programs to consider the economic benefits of natural gas development.

First Nations:

1. Negotiate new Oil and Gas Commission Consultation Process Agreements with Treaty 8 First Nations.
2. Implement Economic Benefit Agreements with four Treaty 8 First Nations.
3. Continue to build partnerships and support with Northwest and Interior British Columbia First Nations.
4. Continue to engage with the First Nations Limited Partnership to implement the Partnership Agreement.

Natural Gas Is a Climate Solution

Addressing Emissions Targets:

1. Continue to implement emission reduction measures while allowing the natural gas sector to maintain its competitive position.
2. Continue to reduce natural gas flaring using innovative solutions, practices and emission reduction technologies designed to reach *BC Energy Plan* goals.
3. Promote the use of carbon capture and storage in B.C. by:
   - Completing development of a regulatory framework.
   - Amending legislation, if required.
   - Working with the BC Oil and Gas Commission to develop regulations.
   - Evaluate potential projects.
4. Establish a BC Energy Efficiency Network to promote improved productivity of B.C.'s industrial sector through the efficient use of natural gas.
5. Develop a revised Energy Efficient Buildings Strategy in 2013 with an emphasis on natural gas efficiency.
6. Encourage biomethane opportunities, including offering consumers low-carbon natural gas.

Effectively Manage Water Quality and Sustainability

1. Continue to develop the FracFocus.ca registry, recently created by the BC Oil and Gas Commission, to ensure it provides public disclosure of ingredients injected into the subsurface for natural gas development.
2. Further protect B.C.'s water resources by developing a comprehensive northeast BC Shale Gas Hydraulic Fracturing Water Strategy by 2013.

Continue Managing Boreal Caribou

1. Continue consulting with First Nations and stakeholders on the Boreal Caribou implementation plan.
2. Monitor and evaluate the effectiveness of implementation measures, including tenure deferrals, management practices, habitat restoration and research.
3. Work with other provinces on a coordinated response to Environment Canada on the federal recovery strategy for the Woodland Caribou, Boreal population.

Collaborate With Other Jurisdictions

1. Collaborate on and improve natural gas and LNG market information gathering and monitoring with the National Energy Board, and through the New West Partnership.
2. Continue working with the federal government to eliminate the need for duplicate federal and provincial environmental assessments and decisions on proposed projects.
3. Continue to engage in intergovernmental and regional forums.
4. Complete negotiations with Haisla Nation and Canada on the regulatory regime for the Kitimat LNG facility on the Haisla Nation reserve near Kitimat.

Courtesy of Nexen Inc.

CANADA STARTS HERE

THE BC JOBS PLAN

BRITISH COLUMBIA

LNG

Liquefied Natural Gas

A Strategy for B.C.'s Newest Industry

British Columbia | Ministry of Energy and Mines

Message from the Premier

THE BC JOBS PLAN RELEASED IN SEPTEMBER is all about leveraging our competitive advantages to benefit British Columbians. Opening new markets for our exports, strengthening infrastructure to get our goods to market, and working directly with employers and communities will all help grow and strengthen our economy – creating jobs in every region of the province.

Building on our strengths is critical. So is breaking new ground. We've always relied on natural resources to fuel our economy. Now, with liquefied natural gas (LNG), we have a rare and exciting opportunity to build a whole new industry and use its development to spur other positive changes, such as growth in our clean-energy sector.

There will be challenges along the way. That is inevitable. It goes hand-in-hand with creating something new. As a government, we are committed to working closely with communities, First Nations and other important stakeholders. We are confident that, working together, we can reach our goals – investment, job creation and new economic opportunities – while protecting the environment and building a better quality of life for future generations.

With this LNG strategy, we are taking the next steps forward to harness British Columbia's strengths for the benefit of all our citizens. It's part of our plan to increase economic prosperity, create an environment where business and investment can flourish, and show the world that Canada really does start here.

Honourable Christy Clark
Premier of British Columbia

Global trade in LNG doubled between 2000 and 2010. It's expected to increase by another 50 per cent by 2020.

Message from the Minister

Honourable Rich Coleman
Minister of Energy and Mines
and Minister Responsible for Housing

1,000 cubic feet of natural gas costs under $4 in North America in late 2011 – versus $16 in Asia.

OVER THE NEXT 20 YEARS, GLOBAL DEMAND FOR NATURAL GAS is expected to rise dramatically, fuelled by rapid economic growth in Asia. With the development of LNG – a shippable form of natural gas – B.C. is ideally positioned to compete for a share of that lucrative market.

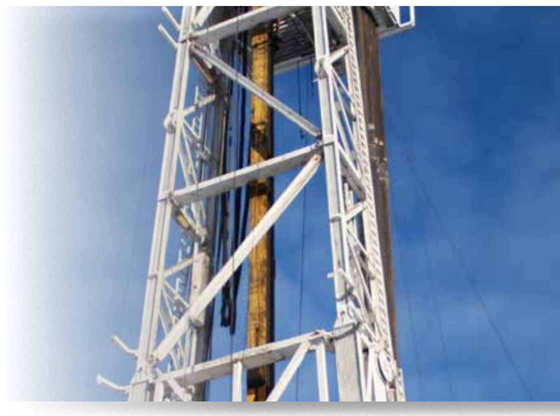
Building a B.C. LNG industry will take time. And other jurisdictions – including the U.S., Australia and Africa – are also moving to develop their LNG potential. The good news is that B.C. is ready: we've been preparing for this opportunity for nearly a decade with progressive royalty programs, infrastructure upgrades, clean energy policies, comprehensive environmental assessments, and direct engagement with industry, First Nations and communities.

We are working hard to build our overseas markets through measures such as the Premier's recent trade mission to Asia. We are working with the industry to attract new capital and foreign investment. The federal government recently approved a 20-year export licence for the LNG facility being built in Kitimat – the first such licence ever issued in Canada.

With *The BC Jobs Plan*, the Province has committed to having our first LNG plant up and running by 2015, with a total of three LNG facilities operating by 2020. These are bold targets, but I am confident British Columbia will meet them.

Developing our LNG export potential is an excellent investment in our future. It will generate thousands of jobs and billions of dollars in new investment. That will mean more revenues for government to pay for services like health care and education. Equally important, it promises long-term stability for families and communities, with well-paying jobs, diversified economies and new opportunities to build expertise in a new global industry.

LNG Development – Our Vision for the Future



Quick Facts About Liquefied Natural Gas

* LNG is natural gas, cooled to -160 degrees Celsius to keep it in a liquid form.
* It is non-toxic, odourless, non-corrosive and less dense than water.
* Compared to conventional natural gas, LNG takes up 600 times less space.
* Unlike conventional natural gas, it can be shipped overseas, dramatically increasing its potential markets.
* LNG has been safely used and transported around the world for 50 years.
* It is a stable, low risk fuel.
* If it spills, LNG will warm, rise and dissipate into the atmosphere.

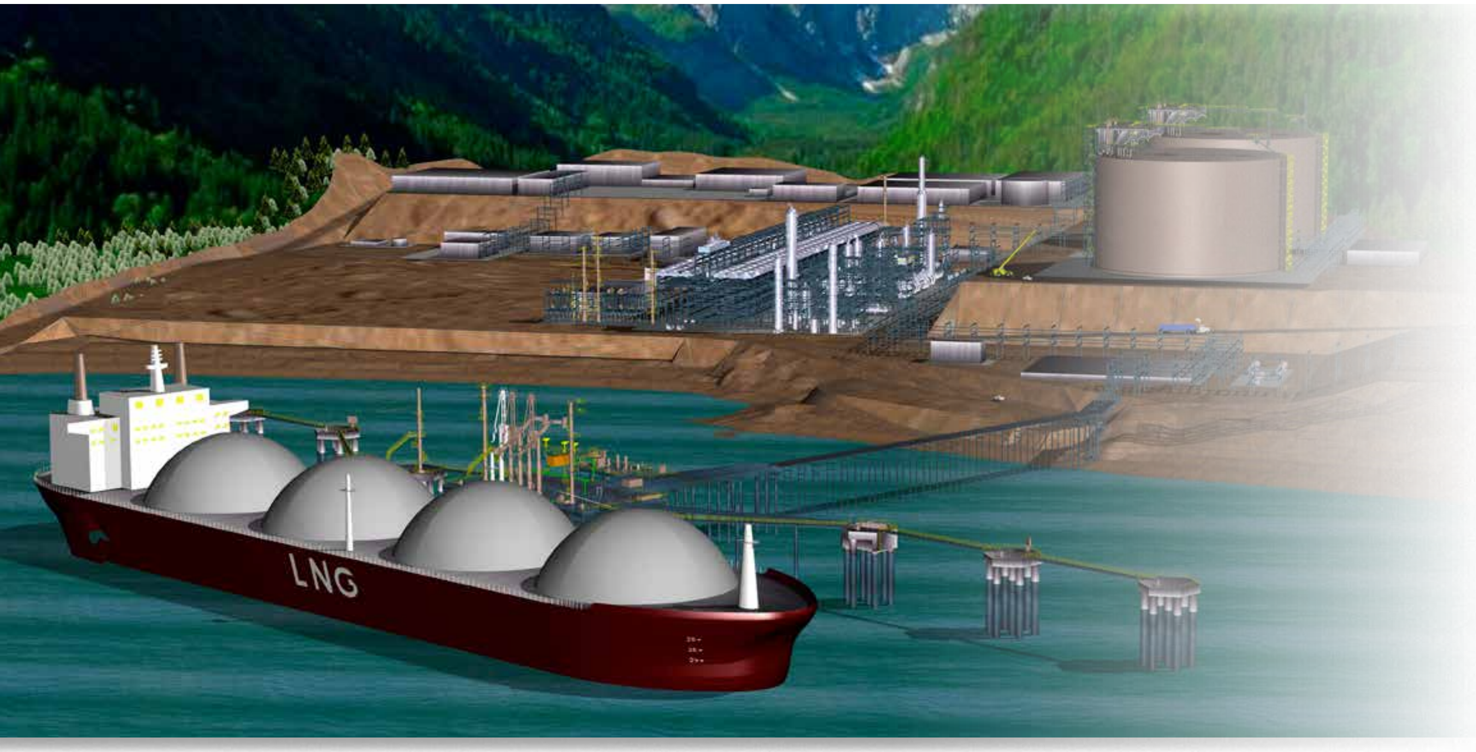
JUST A FEW YEARS AGO, PEOPLE WERE bracing for a shortage of natural gas in North America. Supplies of conventionally accessible gas were declining and contractors were considering options for importing liquefied natural gas – LNG – from other jurisdictions.

That all changed with the advent of technologies allowing for recovery of shale gas – an abundant form of natural gas with significant environmental benefits.

Natural gas is the world's cleanest-burning fossil fuel. For example, converting just one heavy duty truck from diesel to natural gas would reduce the same amount of greenhouse gas emissions as taking approximately 30 cars off the road. As proven supplies increase, so do the incentives to replace coal-fired generation with natural gas. So we believe it has an important role in the global transition to cleaner energy sources.

B.C. has been developing shale gas resources since 2005, generating billions of dollars in government revenue from land sales and royalties. Now we're moving forward to develop the potential of LNG for export.

Multiple investors across the natural gas sector have expressed interest in developing LNG export facilities. The first commercial LNG export facility in Canada is scheduled to open in Kitimat, on B.C.'s central coast, by 2015. And the Province has committed to working with interested investors, such as Shell Canada, to have three facilities in operation by 2020, assuming all environmental and permitting applications are granted.



Courtesy of Apache Canada LTD.

One of the first projects underway, the Kitimat LNG facility, has already earned federal and provincial environmental assessment approvals. It has strong support from the Haisla Nation, on whose land it's being built. And, in October 2011, it was granted the first-ever federal licence to export LNG from Canada. The Kitimat LNG plant will use clean electricity to liquefy natural gas, which results in lower emissions than plants elsewhere in the world.

Moving forward, additional LNG facility developments will use local clean energy with support from B.C.'s natural gas as necessary.

With this strategy, the Province intends to keep that momentum going, generating thousands of jobs and billions of dollars worth of new economic development to benefit families and communities in every part of British Columbia.

LNG: Generating Jobs and Revenues

The Province has committed to having three LNG facilities in operation by 2020, assuming all environmental approvals are granted. Based on current estimates from project proponents, that could mean:

* over $20 billion in direct new investment
* as many as 9,000 new construction jobs
* about 800 long-term jobs
* thousands of potential spin-off jobs, and
* over $1 billion a year in additional revenues to government.

Vision: Three LNG plants in operation by 2020

Goals:

* Keep B.C. competitive in the global LNG market
* Maintain B.C.'s leadership on climate change and clean energy
* Keep energy rates affordable for families, communities and industry

1. Keep B.C. competitive in the global LNG market

NATURAL GAS IS ONE OF B.C.'S MOST ABUNDANT RESOURCES, with vast untapped reserves throughout the northeast. Fears of a North American shortage disappeared in recent years with the advent of technologies making shale gas accessible. And while that has been a significant economic driver and revenue generator for our province, increased supply across North America has led to lower prices.

Natural gas will continue to be an important fuel for British Columbians, heating our homes, powering industry, and fueling our vehicles with fewer emissions than oil, gasoline or diesel. Developing liquefied natural gas for export will allow B.C. to dramatically expand its markets – and meet growing demand in Asia.

B.C. currently produces 1.2 trillion cubic feet (Tcf) of natural gas per year. Meeting our LNG development goals could add another 1.9 Tcf per year.

China and Japan are both pursuing new supply – China to fuel its massive modernization, and Japan to diversify its fuel supply. With demand growing quickly, prices in Asia are also up to four times higher than they are in North America.

All of this adds up to a great opportunity. But B.C. is not alone in pursuing it. Asian demand is fuelling a global race for long-term contracts to supply LNG, and B.C. faces stiff competition from jurisdictions such as Australia, the U.S., Qatar and Africa.

B.C.'s LNG Advantages

B.C. is well positioned to compete for a share of the lucrative Asian LNG market. Our advantages include:

- lower shipping costs, thanks to our proximity to Asia
- secure, stable government
- vast natural gas reserves
- high environmental standards
- potential to access clean electricity
- positive relationships with First Nations peoples
- a well-established service sector
- strong, updated regulations.

The Kitimat plant is on target to be fully operational by 2015 and several other projects are at the proposal stage. Recognizing that time is of the essence, the Province is taking an aggressive approach to developing the sector:

- an efficient regulatory system for LNG growth has been established
- overseas marketing is ramping up, supported by the New West Partnership with Alberta and Saskatchewan
- work is underway to streamline federal and provincial environmental assessments to create a single, more efficient process
- approaches to collaborative solutions for natural gas pipeline development are being explored, and
- collaboration with local communities, First Nations, industry and other levels of government is being strengthened to define more effective working relationships that benefit the entire province.

Next steps in helping to ensure B.C. has a competitive edge in this new global market will include investments in skills training. The Province is working with industry to define its needs and to help ensure the B.C. post-secondary system can deliver the targeted training needed to develop LNG, and to support the broader B.C. oil and gas sector.

2. Maintain B.C.'s leadership on climate change and clean energy

LNG – Helping to Address Global Climate Change

LNG development in B.C. will have lower life cycle green house emissions than anywhere else in the world by promoting the use of clean electricity to power LNG plants.

Natural gas has a key role to play in reducing greenhouse gas emissions (GHGs), and that is one of the driving factors behind its growing use in Asia. B.C. exports of LNG will significantly lower global GHG production by replacing coal-fired power plants and oil-based transportation fuels with a much cleaner alternative.

These reductions will affect B.C.'s own climate action targets, but since climate change is a global phenomenon, they will have a positive overall impact. Because other countries, including China, have their own GHG reduction goals, cleaner-burning LNG is even more attractive.

BRITISH COLUMBIA HAS A LONG HISTORY OF clean energy leadership, dating back to the 1960s when BC Hydro was established. Today, clean hydroelectric power, along with other renewable sources such as wind power and biomass, meets over 93 per cent of British Columbia's electricity needs. We are also offsetting two-thirds of our electricity demand growth through efficiency and conservations measures.

B.C.'s commitment to clean energy is also supported by the landmark Climate Action Plan, the first and most ambitious of its kind in North America.

As part of the Jobs Plan, the Province is examining ways to grow the market for natural gas as a transportation fuel, in both CNG (compressed natural gas) and LNG forms. These alternatives can replace diesel in heavy duty fleets and other vehicles, and thereby help to lower GHG emissions.

At the same time, energy is needed to produce higher volumes of natural gas, and to operate LNG production plants. The first two LNG plants – BC Douglas Channel and Kitimat LNG – will use clean electricity to drive the liquefication process, the first LNG plants to do so in the world. As a result, LNG development in British Columbia will have lower lifecycle greenhouse gas emissions than anywhere else. This will differentiate us in the global LNG export market.

As part of this strategy, the Province and BC Hydro will continue to work with the industry, First Nations, and with clean-energy producers to develop reliable, sustainable sources of supply.

Converting just one heavy duty truck from diesel to natural gas would reduce the same amount of GHG emissions as taking approximately 30 cars off our roads.

"With BC Hydro, our government is planning to meet the power demands required by new LNG facilities. LNG expansion will not be held back by a lack of supply of electricity."

–Canada Starts Here: The BC Jobs Plan

3. Keep energy rates affordable

LIKE MOST MAJOR INDUSTRIES, LNG PRODUCTION REQUIRES a steady source of power. In some cases, that could mean building new transmission lines or other types of infrastructure. That, in turn, has the potential to affect BC Hydro rates – and the Province is committed to ensuring the impacts on families and industry are minimized.

BC Hydro and the Province are currently working with LNG proponents to assess their future electricity needs – recognizing the key priority of keeping rates affordable. To offset the increased expense of operating new LNG facilities in the province, Government will ensure LNG developers contribute capital for infrastructure development and to the electricity supply required to serve each operation.

Another measure protecting consumers stems from a recent review of BC Hydro. That has led to changes in how government will implement its electricity self-sufficiency policy. This policy framework was originally implemented under the 2007 *Energy Plan* when economic growth was strong, natural gas prices were high and other jurisdictions were putting a price on carbon through taxes and planned cap and trade. Since that time, BC Hydro's operating environment has changed, with market electricity prices dropping significantly as a result of the slow economic recovery, low natural gas prices, and the over building of subsidized renewable energy in the United States.

The original self-sufficiency policy required BC Hydro to acquire new electricity supply assuming that inflows into provincial water reservoirs would be at historically low levels, and to acquire an additional 3,000 gigawatt-hours of "insurance" by 2020. Moving forward, BC Hydro will plan electricity needs based on average water conditions, and the insurance requirement will be removed. Future demand from industrial development will now drive the need to purchase additional power.

These changes will enhance BC Hydro's ability to optimize its unique and flexible hydro-based system and transmission connections to the western electricity market, creating more opportunities to earn income through short-term trading for the benefit of ratepayers.

The BC Hydro Review concluded that the impact of moving to average water and removing the insurance requirement would reduce electricity rate increases over the medium and long-term – up to eight per cent by 2016 and 20 per cent by 2020. This new policy direction will ensure that B.C. families and businesses will continue to enjoy some of the lowest electricity rates in North America, even as the government continues moving forward to implement the *Jobs Plan*.

Conclusion

LNG IS A BRAND NEW INDUSTRY WITH MASSIVE POTENTIAL for British Columbia. We have the supply, we have the technology, we have a great geographic advantage and, as we move forward to develop this industry, the whole province will benefit.

Thousands of people will have new jobs. Local economies will be more diversified. New skills training will be developed with new opportunities for future generations.

The LNG industry will generate economic spinoffs in areas such as the service sector and clean-energy development. First Nations will have new sources of economic strength and stability. And the Province will receive more revenues to pay for public services.

With this strategy, the government has laid out its critical priorities for LNG development:

- keeping B.C. competitive in the global LNG market;
- maintaining B.C.'s leadership on climate change and clean energy, and
- keeping energy rates affordable for families, communities and industry.

These three priorities will guide us going forward and help us to establish a thriving, competitive LNG industry that sets new standards for environmental and social responsibility.

As part of *The BC Jobs Plan*, this strategy is all about using our strengths to defend and create jobs in every community. This is B.C.'s time to lead and, together, we will.

Courtesy of TransCanada

"Not only have our people received immediate benefits from the project, in the form of a $56 million payment for the sale of our equity in Kitimat LNG, but the long-term, regular lease and property tax payments combined with the employment and business opportunities associated with the project provide a greater measure of economic stability than we have ever experienced."

– Former Haisla Nation Chief Counsellor Dolores Pollard
March 9, 2011

CANADA STARTS HERE

THE BC JOBS PLAN

BRITISH COLUMBIA

Appendix A-7

RENEWABLE NATURAL GAS OFFERING

APPENDIX A-7 – RENEWABLE NATURAL GAS OFFERING

1. Introduction

Launched in June 2011 for residential customers and March 2012 for commercial customers, FEI's Renewable Natural Gas (RNG) Offering provides customers with the option to purchase a biomethane-blended natural gas supply. The program advances British Columbia's energy and climate change objectives (outlined in Appendix A-5) by developing renewable energy, reducing GHG emissions, and promoting the use of low carbon energy.[1] This appendix outlines biomethane demand from existing and emerging market opportunities in addition to expected supply volumes from approved projects. The program success to date and expected forecast demand have justified continuing the pilot program on a permanent basis; this was approved by the Commission in December 2013.[2]

2. Biomethane Demand

At the end of the program's two year test period (in December 2012), almost 5,000 customers were subscribed to RNG Offering at an annualized demand of nearly 60,000 GJ. This represents close to a 1% participation rate of FEI's residential customers, which is similar to uptake rates of other green energy pricing programs across North America with comparable time in the market. FEI is confident of its decision to pursue a renewable energy program and sees room for continued growth among residential and commercial customers. For the purposes of developing program demand forecasts, the Company has analyzed several scenarios taking into account:

- Ramping up to the industry median of 1.0% and the industry average of 2.1% participation rate, and
- New market opportunities.

The participation rate to date is below the high demand forecast included in the 2010 Biomethane Application but is following the targeted demand of one to two percent, which is the trend of other green energy pricing programs.[3] FEI believes that as the RNG Offering matures

1 The B.C. Bioenergy Strategy aims to "launch British Columbia as a carbon-neutral energy powerhouse in North America [and] help B.C. achieve its targets for zero net greenhouse gas emissions from energy generation, improved air quality, electricity self-sufficiency and increased use of biofuels." *B.C. Bioenergy Strategy, 2009.*

2 BCUC Decision G-210-13, Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis, Dec. 11, 2013.

3 FEI's 2010 primary research showed market potential for 16% of residential customers to sign up for a 10% biomethane blend, which is used as the high demand scenario. Refer to section 6.5 of the 2010 Biomethane application for additional discussion of the high demand forecast compared to the targeted demand. FEI's 2012 primary research showed a 27% market potential uptake for residential customers. Due to current market traction, FEI believes that industry trends better represent potential uptake for the RNG Offering. Refer to section 4 of the 2012 Post Implementation Report for additional discussion on demand.

in the marketplace and awareness of the RNG Offering grows, the achievable market potential will increase and ramp up to the industry average 2.1% participation rate in five years.

The largest impact on demand for biomethane is expected to come from emerging markets in the commercial sector; many such customers have signed letters of intent demonstrating their commitment to buy the RNG offering. Table 1 summarizes the potential demand from large emerging market projects that would be in addition to the growth mentioned above.

Table 1: Potential Biomethane Demand from Emerging Market Projects

Customer	Annual Biomethane Demand (GJ/year)
City of Vancouver	9,000
City of Richmond	10,000
University of British Columbia (UBC)	500,000 to 1,500,000
Direct Energy Systems (FAES Projects)	155,000
Haida Gwaii	280,000
WesPac Energy (Export market)	1,500,000
Total	**2,454,000 – 3,454,000**

In April 2013, the University of British Columbia signed up for an initial 20,000 GJ of biomethane per year and continues to show interest in ramping up to 500,000 to 1,500,000 GJ over the next five years.

2.1 BIOMETHANE DEMAND SCENARIOS

Over the next three years, the potential maximum demand from large volume customers is over 2.5 PJ—and reaches nearly 4 PJ when off-system sales are included as shown in Figure 1.

Due to limited historical data and the evolving nature of emerging markets for biomethane, FEI has developed three scenarios (depicted in Table 2) to illustrate the Low, Moderate and High demand scenarios for the next ten years. The scenarios were built using primary research, secondary research and Letters of Intent from emerging markets.

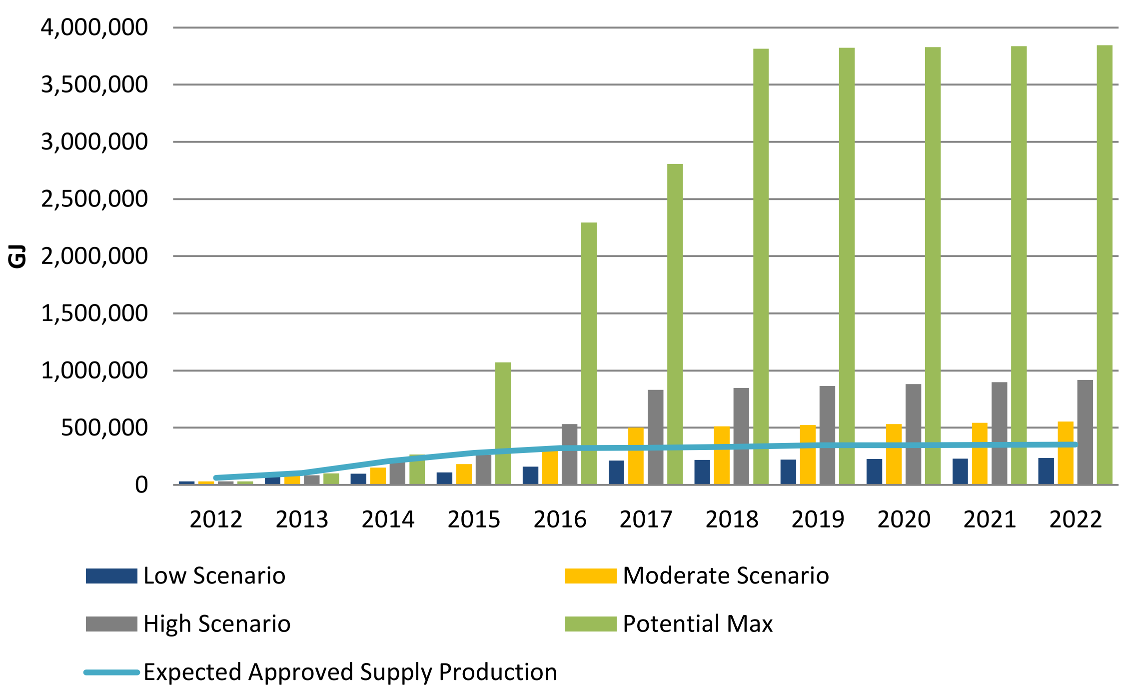
Table 2: RNG Offering 10-Year Demand Scenarios

	Rate Schedule 1-3B	Rate Schedule 11B	Emerging Markets	Annual Demand (GJ) by 2017	Annual Demand (GJ) by 2022*
Low Scenario	1% customer participation by 2017	10% annual growth	10% capture rate	213,275	235,473
Moderate Scenario	2.1% customer participation by 2017	30% annual growth	30% capture rate	502,017	554,267
High Scenario	2.1% customer participation by 2017	50% annual growth	50% capture rate	830,748	917,213
Max Potential	2.1% customer participation by 2017	50% annual growth	100% capture rate & off-system sales	2,807,248	3,844,014

** Annual demand projections past 2017 use a 2% annual growth rate.*

In each of the Low, Moderate and High scenarios described in Table 2, potential demand outstrips supply from existing projects, including beyond 2015 (illustrated below in Figure 1). It is important, therefore, for FEI to be proactive in developing additional supply projects to meet the future demand of customers and to grow the market in B.C.

Figure 1: RNG Demand Forecast for 2012 – 2022

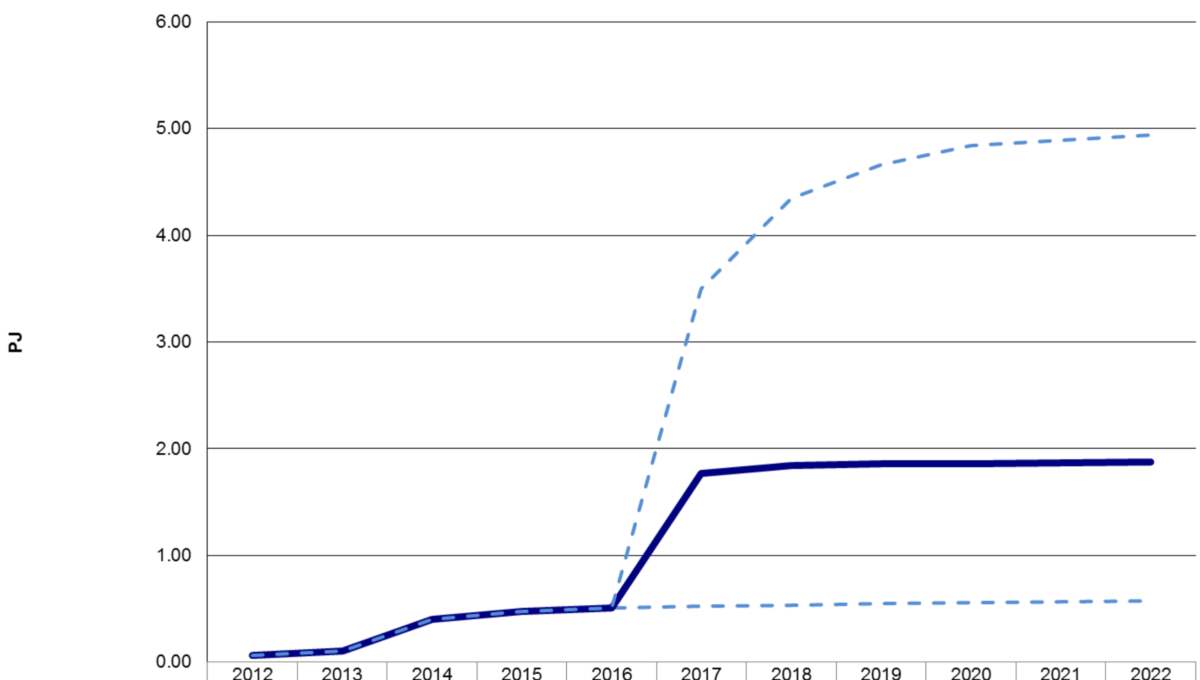


FEI believes that the Moderate demand scenario is both reasonable and appropriate for use in long term planning to meet our customers' needs. The Moderate forecast for residential customers ramps up to a 2.1 percent participation rate, resulting in an annual demand of approximately 130,000 GJ by 2017. The addition of large volume customers can quickly increase demand, however, and expands the Moderate demand forecast in 2017 to 502,017 GJ as shown in Figure 1.

2.2 TEN-YEAR BIOMETHANE SUPPLY FORECAST

FEI revisited its initial ten-year forecast of biomethane supply in British Columbia as part of the two year review of the biomethane program. FEI developed the ten year forecast shown in Figure 3 for the biomethane program using the three supply scenarios described below.

Figure 1: Annual Biomethane Supply Forecast (PJ)



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Low - Approved	0.06	0.10	0.40	0.47	0.51	0.52	0.53	0.55	0.56	0.56	0.57
Known Prosects	0.06	0.10	0.40	0.47	0.51	1.77	1.84	1.86	1.86	1.87	1.88
High Potential	0.06	0.10	0.40	0.47	0.51	3.50	4.35	4.66	4.84	4.89	4.94

As the label implies, the "Low – Approved" curve combines all of the expected supply volumes of currently approved projects. The "Known Prospects" curve represents the maximum contract values of all known prospects that have been in contact with FEI over the past two years. It includes two major projects mentioned in the 2012 Biomethane Application: the City of Vancouver Landfill and the City of Surrey Digester projects. The remainder is a combination of potential sources of supply representing different sources and locations across FEI's service territory.

The "High Potential" curve represents the maximum supply potential based on total known potential within B.C., and was derived from a study conducted by CHFour.[4] FEI used this study as a basis to validate the original estimates of potential in the province which were done for the 2010 Biomethane Application. The CHFour study looks specifically at agricultural waste and the organic fraction of municipal waste and does not include existing landfills or institutional, commercial and industrial (ICI) waste. In addition, the study further refines previous FEI work by focusing on regions where FEI has existing infrastructure only. The report concludes that there is a maximum potential of 5.4 PJs annually, however, based on the author's opinion, that potential would likely translate to a maximum of 2.4 PJs annually. The report ignores *existing* waste in landfills and ICI waste, which typically has a very high biogas yield per ton. Therefore, FEI has adjusted the total potential upwards to include these sources of energy. Specifically, FEI added 2.5 PJs to account for landfill gas (includes Delta Landfill), ICI waste and wastewater plants for a total of approximately 4.9 PJs. FEI believes this is a reasonable estimate based on the report by CHFour and FEI's original assessment of potential done for the 2010 Biomethane Application.

FEI reiterates that total volumes by year may vary significantly due to the difficulty in projecting the timing of supply; of particular note are two very large potential projects which could be in operation by 2016 and account for the sudden increase in supply curve in that year. This challenge is caused by uncertainty of the time it may take to secure supply contracts, timing of demand and timing of government policy.

3. Biomethane Supply Projects

FEI has developed a supply model to ensure the safe, reliable and economical delivery of biomethane. For the supply model, FEI received approval from the Commission to use the existing natural gas distribution network to displace conventional natural gas with carbon neutral biomethane.

In the FEI supply model, biogas producers retain ownership and control over the equipment that digests organic material to create raw biogas, as well as over those assets required to collect raw biogas from collection locations such as digesters, landfills or sewage treatment facilities. Those assets require large investment and currently fall outside of FEI's core expertise.

Upgrading equipment is typically owned by the biogas producer. However, controlling the upgrading process and associated facilities may be required in certain circumstances where a biogas supplier either cannot or is not willing to own the upgrading plant and in such cases, FEI expects to file a CPCN application. In the 2012 Biomethane Application, FEI stated that this will be relatively infrequent and will likely occur only where the supply project is a landfill or in cases where the supplier is a regional or municipal government. In the 2012 Biomethane Application

[4] Refer to attachment 53.2.1 in response to BCUC IR 1.53.2.1 of the 2012 Biomethane Application.

Decision,[5] the Commission specifically allows FEI to own upgraders where the partner is a regional or municipal government; therefore, FEI may enter into future agreements to own upgrading facilities.

FEI launched the RNG Offering with the Fraser Valley Biogas project in 2010 and expanded the program with supply from the Salmon Arm landfill in 2013. These projects and other currently approved projects are summarized below:

Table 3: FEI's Currently Approved Supply Projects

Project	Description	Estimated Supply	Status
Fraser Valley Biogas	A biomethane purchase agreement and FEI interconnection facilities	60,000 GJ/year with potential to increase over the project life	Operational since September 2010
Salmon Arm Landfill	A raw gas purchase agreement with the CSRD. FEI owns and operates the upgrading plant and interconnection facilities	20,000 GJ in the first full year of operation. Supply will increase to 40,000 GJ/year over the next 10 to 15 years	Operational since January 2013
City of Kelowna Glenmore Landfill	A raw gas purchase agreement. FEI owns and operates the upgrading plant and interconnection facilities	60,000 GJ in the first full year of operation. Supply is expected to increase to 118,000 GJ/year over the next 10 to 15 years	Estimated in service Q2 2014
Earth Renu	A biomethane purchase agreement and FEI interconnection facilities	50,000 GJ/ year with potential to increase over the project life	Regulatory approval received in May 2013. Estimated in service 2015
Seabreeze Farm	A biomethane purchase agreement and FEI interconnection facilities	42,0000 GJ/year with potential to increase over the project life	Regulatory approval received in May 2013. Estimated in service 2014
Dicklands Farm	A biomethane purchase agreement and FEI interconnection facilities	46,000 GJ/year with potential to increase over the project life	Regulatory approval received in May 2013. Estimated in service 2014
Metro Vancouver Lulu Island Wastewater Plant	A biomethane purchase agreement and FEI interconnection facilities	40,000 GJ/year	Regulatory approval received in Sept. 2013. Estimated in service 2015

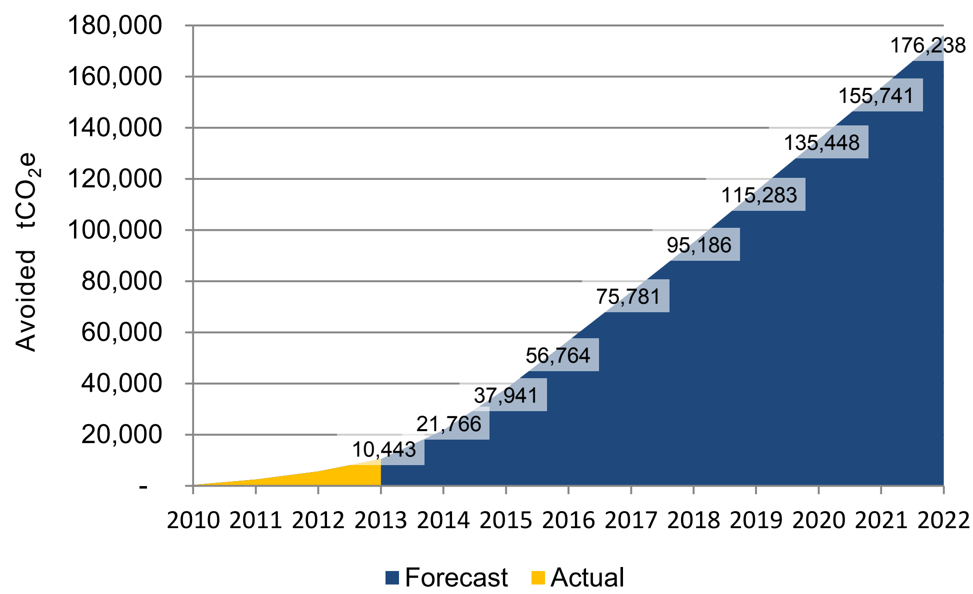
5 BCUC Decision G-210-13, Dec. 11, 2013.

In May 2013, FEI received approval for three additional supply projects (noted in Table) and an increase in the amount of biomethane that it could purchase to a maximum of 530,000 GJ annually.[6] At this time, customer demand projections show that without a further supply cap increase (FEI proposed 3 PJ in its Biomethane Application[7]) and the ability to move forward with additional new supply contracts, biomethane demand could exceed supply by 2015. Although customer demand projections show that biomethane demand may exceed supply by 2015, FEI's request to increase the supply cap to 3 PJ was limited to 1.5 PJ in the BCUC's December 2013 Decision.[8] One of the stated reasons for this decision was the uncertainty of future available supply and the apparent difference between supply estimates from FEI and CHFour. The Commission has therefore directed FEI to issue a Request for Expression of Interest to better understand the potential supply available in British Columbia.

4. GHG Emission Savings

The RNG Offering helps meet customer demand for renewable, clean energy options and also advances the province's goals for biogas development and greenhouse gas emission reductions. Taking into account all currently approved projects, the projected greenhouse gas emissions savings (or avoided emissions) from the RNG Offering from 2010 through 2022 are 176,200 tCO_2e.[9] Shown in Figure 3 below, actual GHG emission savings from 2010 to 2013 were 10,400 tCO_2e.

Figure 3: RNG Offering Cumulative GHG Emissions Savings, 2010 – 2022



6 BCUC Order G-70-13, May 6, 2013.
7 FEI Biomethane Application, 2012.
8 BCUC Decision G-210-13, Dec. 11, 2013.
9 This conservative estimate takes into account the emissions savings from displaced gas only (it does not include the avoided emissions from gas capture).

5. Conclusion

FEI's RNG Offering provides a strategically valuable end-to-end biogas energy service to meet customer demand for sustainable energy options and to support B.C.'s bioenergy and climate change goals. With the ability to notionally replace a percentage of traditional gas supply with biomethane, the Utilities' residential and commercial customers can offset their energy-related GHG emissions with a carbon neutral energy source. Supply and demand for the RNG Offering may be small in relation to the FEI's traditional gas service but the program remains an important part of the Utilities' customer offering.

Appendix A-8

DISCUSSION OF NATURAL GAS FOR TRANSPORTATION INITIATIVES

APPENDIX A-8 – FEU'S NATURAL GAS FOR TRANSPORTATION INITIATIVES

Natural gas has become an increasingly attractive transportation fuel where it provides an alternative to higher cost and higher polluting petroleum-based fuels. Natural gas burns cleaner than gasoline or diesel, which results in less air pollution and fewer greenhouse gas (GHG) emissions. In addition, using natural gas in transportation applications carries a number of other important benefits including more stable fuel costs for users[1], lower operating and maintenance costs for natural gas-fuelled vehicles, and quieter vehicle operation. From a utility perspective, all customers benefit from load added by natural gas for transportation (NGT) customers since largely fixed natural gas delivery costs are spread over a greater volume of throughput, thus the total share of revenue requirements that must be collected from all customers is lower. Greater throughput on the natural gas system results in lower delivery rates than would otherwise be the case.

These and other benefits that are captured by the FEU's NGT strategy are identified below:

Figure 1: NGT Stakeholder Benefits

Production

- Creates new markets for gas
- Royalty revenue for government

Transmission and Distribution

- Incremental gas load drives system and cost efficiencies

Customers

- Lower operating costs for fleets
- Lower delivery charges for all customers

Communities

- Improved air quality
- Quieter vehicle operation
- Reduced GHG emissions

Supported by government regulation, the FEU have shifted focus of their NGT activities away from the light-duty vehicle segment toward heavy duty and return-to-base vehicle fleets, where fuel consumption is large enough to improve the economic justification for the higher upfront capital expenditure of natural gas vehicles. The Companies' NGT solutions are expected to capture a major opportunity for emission reductions in B.C.'s transport sector while providing an important source of load growth on the FEU's systems. This will result in a more cost-effective and efficient utilization of the natural gas distribution system with benefit to all FEU customers.

[1] Historically, natural gas commodity prices have been shown to be more stable compared to the fluctuation of prices for diesel and gasoline. Natural gas fuel costs have historically been 25 to 40 percent less than diesel.

1. Background on FEU's NGT Initiatives

FEI has offered natural gas vehicle (NGV) service and modest levels of vehicle incentive grants since the mid-1990s. These initiatives have failed to gain lasting traction, however, due to a variety of reasons including the high cost of engine conversions and discontinuation of government incentive programs.

In 2009, FEI (then Terasen Gas Inc.) identified an opportunity to play a leadership role in facilitating the development of LNG as a transportation fuel in B.C. Specifically, FEI applied for and received approval of Rate Schedule 16, a five year pilot program for an interruptible LNG sales and dispensing service tariff that would expand the use of the Tilbury LNG facility from a storage function to additionally serve the LNG transportation market.[2] This move was not only intended to support specific government initiatives[3] to promote the growth of LNG as a transportation fuel in B.C., reduce GHG emissions and improve local air quality, but it was also intended to provide benefits to both existing core and new customers within the transportation sector.

FEI subsequently developed the Commercial NGV Demonstration Program in 2010. This program was designed to address the capital cost premium of natural gas vehicles by providing Energy Efficiency and Conservation (EEC) incentive payments to provide up to the full incremental cost of NGVs relative to comparable diesel vehicles. Under this program, FEI provided nearly $5.6 million in EEC incentive funding to four commercial return-to-base fleet customers in 2010 and 2011: Waste Management, Vedder Transport, Kelowna School District and the City of Surrey.[4]

In January 2011, the BCUC raised concern regarding the use of EEC incentives to incent NGV activities, which led to regulatory review and a decision that determined the incentives did not meet the *Clean Energy Act (CEA)*'s definition of a "demand-side measure" (provided in Section 4.2).[5,6] Other than the four projects for which incentives had already been provided, FEI's planned NGT projects were consequently put on hold. At that time, FEI commenced discussions with the B.C. government to establish NGV incentives as prescribed undertakings pursuant to sections 18 and 35(n) of the *CEA*.[7] The outcome of those discussions was the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR), which is described in detail below and in Section 2.2.3.3.

Although the Companies are currently focusing on heavy-duty return-to-base fleets to help establish required natural gas fuelling infrastructure, customers that purchase natural gas within

2 BCUC Order G-65-09
3 As outlined in the 2007 Energy Plan. Additional details on B.C.'s 2007 Energy Plan is provided in Appendix A-5.
4 FEI Natural Gas for Transportation GGRR Application, Part 2, Prudency of 2010-2011 Commercial NGV Demonstration Program Incentives, p. 31.
5 BCUC, "NGV Incentive Review," Commission Letter L-30-22, April 18, 2011.
6 BCUC Order G-145-11
7 Sections 18 and 35(a) of the *CEA* define a prescribed undertaking as "a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia.

the FEI's Lower Mainland service area under Rate Schedule 6 continue to be eligible to obtain an incentive of up to $2,500 to purchase a new, factory-built CNG light-duty vehicle or to convert an existing light-duty vehicle to CNG.[8] These incentives are not awarded under the GGRR Prescribed Undertakings and are not included in the forecast impacts of the NGT incentive program section below.

2. Recent Legislative and Regulatory Background

In May 2012, B.C. policymakers introduced the GGRR through a prescribed undertaking under sections 18 and 35(n) of the *CEA.* The objectives of the GGRR are to: enable public utilities to engage in programs and expenditures that promote natural gas as a transportation fuel in the heavy duty vehicle and marine sectors with a goal to ultimately reduce the province's GHG emissions; support B.C.'s Natural Gas Strategy by diversifying local markets for natural gas; provide a cleaner burning, lower cost alternative to diesel fuel; and foster B.C.'s economic development, jobs and innovation.[9]

The regulation defines three major program areas, or "prescribed undertakings," that permit a public utility to:

- provide grants or interest free loans for the purchase of eligible CNG and LNG vehicles,
- construct or purchase and operate CNG and LNG fuelling stations, and
- provide grants to meet safety guidelines for operating and maintaining eligible vehicles.

For each of these three program areas, the regulation defines a spending cap and a collective total which amounts to $104.5 million. Each prescribed undertaking is independent of the others such that underspending in one prescribed undertaking is not transferable to the others. Furthermore, the GGRR allows for utility discretion whether to provide a grant or an interest free loan; at this time, FEI intends to provide grants for the purchase of a CNG or LNG eligible vehicle.[10] Table 1 provides a breakdown of the expenditure caps for each of the three Prescribed Undertakings established by the GGRR and the specific cost categories and associated expenditure caps within each prescribed undertaking.

8 Light-duty vehicles may include forklifts, pick-up trucks, vans and passenger cars.
9 B.C. Ministry of Energy and Mines, letter to Ms. Alanna Gillis, Commission Secretary BCUC, dated June 8, 2012.
10 The rationale for providing grants as opposed to interest free loans is discussed in Section 5.2.3 of the "FEI Application for Approval of Rate Treatment of Expenditures Under the Greenhouse Gas Reductions (Clean Energy) Regulation and Prudency Review of Incentives Under the 2010-2011 Commercial NGV Demonstration Program," Vol. 1, Aug. 21, 2012, p.19-20.

Table 1: GGRR Prescribed Undertakings ($Million)[11]

Prescribed Undertaking 1 - Grants and Loans for Eligible Vehicles *Total expenditures not to exceed $62 million*		
"Specified vehicles" (medium and heavy duty trucks, transit buses and school buses)	• Under-spending of Prescribed Undertaking 1 category caps can be shifted to increase available grants for the "specified vehicle" category	$41.9
Marine vehicles	• Expenditures not to exceed $11 million	$11.0
Administration, marketing, training and education	• Expenditures not to exceed $3.1 million	$3.1
Safety practices and maintenance facilities	• Expenditures not to exceed $6.0 million	$6.0
Subtotal - Prescribed Undertaking 1		**$62.0**
Prescribed Undertaking 2 - CNG Fuelling Stations *Total expenditures including administration and marketing not to exceed $12 million*		
Expenditures on CNG stations	• Average expenditure on CNG stations not to exceed $2.0 million per station in any year	$11.76
Administration and marketing	• Expenditures not to exceed $0.24 million	$0.24
Subtotal - Prescribed Undertaking 2		**$12.0**
Prescribed Undertaking 3 - LNG Fuelling Stations *Total expenditures including administration and marketing not to exceed $30.5 million*		
Expenditures on LNG stations	• Expenditures not to exceed $2.75 million per station	$24.75
Administration and marketing	• Expenditures not to exceed $0.25 million	$0.25
Tanker truck load-out facilities	• Expenditures not to exceed $5.5 million	$5.5
Subtotal - Prescribed Undertaking 3		**$30.5**
Total GGRR Expenditures ($Million)		**$104.5**

In August 2012, FEI applied for rate treatment of expenditures under the GGRR and a prudency review of incentives under the 2010 – 2011 Commercial NGV Demonstration Program. On October 29, 2012, FEI was granted approval of rate treatment of up to $62 million in expenditures on vehicle grants and loans, administration, marketing, training and education as

[11] Table 1 reflects expenditure caps outlined in the Nov. 2013 GGRR amendment.

established in Section 2(1)(c) of the GGRR.[12] This decision also included approval to recover the nearly $5.6 million in 2010 – 2011 EEC incentive expenditures through rates from FEI's non-bypass natural gas customers.

Given the government's intent to significantly increase the adoption of LNG as a transportation fuel and to ensure the long-term success of a shift to natural gas vehicles, FEI filed an amended Rate Schedule 16 to convert the interruptible LNG sales and dispensing service tariff from a five-year pilot program into a permanent tariff offering. The BCUC granted approval to extend the pilot rate for an additional seven years to December 31, 2020 albeit at a higher rate to capture the fully allocated cost and value of the LNG service.[13]

In Order G-88-13, the Commission set the LNG delivery charge under Rate Schedule 16 at $6.50/GJ, or 53 percent higher than the $4.25/GJ that FEI had requested. The substantial increase in the LNG delivery charge affected market confidence with respect to regulatory uncertainty and rates, and resulted in a number of potential customers who were considering contracting for service under Rate Schedule 16 to either delay adoption of LNG, cancel adoption plans altogether or to significantly reduce LNG vehicle additions from initial forecasts.

In November 2013, however, the B.C. Government issued Special Direction No. 5 to the BCUC under Section 3 of the *UCA.* The direction exempts from BCUC review expenditures on an expansion of the Tilbury facility of up to $400 million and effectively lowers the LNG dispensing rate to $4.35 per GJ. These developments are likely to increase NGT demand and the changes are under review to determine the potential impact on the forecast of annual NGT demand. At the same time, the Government also amended the GGRR to include mine haul trucks and locomotives as vehicles eligible for incentives, increase funding in a number of areas and repeal the regulation's expiry. Details of the Special Direction and amended GGRR are provided in Appendices A-9 and A-10.

While the effect of these recent developments is not considered in the NGT demand forecasts of this LTRP, the potential effect of adding NGT load is considered in determining future system resource needs and alternatives (Section 5). The FEU are also examining the potential for fuel conversion in marine vessels where converting to natural gas makes economic sense. In doing so, the Utilities can assist the B.C. Government in further advancing its goals of promoting LNG as a transportation fuel and reducing GHG emissions by converting vehicles of more carbon intensive fuels (diesel and gasoline) to relatively cleaner burning natural gas.

3. FEU NGT Incentive Program Strategy

Following introduction of the GGRR in 2012, FEI developed an NGT Incentive Program to initiate a market transformation from high-carbon fuels, such as diesel and gasoline, to lower carbon natural gas in the heavy duty vehicle market segment. The program is targeted for commercial return-to-base fleet operators of heavy-duty trucks (highway transport tractors),

[12] BCUC Order G-161-12, October 29, 2012.
[13] BCUC Order G-88-13, June 4, 2013.

buses (transit and school buses), vocational vehicles (waste haulers and delivery vehicles) and marine vessels or ferries that operate primarily in British Columbia. Applications are evaluated in a competitive process measured against defined program criteria and both the process and awards are reviewed by a third party.

During the initial phase of the program, the Utilities have provided funding to offset up to 80 percent of the incremental capital cost between a qualifying natural gas vehicle and the cost of an equivalent diesel vehicle. In 2012, FEI awarded approximately $6 million in incentives through a public and transparent selection process to the following transportation operators to purchase CNG- and LNG-fuelled vehicles for their fleets:

- BC Transit - $937,500
- BFI Canada - $937,958
- City of Vancouver - $1,854,600
- Cold Star Freight Systems Inc. - $450,997
- Emterra Environmental - $745,500
- School District No. 23 (Kelowna) - $67,893
- Smithrite Disposal Ltd. - $953,775

Funding is expected to decrease by 10 percent in each subsequent year as the adoption of natural gas vehicles in heavy-duty transportation increases and the NGT sector matures over time. Although successful applicants to FEU's NGT Incentive Program must primarily fuel the vehicles using natural gas delivered through FEU's distribution system, applicants are not required to use FEU as the fuelling service provider for their fleet. Applicants have the option to install, construct, own and operate a fuelling station themselves, contract fuelling service through a third party, or receive such services from the FEU.

As experience is gained during the Prescribed Undertaking period, the FEU may make modifications to the NGT Incentive Program, including offering interest-free loans in particular circumstances if FEI believes it would be beneficial. Total authorized expenditure under the program is $62 million; although all contribution agreements must be signed by March 31, 2017, the long term effect of the program will be a positive impact to all customers' delivery rates.

4. Forecast Impacts of the NGT Incentive Program

The Companies' NGT solutions are expected to capture a significant opportunity for emission reductions in British Columbia's transport sector while providing an important source of load growth on the FEU's systems. Section 3.3.7 illustrates the forecast NGT demand to 2033 based on FEI's experience from the first two rounds of GGRR incentive funding in 2012 and 2013, the allocated GGRR funding period, and actual NGT customer additions to date. Sections 3.5 and 8 illustrate the effect of increased natural gas use for transportation on the potential to reduce B.C.'s GHG emissions, and Section 5 discusses the impact of growing NGT demand on the FEU's delivery system infrastructure. Below, this section discusses the expected outcome and impacts of the FEU's NGT Incentive Program with respect to total incentive funding issued, forecast vehicle additions, incremental natural gas demand, fuelling station additions, revenue requirements and rates.

4.1 TOTAL INCENTIVES BY VEHICLE TYPE

The table below summarizes the total amount of incentive funding forecast to be provided under Prescribed Undertaking 1.

Table 2: Forecast GGRR Incentive Expenditures, Pre-2013 - 2017F

Incentive Forecast ($000s)	Pre-2013	2013F	2014F	2015F	2016F	2017F
GGRR Phase 3 Incentives[14]	$5,573	-	-	-	-	-
GGRR Phase 1 Rounds 1 & 2[15]	-	$13,371	-	-	-	-
Vehicle Incentives	$5,573	$13,371	$6,178	$4,498	$1,979	-
Marine Vehicle Incentives	-	-	$2,500	$2,500	$2,000	-
Admin, Education, Safety Training	$430	$2,020	$1,850	$1,550	$1,250	-
Total	$6,003	$15,391	$10,528	$8,548	$5,229	-
Cumulative	$6,003	$21,395	$31,923	$40,471	$45,701	$45,701

Although incentives will be provided for both CNG and LNG projects, it is expected that LNG vehicles will account for a majority of the incentives granted. This is due to two factors: the cost premium for an LNG vehicle is higher than for a CNG vehicle, and LNG vehicles tend to travel greater distances on an annual basis therefore consuming more natural gas. Overall, this results in a more efficient use of funding on a dollar-per-GJ-of-throughput basis, which further maximizes the cost benefits of the incentive funding.

Marine vessels are expected to account for approximately $7 million of a total $45 million, with commencement of such funding forecast to occur in 2014. Due to the unique conversion requirements of marine vessels including a longer lead time for engine conversions, marine vessels can require more time and additional infrastructure before they may be able to operate using natural gas fuel.

[14] GGRR Phase 3 incentives are those awarded to four commercial return-to-base fleet customers in 2010 and 2011 under the Commercial NGV Demonstration Program.
[15] GGRR Phase 1 Rounds 1 & 2 incentives are those awarded under Prescribed Undertaking 1.

4.2 FORECAST VEHICLE ADDITIONS

Using assumptions regarding the average price differential between a diesel-fuelled vehicle and a natural gas-fuelled vehicle, FEI has forecasted the number of vehicle additions by year based on the expected GGRR incentives in Table 2. Table 3 below illustrates the number of vehicles that are expected to be operational in the year listed and not when the GGRR incentive call was issued (there is generally a time lag between when the contribution agreements are executed and when the vehicles are put into operation). For instance, FEI issued a 2013 call for CNG vehicle incentives and expects vehicles to be in operation partly in 2014 and partly in 2015. From the 2013 CNG call, FEI has applied reasonable assumptions based on the best information it has from the applicants to estimate their in-operation date. Going forward, FEI expects more vehicles to be in operation in the year in which funding is issued and has incorporated this assumption to develop this forecast. The table below provides a forecast of vehicle additions by type over the remaining Prescribed Undertaking period.

Table 3: Forecast Vehicle Additions, 2014F – 2018F

Vehicle Additions (FEI Only)	2014F	2015F	2016F	2017F	2018F	Total for Period
Vocational Trucks	36	33	103	84	68	324
Busses	2		47	10	4	63
Class 8 Tractors	31	12	66	72	60	241
Marine			1	1	1	3
Total NGT Fleet	**69**	**45**	**217**	**167**	**133**	**631**

4.3 INCREMENTAL NATURAL GAS VOLUMES

The natural gas volume addition that will result from the NGT Incentive Program will increase system load and ultimately lower delivery rates for all customers. Table 4 below provides a conservative estimate of the additional volumes that will be added to the system (irrespective of the fuelling station provider) based on the expected number of vehicle additions previously presented in Table 3. There is a one year lag period built into the forecast to account for the time between incentive approval and the time new vehicles become operational (i.e. vehicles funded in year ‘n’ are shown as load additions in year ‘n+1’).

Table 4: NGT Natural Gas Demand by Vehicle Type, 2013F – 2017F

Cumulative Load Addition (GJ/Year)	2013F	2014F	2015F	2016F	2017F
CNG Vehicle Demand					
Vocational Trucks	109,000	142,000	245,000	329,000	397,000
Busses	13,000	13,000	60,400	70,400	74,400

LNG Vehicle Demand					
Class 8 Tractors	302,000	356,000	653,000	977,000	1,247,000
Marine			150,000	300,000	450,000
Total NGT Fleet	**424,000**	**511,000**	**1,108,400**	**1,676,400**	**2,168,400**

For LNG demand, the maximum volume that can be offered under Rate Schedule 16 is approximately 2.2 petajoules (PJ) per year (or 6,000 GJ/day). The addition of LNG marine vessels and LNG heavy duty Class 8 Tractors will be the largest contributors to overall LNG demand for FEI in the long run. The current forecast is that under the approved daily supply caps, there will be sufficient supply to serve LNG demand under Rate Schedule 16 through the Prescribed Undertaking period.

4.4 CNG AND LNG STATION ADDITIONS

As the NGT Incentive Program is anticipated to increase the number of natural gas vehicles in B.C. as indicated in Table 3, fuelling station infrastructure to accommodate these vehicles will also need to increase. The table below summarizes the anticipated number of annual fuelling station additions from 2013-2017 that FEI anticipates constructing to serve the forecast load previously shown in Table 4.

Table 5: Fuelling Station Additions Built by FEI, 2013F – 2017F

Fuelling Station Additions	2013F	2014F	2015F	2016F	2017F
Vocational Trucks	1	1	1	1	1
Busses			1		1
Class 8 Tractors			1	1	1
Mobile LNG	3	1			
Total Stations	**4**	**2**	**3**	**2**	**3**

The numbers presented in Table 5 assume that all expenditures for vehicle incentives under the GGRR are awarded to qualifying customers over the Prescribed Undertaking period and that FEI will construct half of the CNG fuelling stations required to serve CNG demand. The other half of the required CNG fuelling stations are assumed to be built by independent third parties. FEI believes that this is a reasonable assumption and provides a conservative forecast of the number of CNG fuelling stations that the Company will construct.

Fuelling service can be contracted from FEI, a private supplier or through a third-party contract with the owner of a fuelling station. If an applicant would like a fuelling station on the applicant's property, FEI would own, build and maintain the station through an agreement with the landowner to have access to the fuelling station. Although FEI would intend to pursue full cost recovery from CNG and LNG station customers, Prescribed Undertakings 2 and 3 allow for contracts with less than full cost recovery to qualify as Prescribed Undertaking expenditures. Section 18(2) of the *CEA* provides that the Commission must set rates that allow a public utility to recover the costs of Prescribed Undertaking stations even if the revenues from the station customer(s) do not recover all the costs. Specific rates for each station will vary depending on each individual applicant's costs, consumption and requirements for the fuelling station.

Due to the availability of multiple service providers to provide NGT customers with fuelling service, FEI cannot forecast with a high degree of precision the number of CNG or LNG stations that will be brought forward as Prescribed Undertaking expenditures. FEI plans to seek any required approvals in the future as part of a separate application process for each fuelling station, whether through a Prescribed Undertaking or under FEI's approved General Terms and Conditions (GT&C) 12B, which sets out the terms on which FEI can own and operate CNG or LNG stations.[16] Fuelling station applications will be submitted once the need for additional stations has been identified.

4.5 REVENUE REQUIREMENT AND RATE IMPACTS

FEI anticipates that the number of natural gas-fuelled vehicles will increase in the marketplace, largely as a result of this incentive funding program. The additional volume that results from the program will lead to lower delivery rates for all of FEI's non-bypass customers in the long run through higher throughput on the delivery system, thus spreading costs over a larger consumption base. Table 6 shows the forecast cost of service and benefits that the incentives under the GGRR are expected to produce based on past decisions and forecast spending.

Table 6: Summary of NGT Costs and Benefits for Core Ratepayers

Cost or Benefit ($000s)	2014F	2015F	2016F	2017F	2018F	Total
NGT Incentives and FSVA[17] Cost of Service	4,961	6,197	6,898	6,664	6,418	31,139
Overhead & Marketing Recoveries	(189)	(297)	(406)	(511)	(522)	(1,925)
Delivery Margin Contributions	(2,445)	(5,459)	(8,608)	(11,390)	(11,390)	(39,290)
Net (Benefit) / Cost	**2,328**	**442**	**(2,116)**	**(5,236)**	**(5,493)**	**(10,076)**

FSVA additions are designed to have zero net impact on core customers over time whereas OH&M recoveries and delivery margin contributions are expected to continue into the future.

[16] Additional information on GT&Cs for CNG and LNG service can be found in the FEI 2014-2018 PBR Application Evidentiary Update, July 16, 2013.

[17] The FSVA, or Fuelling Stations Variance Account, was established pursuant to Order G-161-12 whereby the account would capture "the total revenue surplus or deficiency pertaining to fuelling station facility costs that have not been forecast in rates, as well as the administration and application costs."

The anticipated rate impact of carrying out Prescribed Undertaking 1 is a cumulative net benefit to core ratepayers of approximately $10 million by 2018.[18]

4.6 SUMMARY

The number of natural gas-fuelled vehicles in B.C. is anticipated to increase throughout the GGRR incentive funding period. Furthermore, since NGT vehicles provide substantial cost savings relative to vehicles that consume traditional fuels, this growth is expected to be sustained well beyond the end of the FEU's Incentive Program in 2017. The FEU's NGT initiatives provide benefits not only to NGT customers that receive incentive funding under the program, but also to other new and existing FEI customers through increased throughput of natural gas on the delivery system, which results in more cost-effective and efficient utilization of the distribution system as a whole.

5. Conclusion

The Companies' NGT strategy represents a significant opportunity to provide load building benefits that keep customers' costs down while also working toward B.C.'s GHG emission reduction goals. Although NGT demand is expected to comprise a relatively small portion of FEI's overall gas supply portfolio in the short term, there are immediate benefits from adopting natural gas for transportation such as reduced fuel and operating costs for NGT customers, better air quality due to reduced emissions, and minimizing environmental hazards associated with oil storage tanks. NGT demand adds value to new and existing customers by increasing the year-round load on the gas distribution system, thereby increasing throughput and putting downward pressure on delivery rates for all natural gas customers. For these reasons, FEI is also looking at fuel conversions in marine vessels and the railway industry to help broaden the development of the NGT market in B.C. These efforts will further assist B.C. in achieving its GHG reduction goals by converting the province's transportation fleet from more carbon intensive fuels, such as diesel and gasoline, to relatively cleaner burning natural gas.

[18] The delivery rate impacts for both scenarios assume that all vehicles are fuelled by CNG or LNG from FEI's distribution system and LNG facilities.

Appendix A-9

GREENHOUSE GAS (CLEAN ENERGY) REGULATION AMENDMENT

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 556 , *Approved and Ordered* November 27, 2013

Judith I. Guichon
Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012, is amended as set out in the attached Schedule.

DEPOSITED

November 28, 2013

B.C. REG. 235/2013

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

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

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 35

Other: OIC 295/2012

October 31, 2013 R/541/2013/27

SCHEDULE

1 *Section 1 of the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012, is amended in the definition of* "eligible vehicle" *by striking out* "and" *at the end of paragraph (a), by adding* "," *at the end of paragraph (b), and by adding the following paragraphs:*

(c) a mine haul truck, and

(d) a locomotive.

2 *Section 2 is amended*

(a) in subsection (1) (b) by adding "an expenditure on" *before* "a grant or zero-interest loan",

(b) in subsection ((1) (c) (ii) (B) by striking out "$4 million" *and substituting* "$6 million",

(c) by adding the following subsection:

(1.1) Despite the reference in subsection (1) (a) to an open and competitive application process, a public utility may, in carrying out the undertaking described in subsection (1), give priority to a person in British Columbia who fuels an eligible vehicle using natural gas delivered through the public utility's pipeline system.,

(d) by repealing subsection (2) (a) and substituting the following:

(a) the public utility, before April 1, 2017, enters into a binding commitment to

(i) construct and operate, or

(ii) purchase and operate

one or more compressed natural gas fuelling stations, including storage, compression and dispensing equipment and facilities, within the service territory of the public utility for the purposes of providing compressed natural gas fuel and fuelling services to owners of vehicles that operate on compressed natural gas;,

(e) in subsection (2) (b) (i) by striking out "$1.1 million" *and substituting* "$2 million",

(f) in subsection (2) (c) by striking out "during the undertaking period",

(g) by repealing subsection (3) (a) and substituting the following:

(a) the public utility, before April 1, 2017, enters into a binding commitment to

(i) construct and operate, or

(ii) purchase and operate

one or more tanker truck load-outs, liquefied natural gas tank trailers or liquefied natural gas fuelling stations for the purposes of providing within British Columbia liquefied natural gas fuel and fuelling services to owners of vehicles that operate on liquefied natural gas;, *(h) in subsection (3) (b) (ii) by striking out* "$4 million" *and substituting* "$5.5 million",

(i) in subsection (3) (c) by striking out "during the undertaking period", *and*

(j) by adding the following subsection:

(4) In subsections (1) to (3), **"expenditures"** includes, except with respect to expenditures on administration and marketing, binding commitments to incur expenditures in the future.

3 *Section 3 is repealed.*

Appendix A-10

B.C. GOVERNMENT SPECIAL DIRECTION NO. 5 TO THE BCUC

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 557 , *Approved and Ordered* November 27, 2013

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Direction No. 5 to the British Columbia Utilities Commission is made.

DEPOSITED
November 28, 2013
B.C. REG. 245/2013

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

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

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3

Other:

November 4, 2013 R/589/2013/27

SCHEDULE

DIRECTION NO. 5 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

"applicable customers" means customers of a utility other than customers receiving service

(a) under a fixed rate, or

(b) in the Fort Nelson service area of the utility, unless the Fort Nelson service area no longer has a distinct rate base;

"CNG" means compressed natural gas;

"CNG service" means a service that includes one or both of the following:

(a) compressing and dispensing of natural gas through specialized fuelling facilities or equipment;

(b) transporting CNG using specialized trailers or equipment;

"expansion facilities" means LNG facilities to be constructed, owned and operated, after this direction comes into force, by a utility at Tilbury Island, Delta, British Columbia;

"fixed rate" means a charge for natural gas service not subject to adjustment based on changes in the revenue requirements of a utility;

"LNG" means liquefied natural gas;

"LNG dispensing service" means the dispensing service referred to in sections 3 to 5 of the LNG rate schedule;

"LNG facility" means a facility that produces, stores and dispenses LNG and, in some cases, vaporizes LNG;

"LNG rate schedule" means the utility's Liquefied Natural Gas Sales, Dispensing and Transportation Service Rate Schedule 46 as set out in Appendix 1 attached to this direction;

"LNG service" means one or more of the following services:

(a) procurement of natural gas and electrical power for the purposes of LNG production;
(b) procurement of LNG;
(c) transmission and distribution of natural gas to an LNG facility;
(d) production of LNG from natural gas at an LNG facility;
(e) storage of LNG;
(f) provision or sale of LNG, including LNG dispensing service;
(g) use of LNG fuelling stations and fuelling equipment;
(h) transportation of LNG, including LNG transportation service;
(i) use of cryogenic receptacles, including, but not limited to, tankers, containers and vessels;

"LNG transportation service" means the transportation service referred to in section 6 of the LNG rate schedule;

"utility" means

(a) FortisBC Energy Inc.
(b) FortisBC Energy (Vancouver Island) Inc., or
(c) FortisBC Energy (Whistler) Inc.,

or any of those entities' successor entities on amalgamation, merger or consolidation.

Application

2 This direction is issued to the commission under section 3 of the Act.

CNG services and LNG services

3 In setting rates under the Act for a utility, the commission must do all of the following:

(a) treat CNG service and LNG service, and all costs and revenues related to those services, as part of the utility's natural gas class of service;
(b) allocate all costs and revenues related to CNG service and LNG service to all applicable customers;
(c) allow recovery of costs of purchasing LNG under the agreement referred to in section 5 (1) (b) of this direction.

Expansion facilities

4 (1) The commission must not exercise its power under section 45 (5) of the Act in respect of the expansion facilities.

(2) In setting rates under the Act for FortisBC Energy Inc., the commission must do both of the following:

(a) include in the utility's natural gas class of service rate base the lesser of
(i) the capital costs of constructing the expansion facilities, and
(ii) $400 million;
(b) include the utility's feasibility and development costs on or after January 1, 2013, related to the expansion facilities, plus a return on those

costs equal to the utility's weighted average cost of capital, in the utility's natural gas class of service rate base.

LNG rate schedule and LNG purchase agreement

5 (1) Within 20 days of the date this direction comes into force, the commission must do all of the following:

(a) issue an order setting the LNG rate schedule as a rate for FortisBC Energy Inc. effective on the date the order is issued;

(b) accept for filing under section 71 of the Act the Gas Liquefaction, Storage and Dispensing Service Agreement between FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy Inc. as set out in Appendix 2 attached to this direction;

(c) issue an order setting the agreement referred to in paragraph (b) as a rate for FortisBC Energy (Vancouver Island) Inc.

(2) The commission must not do anything to amend, cancel or suspend the LNG rate schedule, except on application by the utility.

(3) If FortisBC Energy Inc. applies to the commission to amend a charge in the LNG rate schedule, the commission must not set the charge by reference to charges imposed by other providers providing similar services.

(4) The commission must not exercise a power under the Act in a way that would directly or indirectly prevent FortisBC Energy Inc. from providing LNG dispensing service under the LNG rate schedule.

APPENDIX 1

FORTISBC ENERGY INC.

RATE SCHEDULE 46
LIQUEFIED NATURAL GAS SALES,
DISPENSING AND TRANSPORTATION SERVICE

TABLE OF CONTENTS

1 Definitions

1.1 **Definitions** – Except where the context requires otherwise, all words and phrases defined below or in the General Terms and Conditions of FortisBC Energy Inc. (FortisBC Energy) and used in this Rate Schedule have the meanings set out below or in the General Terms and Conditions of FortisBC Energy. Where any of the definitions set out below conflicts with the definitions in the General Terms and Conditions of FortisBC Energy, the definitions set out below govern.

(a) **Available LNG Capacity** – means the total quantity of LNG available for sale to all Customers from LNG Facilities under this Rate Schedule as determined by FortisBC Energy in its sole discretion. FortisBC Energy's determination of the Available LNG Capacity may consider FortisBC Energy's assessment of its overall LNG liquefaction and storage requirements, which include providing peaking and emergency resources.

(b) **Biomethane Energy Recovery Charge (BERC)** – means the charge approved by the British Columbia Utilities Commission that is applicable for Customers selecting a percentage of Biomethane as a portion of their Gas.

(c) **Contract Demand** – means the minimum quantity of LNG, measured in Gigajoules, that FortisBC Energy agrees to supply and the Customer agrees to purchase and pay per year under the LNG Agreement, whether or not such quantity is actually consumed by the Customer.

(d) **Contract Term** – means the term specified in the LNG Agreement, and will expire at 12:00 a.m. Pacific Standard Time on the Expiry Date.

(e) **Customer** – means a Person entering into the LNG Agreement or LNG Transportation Service Agreement with FortisBC Energy.

(f) **Day** – means any period of twenty-four consecutive hours beginning and ending at 12:00 a.m. Pacific Standard Time.

(g) **Delivery Charge** – means the sum of:

(i) a LNG Facility Charge, which is the unit cost per Gigajoule to deliver natural gas from the Interconnection Point to the LNG Facilities, and to produce, store, and Dispense all LNG at the LNG Facilities, excluding the Electricity Surcharge; and

(ii) an Electricity Surcharge, which is the unit cost per Gigajoule for electricity consumed by the LNG Facilities to produce, store and Dispense all LNG at the LNG Facilities.

(h) **Dispensing or any form of the verb Dispense** – means the act of filling a Tanker with LNG from the LNG Facilities.

(i) **Expiry Date** – means the date specified in the LNG Agreement when service under the LNG Agreement ceases.

(j) **Force Majeure** – means any acts of God, strikes, lockouts, or other industrial disturbances, civil disturbances, arrests and restraints of rulers or people, interruptions by government or court orders, present or future valid orders of any regulatory body having proper jurisdiction, acts of the public enemy, wars, riots, blackouts, insurrections, failure or inability to secure materials or labour by reason or regulations or orders of government, serious epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to machinery, liquefaction, storage, and dispensing equipment, or lines of pipes, or freezing of wells or pipelines, or the failure of Gas supply, temporary or otherwise, from a Supplier of Gas, or a declaration of Force Majeure by a gas Transporter that results in Gas being unavailable for delivery at the Interconnection Point, or any major disabling event or circumstance in relation to the normal operations of the party concerned as a whole which is beyond the reasonable control of the party directly affected and results in a material delay, interruption or failure by such party in carrying out its obligations under the Rate Schedule. Force Majeure events cannot be due to negligence of the party claiming Force Majeure.

(k) **Gas** – means natural gas (including odorant added by FortisBC Energy), or Biomethane, or a mixture of any or all of the above.

(l) **Interconnection Point** – means the point where the FortisBC Energy System interconnects with the facilities of Westcoast Energy Inc. at Sumas.

(m) **LNG** – means liquefied natural gas.

(n) **LNG Facilities** – means the current or future LNG production and storage plants and equipment that are owned or operated by FortisBC Energy or are under contract with FortisBC Energy to provide LNG to FortisBC Energy, but excludes any marine loading facilities.

(o) **LNG Agreement** – means the Liquefied Natural Gas Sales and Dispensing Service Agreement between FortisBC Energy and the Customer for the provision of LNG Service, a form of which is attached to this Rate Schedule.

(p) **LNG Service** – means the service of the liquefaction, storage and Dispensing of LNG from the LNG Facilities, and includes Long-Term LNG Service, Short-Term LNG Service and Spot LNG Service. LNG Service does not include LNG Transportation Service or marine loading service.

(q) **LNG Spot Charge** – means the LNG spot charge per Gigajoule of LNG as set out in the Table of Charges.

(r) **LNG Transportation Service** – means the optional service provided by FortisBC Energy as further specified in section 6 of this Rate Schedule that consists of:

(i) use of a Tanker owned or provided by FortisBC Energy;

(ii) hauling via land of the Tanker loaded with LNG from the LNG Facilities to a Customer designated location;

(iii) unloading of LNG from the Tanker; and,

(iv) hauling of the empty Tanker from the Customer designated location to the LNG Facilities.

(s) **LNG Transportation Service Agreement** – means the LNG Transportation Service Agreement for LNG Transportation Service between FortisBC Energy and the Customer, a form of which is attached to this Rate Schedule.

(t) **Long-Term LNG Service** – means LNG Service under this Rate Schedule with a minimum Contract Term of five (5) years or more and a specified Contract Demand for the duration of the Contract Term.

(u) **Minimum Monthly Charge** – means a minimum Monthly charge, applicable to Long-Term LNG Service and Short-Term LNG Service only, calculated by multiplying one-twelfth of the annual Contract Demand by the Delivery Charge.

(v) **Month** – means, subject to any changes from time to time required by FortisBC Energy, the period beginning at 12:00 a.m. Pacific Standard Time on the first day of the calendar month and ending at 12:00 a.m. Pacific Standard Time on the first day of the next succeeding calendar month.

(w) **Process Fuel Gas** – means Gas consumed in the production of LNG at the LNG Facilities, which for 2013 and 2014 is deemed to be a quantity equal to 1% (one percent) of the LNG Dispensed to the Customer, but thereafter the percentage is to be updated annually based on the prior year's actual fuel gas consumption at the LNG Facilities.

(x) **Rate Schedule 46 or this Rate Schedule** – means this Rate Schedule, inclusive of the appended Table of Charges, LNG Agreement, and, if applicable, the LNG Transportation Service Agreement.

(y) **Short-Term LNG Service** – means the LNG Service under this Rate Schedule with a minimum Contract Term of one (1) year and a maximum Contract Term of less than five (5) years and a specified Contract Demand for the duration of the Contract Term.

(z) **Spot LNG Service** – means the Dispensing and sales of LNG on a spot load basis to a Customer at the LNG Spot Charge per Gigajoule, as further specified in section 3.4 of this Rate Schedule.

(aa) **Supplier of Gas** – means a party who sells natural gas to the Customer or FortisBC Energy.

(bb) **Table of Charges** – means the appended table or tables of prices, fees and charges.

(cc) **Tanker** – means a cryogenic receptacle used for receiving, storing and transporting LNG, including without limitation, portable tankers, ISO containers, or other similar equipment.

(dd) **Transporter** – means, in the case of the Inland and Lower Mainland service areas, Westcoast Energy Inc., FortisBC Huntingdon Inc., and any other gas pipeline transportation company connected to the facilities of FortisBC Energy from which FortisBC Energy receives natural gas for the purposes of natural gas transportation or resale.

2 Applicability

2.1 Applicability – This Rate Schedule applies to the LNG Service provided by FortisBC Energy from the LNG Facilities. This Rate Schedule also applies to the optional LNG Transportation Service if a Customer elects such optional service.

2.2 Amendment of Rate Schedule – Amendments to this Rate Schedule must be in accordance with the Direction to the British Columbia Utilities Commission respecting FortisBC Energy's Liquefied Natural Gas Service and Compressed Natural Gas Service.

3 Conditions of LNG Service

3.1 Availability of LNG Service – FortisBC Energy will only provide LNG Service to a Customer if

(a) adequate capacity exists on the FortisBC Energy System;

(b) there is Available LNG Capacity that is not already subject to the Contract Demand under LNG Agreements for Long-Term LNG Service or Short-Term LNG Service; and

(c) the Customer has entered into a LNG Agreement.

FortisBC Energy will endeavor to provide LNG Service from one of the LNG Facilities selected by the Customer in its LNG Agreement, but reserves the right, in its sole discretion, to designate at the time of entering the LNG Agreement and/or during the Contract Term another facility for Dispensing some or all of the Contract Demand.

3.2 Limitation on Short-Term LNG Service – If, in the determination of FortisBC Energy, the sum of the Contract Demand of all LNG Agreements for Short-Term LNG Service exceeds 20% of the Available LNG Capacity, FortisBC Energy may in its sole discretion:

(a) decline to enter into new LNG Agreements for Short-Term LNG Service; or

(b) limit the Contract Demand under new LNG Agreements for Short-Term LNG Service.

3.3 LNG Service Priority Where There Are Competing Requests for LNG Service – In allocating Available LNG Capacity that is not already committed as Contract Demand under a LNG Agreement among competing requests for new Long-Term LNG Service or Short-Term LNG Service, FortisBC Energy will give priority based on

(a) first, length of Contract Term, with longer terms having priority over shorter terms;

(b) and if the desired Contract Term is the same for more than one potential Customers, then by volume, with larger volumes having priority over smaller volumes.

3.4 Spot LNG Service Availability – Spot LNG Service is the lowest priority LNG Service and will be conditional based on the availability of sufficient capacity remaining after deducting the Contract Demand from all LNG Agreements for Long-Term LNG Service and Short-Term LNG Service from the Available LNG Capacity. FortisBC Energy is under no obligation to reserve or set aside Available LNG Capacity for either new or existing Spot LNG Service. The Customer may request Spot LNG Service without contracting for Long-Term LNG Service or Short-Term LNG Service.

3.5 LNG Service Subject to Curtailment – LNG Service is subject to curtailment under section 5.2 (Curtailment of Dispensing Service) of this Rate Schedule.

4 Purchase of LNG

4.1 **Determination of Contract Demand** – FortisBC Energy will determine the Contract Demand for each Customer, taking into consideration the Customer's forecast Daily or Monthly LNG requirements, the Available LNG Capacity, the Contract Demand under other LNG Agreements, and other service and operational requirements. FortisBC Energy may, in its sole discretion, specify a per Customer or per project limit on the Customer's Contract Demand.

4.2 **Allocation of Contract Demand** – At the time the Customer enters into a LNG Agreement, FortisBC Energy will allocate the Contract Demand equally over either the Days or Months of the year, with the choice of Days or Months being at the sole discretion of FortisBC Energy.

4.3 **Alternative Supplier of LNG** – In the event that FortisBC Energy is not able to supply LNG by reason of a curtailment under section 5.2 (Curtailment of Dispensing Service) of this Rate Schedule, the Customer may utilize a temporary LNG supplier until FortisBC Energy is able to resume supply and the Contract Demand shall be adjusted by the amount of LNG obtained from such temporary supplier.

4.4 **Purchase Over Contract Demand** – A Customer may purchase in excess of the Contract Demand as Spot LNG Service, subject to section 3.4 (Spot LNG Service Availability). The rate payable for any excess quantity purchased shall be the Spot Load Charge as specified in section 8.1 (LNG Service Charges).

5 Dispensing of LNG

5.1 **Dispensing of LNG** – Subject to section 13.2 (Right to Restrict) of the General Terms and Conditions of FortisBC Energy and all of the terms and conditions of this Rate Schedule, the Customer or its agent(s) is responsible for directly connecting Tanker or other similar equipment to the LNG Facilities for Dispensing unless the Customer has entered into a LNG Transportation Service Agreement.

5.2 **Curtailment of Dispensing Service** – FortisBC Energy may, for any length of time, curtail under this Rate Schedule by reason of Force Majeure under section 16, for Periodic Repair by FortisBC Energy under section 16.7 of this Rate Schedule, and for purposes and reasons under section 13.2 (Right to Restrict) of the General Terms and Conditions of FortisBC Energy.

If FortisBC Energy determines that curtailment under this Section is required, FortisBC Energy will curtail in the following manner:

(a) Spot LNG Service will be curtailed first.

(b) If further curtailment is required, then Short-Term LNG Service will be curtailed before Long-Term LNG Service. Short-Term LNG Service will be curtailed pro-rata based on Contract Demand.

(c) If further curtailment is required, then Long-Term LNG Service with a Contract Term of between five (5) and ten (10) years in duration will be curtailed pro-rata based on Contract Demand.

(d) If further curtailment is required, then Long-Term LNG Service with a Contract Term longer than ten (10) years will be curtailed pro-rata based on Contract Demand.

In the event of any curtailment in excess of 72 hours in any given Month, then the Minimum Monthly Charge will be prorated in that Month to reflect the full duration of the curtailment. The Customer remains responsible for the total Minimum Monthly Charge if the curtailment is less than 72 hours in that Month.

5.3 **Notice of Curtailment** – Notwithstanding section 13.3 (Notice) of the General Terms and Conditions, unless prevented by Force Majeure, each notice from FortisBC Energy to the Customer with respect to curtailment of LNG Service by FortisBC Energy will be by telephone, email or fax and will specify the portion of the Customer's Contract Demand that is to be curtailed and the time at which such curtailment is to commence.

5.4 **Title Transfer** – Possession of, title to and risk of loss of, damage to, or damage caused by the LNG sold and Dispensed hereunder shall pass from FortisBC Energy to the Customer at the LNG Facilities; specifically, title transfer shall occur at the point of Dispensing to the Tanker or at outlet flange of the FortisBC Energy mass flow meter as applicable. This is the case irrespective of whether FortisBC Energy has provided the Tanker for the LNG Transportation Service.

6 Transportation of LNG

6.1 **Transportation of LNG** – The Customer is responsible for providing a Tanker and for hauling the Tanker from the LNG Facilities unless it has entered into a LNG Transportation Service Agreement.

6.2 **Availability of LNG Transportation Service** – Services provided by FortisBC Energy under this Rate Schedule can also include, at the option of a Customer, LNG Transportation Service. FortisBC Energy will only provide LNG Transportation Service to the Customer if

(a) FortisBC Energy has Tankers;

(b) FortisBC Energy has available Tanker capacity taking into account other LNG Transportation Service Agreements and any safety and regulatory requirements;

(c) FortisBC Energy has determined in its sole discretion that it has the operational ability to provide the service;

(d) FortisBC Energy is able to contract with third parties to provide hauling of the Tanker at the desired times;

(e) the Customer has entered into a LNG Agreement for a Contract Term at least as long as the term for which LNG Transportation Service is sought; and

(f) the Customer has entered into a LNG Transportation Service Agreement.

FortisBC Energy is under no obligation to procure additional Tanker capacity or hauling services to provide new LNG Transportation Service.

6.3 **Charges for LNG Transportation Service** – a Customer who selects the LNG Transportation Service and enters into a LNG Transportation Service Agreement will be responsible for both the LNG Tanker Charge and the Tanker Hauling Charge as specified in section 8.2 of this Rate Schedule.

7 Rights and Responsibilities

7.1 **Responsibility for Compliance** – The Customer, in its acceptance, transport, use or storage of the LNG, shall at all times be in compliance with the requirements of all applicable laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter, including, but not limited to, the federal *Transportation of Dangerous Goods Act* and associated regulations and British Columbia's *Environmental Management Act* and associated regulations. It is the sole responsibility of the Customer to ensure that any personnel, vehicle or Tanker provided by the Customer or its agent for Dispensing and transportation meets those requirements.

7.2 **Right to Refuse** – Notwithstanding subsection 7.1 above, FortisBC Energy at its sole discretion may refuse to Dispense LNG to the Customer, if in FortisBC Energy's good faith determination, the Dispensing or transportation of LNG to the Customer may be contrary to any laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction, including, but not limited to, the federal *Transportation of Dangerous Goods Act* and its associated regulations and British Columbia's *Environmental Management Act* and associated regulations.

7.3 **Responsibility for LNG Transportation Emergency Response** – The Customer acknowledges that FortisBC Energy will incur costs to comply with applicable laws relating to emergency response during the transportation of the LNG Dispensed to the Customer under this Rate Schedule whether or not the Customer has not selected the LNG Transportation Service. FortisBC Energy reserves the right to charge the Customer for costs FortisBC Energy incurs to comply with such laws.

In the event FortisBC Energy responds to a transportation emergency involving LNG Dispensed to the Customer under this Rate Schedule, the Customer shall at its expense provide assistance to FortisBC Energy upon request. The Customer shall reimburse FortisBC Energy for all costs incurred by FortisBC Energy responding to such an emergency.

7.4 **Required Insurance** – The Customer must maintain General Commercial Liability Insurance for bodily injury, death and property damage in the minimum amount of $5,000,000 per occurrence naming FortisBC Energy as an additional insured with respect to LNG Service or LNG Transportation Service provided to the Customer.

8 Terms of Payment

8.1 LNG Service Charges – The Customer will pay to FortisBC Energy the following charges for LNG Service as provided in the Table of Charges:

(i) For Long-Term LNG Service and Short-Term LNG Service, the Customer will pay to FortisBC Energy all of the following charges:

(A) A charge calculated as the greater of

i. the Delivery Charge, multiplied by the quantity of LNG, measured in Gigajoules, Dispensed to the Customer,

or

ii. the Minimum Monthly Charge; plus

(B) A Commodity Charge calculated by multiplying

i. the quantity of LNG, measured in Gigajoules, Dispensed to the Customer plus Process Fuel Gas

by

ii. the sum of Sumas Monthly Index Price plus Market Factor

and by

iii. the percentage of LNG supplied from conventional natural gas as selected by the Customer; plus

(C) where a Customer has selected a percentage of Biomethane as part of the Gas to be used in providing LNG Service, a Biomethane Energy Recovery Charge calculated by multiplying

i. the quantity of LNG, measured in Gigajoules, Dispensed to the Customer

by

ii. the selected percentage of Biomethane

and by

iii. the BERC.

(ii) A Long-Term LNG Service or Short-Term LNG Service Customer whose Contract Demand is greater than 1,825,000 Gigajoules may choose to provide its own natural gas commodity and Process Fuel Gas to the Interconnection Point. In such cases, the Customer will not be subject to a Commodity Charge.

(iii) Spot Load LNG Charge - For Spot LNG Service, the Customer will pay to FortisBC Energy all of the charges in section 8.1(i), except that, in lieu of the charge under section 8.1(i)(A), the Customer will pay a Spot Charge calculated by multiplying:

i. the quantity of LNG, measured in Gigajoules, Dispensed to the Customer plus Process Fuel Gas

by

ii. the LNG Spot Charge.

8.2 LNG Transportation Service Charges – The Customer will pay to FortisBC Energy both of the following charges for LNG Transportation Service as provided in the Table of Charges:

(i) LNG Tanker Charge – a charge per Day or partial Day for the use of a Tanker owned or provided by FortisBC Energy; and

(ii) LNG Tanker Hauling Charge – a hauling fee based on the cost to FortisBC Energy to contract with a third-party contractor to haul the Tanker, plus 15%.

8.3 Currency – Unless otherwise indicated, all dollar amounts or the use of the symbol "$" in this Rate Schedule, including the Table of Charges and the LNG Agreement and LNG Transportation Service Agreement shall be deemed to refer to Canadian dollars.

8.4 Payment of Amounts – The Customer will pay to FortisBC Energy all of the applicable charges set out in the Table of Charges for LNG Service and, if applicable, Table of Charges for LNG Transportation Service.

9 Daily Loading and Scheduling

9.1 Requested Quantity and Loading Schedule – At least 24 hours in advance of the Day of the Customer's desired loading time, the Customer or its agent will provide FortisBC Energy by fax or email such information as may be requested by FortisBC Energy, which will include, but is not limited to, the Customer's requested quantity of LNG for the given Day.

9.2 Adjustment of Loading Schedule – FortisBC Energy may adjust, in consultation with the Customer or its agents, the Customer's loading schedule when in the reasonable determination of FortisBC Energy such modification is necessary in order to:

(a) minimize the costs to FortisBC Energy of Dispensing LNG;

(b) accommodate multiple Customers; or

(c) if the Customer is taking LNG Transportation Service, address the non-availability of the Tanker or non-availability of third parties for hauling the Tanker.

10 Term of LNG Agreement

10.1 Renewal – There is no right of renewal of a LNG Agreement. A Customer seeking LNG Service beyond the Contract Term must enter into a new LNG Agreement.

10.2 Early Termination by FortisBC Energy – The term of the LNG Agreement is subject to early termination by FortisBC Energy in accordance with section 13 (Default or Bankruptcy).

10.3 Survival of Covenants – Upon termination of the LNG Agreement, whether pursuant to section 13 (Default or Bankruptcy) of this LNG Rate Schedule or otherwise,

(a) all claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and

(b) all of the provisions in the LNG Agreement and this Rate Schedule relating to the obligations of any of the parties to account to or indemnify the other and to pay to the other any monies owing as at the date of termination in connection with this Rate Schedule,

will survive such termination.

11 Statements and Payments

11.1 **Statements to be Provided** – FortisBC Energy will, on or about the 15th Day of each Month, deliver to the Customer, a statement for the preceding Month showing all services provided to the Customer or its agents and the amount due. Any errors in any statement will be promptly reported to the other party as provided hereunder, and statements will be final and binding unless questioned within one year after the date of the statement.

11.2 **Payment and Late Payment Charge** – Payment for the full amount of the statement, including all taxes imposed by any federal, provincial, municipal, territorial, local or any agency or political subdivision thereon, will be made to FortisBC Energy at its office in Surrey, British Columbia, or at such other place in Canada as FortisBC Energy will designate, on or before the 1st business Day after the 30th calendar Day following the billing date. If the Customer fails or neglects to make any payment required under this Rate Schedule, or any portion thereof, to FortisBC Energy when due, FortisBC Energy will include in the next bill to the Customer a late payment charge specified in the Standard Fees and Charges Schedule of the General Terms and Conditions.

11.3 **Form of Payments** – All payments required to be made under statements and invoices rendered pursuant to this Rate Schedule will be made by wire transfer to, or cheque or bank cashier's cheque drawn on a Canadian chartered bank or trust company, payable in lawful money of Canada at par in immediately available funds in Vancouver, British Columbia.

11.4 **Examination of Records** – Each of FortisBC Energy and the Customer will have the right to examine at reasonable times the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, charge, computation or demand made pursuant to any provisions of this Rate Schedule.

11.5 **Security** – In order to secure the prompt and orderly payment of the charges to be paid by the Customer or its assignees as specified in section 19.3 (Remedies Cumulative) of this Rate Schedule to FortisBC Energy under this Rate Schedule, FortisBC Energy may require the Customer or its assignees to provide, and at all times maintain, an irrevocable letter of credit in favour of FortisBC Energy issued by a financial institution acceptable to FortisBC Energy in an amount equal to the estimated maximum amount payable by the Customer under this Rate Schedule for a period of 90 Days and in a form satisfactory to FortisBC Energy. If the Customer or its assignees is able to provide alternative security acceptable to FortisBC Energy, FortisBC Energy may in its sole discretion accept such security in lieu of a letter of credit.

12 Measurement

12.1 **Unit of Measurement** – The unit of measurement of LNG for all purposes hereunder will be kilograms or pounds.

12.2 **Determination of Quantity** – The quantity of LNG Dispensed pursuant to this Rate Schedule shall be measured at the scale at the LNG Facilities or an alternate scale that is approved and certified by Measurement Canada. The Tanker or other cryogenic receptacle into which the LNG is Dispensed will be weighed at the scale before and after Dispensing. The measurement of the amount of LNG Dispensed shall be based on the difference, expressed in kilograms or pounds, of these two weights. In the event that the cryogenic receptacle cannot be weighed by the scale, then the quantity of LNG Dispensed shall be measured through the use of mass flow meters.

12.3 Conversion to Energy Units — In accordance with the *Electricity and Gas Inspection Act* of Canada, volumes of LNG Dispensed each Day will be converted to energy units by multiplying the standard volume by the Heat Content of each unit of LNG. Volumes will be specified in kilograms or pounds rounded to the nearest unit and energy will be specified in Gigajoules rounded to one decimal place. FortisBC Energy will use the following formula to convert kilograms or pounds of LNG to GJ of LNG:

Converting Weight of LNG to Gigajoules

	Gross Weight after LNG Dispensing (kilograms or pounds)
minus	Gross Weight prior to Dispensing (kilograms or pounds)
equals	Net Weight of the Delivered LNG (kilograms or pounds)
	Net Weight of the Delivered LNG (kilograms or pounds)
multiplied by	The energy density as determined by FortisBC Energy through analysis of vaporized LNG on a periodic basis. For greater certainty, unless otherwise determined by FortisBC Energy, the energy density shall be 0.055058 gigajoule/kilogram or 0.024974 gigajoule/pound equals Delivered LNG (Gigajoule)

13 Default or Bankruptcy

13.1 Default by the Customer – If the Customer at any time fails or neglects

(a) to make any payment due to FortisBC Energy or as designated under this Rate Schedule within 30 calendar Days after payment is due, or

(b) to correct any default of any of the other terms, covenants, conditions or obligations imposed upon it under this Rate Schedule, within 30 calendar Days after FortisBC Energy gives to the Customer notice of such default, or

(c) in the case of a default that cannot with due diligence be corrected within a period of 30 Days, the Customer fails to proceed promptly after the giving of such notice to correct the same and thereafter to prosecute the correcting of such default with all due diligence,

then FortisBC Energy may in addition to any other remedy that it has, at its option and without liability therefor:

(d) suspend further LNG Service to the Customer until the default has been fully remedied, and no such suspension or refusal will relieve the Customer from any obligation under this Rate Schedule, or

(e) suspend further LNG Service to the Customer and terminate the Customer's LNG Agreement.

13.2 Bankruptcy or Insolvency of the Customer – If the Customer becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency or a receiver is appointed pursuant to a statute or under a debt instrument or the Customer seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose or commences proceedings under the *Companies' Creditors Arrangement Act* of Canada, FortisBC Energy will have the right, at its sole discretion, to terminate the supply of LNG, the LNG Agreement by giving notice in writing to the Customer and thereupon FortisBC Energy may cease further supply of LNG to the Customer.

13.3 **Obligations of Customer Upon Suspension or Termination** – In the event of a suspension of LNG Service, or termination of a LNG Agreement, any amount then outstanding for service provided under this Rate Schedule will immediately be due and payable by the Customer. The Contract Demand shall not be reduced during the period of any suspension. In the event of early termination of a LNG Agreement, an amount equal to the Minimum Monthly Charge that would have otherwise been payable for the remainder of the Contract Term will become immediately due and payable by the Customer.

14 Notice

14.1 **Notice** – Any notice, request, statement or bill that is required to be given or that may be given under this Rate Schedule will be in writing and will be considered as fully delivered when mailed, personally delivered or sent by fax to the other in accordance with the following:

If to FortisBC Energy	FORTISBC ENERGY INC.
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8
BILLING AND PAYMENT:	Attention: Industrial Billing Telephone: 1-855-873-8773 Fax: 1-888-224-2720 Email industrial.billing@fortisbc.com
CUSTOMER RELATIONS:	Attention: Business Development Telephone : (778) 571-3286 (604) 592-7949 Email : LNG@fortisbc.com
LEGAL AND OTHER:	Attention: Director, Legal and Governance Services Telephone: (604) 443-6512 Fax: (604) 443-6540

If to the Customer, then as set out in the Customer's LNG Service Agreement and, if applicable, LNG Transportation Service Agreement.

14.2 **Specific Notices** – Notwithstanding section 14.1 (Notice) and section 5.3 (Notice of Curtailment), notices with respect to suspension of LNG Service by FortisBC Energy for reasons of Force Majeure will be sufficient if given by FortisBC Energy in accordance with section 13.3 (Notice) of the General Terms and Conditions.

15 Indemnity and Limitation on Liability

15.1 Limitation on Liability – FortisBC Energy, its employees, contractors or agents are not responsible or liable for any loss, damage, costs or injury (including death) incurred by the Customer or any person claiming by or through the Customer caused by or resulting from, directly or indirectly, any discontinuance, suspension or curtailment of, or failure or defect in, or refusal to provide LNG Service, unless the loss, damage, costs or injury (including death) is directly attributable to the gross negligence or willful misconduct of FortisBC Energy, its employees, contractors or agents provided, however that FortisBC Energy, its employees, contractors and agents are not responsible or liable for any loss of profit, loss of revenues, or other economic loss even if the loss is directly attributable to the gross negligence or willful misconduct of FortisBC Energy, its employees, contractors or agents.

15.2 Customer Indemnity – The Customer will indemnify and hold harmless FortisBC Energy, its employees, contractors and agents from all claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of

(a) the negligence or willful misconduct of the Customer, employees, contractors or agents; or

(b) the breach by the Customer of any of the provisions contained in this Rate Schedule, including the LNG Agreement and if applicable the LNG Transportation Service Agreement, including those related to the payment by the Customer of all federal, provincial, and municipal taxes (or payments made in lieu thereof).

16 Force Majeure

16.1 Force Majeure – Subject to the other provisions of this section 16, if either party is unable or fails by reason of Force Majeure to perform in whole or in part any obligation or covenant set out in this Rate Schedule, the obligations of both FortisBC Energy and the Customer will be suspended to the extent necessary for the period of the Force Majeure condition.

16.2 Curtailment Notice – If FortisBC Energy claims suspension pursuant to this section 16, FortisBC Energy will be deemed to have issued to the Customer a notice of curtailment.

16.3 Exceptions - Neither party will be entitled to the benefit of the provisions of section 16.1 under any of the following circumstances:

(a) to the extent that the failure was caused by the negligence or contributory negligence of the party claiming suspension,

(b) subject to section 16.5 (No Exception for Payments) to the extent that the failure was caused by the party claiming suspension having failed to diligently attempt to remedy the condition and to resume the performance of the covenants or obligations with reasonable dispatch, or

(c) unless as soon as possible after the happening of the occurrence relied on or as soon as possible after determining that the occurrence was in the nature of Force Majeure and would affect the claiming party's ability to observe or perform any of its covenants or obligations under this Rate Schedule, the party claiming suspension will have given to the other party notice to the effect that the party is unable by reason of Force Majeure (the nature of which will be specified) to perform the particular covenants or obligations.

16.4 **Notice to Resume** – The party claiming suspension will likewise give notice, as soon as possible after the Force Majeure condition has ceased, to the effect that it has ceased and that the party has resumed, or is then in a position to resume, the performance of the covenants or obligations.

16.5 **Settlement of Labour Disputes** – Notwithstanding any of the provisions of this section 16, the timing and terms and conditions of the settlement of strikes, labour disputes or industrial disturbances will be entirely within the discretion of the particular party involved and the party may make settlement of it at the time and on terms and conditions as it may deem to be advisable and no delay in making settlement will deprive the party of the benefit of section 16.1.

16.6 **No Exemption for Payments** – Notwithstanding any of the provisions of this section 16, Force Majeure will not relieve or release either party from its obligations to make payments to the other party under a LNG Agreement or LNG Transportation Service Agreement. In the event of any Force Majeure event affecting FortisBC Energy that results in a curtailment in excess of 72 hours per Month, then the Minimum Monthly Charge as specified in section 8.1 (LNG Service Charges) of this Rate Schedule will be prorated accordingly. Should an event of Force Majeure affecting the Customer prevent the Customer from taking LNG Service, the Minimum Monthly Charge will not be reduced.

16.7 **Periodic Repair by FortisBC Energy** – FortisBC Energy may temporarily suspend Dispensing of LNG from the LNG Facilities for the purpose of repairing or replacing a portion of the FortisBC Energy System or its equipment and FortisBC Energy will make reasonable efforts to give the Customer as much notice as possible with respect to such suspension, not to be less than 24 hours prior notice except when prevented by Force Majeure. FortisBC Energy will make reasonable efforts to schedule repairs or replacement to minimize suspension or curtailment of LNG Service to the Customer, and to restore Service as quickly as possible.

17 Disputes

17.1 **Mediation** – Where any dispute arises out of or in connection with the LNG Service, FortisBC Energy and the Customer agree to try to resolve the dispute by participating in a structured mediation conference with a mediator under the National Arbitration Rules of the ADR Institute of Canada, Inc.. The mediation will take place in Vancouver, BC.

17.2 **Arbitration** – If FortisBC Energy and the Customer fail to resolve the dispute through mediation within 30 days of a party giving written notice of a dispute, then either party may refer the dispute to binding arbitration for final resolution. The place of arbitration will be Vancouver, BC, and the substantive law governing the dispute will be the law of British Columbia. Unless otherwise agreed by the parties in writing, the arbitration will be conducted by a single arbitrator in accordance with the National Arbitration Rules of the ADR Institute of Canada, Inc..

17.3 **Award** – The arbitrator shall have the authority to award:

(a) money damages, to the extent provided in the Rate Schedule;

(b) interest on unpaid amounts from the date due;

(c) specific performance; and

(d) permanent relief.

17.4 **Obligations Continue** – The parties will continue to fulfill their respective obligations pursuant to this Rate Schedule, the LNG Agreement, and, if applicable, the LNG Transportation Service Agreement during the resolution of any dispute in accordance with this section 17.

18 Interpretation

18.1 **Interpretation** – Except where the context requires otherwise or except as otherwise expressly provided, in this Rate Schedule, including the LNG Agreement and LNG Transportation Service Agreement,

(a) all references to a designated section are to the designated section of this Rate Schedule unless otherwise specifically stated;

(b) the singular of any term includes the plural, and vice versa, and the use of any term is equally applicable to any gender and, where applicable, body corporate;

(c) any reference to a corporate entity includes and is also a reference to any corporate entity that is a successor by merger, amalgamation, consolidation or otherwise to such entity;

(d) all words, phrases and expressions used in this Rate Schedule that have a common usage in the gas industry and that are not defined in this Rate Schedule or in the General Terms and Conditions have the meanings commonly ascribed thereto in the gas industry; and

(e) the headings of the sections set out in this Rate Schedule are for convenience of reference only and will not be considered in any interpretation of this Rate Schedule.

19 Miscellaneous

19.1 **No joint venture or partnership** – Nothing contained in this Rate Schedule, including the LNG Agreement and the LNG Transportation Service Agreement shall be construed to place the parties in the role of partners or joint venturers or agents and no party shall have the power to obligate or bind any other party in any manner whatsoever.

19.2 **Waiver** – No waiver by either FortisBC Energy or the Customer of any default by the other in the performance of any of the provisions of this Rate Schedule will operate or be construed as a waiver of any other or future default or defaults, whether of a like or different character.

19.3 **Remedies Cumulative** – All rights and remedies of each party under this Rate Schedule are cumulative and may be exercised at any time and from time to time, independently and in combination.

19.4 **Enurement** – This Rate Schedule, including the LNG Agreement and, if applicable, the LNG Transportation Service Agreement, will enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns, including without limitation, successors by merger, amalgamation or consolidation.

19.5 **Assignment** – The Customer may not assign its rights under this Rate Schedule, including the LNG Agreement and, if applicable, the LNG Transportation Service Agreement, in whole or in part without the prior written consent of FortisBC Energy, provided, however, that Customer may assign without the consent of FortisBC Energy if:

(a) such assignment is made pursuant to the assignment of all of the Customer's rights and obligations hereunder to a partnership, limited liability company, corporation, trust or other organization in whatever form succeeds to all or substantially all of the Customer's assets and business;

(b) the assignee assumes such obligations by contract, operation of law, or otherwise; and

(c) at least five (5) days prior to the assignee taking service under this Rate Schedule, the Customer provides notice in writing to FortisBC Energy of the assignment of its rights and obligations as Customer under this Rate Schedule, and the assignee provides confirmation in writing to FortisBC Energy of its assumption of rights and obligations as Customer under this Rate Schedule.

Upon such assumption of obligations, and if required, the receipt of the prior written consent of FortisBC Energy, which consent shall not be unreasonably delayed or withheld, the Customer shall be relieved of and fully discharged from all obligations hereunder. This provision applies to every proposed assignment by the Customer.

19.6 Law – This Rate Schedule will be construed and interpreted in accordance with the applicable laws of the Province of British Columbia and the laws of Canada.

19.7 Time is of Essence – Time is of the essence of this Rate Schedule and of the terms and conditions thereof.

19.8 Subject to Legislation – Notwithstanding any other provision hereof, this Rate Schedule and the rights and obligations of FortisBC Energy and the Customer under this Rate Schedule are subject to all present and future laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over FortisBC Energy or the Customer.

19.9 Further Assurances – Each of FortisBC Energy and the Customer will, on demand by the other, execute and deliver or cause to be executed and delivered all such further documents and instruments and do all such further acts and things as the other may reasonably require to evidence, carry out and give full effect to the terms, conditions, intent and meaning of this Rate Schedule, including the LNG Agreement and, if applicable, the LNG Transportation Service Agreement, and to assure the completion of the transactions contemplated hereby.

Table of Charges
for LNG Transportation Service

All sales and service taxes, carbon tax and any future new taxes, are extra and shall be applied as applicable.

2013 LNG Tanker Charge per Day or Partial Day	$249.00
LNG Tanker Charge per Day or Partial Day for 2014 and subsequent years	2013 LNG Tanker Charge, escalated annually at the greater of 2% or the British Columbia Consumer Price Index.
LNG Tanker Hauling Charge	FortisBC Energy cost plus 15% Administration Charge

Table of Charges
for LNG Service

All sales and service taxes, carbon tax and any future new taxes, are extra and shall be applied as applicable.

2013 LNG Facility Charge	$ 3.47/GJ
2013 Electricity Surcharge	$ 0.88/GJ
Commodity Charge per Gigajoule	Sumas Monthly Index Price[1] plus the Market Factor[2]
Charge per Gigajoule of Biomethane supplied (if applicable)	Current approved BERC rate
2013 LNG Spot Charge	$ 4.60/GJ
LNG Facility Charges, Electricity Surcharges, premiums, and LNG Spot Charges for 2014 and thereafter	Per Note 3

Notes:

1. **Sumas Monthly Index Price** – means the Sumas Monthly Index Price as set out in Inside F.E.R.C.'s Gas Market Report for gas delivered to Northwest Pipeline Corporation at Sumas, converted to Canadian dollars using the noon exchange rate as quoted by the Bank of Canada for the first Day of each Month in which the Sumas Monthly Index Price shall apply. Energy units are converted from MMBtu to Gigajoule by application of a conversion factor equal to 1.055056 Gigajoule per MMBtu.

2. **Market Factor** – means the charge that is the premium above the Sumas Monthly Index that is calculated by FortisBC Energy for that Month to cover costs related to securing incremental natural gas supply for that Month, including market premiums levied by suppliers for ensuring physical delivery of natural gas and any demand charges related to incremental physical purchases and contribution to the reservation fees and variable costs of core assets which may be used during that Month. For greater clarity, this premium will be based on actual market quotations at Sumas received by FortisBC Energy.

3. **LNG Facility Charges, Electricity Surcharges, premiums and LNG Spot Charges for 2014 and beyond** – The LNG Facility Charges, Electricity Surcharges, premiums and LNG Spot Charges for 2014 and thereafter will be determined by taking the base charges shown in (1) below, which are expressed in 2013 dollars, and resetting and adjusting those base charges annually on January 1 in accordance with (2) below.

(1) The following base charges, expressed in 2013 dollars, shall apply in accordance with the specified aggregate daily Contract Demand for all Customers and the specified Available LNG Capacity:

(a) Where on January 1 of a given year each of the aggregate prorated daily Contract Demand for all Customers and the Available LNG Capacity is between 0 Gigajoules per day and 35,000 Gigajoules per day, the following base charges apply for that year:

LNG Facility Charge	$ 3.47/GJ
Electricity Surcharge	$ 0.88/GJ
LNG Spot Charge	$ 4.60/GJ

(b) Where on January 1 of a given year each of the aggregate prorated daily Contract Demand for all Customers and the Available LNG Capacity is at least 35,000 Gigajoules per day and less than 100,000 Gigajoules per day, the following base charges apply for that year:

LNG Facility Charge	$ 2.68/GJ
Electricity Surcharge	$ 0.87/GJ
LNG Spot Charge	$ 4.20/GJ

(c) Where on January 1 of a given year each of the aggregate prorated daily Contract Demand for all Customers and the Available LNG Capacity is at least 100,000 Gigajoules per day, the following base charges apply for that year:

LNG Facility Charge	$ 1.84/GJ
Electricity Surcharge	$ 0.86/GJ
LNG Spot Charge	$ 3.35/GJ

(2) The base charges shown in (1) above, which are presented in 2013 dollars, will be reset and adjusted annually as follows:

(a) The LNG Facility Charge and all premium charges in (d) below shall be escalated annually at the greater of 2% or the British Columbia Consumer Price Index.

(b) The Electricity Surcharge shall be adjusted based upon the actual prior year electricity use per Gigajoule of LNG output of the LNG Facilities and actual BC Hydro rate increases incurred at the LNG Facilities.

(c) The LNG Spot Charge is $0.25/GJ greater than the sum of the LNG Facility Charge and adjusted Electricity Surcharge, as adjusted under (a) and (b) above.

(d) Where each of the aggregate prorated daily Contract Demand for all Customers and the Available LNG Capacity is at least 35,000 Gigajoules per day:

i. Customers with a daily prorated Contract Demand of less than 5,000 GJ/day shall pay a premium of $0.15/GJ;

ii. Customers with a Contract Term of less than 10 years shall pay a premium of $0.25/GJ; and

iii. Customers with a daily prorated Contract Demand of less than 5,000 GJ/day and a Contract Term of less than 10 years shall pay a premium of $0.40/GJ.

LIQUEFIED NATURAL GAS SALES
AND DISPENSING SERVICE AGREEMENT

This Agreement (LNG Natural Gas Sales and Dispensing Agreement or LNG Agreement) is dated ____________, 20___ (Effective Date) between FortisBC Energy Inc. (FortisBC Energy) and ______________________________________ (Customer).

WHEREAS:

A. FortisBC Energy owns and operates the FortisBC Energy System in British Columbia.

B. The Customer has requested that FortisBC Energy provide services for liquefaction of natural Gas and Dispensing of LNG from the LNG Facilities.

NOW THEREFORE THIS LNG AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

1. Specific Information

Applicable Rate Schedule:	46
Type of Service:	☐ Long Term ☐ Short Term ☐ Spot
Dispensing Point Preferred by Customer:	☐ Tilbury ☐ Mt. Hayes ☐ Other
Contract Demand:	__________ Gigajoules per Year
Contract Demand Allocation	☐ Daily ☐ Monthly
Biomethane Percentage Selection:	______________________
Commencement Date:	______________________
Expiry Date:	______________________
Service Address:	______________________
Account Number:	______________________

2. Incorporation of Rate Schedule

2.1 Additional Terms – All rates, terms and conditions and definitions set out in the LNG Sales, Dispensing and Transportation Service Rate Schedule as any of them may be amended in accordance with section 2.2 (Amendment of Rate Schedule) of this Rate Schedule and in the General Terms and Conditions of FortisBC Energy as any of them may be amended by FortisBC Energy and approved by the British Columbia Utilities Commission, are in addition to the terms and conditions contained in this LNG Agreement and form part of this LNG Agreement and bind FortisBC Energy and the Customer as if set out in this LNG Agreement.

2.2 Conflict – Where anything in this LNG Agreement conflicts with either the other terms in Rate Schedule or the General Terms and Conditions of FortisBC Energy, the provisions of this LNG Agreement govern. Where anything in the Rate Schedule conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of FortisBC Energy, the provisions of the Rate Schedule govern.

3 General

3.1 Amendments to be in Writing – Except as otherwise set out in the Rate Schedule, no amendment or variation of this LNG Agreement will be effective or binding upon the parties unless such amendment or variation is set out in writing and duly executed by the parties.

3.2 Notice – Any notices or other communication which may be or is required to be given or made pursuant to the Agreement shall, unless otherwise expressly provided herein, shall be in writing and shall be personally delivered to or sent by facsimile to either party at its address set forth below:

<u>If to FortisBC Energy</u>: FORTISBC ENERGY INC.

MAILING ADDRESS: 16705 Fraser Highway
Surrey, B.C.
V4N 0E8

<u>If to the Customer</u>: ____________________

MAILING ADDRESS: ____________________

____

____

Attention: ________________

3.3 Severability – If any provision of this LNG Agreement is determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, such determination does not impair or affect the validity, legality or enforceability of any other provision of this LNG Agreement.

3.4 **Execution** – This LNG Agreement may be executed in counterparts, each of which shall be deemed as an original, but all of which shall constitute one and the same instrument. Delivery of an executed counterpart of this letter by facsimile or electronic transmission hereof shall be as effective as delivery of an originally executed counterpart hereof.

IN WITNESS WHEREOF the parties hereto have executed this LNG Agreement.

FORTISBC ENERGY INC.	______________________ (Legal name of Customer)
BY: ______________________ (Signature)	BY: ______________________ (Signature)
______________________ (Title)	______________________ (Title)
______________________ (Name – Please Print)	______________________ (Name – Please Print)
DATE: ______________________	DATE: ______________________
	BY: ______________________ (Signature)
	______________________ (Title)
	______________________ (Name – Please Print)
	DATE: ______________________

LNG TRANSPORTATION SERVICE AGREEMENT

THIS AGREEMENT (LNG Transportation Service Agreement or Agreement) is made effective as of the _____ of ____________, 20__ (the Effective Date) between FortisBC Energy Inc. (FortisBC Energy) and ____ (the Customer).

NOW THEREFORE, in consideration of the mutual promises set out herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged) the parties agree as follows:

1. Incorporation by Rate Schedule

1.1 Additional Terms – All rates, terms and conditions and definitions set out in the LNG Sales, Dispensing and Transportation Service Rate Schedule (Rate Schedule 46) as any of them may be amended in accordance with section 2.2 (Amendment of Rate Schedule) of this Rate Schedule and in the General Terms and Conditions of FortisBC Energy as any of them may be amended by FortisBC Energy and approved by the British Columbia Utilities Commission, are in addition to the terms and conditions contained in this Agreement and form part of this Agreement and bind FortisBC Energy and the Customer as if set out in this Agreement.

1.2 Conflict – Where anything in this Agreement conflicts with either the other terms in Rate Schedule 46 or the General Terms and Conditions of FortisBC Energy, the provisions of this Agreement govern. Where anything in Rate Schedule 46 conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of FortisBC Energy, the provisions of Rate Schedule 46 govern.

2. Additional Definitions

2.1 Approvals – means those consents, permits, filings, orders or other approvals of any municipal, provincial, or federal governmental authority having jurisdiction over any aspect of the LNG Transportation Service.

3. Term

3.1 Term – The term of this Agreement (the Term) shall commence on the Effective Date and shall expire no later than the date the Customer's LNG Agreement expires or terminates.

4. LNG Transportation Service

4.1 Subject to the terms and conditions of Rate Schedule 46 and section 9 of this Agreement, FortisBC Energy shall perform the LNG Transportation Service:

(a) in accordance with good industry practices and in a good and workmanlike manner;

(b) in accordance with the requirements of applicable Approvals, laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter, including, but not limited to, the federal *Transportation of Dangerous Goods Act*; and

(c) in accordance with all reasonable safety procedures required by the Customer with respect to the Customer's property or designated location.

5. Request for LNG Transportation Service

5.1 Subject to section 6.2 (Availability of LNG Transportation Service) of Rate Schedule 46, if the Customer wishes to use LNG Transportation Service, the Customer or its agents shall notify FortisBC Energy by fax or email prior to 12:00 am Pacific Standard Time (or other such time as may be specified from time to by FortisBC Energy) and provide FortisBC Energy with such information as may be requested by FortisBC Energy, which shall include, but is not limited to, the Customer's desired quantity of LNG and the desired date and time of arrival of LNG at the Customer designated location, provided FortisBC Energy receives such notice no later than 48 hours prior to the requested date and time of arrival of the Tanker at the Customer designated location.

6. Subcontracting

6.1 FortisBC Energy may, without prior consent of the Customer, retain the services of a qualified third party to perform some or all of its obligations under this Agreement.

7. Ownership of the Tanker and Rental of Tanker

7.1 Ownership of the Tanker – FortisBC Energy shall retain all right, title and interest in and to the Tanker whether or not the Tanker (or any part thereof) is affixed to the Customer's property and the Customer acknowledges and agrees that notwithstanding any rule of law or equity to the contrary, the Tanker shall not be considered a fixture. The Customer shall have no right, title or interest in the Tanker other than the right to rent and utilize the Tanker in accordance with the terms and conditions of this Agreement.

7.2 With respect to storage of LNG in the Tanker at the Customer designated location, to the extent that FortisBC Energy has consented to such storage, the Customer shall:

(a) comply with the requirements of any applicable Approvals, laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter;

(b) be responsible for ensuring that the Tanker is provided with security satisfactory to FortisBC Energy in the form of locked fencing, video surveillance and periodic patrol outside of business hours;

(c) be responsible for all costs and expenses incurred by FortisBC Energy to repair:

(i) any and all damage to the Tanker arising directly or indirectly from the acts or omissions of the Customer or its agents or other persons for whom at law the Customer is responsible; and

(ii) any and all damage to the Tanker arising directly or indirectly from the acts or omissions of a third party.

7.3 The Customer acknowledges and agrees that FortisBC Energy is not responsible for storage of LNG in the Tanker at the Customer designated location and is not obligated to consent to the Customer using the Tanker as storage at the Customer designated location.

8. LNG Tanker and Tanker Hauling Charges

8.1 LNG Tanker Hauling Charge – In addition to any fees or charges related to the supply of LNG pursuant to Rate Schedule 46, in exchange for performance by FortisBC Energy of the LNG Transportation Service, the Customer agrees to pay FortisBC Energy the LNG Hauling Charge as set out in the Table of Charges under Rate Schedule 46, as which may be amended in accordance with section 2.2 (Amendment of Rate Schedule) of the Rate Schedule..

8.2 LNG Tanker Charge – In addition to any fees or charges related to the sale and Dispensing of LNG pursuant to Rate Schedule 46 or the LNG Transportation Service, the Customer agrees to pay FortisBC Energy the LNG Tanker Charge as set out in the Table of Charges under Rate Schedule 46, as which may be amended in accordance with section 2.2 (Amendment of Rate Schedule) of the Rate Schedule, for each Day or partial Day that the Tanker is in use for providing the LNG Transportation Service to the Customer, including Days or partial Days that the Tanker is used to provide storage of LNG at the Customer designated location.

9. Access to the Customer Location

9.1 Access – The Customer shall provide cleared and graded lands at the Customer designated location satisfactory to FortisBC Energy to allow FortisBC Energy to perform the LNG Transportation Service. The Customer shall ensure that there is no traffic at the Customer designated location within a 15 metre perimeter of the Tanker during any unloading of LNG.

10. Permits and Approvals

10.1 FortisBC Energy Approvals – Except as otherwise specified herein, FortisBC Energy shall be responsible, at its sole cost, for obtaining and maintaining the necessary Approvals with respect to the LNG Transportation Service and maintenance of the Tanker, including the necessary approvals of the British Columbia Utilities Commission, and shall ensure such Approvals are duly transferred or provided to the Customer where appropriate. The Customer shall use its commercially reasonable efforts to assist FortisBC Energy in obtaining such Approvals where necessary.

10.2 The Customer Approvals – The Customer shall be responsible, at its sole cost, for obtaining and maintaining the necessary Approvals required for the storage of LNG in the Tanker at the Customer designated location and shall ensure such Approvals are duly transferred or provided to FortisBC Energy where appropriate. FortisBC Energy shall use its commercially reasonable efforts to assist the Customer in obtaining such Approvals where necessary.

11. Termination

11.1 A party to this Agreement shall be in default under this Agreement if such party becomes insolvent, files any proceeding in bankruptcy or acquires the status of a bankrupt, has a receiver or receiver manager appointed with respect to any of its assets or seeks the benefit of any statute providing protection from creditors. Subject to section 15 of this Agreement, a party to this Agreement shall also be in default under this Agreement if such party is in breach of a material term, covenant, agreement, condition or obligation imposed on it under this Agreement, including without limitation, failure to comply with applicable Approvals, laws and regulations as provided in this Agreement, provided:

(a) the other party provides the defaulting party with a written notice of such default and a 30-day period within which to cure such a default (the Cure Period); and

(b) the defaulting party fails to cure such default by the expiry of the Cure Period, or if such default is not capable of being cured within the Cure Period, fails to commence in good faith the curing of such default upon receipt of written notice from the other party and to continue to diligently pursue the curing of such default thereafter until cured.

11.2 If a party to this Agreement is in default of this Agreement, the other party may at its option and without liability therefore or prejudice to any other right or remedy it may have, terminate this Agreement, provided that the defaulting party pay any monies due and owing to the other party within 15 calendar Days of the other's party's written notice to terminate this Agreement.

11.3 Either party may terminate this Agreement at any time upon giving 120 calendar days prior written notice to the other party.

12. Additional Insurance Requirements

12.1 Insurance Requirements of the Customer – Without limiting section 7.4 (Required Insurance) of Rate Schedule 46, the Customer shall obtain at its own expense, maintain during the Term of the Agreement and provide proof to FortisBC Energy, the following insurance coverage:

(a) Workers' Compensation Insurance in accordance with the statutory requirements in British Columbia for all its employees engaged in any of the work or services under this Agreement; and

(b) a minimum of $5 million of automobile liability insurance and any other insurance coverage required by law.

All insurance policies required herein shall provide that the insurance with respect to this Agreement shall not be cancelled or changed without the insurer giving at least 10 calendar days written notice to FortisBC Energy and shall be purchased from insurers registered in and licensed to underwrite insurance in British Columbia. Where the Customer fails to comply with the requirements of this section 12, FortisBC Energy may take all necessary steps to affect and maintain the required insurance coverage at the Customer's expense.

12.2 Insurance Requirements of FortisBC Energy – FortisBC Energy shall obtain at its own expense, maintain during the Term of the LNG Transportation Service Agreement and provide proof to the Customer upon request, the following insurance coverage:

(a) Workers' Compensation Insurance in accordance with the statutory requirements in British Columbia for all its employees engaged in any of the work or services under this Agreement; and

(b) General Commercial Liability Insurance for bodily injury, death and property damage in the amount of $5 million per occurrence naming the Customer as an additional insured with respect to this Agreement.

All insurance policies required herein shall provide that the insurance with respect to this Agreement shall not be cancelled or changed without the insurer giving at least 10 calendar days written notice to the Customer and shall be purchased from insurers registered in and licensed to underwrite insurance in British Columbia. Where FortisBC Energy fails to comply with the requirements of this section of this Agreement, the Customer may take all necessary steps to affect and maintain the required insurance coverage at FortisBC Energy's expense.

13. Environmental Covenant

13.1 "Contaminants" means collectively, any contaminant, toxic substances, dangerous goods, or pollutant or any other substance which when released to the natural environment is likely to cause, at some immediate or future time, material harm or degradation to the natural environment or material risk to human health, and includes any radioactive materials, asbestos materials, urea formaldehyde, underground or aboveground tanks, pollutants, contaminants, deleterious substances, dangerous substances or goods, hazardous, corrosive or toxic substances, hazardous waste or waste of any kind, pesticides, defoliants, or any other solid, liquid, gas, vapour, odour or any other substance the storage, manufacture, disposal, handling, treatment, generation, use, transport, remediation or release into the environment of which is now or hereafter prohibited, controlled or regulated by law.

13.2 The Customer acknowledges and agrees that FortisBC Energy and its employees, directors and officers are not responsible and shall not be responsible for any Contaminants now present, or present in the future, in, on or under the Customer designated location, or that may or may have migrated on or off the Customer designated location except to the extent that the presence of such Contaminants is a direct result of the negligent acts or omissions of FortisBC Energy or person for whom it is in law responsible in carrying out the LNG Transportation Service.

14. Limitation of Liability and Indemnity

14.1 The Customer acknowledges and agrees that FortisBC Energy and its employees, directors and officers are not responsible for and shall not be responsible for any claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) incurred by the Customer or any third party except to the extent such claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) are a direct result of FortisBC Energy's breach of this Agreement, or the negligence or willful misconduct of FortisBC Energy, its employees or contractors in performing the LNG Transportation Service.

14.2 The Customer shall indemnify and hold harmless FortisBC Energy and its employees, directors and officers from and against any and all claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) except to the extent such claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) are a direct result of FortisBC

Energy's breach of this Agreement, or the negligence or willful misconduct of FortisBC Energy, its employees or contractors in performing the LNG Transportation Service.

14.3 FortisBC Energy shall indemnify and hold harmless the Customer and its employees, directors and officers from and against any and all claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of:

(a) the negligence or willful misconduct of FortisBC Energy, its employees, or contractors; or

(b) the breach by FortisBC Energy of this Agreement.

14.4 FortisBC Energy's liability to the Customer and the Customer's liability to FortisBC Energy under section 15 of this Agreement for damages from any cause whatsoever including but not limited to a cause in the nature of a breach of a material term, covenant, agreement, condition or obligation imposed under this Agreement regardless of the form(s) of action, whether in contract or tort, including negligence or strict liability or otherwise, shall be limited to the payment of direct damages and such damages shall in no event in the aggregate exceed $100,000 over the Term of this Agreement. Each party has a duty to mitigate the damages that would otherwise be recoverable from the other party pursuant to this Agreement by taking appropriate and commercially reasonable actions to reduce or limit the amount of such damages or amounts.

14.5 Notwithstanding the foregoing, in no event shall either party be responsible or liable under this Agreement for any indirect, consequential, punitive, exemplary or incidental damages of the other or any third party arising out of or related to the Agreement, including but not limited to loss of profit, loss of revenues, or other special damages, even if the loss is directly attributable to the negligence or willful misconduct of such party, its employees, or contractors.

15. Force Majeure

15.1 Except with regard to a party's obligation to make payment due under the Agreement, if either party is unable or fails by reason of Force Majeure to perform in whole or in part any obligation or covenant set forth in this Agreement, such inability or failure shall be deemed not to be a breach of such obligation or covenant and the obligations of both parties under this Agreement shall be suspended to the extent necessary during the continuation of any inability or failure so caused by such Force Majeure.

15.2 The parties intend that the term "Force Majeure" shall have the same meaning as in the Rate Schedule, and without limiting that provision, Force Majeure under this Agreement also includes :

(a) unavailability of LNG from the LNG Facilities by reason of curtailment or otherwise; and

(b) unavailability of the Tanker due to FortisBC Energy's use of the Tanker in providing emergency services as may be required in the event of FortisBC Energy's pipeline failure or other disruption to the FortisBC Energy System;

(c) disruption in third party hauling services.

16. Survival

16.1 Upon the termination of this Agreement:

(a) All claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and,

(b) All of the provisions in this agreement relating to the obligation of either of the parties to provide information to the other in connection with this Agreement

will survive such termination.

17. General

17.1 Amendments to be In Writing – Except as otherwise set out in the Rate Schedule, no amendment or variation of this LNG Transportation Service Agreement will be effective or binding upon the parties unless such amendment or variation is set out in writing and duly executed by the parties.

17.2 Notice – Any notices or other communication which may be or is required to be given or made pursuant to the Agreement shall, unless otherwise expressly provided herein, shall be in writing and shall be personally delivered to or sent by facsimile to either party at its address set forth below:

If to FortisBC Energy	FORTISBC ENERGY INC.
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8
If to the Customer	______________________
MAILING ADDRESS:	______________________ ______________________ ______________________
	Attention: ______________

17.3 Severability – If any provision of this Agreement is determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, such determination does not impair or affect the validity, legality or enforceability of any other provision of this Agreement.

17.4 **Execution** – This Agreement may be executed in counterparts, each of which shall be deemed as an original, but all of which shall constitute one and the same instrument. Delivery of an executed counterpart of this letter by facsimile or electronic transmission hereof shall be as effective as delivery of an originally executed counterpart hereof.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the day and year first above written.

FORTISBC ENERGY INC.
by its authorized signatory:

____

____

THE CUSTOMER: ________________
by its authorized signatory:

____

____

APPENDIX 2

GAS LIQUEFACTION, STORAGE AND DISPENSING SERVICE AGREEMENT

Between

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

and

FORTISBC ENERGY INC.

GAS LIQUEFACTION, STORAGE AND DISPENSING SERVICE AGREEMENT

This GAS LIQUEFACTION, STORAGE AND DISPENSING SERVICE AGREEMENT made as of this ______ day of ____________, 2013.

BETWEEN:

FORTISBC ENERGY (VANCOUVER ISLAND) INC. a company incorporated under the laws of British Columbia having an office at 16705 Fraser Highway, Surrey, British Columbia ("FEVI")

AND:

FORTISBC ENERGY INC. a company incorporated under the laws of British Columbia having an office at 16705 Fraser Highway, Surrey, British Columbia ("FEI")

as sometimes referred to herein jointly as the "Parties" and individually as a "Party".

WHEREAS:

A. FEVI operates a Liquefied Natural Gas ("LNG") Storage Facility on Vancouver Island at Mount Hayes near Ladysmith.

B. FEVI operates an integrated natural gas transmission and distribution system that serves customers on the Sunshine Coast and Vancouver Island.

C. FEI wishes to contract with FEVI for gas liquefaction, storage and dispensing services for the benefit of FEI's customers under its Rate Schedule 46 - Liquefied Natural Gas Sales, Dispensing and Transportation Service.

NOW THEREFORE, in consideration of the promises set forth herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. DEFINITIONS

In this Agreement:

"Agreement" means this Gas Liquefaction, Storage and Dispensing Service Agreement;

"BCUC" means the British Columbia Utilities Commission and any successor regulatory authority;

"Day" means any period of 24 consecutive hours beginning and ending at 12:00 midnight;

"FEVI System" means the FEVI transmission system;

"Force Majeure" means any acts of God, strikes, lockouts, or other industrial disturbances, civil disturbances, arrests and restraints of rulers or people, interruptions by government or court orders, present or future valid orders of any regulatory body having proper jurisdiction, acts of the public enemy, wars, riots, blackouts, insurrections, failure or inability to secure materials or labour by reason or regulations or orders of government, serious epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to machinery, liquefaction, storage, and dispensing equipment, or lines of pipes, or freezing of wells or pipelines, or the failure of gas supply, temporary or otherwise, from a Supplier of Gas, or a declaration of Force Majeure by a gas Transporter that results in gas being unavailable for delivery at the Interconnection Point, or any major disabling event or circumstance in relation to the normal operations of the party concerned as a whole which is beyond the reasonable control of the party directly affected and results in a material delay, interruption or failure by such party in carrying out its obligations under the Agreement. Force Majeure events cannot be due to negligence of the party claiming Force Majeure;

"Interconnection Point" means the point where the FortisBC Energy System interconnects with the facilities of Westcoast Energy Inc. at Sumas;

"LNG" means liquefied natural gas;

"LNG Facility" is the LNG Production and Storage facility at Mount Hayes near Ladysmith on Vancouver Island;

"LNG Service" has the meaning set out in section 3;

"Service Charge" means the charge for LNG Service set out in section 7;

"Supplier of Gas" means a party who sells natural gas to FEVI or FEI;

"Tanker" means a cryogenic receptacle used for receiving, storing and transporting LNG, including without limitation, portable tankers, ISO containers, vessels or other similar equipment;

"Term" has the meaning set out in section 2; and

"Transporter" means Westcoast Energy Inc., FortisBC Huntingdon Inc., and any other gas pipeline transportation company connected to the facilities of FEI from which FEI receives natural gas for the purposes of natural gas transportation or resale.

2. TERM

2.1 The commencement date for the provision of LNG Service under this Agreement is the later of June 1, 2014 or such date notified by FEVI to FEI pursuant to section 2.4 ("Commencement Date").

2.2 The term of this Agreement shall continue until termination or expiry of the Storage and Delivery Agreement made between the parties as of January 10, 2008 (the "Term") and as amended from time to time.

2.3 Notwithstanding Section 2.2, FEI may provide FEVI with two months' written notice of termination at any time during the term of the Agreement.

2.4 FEVI will provide 60 days written prior notice to FEI of the Commencement Date. FEVI will notify FEI in writing of any expected change in the Commencement Date due to delay in commencement of construction of the facility necessary to provide LNG Dispensing Service.

3. LNG SERVICE

3.1 During the Term of this Agreement, FEVI will liquefy gas supplied by FEI or FEI's customers for the purpose, and then store and dispense such LNG into Tankers (the "LNG Service") provided by FEI or FEI's customers. Title transfer shall occur at the inlet flange of the Tanker or at the outlet flange of the FEVI meter as applicable. FEI shall at all times be in compliance with the requirements of all applicable laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter, including, but not limited to, the federal *Transportation of Dangerous Goods Act* and associated regulations and British Columbia's *Environmental Management Act* and associated regulations. FEI shall require of its customers that any personnel, vehicle or Tanker provided by its customers or their agents for LNG Service meets those requirements.

3.2 Notwithstanding section 3 above, FEVI may at its sole discretion refuse to provide LNG Service to any of FEI's customers, if in FEVI's opinion, the supply of LNG to such customer may be contrary to any laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction including, but not limited to, the federal *Transportation of Dangerous Goods Act* and its associated regulations and British Columbia's *Environmental Management Act* and associated regulations.

3.3 At least 24 hours in advance of the Day of FEI's or FEI's customer's desired loading time, FEI or FEI's customer or its agent, as the case may be, will provide FEVI by fax or email, prior to 12:00 a.m. Pacific Standard Time on each Day (or such other time as may be agreed to from time to time by the parties) such information as may be requested by FEVI, which will include, but is not limited to, FEI's and its customers' requested quantity of LNG for the given Day. Loading of Tankers with LNG shall take place between 8:00 a.m. - 4:00 p.m. (Pacific Standard Time) Monday through Friday (excluding British Columbia statutory holidays) or such other times as agreed upon by the parties from time to time.

4. CONTRACT LEVELS

FEVI will make available to FEI a minimum of 17,600 Gigajoules per week of LNG Service at the LNG Facility or such other minimum or maximum weekly volumes as may be determined from time to time by FEVI with reference to the LNG requirements of each of the parties.

5. PERFORMANCE OBLIGATIONS

5.1 Subject to section 6, Force Majeure, FEVI shall provide LNG Service on each day except when planned maintenance of the LNG Facility prevents FEVI from providing the LNG Service.

5.2 FEVI will use reasonable commercial efforts to schedule planned maintenance such that planned maintenance does not interfere with providing the LNG Service. Prior to April 1 of each year in the Term, FEVI will provide FEI with a forecast schedule of planned maintenance to take place over the next 12 months.

6. FORCE MAJEURE

6.1 Except for FEI's obligation to make payments under this Agreement, if either Party is rendered unable, in whole or in part, by Force Majeure to carry out its obligations under this Agreement, then upon such Party's giving notice of the particulars of such Force Majeure to the other Party as soon as reasonably possible (with such notice to be confirmed in writing), the obligations of the Party giving such notice, from the inception of the Force Majeure, will be suspended and excused during the continuance of any inability so caused. The obligations of the affected Party will be suspended and excused for such time only to the extent they are effected by such Force Majeure. The cause of the Force Majeure will be remedied by the affected Party with all reasonable diligence and dispatch.

7. SERVICE CHARGE

Each month, FEI will pay to FEVI an amount (the "Service Charge") per gigajoule of LNG liquefied, stored and dispensed under this Agreement equal to the total of the Delivery Charge per Gigajoule (not including any premiums that may be charged by FEI to FEI's customers) set out in FEI's Rate Schedule 46 for FEI's Long-Term and Short-Term LNG Service, as adjusted or amended from time to time by FEI.

8. BILLING

8.1 FEVI will provide FEI by the 15th day of each month beginning in the month following the commencement of the term of this Agreement with an invoice for the Service Charges for LNG Service provided in the preceding month plus applicable taxes. In the event that FEI is late in paying the invoice then FEVI will assess FEI and FEI will pay to FEVI a late payment fee equal to the current prime interest rate charged by the Main Branch of the Toronto-Dominion Bank in Vancouver, British Columbia, to its most creditworthy commercial customers, plus 4%, per annum calculated on a daily basis.

9. NOTICES

9.1 Except as may be expressly provided otherwise in this Agreement, any notice, request, authorization, direction, or other communication under this Agreement will be made given in writing and will be delivered in person, or by facsimile transmission, properly addressed to the intended recipient as follows:

a) If to FEI: FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N OE8
Attention: VP, Energy Supply & Resource Development
Facsimile: 604-592-7420

b) If to FEVI: FortisBC Energy (Vancouver Island) Inc.
16705 Fraser Highway
Surrey, B.C. V4N OE8
Attention: VP, Strategic Planning, Corporate Development & Regulatory Affairs
Facsimile: 604-576-7074

Either Party may change its address specified above by giving the other Party notice of such change in accordance with this section 9.

10. GOVERNING LAW

10.1 This Agreement and the respective rights and duties of the Parties arising out of this Agreement will be governed by and construed, enforced and performed in accordance with the laws of the Province of British Columbia.

11. EFFECT OF WAIVER OR CONSENT

11.1 No waiver or consent by either Party, expressed or implied, or any breach or default by the other Party in the performance of any of such other Party's obligations under this Agreement will operate or be construed as a waiver or consent to any other breach or default hereunder. Failure of a Party to complain of any act of the other Party or to declare the other Party in breach or default with respect to this Agreement, irrespective of how long that failure continues, does not constitute a waiver by the Party of any of its rights with respect to that breach or default.

12. HEADINGS

12.1 The headings for the sections of this Agreement are for convenience of reference only and in no way affect the meaning or interpretation of any of the provisions of this Agreement.

13. SEVERABILITY

13.1 Except as otherwise stated in this Agreement, any provision or section declared or rendered unlawful by a court of law or regulatory agency with jurisdiction over this Agreement, the Parties or either of them, or deemed unlawful because of statutory change, will thereupon be deemed to have been severed from this Agreement and will not otherwise affect the lawful obligations that arise under other provisions of this Agreement.

14. ASSIGNMENT

14.1 Subject to the provisions of this section 14, this Agreement will enure to and be binding upon the respective successors and permitted assigns of the Parties. Neither Party may assign this Agreement without the prior written consent of the other Party, which consent will not be unreasonably withheld, provided, that either Party may assign its interest under this Agreement (a) to any entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with such Party, (b) to any entity into which it consolidates or merges or (c) as security to the holder of any indebtedness, present or future, of such Party, without the prior written approval of the other Party, but no such assignment will operate to relieve the assigning Party of any of its obligations under this Agreement. Any Party's transfer or assignment in violation of this section 14 will be void.

15. RESPONSIBILITY FOR DAMAGE

15.1 As between the Parties, FEVI will be deemed to be in exclusive control and possession of gas which is the subject of this Agreement and will be responsible for any damage or injury caused thereby prior to the point of transfer of title set out in section 3. As between the Parties, FEI will be deemed to be responsible for any damage or injury or damage caused thereby after the point at which FEI or FEI's customers receives gas pursuant to this Agreement.

16. INDEMNITY

16.1 FEI hereby indemnifies and saves FEVI harmless from and against all claims by FEI's customers and any other third parties in respect to loss of life, personal injury, loss or damage to property relating to the provision of LNG Service to FEI's customers.

17. TERMINATION

17.1 If either Party is at any time in material breach of or default under this Agreement (the "Defaulting Party"), the other Party (the "terminating Party") will have the right to terminate this Agreement by giving the Defaulting Party written notice of such termination. Such termination will be effective upon the Defaulting Party's receipt of such notice of termination pursuant to this section 17. For the purposes of this section 17, a Party will be deemed to be in material breach if or default under this Agreement if such Party:

a) fails to cure any material breach under this Agreement by such Party prior to the later of (i) the expiration of thirty days after the Terminating Party gives the Defaulting Party written notice of the breach or default; and (ii) the date upon which the Terminating Party gives the Defaulting Party written notice of termination;

b) is unable to meet its obligations as they become due or such Party's liabilities exceed its assets in the aggregate; or

c) makes a general assignment of substantially all of its assets for the benefits of its creditors, files a petition of bankruptcy, commences, authorizes or acquiesces in the commencement of a proceeding or cause under any bankruptcy, insolvency or similar law for the protection of creditors or have such petition filed or proceeding commenced against it, or seeks other relief under any applicable insolvency laws.

In no event will either Party incur any liability (whether for lost revenues or lost profits or otherwise) as a result of any termination of this Agreement pursuant to this section 17.

17.2 All rights and remedies of either Party under this Agreement and at law and in equity will be cumulative and not mutually exclusive and the exercise by one Party of one right or remedy will not be deemed a waiver of any other right or remedy available to that Party. Nothing contained in any provision of this Agreement will be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement.

18. WAIVER OF CERTAIN DAMAGES

18.1 Subject to the Indemnity provided to FEVI in section 16, in no other event will either Party be liable to the other Party for consequential, incidental, punitive, special, exemplary or indirect damages, in tort, strict liability, warranty, contract, equity or otherwise.

19. DISPUTE RESOLUTION

19.1 All disputes arising under or relating to this Agreement, except only disputes with respect to which the BCUC has jurisdiction, which the BCUC is prepared to exercise, shall, after the parties have attempted in good faith to settle the dispute between themselves, be submitted to and finally settled by arbitration under the Commercial Arbitration Act. The arbitration will take place in Vancouver, British Columbia before a single arbitrator and will be administered by the British Columbia Commercial Arbitration Centre ("BCICAC") in accordance with its "Procedures for Cases under the BCICAC Rules.

20. ENTIRE AGREEMENT

20.1 This Agreement constitutes the entire agreement and supersedes all others between the Parties relating to the subject matter contemplated by this Agreement. There are no prior or contemporaneous agreements or representations (whether written or oral) affecting such subject matter. No amendment, modification or change to this Agreement will be enforceable, except as specifically provided for in this Agreement, unless reduced to writing and hereafter signed (which may be done by facsimile) by both Parties.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their authorized representatives as of the date first written above.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

BY:________________________
(Signature)

____
(Name – Please Print)

____
(Title)

FORTISBC ENERGY INC.

BY:________________________
(Signature)

____
(Name – Please Print)

____
(Title)

Appendix B

ENERGY DEMAND FORECASTING

Appendix B-1

DEMAND FORECAST TABLES

FEVI - Reference Case
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
AGS	939	1,072	1,213	1,347	1,489	1,552
HLF	14	6	6	6	6	6
ILF	8	8	8	8	8	8
LCS1	1,360	1,371	1,518	1,656	1,796	1,855
LCS2	514	526	663	819	1,013	1,105
LCS3	119	127	127	127	127	127
RGS	92,554	99,869	109,478	118,094	126,492	129,931
SCS1	5,168	4,968	5,111	5,229	5,338	5,382
SCS2	1,434	1,466	1,573	1,675	1,776	1,818
Transportation	4	4	4	4	4	4
Grand Total	**102,114**	**109,417**	**119,701**	**128,965**	**138,049**	**141,788**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,202.3	1,196.6	1,171.8	1,149.1	1,128.0	1,120.0
HLF	8,807.9	22,088.5	21,961.9	21,740.1	21,578.8	21,443.8
ILF	14,358.7	14,123.3	13,809.5	13,521.8	13,259.2	13,155.7
LCS1	947.3	1,051.7	1,027.8	1,006.3	986.8	979.1
LCS2	2,494.7	3,317.6	3,225.7	3,147.5	3,078.3	3,052.0
LCS3	19,766.1	14,581.0	14,311.1	14,050.9	13,811.5	13,711.2
RGS	49.0	45.6	42.4	40.3	38.7	37.8
SCS1	99.0	104.4	102.4	100.6	98.9	98.3
SCS2	333.3	349.7	343.5	337.8	332.5	330.4
Transportation	1,888,106.5	2,013,617.5	2,003,399.1	1,984,947.9	1,971,139.1	1,959,841.2

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,128,950	1,282,745	1,421,349	1,547,811	1,679,576	1,738,174
HLF	123,311	132,531	131,772	130,441	129,473	128,663
ILF	114,869	112,987	110,476	108,175	106,073	105,246
LCS1	1,288,371	1,441,911	1,560,184	1,666,407	1,772,241	1,816,211
LCS2	1,282,299	1,745,037	2,138,655	2,577,786	3,118,316	3,372,507
LCS3	2,352,161	1,851,785	1,817,511	1,784,467	1,754,063	1,741,322
RGS	4,536,278	4,552,316	4,636,866	4,761,826	4,899,153	4,915,104
SCS1	511,531	518,412	523,437	526,070	528,106	528,867
SCS2	477,926	512,626	540,389	565,836	590,516	600,650
Transportation	7,552,426	8,054,470	8,013,597	7,939,792	7,884,557	7,839,365
Grand Total	**19,368,121**	**20,204,820**	**20,894,237**	**21,608,611**	**22,462,075**	**22,786,108**

FEVI - Scenario A

Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
AGS	939	1,072	1,213	1,347	1,489	1,552
HLF	14	6	6	6	6	6
ILF	8	8	8	8	8	8
LCS1	1,360	1,371	1,518	1,656	1,796	1,855
LCS2	514	526	663	819	1,013	1,105
LCS3	119	127	127	127	127	127
RGS	92,554	99,869	109,478	118,094	126,492	129,931
SCS1	5,168	4,968	5,111	5,229	5,338	5,382
SCS2	1,434	1,466	1,573	1,675	1,776	1,818
Transportation	4	4	4	4	4	4
Grand Total	**102,114**	**109,417**	**119,701**	**128,965**	**138,049**	**141,788**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,202.3	1,182.3	1,122.7	1,054.1	1,001.9	983.6
HLF	8,807.9	22,484.1	22,693.7	22,784.7	22,996.7	23,012.0
ILF	14,358.7	14,008.8	13,363.3	12,621.4	12,060.6	11,860.2
LCS1	947.3	1,042.9	994.9	941.0	901.0	886.8
LCS2	2,494.7	3,288.3	3,119.7	2,940.3	2,806.7	2,760.1
LCS3	19,766.1	14,516.2	14,006.2	13,408.3	12,963.5	12,799.6
RGS	49.0	44.9	41.5	39.2	37.2	36.2
SCS1	99.0	103.5	99.2	94.1	90.3	89.0
SCS2	333.3	346.5	332.0	315.0	302.5	298.0
Transportation	1,888,106.5	2,067,223.4	2,111,636.2	2,148,339.5	2,190,771.3	2,201,541.8

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,128,950	1,267,412	1,361,894	1,419,906	1,491,877	1,526,586
HLF	123,311	134,905	136,162	136,708	137,980	138,072
ILF	114,869	112,071	106,906	100,971	96,485	94,882
LCS1	1,288,371	1,429,862	1,510,234	1,558,356	1,618,167	1,645,015
LCS2	1,282,299	1,729,641	2,068,384	2,408,129	2,843,225	3,049,892
LCS3	2,352,161	1,843,560	1,778,789	1,702,859	1,646,364	1,625,555
RGS	4,536,278	4,488,526	4,542,287	4,624,897	4,711,480	4,703,397
SCS1	511,531	514,189	506,794	491,957	482,148	478,967
SCS2	477,926	508,038	522,289	527,707	537,170	541,812
Transportation	7,552,426	8,268,893	8,446,545	8,593,358	8,763,085	8,806,167
Grand Total	**19,368,121**	**20,297,097**	**20,980,283**	**21,564,849**	**22,327,981**	**22,610,345**

FEVI - Scenario B

Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
AGS	939	1,072	1,213	1,347	1,489	1,552
HLF	14	6	6	6	6	6
ILF	8	8	8	8	8	8
LCS1	1,360	1,371	1,518	1,656	1,796	1,855
LCS2	514	526	663	819	1,013	1,105
LCS3	119	127	127	127	127	127
RGS	92,554	99,869	109,478	118,094	126,492	129,931
SCS1	5,168	4,968	5,111	5,229	5,338	5,382
SCS2	1,434	1,466	1,573	1,675	1,776	1,818
Transportation	4	4	4	4	4	4
Grand Total	**102,114**	**109,417**	**119,701**	**128,965**	**138,049**	**141,788**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,202.3	1,173.6	1,085.0	975.4	897.2	870.7
HLF	8,807.9	19,978.3	19,792.8	19,463.6	19,285.4	19,163.0
ILF	14,358.7	13,770.7	12,798.1	11,603.6	10,746.7	10,452.0
LCS1	947.3	1,024.2	952.2	865.5	804.3	783.4
LCS2	2,494.7	3,238.2	2,997.1	2,718.9	2,522.8	2,456.7
LCS3	19,766.1	14,092.2	13,296.0	12,308.1	11,601.3	11,353.0
RGS	49.0	45.1	41.6	39.4	37.4	36.3
SCS1	99.0	101.6	94.9	86.4	80.5	78.5
SCS2	333.3	341.3	318.7	290.5	270.7	264.0
Transportation	1,888,106.5	1,789,792.1	1,802,790.4	1,808,340.4	1,817,768.5	1,816,141.6

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,128,950	1,258,095	1,316,073	1,313,900	1,335,916	1,351,303
HLF	123,311	119,870	118,757	116,781	115,712	114,978
ILF	114,869	110,166	102,385	92,829	85,974	83,616
LCS1	1,288,371	1,404,241	1,445,406	1,433,308	1,444,439	1,453,149
LCS2	1,282,299	1,703,280	1,987,095	2,226,775	2,555,624	2,714,657
LCS3	2,352,161	1,789,710	1,688,595	1,563,124	1,473,360	1,441,837
RGS	4,536,278	4,499,314	4,558,651	4,649,070	4,732,716	4,722,333
SCS1	511,531	504,947	484,836	451,967	429,632	422,263
SCS2	477,926	500,289	501,272	486,648	480,796	479,938
Transportation	7,552,426	7,159,168	7,211,162	7,233,362	7,271,074	7,264,567
Grand Total	**19,368,121**	**19,049,079**	**19,414,231**	**19,567,764**	**19,925,242**	**20,048,640**

FEVI - Scenario C
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
AGS	939	1,072	1,213	1,347	1,489	1,552
HLF	14	6	6	6	6	6
ILF	8	8	8	8	8	8
LCS1	1,360	1,371	1,518	1,656	1,796	1,855
LCS2	514	526	663	819	1,013	1,105
LCS3	119	127	127	127	127	127
RGS	92,554	99,869	109,478	118,094	126,492	129,931
SCS1	5,168	4,968	5,111	5,229	5,338	5,382
SCS2	1,434	1,466	1,573	1,675	1,776	1,818
Transportation	4	4	4	4	4	4
Grand Total	**102,114**	**109,417**	**119,701**	**128,965**	**138,049**	**141,788**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,202.3	1,212.2	1,212.9	1,221.8	1,236.4	1,243.5
HLF	8,807.9	22,710.0	23,240.5	23,695.1	24,207.8	24,352.8
ILF	14,358.7	14,313.1	14,294.0	14,339.1	14,398.3	14,430.4
LCS1	947.3	1,067.0	1,066.3	1,075.3	1,087.8	1,091.7
LCS2	2,494.7	3,362.1	3,337.1	3,341.7	3,360.7	3,371.3
LCS3	19,766.1	14,797.7	14,828.1	14,911.8	15,002.9	15,036.3
RGS	49.0	45.7	43.0	41.2	40.1	39.4
SCS1	99.0	105.9	106.3	107.6	109.1	109.6
SCS2	333.3	354.6	356.1	360.6	366.2	368.0
Transportation	1,888,106.5	2,068,340.3	2,112,903.2	2,149,599.9	2,191,053.3	2,202,227.7

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,128,950	1,299,502	1,471,251	1,645,789	1,840,997	1,929,982
HLF	123,311	136,260	139,443	142,170	145,247	146,117
ILF	114,869	114,505	114,352	114,713	115,187	115,443
LCS1	1,288,371	1,462,884	1,618,675	1,780,683	1,953,688	2,025,039
LCS2	1,282,299	1,768,474	2,212,488	2,736,839	3,404,438	3,725,306
LCS3	2,352,161	1,879,308	1,883,165	1,893,793	1,905,374	1,909,614
RGS	4,536,278	4,568,426	4,707,371	4,865,118	5,076,189	5,124,798
SCS1	511,531	526,018	543,192	562,456	582,492	589,807
SCS2	477,926	519,899	560,182	603,962	650,309	668,952
Transportation	7,552,426	8,273,361	8,451,613	8,598,399	8,764,213	8,808,911
Grand Total	**19,368,121**	**20,548,637**	**21,701,732**	**22,943,922**	**24,438,133**	**25,043,970**

FEVI - Scenario D
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
AGS	939	1,072	1,213	1,347	1,489	1,552
HLF	14	6	6	6	6	6
ILF	8	8	8	8	8	8
LCS1	1,360	1,371	1,518	1,656	1,796	1,855
LCS2	514	526	663	819	1,013	1,105
LCS3	119	127	127	127	127	127
RGS	92,554	99,869	109,478	118,094	126,492	129,931
SCS1	5,168	4,968	5,111	5,229	5,338	5,382
SCS2	1,434	1,466	1,573	1,675	1,776	1,818
Transportation	4	4	4	4	4	4
Grand Total	**102,114**	**109,417**	**119,701**	**128,965**	**138,049**	**141,788**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,202.3	1,188.0	1,147.5	1,106.3	1,076.6	1,066.5
HLF	8,807.9	20,186.9	19,930.5	19,584.7	19,327.8	19,171.3
ILF	14,358.7	13,939.0	13,468.0	12,990.5	12,640.3	12,516.1
LCS1	947.3	1,037.2	1,002.0	967.4	942.7	934.1
LCS2	2,494.7	3,275.3	3,145.7	3,023.3	2,933.4	2,902.1
LCS3	19,766.1	14,221.6	13,794.1	13,355.0	13,024.9	12,902.1
RGS	49.0	45.0	41.6	39.4	37.6	36.7
SCS1	99.0	103.0	100.0	96.9	94.8	94.0
SCS2	333.3	345.6	335.8	325.7	318.7	316.3
Transportation	1,888,106.5	1,803,418.5	1,785,764.1	1,761,341.2	1,741,383.8	1,728,624.4

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
AGS	1,128,950	1,273,518	1,391,925	1,490,216	1,603,110	1,655,233
HLF	123,311	121,121	119,583	117,508	115,967	115,028
ILF	114,869	111,512	107,744	103,924	101,123	100,129
LCS1	1,288,371	1,421,966	1,521,021	1,602,046	1,693,157	1,732,794
LCS2	1,282,299	1,722,826	2,085,588	2,476,120	2,971,578	3,206,842
LCS3	2,352,161	1,806,140	1,751,851	1,696,087	1,654,162	1,638,566
RGS	4,536,278	4,493,202	4,559,372	4,653,461	4,762,130	4,764,131
SCS1	511,531	511,575	510,925	506,645	505,782	505,971
SCS2	477,926	506,702	528,183	545,507	565,965	574,992
Transportation	7,552,426	7,213,674	7,143,057	7,045,365	6,965,535	6,914,498
Grand Total	**19,368,121**	**19,182,236**	**19,719,250**	**20,236,879**	**20,938,509**	**21,208,182**

FEW - Reference Case

Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	83	82	84	86	89	90
LGS2	50	50	51	52	53	54
LGS3	24	24	24	24	24	24
Res SGS1/SGS2	2,296	2,485	2,761	3,000	3,244	3,341
SGS1C	196	217	253	285	320	334
Grand Total	**2,649**	**2,858**	**3,173**	**3,447**	**3,730**	**3,843**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	1,429.5	1,403.2	1,378.6	1,355.8	1,334.5	1,326.3
LGS2	2,749.9	2,701.5	2,649.2	2,600.5	2,553.8	2,535.2
LGS3	8,693.3	8,550.3	8,408.2	8,273.6	8,143.3	8,091.0
Res SGS1/SGS2	97.7	94.9	91.0	88.6	86.6	85.4
SGS1C	281.9	298.6	294.2	290.1	286.3	284.8

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	118,646	115,064	115,801	116,602	118,769	119,365
LGS2	137,493	135,074	135,108	135,224	135,354	136,901
LGS3	208,638	205,208	201,797	198,565	195,439	194,184
Res SGS1/SGS2	224,217	235,715	251,227	265,759	280,929	285,298
SGS1C	55,254	64,805	74,428	82,666	91,627	95,117
Grand Total	**744,248**	**755,866**	**778,361**	**798,817**	**822,117**	**830,866**

FEW - Scenario A
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	83	82	84	86	89	90
LGS2	50	50	51	52	53	54
LGS3	24	24	24	24	24	24
Res SGS1/SGS2	2,296	2,485	2,761	3,000	3,244	3,341
SGS1C	196	217	253	285	320	334
Grand Total	**2,649**	**2,858**	**3,173**	**3,447**	**3,730**	**3,843**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	1,429.5	1,386.2	1,322.5	1,249.0	1,193.4	1,173.9
LGS2	2,749.9	2,674.4	2,558.8	2,427.6	2,326.6	2,290.4
LGS3	8,693.3	8,449.5	8,085.0	7,662.5	7,339.0	7,223.5
Res SGS1/SGS2	97.7	93.5	89.2	86.2	83.5	81.8
SGS1C	281.9	296.0	284.7	271.4	261.8	258.4

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	118,646	113,666	111,089	107,413	106,209	105,655
LGS2	137,493	133,720	130,500	126,234	123,311	123,681
LGS3	208,638	202,787	194,041	183,900	176,136	173,363
Res SGS1/SGS2	224,217	232,328	246,281	258,471	270,783	273,458
SGS1C	55,254	64,229	72,017	77,356	83,775	86,289
Grand Total	**744,248**	**746,731**	**753,928**	**753,374**	**760,215**	**762,446**

FEW - Scenario B

Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	83	82	84	86	89	90
LGS2	50	50	51	52	53	54
LGS3	24	24	24	24	24	24
Res SGS1/SGS2	2,296	2,485	2,761	3,000	3,244	3,341
SGS1C	196	217	253	285	320	334
Grand Total	**2,649**	**2,858**	**3,173**	**3,447**	**3,730**	**3,843**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	1,429.5	1,376.9	1,281.5	1,163.2	1,079.0	1,050.6
LGS2	2,749.9	2,641.3	2,471.2	2,263.1	2,112.5	2,060.4
LGS3	8,693.3	8,399.9	7,858.9	7,183.9	6,699.1	6,532.6
Res SGS1/SGS2	97.7	93.7	89.4	86.4	83.6	81.8
SGS1C	281.9	291.2	273.3	251.1	235.6	230.3

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	118,646	112,909	107,646	100,035	96,034	94,558
LGS2	137,493	132,064	126,031	117,684	111,962	111,261
LGS3	208,638	201,599	188,613	172,414	160,779	156,782
Res SGS1/SGS2	224,217	232,786	246,956	259,240	271,173	273,444
SGS1C	55,254	63,187	69,147	71,559	75,386	76,913
Grand Total	**744,248**	**742,544**	**738,393**	**720,932**	**715,333**	**712,958**

FEW - Scenario C
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	83	82	84	86	89	90
LGS2	50	50	51	52	53	54
LGS3	24	24	24	24	24	24
Res SGS1/SGS2	2,296	2,485	2,761	3,000	3,244	3,341
SGS1C	196	217	253	285	320	334
Grand Total	**2,649**	**2,858**	**3,173**	**3,447**	**3,730**	**3,843**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	1,429.5	1,422.2	1,428.3	1,448.7	1,482.0	1,496.6
LGS2	2,749.9	2,738.8	2,742.6	2,769.9	2,813.5	2,834.1
LGS3	8,693.3	8,660.6	8,686.8	8,782.1	8,949.4	9,028.5
Res SGS1/SGS2	97.7	95.3	92.9	91.0	90.5	90.1
SGS1C	281.9	303.1	305.2	309.8	316.7	319.6

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	118,646	116,622	119,980	124,591	131,897	134,697
LGS2	137,493	136,938	139,870	144,034	149,116	153,041
LGS3	208,638	207,853	208,484	210,771	214,784	216,685
Res SGS1/SGS2	224,217	236,798	256,364	272,973	293,660	300,973
SGS1C	55,254	65,776	77,225	88,297	101,354	106,734
Grand Total	**744,248**	**763,987**	**801,923**	**840,666**	**890,812**	**912,130**

FEW - Scenario D
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	83	82	84	86	89	90
LGS2	50	50	51	52	53	54
LGS3	24	24	24	24	24	24
Res SGS1/SGS2	2,296	2,485	2,761	3,000	3,244	3,341
SGS1C	196	217	253	285	320	334
Grand Total	**2,649**	**2,858**	**3,173**	**3,447**	**3,730**	**3,843**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	1,429.5	1,392.0	1,349.2	1,305.9	1,275.5	1,265.4
LGS2	2,749.9	2,665.2	2,579.4	2,493.7	2,430.0	2,407.4
LGS3	8,693.3	8,479.1	8,228.2	7,971.2	7,784.8	7,719.5
Res SGS1/SGS2	97.7	93.6	89.7	87.0	84.8	83.4
SGS1C	281.9	294.6	286.8	278.9	273.5	271.5

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
LGS1	118,646	114,143	113,332	112,311	113,520	113,882
LGS2	137,493	133,260	131,548	129,671	128,788	129,997
LGS3	208,638	203,497	197,476	191,310	186,835	185,268
Res SGS1/SGS2	224,217	232,649	247,532	260,868	274,969	278,722
SGS1C	55,254	63,934	72,572	79,482	87,504	90,697
Grand Total	**744,248**	**747,484**	**762,461**	**773,641**	**791,617**	**798,566**

Coastal Region - Reference Case
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	532,550	538,391	551,166	562,686	573,339	577,389
Rate 2	53,387	50,357	50,971	51,524	52,031	52,223
Rate 3	4,062	3,918	3,918	3,918	3,918	3,918
Rate 4	1	33	33	33	33	33
Rate 5	197	191	191	191	191	191
Rate 6	18	14	14	14	14	14
Rate 7	1					
Rate 22	22	24	24	24	24	24
Rate 23	1,183	1,433	1,676	1,926	2,190	2,299
Rate 25	435	421	421	421	421	421
Rate 27	80	76	76	76	76	76
Grand Total	**591,936**	**594,858**	**608,490**	**620,813**	**632,237**	**636,588**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	97.5	94.3	87.7	84.5	81.7	80.4
Rate 2	315.7	338.7	333.8	328.7	323.8	321.7
Rate 3	3,510.4	3,524.5	3,470.9	3,416.3	3,364.8	3,342.7
Rate 4	72,902.5	2,434.6	2,399.3	2,362.9	2,329.1	2,314.1
Rate 5	11,703.8	11,278.1	11,080.0	10,884.9	10,698.3	10,622.7
Rate 6	3,620.4	4,021.5	3,968.3	3,915.1	3,864.5	3,843.4
Rate 7	2,730.5					
Rate 22	532,245.4	558,467.0	552,829.0	546,586.4	540,876.5	538,104.2
Rate 23	4,835.0	4,834.6	4,769.0	4,701.1	4,637.5	4,609.5
Rate 25	20,629.1	21,198.5	20,943.9	20,673.2	20,423.1	20,308.0
Rate 27	67,989.4	70,354.9	69,733.2	68,996.4	68,344.4	67,996.1

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	51,917,831	50,758,806	48,352,159	47,522,048	46,830,951	46,396,950
Rate 2	16,853,002	17,057,947	17,014,305	16,935,103	16,849,844	16,801,319
Rate 3	14,259,191	13,808,922	13,598,827	13,384,967	13,183,327	13,096,848
Rate 4	72,902	80,341	79,177	77,976	76,859	76,366
Rate 5	2,305,653	2,154,125	2,116,271	2,079,014	2,043,372	2,028,935
Rate 6	65,168	56,301	55,557	54,812	54,103	53,808
Rate 7	2,731	-	-	-	-	-
Rate 22	11,709,399	13,403,208	13,267,896	13,118,074	12,981,035	12,914,500
Rate 23	5,719,794	6,928,005	7,992,884	9,054,375	10,156,038	10,597,254
Rate 25	8,973,676	8,924,565	8,817,400	8,703,400	8,598,120	8,549,689
Rate 27	5,439,152	5,346,971	5,299,727	5,243,729	5,194,174	5,167,704
Grand Total	**117,318,497**	**118,519,191**	**116,594,202**	**116,173,497**	**115,967,824**	**115,683,373**

Coastal Region - Scenario A
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	532,550	538,391	551,166	562,686	573,339	577,389
Rate 2	53,387	50,357	50,971	51,524	52,031	52,223
Rate 3	4,062	3,918	3,918	3,918	3,918	3,918
Rate 4	1	33	33	33	33	33
Rate 5	197	191	191	191	191	191
Rate 6	18	14	14	14	14	14
Rate 7	1					
Rate 22	22	24	24	24	24	24
Rate 23	1,183	1,433	1,676	1,926	2,190	2,299
Rate 25	435	421	421	421	421	421
Rate 27	80	76	76	76	76	76
Grand Total	**591,936**	**594,858**	**608,490**	**620,813**	**632,237**	**636,588**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	97.5	92.9	85.6	81.5	77.9	76.2
Rate 2	315.7	337.2	327.5	315.8	306.2	302.3
Rate 3	3,510.4	3,508.7	3,408.2	3,288.8	3,191.0	3,152.6
Rate 4	72,902.5	2,422.7	2,354.4	2,272.5	2,205.4	2,178.6
Rate 5	11,703.8	11,201.0	10,816.9	10,373.3	10,002.4	9,861.5
Rate 6	3,620.4	3,999.4	3,886.7	3,750.5	3,638.5	3,595.5
Rate 7	2,730.5					
Rate 22	532,245.4	564,809.7	563,298.2	559,916.5	558,659.5	557,852.8
Rate 23	4,835.0	4,831.6	4,725.3	4,594.5	4,489.8	4,448.2
Rate 25	20,629.1	21,256.3	20,923.0	20,493.7	20,168.4	20,032.9
Rate 27	67,989.4	71,155.9	71,077.9	70,744.5	70,677.5	70,580.0

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	51,917,831	50,034,290	47,172,858	45,853,331	44,644,282	43,982,912
Rate 2	16,853,002	16,978,214	16,693,716	16,271,156	15,929,813	15,789,279
Rate 3	14,259,191	13,746,950	13,353,426	12,885,704	12,502,186	12,352,002
Rate 4	72,902	79,949	77,695	74,992	72,778	71,894
Rate 5	2,305,653	2,139,387	2,066,023	1,981,305	1,910,449	1,883,546
Rate 6	65,168	55,991	54,414	52,507	50,938	50,336
Rate 7	2,731	-	-	-	-	-
Rate 22	11,709,399	13,555,433	13,519,156	13,437,995	13,407,828	13,388,466
Rate 23	5,719,794	6,923,676	7,919,614	8,848,971	9,832,767	10,226,482
Rate 25	8,973,676	8,948,894	8,808,571	8,627,840	8,490,887	8,433,869
Rate 27	5,439,152	5,407,850	5,401,924	5,376,579	5,371,490	5,364,081
Grand Total	**117,318,497**	**117,870,634**	**115,067,398**	**113,410,382**	**112,213,418**	**111,542,870**

Coastal Region - Scenario B
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	532,550	538,391	551,166	562,686	573,339	577,389
Rate 2	53,387	50,357	50,971	51,524	52,031	52,223
Rate 3	4,062	3,918	3,918	3,918	3,918	3,918
Rate 4	1	33	33	33	33	33
Rate 5	197	191	191	191	191	191
Rate 6	18	14	14	14	14	14
Rate 7	1					
Rate 22	22	24	24	24	24	24
Rate 23	1,183	1,433	1,676	1,926	2,190	2,299
Rate 25	435	421	421	421	421	421
Rate 27	80	76	76	76	76	76
Grand Total	**591,936**	**594,858**	**608,490**	**620,813**	**632,237**	**636,588**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	97.5	93.2	86.0	82.2	78.6	76.9
Rate 2	315.7	330.4	315.4	296.3	280.8	274.9
Rate 3	3,510.4	3,432.0	3,278.5	3,085.6	2,930.7	2,872.1
Rate 4	72,902.5	2,379.7	2,276.1	2,145.1	2,040.2	2,000.1
Rate 5	11,703.8	11,040.2	10,485.6	9,799.2	9,244.4	9,038.4
Rate 6	3,620.4	3,955.2	3,782.2	3,560.7	3,383.8	3,317.8
Rate 7	2,730.5					
Rate 22	532,245.4	522,352.0	512,863.0	499,864.6	490,069.9	486,069.9
Rate 23	4,835.0	4,662.9	4,483.8	4,255.1	4,072.0	4,002.1
Rate 25	20,629.1	20,281.9	19,640.5	18,811.4	18,156.4	17,901.3
Rate 27	67,989.4	65,466.3	64,337.9	62,773.4	61,590.2	61,076.7

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	51,917,831	50,198,079	47,426,931	46,232,070	45,054,249	44,397,486
Rate 2	16,853,002	16,638,485	16,077,955	15,265,809	14,612,113	14,358,671
Rate 3	14,259,191	13,446,392	12,845,067	12,089,244	11,482,365	11,252,878
Rate 4	72,902	78,530	75,111	70,790	67,325	66,002
Rate 5	2,305,653	2,108,686	2,002,744	1,871,650	1,765,680	1,726,326
Rate 6	65,168	55,372	52,951	49,850	47,373	46,449
Rate 7	2,731	-	-	-	-	-
Rate 22	11,709,399	12,536,447	12,308,713	11,996,751	11,761,677	11,665,677
Rate 23	5,719,794	6,681,986	7,514,802	8,195,271	8,917,587	9,200,787
Rate 25	8,973,676	8,538,672	8,268,632	7,919,618	7,643,832	7,536,440
Rate 27	5,439,152	4,975,440	4,889,678	4,770,777	4,680,859	4,641,828
Grand Total	**117,318,497**	**115,258,091**	**111,462,584**	**108,461,831**	**106,033,059**	**104,892,543**

Coastal Region - Scenario C
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	532,550	538,391	551,166	562,686	573,339	577,389
Rate 2	53,387	50,357	50,971	51,524	52,031	52,223
Rate 3	4,062	3,918	3,918	3,918	3,918	3,918
Rate 4	1	33	33	33	33	33
Rate 5	197	191	191	191	191	191
Rate 6	18	14	14	14	14	14
Rate 7	1					
Rate 22	22	24	24	24	24	24
Rate 23	1,183	1,433	1,676	1,926	2,190	2,299
Rate 25	435	421	421	421	421	421
Rate 27	80	76	76	76	76	76
Grand Total	**591,936**	**594,858**	**608,490**	**620,813**	**632,237**	**636,588**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	97.5	94.3	88.1	84.8	82.2	81.0
Rate 2	315.7	344.2	347.7	354.0	360.7	363.2
Rate 3	3,510.4	3,579.6	3,607.3	3,652.0	3,713.9	3,740.5
Rate 4	72,902.5	2,470.2	2,487.2	2,508.5	2,536.4	2,547.7
Rate 5	11,703.8	11,444.3	11,502.6	11,625.1	11,828.7	11,924.0
Rate 6	3,620.4	4,071.6	4,095.3	4,137.9	4,182.5	4,201.8
Rate 7	2,730.5					
Rate 22	532,245.4	569,715.5	577,335.0	585,775.9	594,176.3	597,193.7
Rate 23	4,835.0	4,915.0	4,962.8	5,025.9	5,100.7	5,131.9
Rate 25	20,629.1	21,563.6	21,787.4	22,049.0	22,364.7	22,486.7
Rate 27	67,989.4	71,857.6	72,972.9	74,079.1	75,262.3	75,673.3

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	51,917,831	50,789,945	48,573,673	47,727,200	47,144,919	46,750,780
Rate 2	16,853,002	17,334,508	17,723,203	18,240,709	18,768,860	18,965,127
Rate 3	14,259,191	14,024,865	14,133,429	14,308,698	14,550,917	14,655,243
Rate 4	72,902	81,515	82,076	82,780	83,700	84,075
Rate 5	2,305,653	2,185,857	2,196,988	2,220,393	2,259,275	2,277,478
Rate 6	65,168	57,002	57,335	57,931	58,555	58,825
Rate 7	2,731	-	-	-	-	-
Rate 22	11,709,399	13,673,171	13,856,040	14,058,622	14,260,232	14,332,648
Rate 23	5,719,794	7,043,207	8,317,714	9,679,864	11,170,633	11,798,162
Rate 25	8,973,676	9,078,273	9,172,498	9,282,624	9,415,535	9,466,909
Rate 27	5,439,152	5,461,176	5,545,938	5,630,010	5,719,932	5,751,172
Grand Total	**117,318,497**	**119,729,520**	**119,658,894**	**121,288,831**	**123,432,557**	**124,140,419**

Coastal Region - Scenario D
Year End Accounts by Rate Class

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	532,550	538,391	551,166	562,686	573,339	577,389
Rate 2	53,387	50,357	50,971	51,524	52,031	52,223
Rate 3	4,062	3,918	3,918	3,918	3,918	3,918
Rate 4	1	33	33	33	33	33
Rate 5	197	191	191	191	191	191
Rate 6	18	14	14	14	14	14
Rate 7	1					
Rate 22	22	24	24	24	24	24
Rate 23	1,183	1,433	1,676	1,926	2,190	2,299
Rate 25	435	421	421	421	421	421
Rate 27	80	76	76	76	76	76
Grand Total	**591,936**	**594,858**	**608,490**	**620,813**	**632,237**	**636,588**

Annual Use Rate per Customer by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	97.5	92.9	85.7	81.6	78.1	76.4
Rate 2	315.7	333.3	326.1	318.7	313.2	311.1
Rate 3	3,510.4	3,457.4	3,376.1	3,292.6	3,228.2	3,203.6
Rate 4	72,902.5	2,397.9	2,345.2	2,290.2	2,248.4	2,232.0
Rate 5	11,703.8	11,115.9	10,817.3	10,517.2	10,282.1	10,195.3
Rate 6	3,620.4	3,991.8	3,917.5	3,839.9	3,783.3	3,762.5
Rate 7	2,730.5					
Rate 22	532,245.4	525,669.7	517,171.2	508,106.1	500,849.9	497,744.9
Rate 23	4,835.0	4,698.2	4,598.6	4,494.8	4,414.2	4,382.6
Rate 25	20,629.1	20,431.3	20,044.4	19,636.2	19,318.9	19,189.8
Rate 27	67,989.4	65,965.3	64,951.0	63,829.3	62,932.9	62,523.9

Annual Demand by Rate Class (GJ)

Rate Class	2011	2016	2021	2026	2031	2033
Rate 1	51,917,831	50,038,207	47,227,387	45,903,863	44,750,123	44,114,798
Rate 2	16,853,002	16,783,451	16,622,631	16,419,784	16,295,880	16,245,950
Rate 3	14,259,191	13,546,145	13,227,501	12,900,225	12,648,176	12,551,546
Rate 4	72,902	79,130	77,392	75,578	74,196	73,655
Rate 5	2,305,653	2,123,131	2,066,112	2,008,781	1,963,874	1,947,309
Rate 6	65,168	55,886	54,845	53,758	52,966	52,675
Rate 7	2,731	-	-	-	-	-
Rate 22	11,709,399	12,616,072	12,412,108	12,194,547	12,020,397	11,945,877
Rate 23	5,719,794	6,732,589	7,707,264	8,657,017	9,667,116	10,075,621
Rate 25	8,973,676	8,601,578	8,438,699	8,266,844	8,133,273	8,078,920
Rate 27	5,439,152	5,013,361	4,936,275	4,851,024	4,782,900	4,751,819
Grand Total	**117,318,497**	**115,589,551**	**112,770,214**	**111,331,421**	**110,388,901**	**109,838,170**

Interior - Reference Case
Year End Accounts by Rate Class

Core	2011	2016	2021	2026	2031	2033
Rate 1	233,646	241,003	251,664	261,046	269,575	272,924
Rate 2	23,292	23,345	24,238	25,033	25,789	26,107
Rate 3	787	748	748	748	748	748
Rate 4	4	12	12	12	12	12
Rate 5	27	25	25	25	25	25
Rate 6	2	2	2	2	2	2
Rate 7	2	3	3	3	3	3
Rate 22	22	22	22	22	22	22
Rate 23	250	330	402	488	586	631
Rate 25	77	75	75	75	75	75
Rate 27	18	19	19	19	19	19
Grand Total	**258,127**	**265,584**	**277,210**	**287,473**	**296,856**	**300,568**

Annual Use Rate per Customer by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	211.6	203.6	190.9	184.5	179.1	176.4
Rate 2	3,639.1	3,591.4	3,512.2	3,440.8	3,374.9	3,347.2
Rate 3	3,719.1	3,726.1	3,668.7	3,611.3	3,561.1	3,534.9
Rate 4	23,377.7	7,808.3	7,711.5	7,611.1	7,736.9	7,476.9
Rate 5	12,269.3	12,662.1	12,440.2	12,216.8	11,989.9	11,921.3
Rate 6	2,168.3	2,183.4	2,193.7	2,203.6	2,210.5	2,212.5
Rate 7	56,318.9	37,554.6	37,554.7	37,554.3	37,554.1	37,553.7
Rate 22	1,044,786.1	1,186,491.7	1,177,449.7	1,165,526.6	1,156,722.0	1,149,369.5
Rate 23	5,573.8	5,556.2	5,473.7	5,391.8	5,191.7	5,286.0
Rate 25	83,675.8	88,363.0	87,481.0	86,416.9	84,986.2	84,977.1
Rate 27	82,833.1	72,047.6	71,218.8	70,269.0	69,896.8	68,989.1

Annual Demand by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	17,573,321	17,480,468	17,060,939	17,055,683	17,083,991	17,016,807
Rate 2	6,378,245	6,589,032	6,735,539	6,853,571	6,973,140	7,029,019
Rate 3	2,926,922	2,787,120	2,744,157	2,701,249	2,663,697	2,644,111
Rate 4	93,511	93,699	92,538	91,333	92,843	89,723
Rate 5	331,272	316,551	311,004	305,419	299,746	298,031
Rate 6	4,337	4,367	4,387	4,407	4,421	4,425
Rate 7	112,638	112,664	112,664	112,663	112,662	112,661
Rate 22	22,985,295	26,102,818	25,903,893	25,641,586	25,447,884	25,286,128
Rate 23	1,393,445	1,833,554	2,200,444	2,631,179	3,042,318	3,335,455
Rate 25	4,401,280	4,565,493	4,518,975	4,463,717	4,378,680	4,389,093
Rate 27	1,490,995	1,368,904	1,353,156	1,335,111	1,328,039	1,310,793
Grand Total	**57,691,260**	**61,254,671**	**61,037,697**	**61,195,919**	**61,427,421**	**61,516,247**

Interior - Scenario A
Year End Accounts by Rate Class

Core	2011	2016	2021	2026	2031	2033
Rate 1	233,646	241,003	251,664	261,046	269,575	272,924
Rate 2	23,292	23,345	24,238	25,033	25,789	26,107
Rate 3	787	748	748	748	748	748
Rate 4	4	12	12	12	12	12
Rate 5	27	25	25	25	25	25
Rate 6	2	2	2	2	2	2
Rate 7	2	3	3	3	3	3
Rate 22	22	22	22	22	22	22
Rate 23	250	330	402	488	586	631
Rate 25	77	75	75	75	75	75
Rate 27	18	19	19	19	19	19
Grand Total	**258,127**	**265,584**	**277,210**	**287,473**	**296,856**	**300,568**

Annual Use Rate per Customer by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	211.6	200.4	185.9	177.7	170.4	166.9
Rate 2	3,639.1	3,567.1	3,423.2	3,263.3	3,126.8	3,072.6
Rate 3	3,719.1	3,712.2	3,604.0	3,473.0	3,366.8	3,319.4
Rate 4	23,377.7	7,885.3	7,818.2	7,718.6	7,898.9	7,623.7
Rate 5	12,269.3	12,632.4	12,265.1	11,823.2	11,430.5	11,303.8
Rate 6	2,168.3	2,163.1	2,123.8	2,062.6	2,007.8	1,985.9
Rate 7	56,318.9	38,886.6	40,265.9	41,693.8	43,172.6	43,778.3
Rate 22	1,044,786.1	1,215,468.2	1,235,293.5	1,252,309.9	1,273,254.8	1,277,503.8
Rate 23	5,573.8	5,559.1	5,433.7	5,280.0	5,015.3	5,103.7
Rate 25	83,675.8	89,965.8	90,573.3	90,940.8	90,976.0	91,623.9
Rate 27	82,833.1	73,242.2	73,443.4	73,427.7	74,138.1	73,606.6

Annual Demand by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	17,573,321	17,189,924	16,626,366	16,438,636	16,266,502	16,109,605
Rate 2	6,378,245	6,555,084	6,590,829	6,542,586	6,521,243	6,521,342
Rate 3	2,926,922	2,776,760	2,695,813	2,597,832	2,518,356	2,482,922
Rate 4	93,511	94,624	93,819	92,624	94,787	91,485
Rate 5	331,272	315,811	306,626	295,579	285,763	282,595
Rate 6	4,337	4,326	4,248	4,125	4,016	3,972
Rate 7	112,638	116,660	120,798	125,081	129,518	131,335
Rate 22	22,985,295	26,740,300	27,176,456	27,550,818	28,011,606	28,105,084
Rate 23	1,393,445	1,834,516	2,184,352	2,576,625	2,938,939	3,220,437
Rate 25	4,401,280	4,643,023	4,665,383	4,674,307	4,655,484	4,697,699
Rate 27	1,490,995	1,391,603	1,395,425	1,395,127	1,408,623	1,398,525
Grand Total	**57,691,260**	**61,662,630**	**61,860,115**	**62,293,338**	**62,834,836**	**63,045,000**

Interior - Scenario B
Year End Accounts by Rate Class

Core	2011	2016	2021	2026	2031	2033
Rate 1	233,646	241,003	251,664	261,046	269,575	272,924
Rate 2	23,292	23,345	24,238	25,033	25,789	26,107
Rate 3	787	748	748	748	748	748
Rate 4	4	12	12	12	12	12
Rate 5	27	25	25	25	25	25
Rate 6	2	2	2	2	2	2
Rate 7	2	3	3	3	3	3
Rate 22	22	22	22	22	22	22
Rate 23	250	330	402	488	586	631
Rate 25	77	75	75	75	75	75
Rate 27	18	19	19	19	19	19
Grand Total	**258,127**	**265,584**	**277,210**	**287,473**	**296,856**	**300,568**

Annual Use Rate per Customer by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	211.6	201.1	186.9	179.2	171.8	168.2
Rate 2	3,639.1	3,514.0	3,307.9	3,060.5	2,854.6	2,775.2
Rate 3	3,719.1	3,617.2	3,445.8	3,226.5	3,046.8	2,973.0
Rate 4	23,377.7	7,362.9	7,165.8	6,901.4	6,894.5	6,604.1
Rate 5	12,269.3	12,260.9	11,684.7	10,954.7	10,325.6	10,105.6
Rate 6	2,168.3	2,151.1	2,071.1	1,948.0	1,841.2	1,799.4
Rate 7	56,318.9	33,798.0	34,650.4	35,523.9	36,419.8	36,784.1
Rate 22	1,044,786.1	1,057,085.1	1,058,231.2	1,056,209.9	1,057,197.0	1,054,047.5
Rate 23	5,573.8	5,325.3	5,107.6	4,831.4	4,487.1	4,513.2
Rate 25	83,675.8	79,691.7	79,175.6	78,332.6	77,252.6	77,345.4
Rate 27	82,833.1	65,585.3	64,782.5	63,639.6	63,178.5	62,314.2

Annual Demand by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	17,573,321	17,246,731	16,714,068	16,566,995	16,398,018	16,238,617
Rate 2	6,378,245	6,426,466	6,335,199	6,099,961	5,912,970	5,847,270
Rate 3	2,926,922	2,705,641	2,577,428	2,413,407	2,279,006	2,223,787
Rate 4	93,511	88,355	85,990	82,817	82,735	79,249
Rate 5	331,272	306,522	292,118	273,868	258,139	252,640
Rate 6	4,337	4,302	4,142	3,896	3,682	3,599
Rate 7	112,638	101,394	103,951	106,572	109,259	110,352
Rate 22	22,985,295	23,255,873	23,281,085	23,236,618	23,258,333	23,189,045
Rate 23	1,393,445	1,757,337	2,053,265	2,357,732	2,629,453	2,847,851
Rate 25	4,401,280	4,144,898	4,105,520	4,046,318	3,967,634	3,977,676
Rate 27	1,490,995	1,246,121	1,230,868	1,209,153	1,200,391	1,183,969
Grand Total	**57,691,260**	**57,283,640**	**56,783,634**	**56,397,337**	**56,099,620**	**55,954,054**

Interior - Scenario C
Year End Accounts by Rate Class

Core	2011	2016	2021	2026	2031	2033
Rate 1	233,646	241,003	251,664	261,046	269,575	272,924
Rate 2	23,292	23,345	24,238	25,033	25,789	26,107
Rate 3	787	748	748	748	748	748
Rate 4	4	12	12	12	12	12
Rate 5	27	25	25	25	25	25
Rate 6	2	2	2	2	2	2
Rate 7	2	3	3	3	3	3
Rate 22	22	22	22	22	22	22
Rate 23	250	330	402	488	586	631
Rate 25	77	75	75	75	75	75
Rate 27	18	19	19	19	19	19
Grand Total	**258,127**	**265,584**	**277,210**	**287,473**	**296,856**	**300,568**

Annual Use Rate per Customer by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	211.6	203.8	192.1	185.7	180.9	178.5
Rate 2	3,639.1	3,643.8	3,643.6	3,667.1	3,697.9	3,710.2
Rate 3	3,719.1	3,784.5	3,812.4	3,860.8	3,922.4	3,942.3
Rate 4	23,377.7	7,952.8	8,040.2	8,136.3	8,470.1	8,262.9
Rate 5	12,269.3	12,859.2	12,919.3	12,993.9	13,064.2	13,122.0
Rate 6	2,168.3	2,211.7	2,273.0	2,345.9	2,425.7	2,461.6
Rate 7	56,318.9	38,275.1	39,009.5	39,757.4	40,519.8	40,828.6
Rate 22	1,044,786.1	1,219,681.8	1,244,165.5	1,266,287.0	1,291,386.2	1,297,837.3
Rate 23	5,573.8	5,652.0	5,700.0	5,769.9	5,706.5	5,880.0
Rate 25	83,675.8	90,895.6	92,631.0	94,235.9	95,392.6	96,533.2
Rate 27	82,833.1	73,928.9	75,107.8	76,199.2	77,873.8	77,714.6

Annual Demand by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	17,573,321	17,501,919	17,209,451	17,189,825	17,296,655	17,260,699
Rate 2	6,378,245	6,690,941	7,004,843	7,355,400	7,718,253	7,872,840
Rate 3	2,926,922	2,830,800	2,851,640	2,887,869	2,933,938	2,948,816
Rate 4	93,511	95,434	96,482	97,636	101,642	99,155
Rate 5	331,272	321,479	322,982	324,846	326,605	328,051
Rate 6	4,337	4,423	4,546	4,692	4,851	4,923
Rate 7	112,638	114,825	117,028	119,272	121,559	122,486
Rate 22	22,985,295	26,833,001	27,371,641	27,858,314	28,410,495	28,552,420
Rate 23	1,393,445	1,865,167	2,291,393	2,815,713	3,344,030	3,710,285
Rate 25	4,401,280	4,688,163	4,770,605	4,847,595	4,888,945	4,957,677
Rate 27	1,490,995	1,404,648	1,427,048	1,447,785	1,479,602	1,476,578
Grand Total	**57,691,260**	**62,350,801**	**63,467,660**	**64,948,945**	**66,626,577**	**67,333,929**

Interior - Scenario D
Year End Accounts by Rate Class

Core	2011	2016	2021	2026	2031	2033
Rate 1	233,646	241,003	251,664	261,046	269,575	272,924
Rate 2	23,292	23,345	24,238	25,033	25,789	26,107
Rate 3	787	748	748	748	748	748
Rate 4	4	12	12	12	12	12
Rate 5	27	25	25	25	25	25
Rate 6	2	2	2	2	2	2
Rate 7	2	3	3	3	3	3
Rate 22	22	22	22	22	22	22
Rate 23	250	330	402	488	586	631
Rate 25	77	75	75	75	75	75
Rate 27	18	19	19	19	19	19
Grand Total	**258,127**	**265,584**	**277,210**	**287,473**	**296,856**	**300,568**

Annual Use Rate per Customer by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	211.6	200.4	186.2	178.1	171.2	167.9
Rate 2	3,639.1	3,548.2	3,439.1	3,332.3	3,245.4	3,210.5
Rate 3	3,719.1	3,649.5	3,563.3	3,473.3	3,405.5	3,375.0
Rate 4	23,377.7	7,420.8	7,288.7	7,148.6	7,232.0	6,990.9
Rate 5	12,269.3	12,369.0	12,056.4	11,730.9	11,453.0	11,367.8
Rate 6	2,168.3	2,172.2	2,162.2	2,146.2	2,137.1	2,133.8
Rate 7	56,318.9	33,798.7	33,798.5	33,797.7	33,797.2	33,796.7
Rate 22	1,044,786.1	1,066,479.9	1,052,884.0	1,037,071.3	1,024,490.0	1,016,318.7
Rate 23	5,573.8	5,372.8	5,249.4	5,122.0	4,910.5	4,981.2
Rate 25	83,675.8	79,970.9	78,341.1	76,591.1	74,620.3	74,355.1
Rate 27	82,833.1	65,932.2	64,590.1	63,155.4	62,323.7	61,361.2

Annual Demand by Rate Class (GJ)

Core	2011	2016	2021	2026	2031	2033
Rate 1	17,573,321	17,195,432	16,658,745	16,481,038	16,345,034	16,204,912
Rate 2	6,378,245	6,491,422	6,585,815	6,641,244	6,727,734	6,773,910
Rate 3	2,926,922	2,729,840	2,665,343	2,598,034	2,547,280	2,524,475
Rate 4	93,511	89,049	87,465	85,784	86,784	83,891
Rate 5	331,272	309,224	301,410	293,272	286,326	284,196
Rate 6	4,337	4,344	4,324	4,292	4,274	4,268
Rate 7	112,638	101,396	101,395	101,393	101,392	101,390
Rate 22	22,985,295	23,462,558	23,163,448	22,815,569	22,538,779	22,359,012
Rate 23	1,393,445	1,773,022	2,110,274	2,499,520	2,877,532	3,143,149
Rate 25	4,401,280	4,165,257	4,084,691	3,997,605	3,890,360	3,887,785
Rate 27	1,490,995	1,252,712	1,227,212	1,199,953	1,184,150	1,165,864
Grand Total	**57,691,260**	**57,574,256**	**56,990,124**	**56,717,705**	**56,589,645**	**56,532,851**

NGT - Annual Demand by Region (GJ)
Reference Case

Region	2011	2016	2021	2026	2031	2033
Interior	87,873	674,598	1,719,713	4,008,357	9,342,792	13,106,322
LM	106,392	997,503	2,536,761	5,912,755	13,781,618	19,333,226
FEVI	-	14,672	14,672	14,672	14,672	14,672
FEW	223	4,278	10,722	24,992	58,251	81,716
Grand Total	**194,488**	**1,691,051**	**4,281,868**	**9,960,775**	**23,197,333**	**32,535,936**

Low Case

Region	2011	2016	2021	2026	2031	2033
Interior	87,873	674,598	873,872	873,872	873,872	873,872
LM	106,392	997,503	1,289,055	1,289,055	1,289,055	1,289,055
FEVI	-	-	-	-	-	-
FEW	223	4,278	5,448	5,448	5,448	5,448
Grand Total	**194,488**	**1,676,379**	**2,168,375**	**2,168,375**	**2,168,375**	**2,168,375**

High Case

Region	2011	2016	2021	2026	2031	2033
Interior	87,873	674,598	2,045,106	5,919,719	17,135,085	26,213,217
LM	106,392	997,503	3,016,751	8,732,218	25,276,081	38,667,297
FEVI	-	29,344	29,344	29,344	29,344	29,344
FEW	223	4,278	12,751	36,909	106,835	163,435
Grand Total	**194,488**	**1,705,723**	**5,103,952**	**14,718,190**	**42,547,345**	**65,073,293**

Appendix B-2

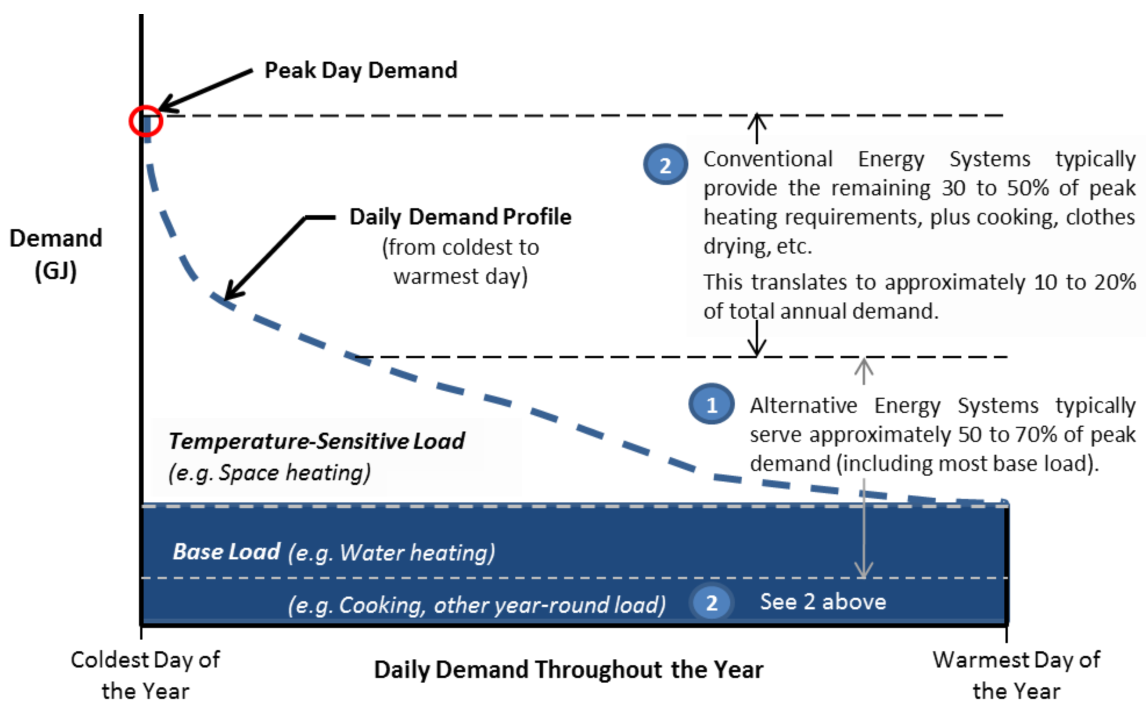
RENEWABLE THERMAL ENERGY

APPENDIX B-2 – RENEWABLE THERMAL ENERGY

Thermal energy solutions include renewable energy systems such as geoexchange, waste heat recovery and solar thermal energy. As these energy alternatives evolve and grow in the marketplace, the Utilities must forecast demand for these new products and services in order to understand the impacts on conventional natural gas demand. This appendix provides an overview of renewable thermal energy as well as how it relates to the end-use forecasting scenarios.

Figure 1 (below) illustrates how a renewable thermal energy system can impact a customer's need for conventional energy service. The figure shows thermal energy demand throughout the year for a typical residential or commercial customer from the coldest day of the year to the warmest. Demand during warmer days (right side of the graph) is referred to as base load because it serves year round needs such as cooking, water heating and possibly a small amount of space heating. As temperature decreases (moving from right to left along the graph), energy demand increases, primarily due to increased space heating requirements, and is highest on the coldest day of the year (peak day).

Figure 1: Annual Heating Demand Profile for a Typical Residential or Commercial Customer



Designing a thermal energy system to meet demand on every single day of the year, including the coldest day, is cost-prohibitive. Therefore, such systems are typically designed to meet thermal energy demand for approximately 50% to 70% of peak day requirements, including a portion of the base load (see point 1 in Figure 1). This type of system can therefore serve approximately 80% to 90% of this customer's annual demand. The remaining demand (see point 2 in

Figure) is then supplemented by conventional energy systems, which the FEU believe is best met by natural gas where it is available.

Modelling energy demand for commercial and industrial thermal end-uses is more complex since demand is subject to market cycles and trends that differ from those impacting the residential sector. Furthermore, district and discrete energy systems are more complicated than conventional energy systems since each system can vary in size, technology, energy combinations and end-use applications depending on individual customer or community needs.

The Reference Case scenario was used as a baseline to produce the new end-use forecasting methodology consisting of four alternative forecasts, each implementing the assumptions in one of the four alternative scenarios described in Section 3.2.2.4. In the end-use forecasting methodology, thermal energy demand features prominently in Scenarios A and B, where markets move toward decentralized or self-generated energy systems. This has the effect of displacing natural gas consumption, particularly for space and water heating. With limited but growing market penetration of renewable thermal energy systems, the FEU must continue to monitor thermal energy demand in order to gauge its impact over time on the Utilities' natural gas infrastructure, annual and peak day demand, system capacity needs and rate design issues.

Appendix B-3

INTRODUCTION TO THE END-USE DEMAND FORECASTING SCENARIOS

APPENDIX B-3 – END-USE ANNUAL DEMAND FORECASTING SCENARIO DESCRIPTIONS

This end-use annual demand forecasting scenario appendix describes how each of the four future scenarios were modelled to create a range of future annual demand expectations from residential, commercial and industrial customers for use in the long term resource planning process. These four scenarios are intended to bound the possible planning environments in which the FEU will operate over the next 20 years. Each scenario is constructed by making incremental changes to an original reference case that is based primarily on data developed for the 2010 Conservation Potential Review (CPR). The four future scenarios are intended to provide insight into the impact on demand of a broader range of potential future conditions than has been examined in previous LTRPs. These four scenarios were developed based on key, critical uncertainties that have been identified with input from both internal FEU stakeholders and members of the external Resource Planning Advisory Group. The identified critical uncertainties represent those future conditions that stakeholders have identified as having the potential to have the biggest impact on the FEU's business. This appendix explains how model inputs were developed from the scenario descriptions as well as how these inputs were varied based on the scenario descriptions to create a different demand expectation for each scenario.

1. Explanation of Scenario A

Scenario A is one of four scenarios intended to bound the possible business environments in which the FEU will operate over the next 20 years. Each scenario is constructed by making incremental changes to an original reference case that is based primarily on data developed for the 2010 Conservation Potential Review. Scenario A explanations for each of the residential, commercial and industrial sectors follow below.

1.1 RESIDENTIAL

Scenario A: Abundant supply and decentralized energy markets				
Description: Natural gas supply is abundant due to shale gas developments but government policy focuses on strict carbon emission reductions, which drives the development and adoption of new, decentralized low carbon/carbon neutral technologies and limits the market penetration of natural gas.				
Baseline Scenario: The scenario from which Scenario A is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC residential customers and their average usage per customer (UPC) in 2011. Including expected changes in natural gas usage over the forecast period, the average residential UPC in the original reference case shows a decline of approximately 1% per year.				
Assumptions	**Interpretation**	**Actions Taken**	**Results for This Assumption**	**Cumulative Results**
Low gas price	Gas prices in this scenario follow the same projected rate of increase that was used to develop the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.)	• The effects of this change in gas cost are combined with the effects of increased carbon price, below.	See below.	No change from the original reference case based on the 2010 CPR. See below.

	Under Scenario A, gas commodity prices rise to bring the cost with delivery to \$8.17/GJ before carbon price.			
High carbon price	B.C.'s carbon price is \$30/tonne, which works out to 5.7 cents/m^3 or \$1.48/GJ out of a total price of about \$9.75/GJ.[1] It is proposed to gradually increase this to \$120/tonne, bringing the total price of gas to about \$14.17/GJ. The price increase, including the change in both commodity and carbon price, would be approximately 5%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.2. Thus, a 5% increase in gas price would tend to decrease residential consumption by approximately 1% over the long term.	• The proportion of new customers choosing to heat with fuels other than gas was increased for all regions and all house types, to result in a 1% reduction in the overall growth in gas-heated dwellings by 2031. The total number of accounts would not be different – just the proportion installing furnaces and boilers. • By 2031, 1% of existing dwellings requiring a replacement furnace are assumed to switch to another fuel (mostly ASHP), at natural rate of furnace replacement. • By 2031, 1% of existing dwellings requiring a replacement gas DHW tank are assumed to switch to electric tanks, at natural rate of DHW replacement. These three fuel choice adjustments, with 1% changes in each case, are introduced gradually, as the commodity and carbon prices gradually change. They produce a total change somewhat smaller than the result suggested by price elasticity, so there may be some additional reduction from the price change. In reality the carbon price may produce a mixture of fuel choice changes and efficiency improvements. For reasons of clarity, we have kept the efficiency changes separate, as a response to carbon reduction policy, below.	Total decrease in UPC by 2031 is approximately 0.6% for these three changes.	Decrease in UPC by 2031 is approximately 0.6% compared to the original reference case based on the 2010 CPR.

[1] Rate 1, including taxes but not fixed daily charges.

Strong economic growth	Economic growth would pull population increases in its wake, with a lag of a year or two. (Effects on commercial floor space growth and industrial production would be more direct.) Decision was to make no change in housing starts or housing types.	• None. Strong economic growth is considered an aspect of the planning environment that is needed for the policy and technological changes envisioned as part of this scenario.	No change.	No change.
Policy focused on carbon reduction	In the residential sector, this amplifies the effect of high carbon price, by providing education and "moral suasion" to get people to respond faster. Specifically, adoption of the EGH 80 homes would be accelerated, more people would undertake more envelope improvement measures, and more people would improve the efficiency of their furnaces and DHW.	• Furnaces are assumed to improve to an average of 94% efficiency instead of the 90% efficiency assumed in the original reference case based on the 2010 CPR. • Overall effect of envelope renovations is increased by 50% (either an average reno results in 3% reduction in space heating versus the current 2%, or else rate of renos increases). • Adoption of EGH 80 housing in new construction begins in 2013. • 40% of new DHW units, both replacement (at natural rate) and new construction, are assumed to be EF 0.8. (This is relative to nearly 20% of DHW that are either tankless or condensing in post-2005 houses.)	These changes result in a total UPC reduction of approximately 3.3% by 2031.	Overall decrease in UPC by 2031 is 3.9% compared to the original reference case based on the 2010 CPR.
Renewable thermal & energy efficiency a priority, including the use of "Smart" technology	There would also be an increased switch from natural gas towards renewable supply and district energy. Renewable energy is assumed to displace both natural gas and other fuels such as electricity. It is assumed to displace them in approximately the ratio of their initial shares	• Proposed to reach 1% share of renewables in space heating, DHW and pools by 2021 and then stabilize after that. Proposed to reach 0.5% share in existing dwellings by 2021 and then stabilize, for the same end uses. • The share reached by district energy was based on an internal study of market potential done by FortisBC. The study assumed negligible penetration of the	These two changes result in a further 0.6% decrease in UPC by 2031.	Overall decrease in UPC by 2031 is 4.5% compared to the original reference case based on the 2010 CPR.

	of the end use.	residential market before 2021. By 2030 a penetration of up to 0.37% (displacing natural gas) was estimated to be technically possible. Scenario A includes a somewhat less aggressive adoption curve for district energy, so we assumed penetration in 2031 would reach just over 0.25%. District energy was assumed to affect the space heating and DHW end uses.		
Energy strategies are consistent within regions, but may be disparate among regions	This input was intended to provide context for the scenario as a whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

1.2 COMMERCIAL

Scenario A: Abundant supply and decentralized energy markets				
Description: Natural gas supply is abundant due to shale gas developments but government policy focuses on strict carbon emission reductions, which drives the development and adoption of new, decentralized low carbon/carbon neutral technologies and limits the market penetration of natural gas				
Baseline Scenario: The scenario from which Scenario A is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC commercial customers and their gas consumption in 2011. Energy intensity in the commercial model is expressed as energy utilization intensity (EUI), in MJ of natural gas per m^2 of floor area. Including expected changes in natural gas usage over the forecast period, the average residential EUI in the original reference case shows a decline of approximately 0.3% per year.				
Assumptions	**Interpretation**	**Actions Taken**	**Results for This Assumption**	**Cumulative Results**
Low gas price	Gas prices in this scenario follow	• The effects of this change in gas cost are	See below.	No change from the

	the same projected rate of increase that was used to develop the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.) Under Scenario A, gas commodity prices rise to bring the cost with delivery to $8.17/GJ before carbon price.	combined with the effects of increased carbon price, below.		original reference case based on the 2010 CPR. See below.
High carbon price	B.C.'s carbon price is $30/tonne, which works out to 5.7 cents/m^3 or $1.48/GJ out of a total price of about $7.10/GJ.[2] It is proposed to gradually increase this to $120/tonne, bringing the total price of gas to about $14.17/GJ. The price increase, including the change in both commodity and carbon price, would be approximately 5%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.5. Thus, a 5% increase in gas price would tend to decrease commercial consumption by approximately 2½% over the long term.[3]	• The proportion of new building choosing non-gas heating increased for all regions and all building types, to result in a 2.5% reduction in the overall growth in gas-heated buildings by 2031. The total number of accounts would not be different – just the proportion installing gas heat. • The percentage of existing commercial buildings with roof-top HVAC systems is roughly 30%, with approximately another 10% heated by forced air furnaces. By 2031, the rate at which these buildings are assumed to switch to another fuel (mostly ASHP), at natural rate of RTU/furnace replacement, will have reached 2.5%. • Approximately 40% of existing buildings heat SWH with a gas-fired hot-water tank.	Total decrease in EUI by 2031 is approximately 1.3% for these changes.	Decrease in EUI by 2031 is approximately 1.3% compared to the original reference case based on the 2010 CPR.

2 Rate 2, not including taxes or fixed daily charges.
3 Residential price elasticity data is from http://www.nrel.gov/docs/fy06osti/39512.pdf , although http://www.eia.gov/oiaf/analysispaper/elasticity/pdf/tbl.pdf suggests that the long term price elasticity is higher. Additional information on price elasticity can be found at http://www.sustainableprosperity.ca/dl843&display

		By 2031, the rate at which these buildings are assumed to switch to electric tanks, at natural rate of DHW replacement, will have reached 2.5%. • Existing buildings with gas boilers for space heating and/or DHW can also change fuels when they replace equipment, particularly if the cost of gas greatly exceeds the cost of providing the same service with electricity. These fuel choice adjustments, with 2.5% changes in each case, are introduced gradually, as the commodity and carbon prices gradually change. They produce a change in EUI of approximately 1.3% in 20 years, somewhat less than price elasticity would predict. In reality the carbon price may produce a mixture of fuel choice changes and efficiency improvements. For reasons of clarity, we have kept the efficiency changes separate, as a response to carbon reduction policy, below.		
Strong economic growth	Economic growth would directly increase commercial floor space growth, though not in every sector. Growth in segments like schools follow population trends, so should not be changed if the residential sector growth was not changed. Growth in segments like restaurants would be faster in a time of high economic growth.	• No change to commercial floor space in response to economic growth assumptions is included in the model.	No change.	No change.

Policy focused on carbon reduction	In the commercial sector, this amplifies the effect of high carbon price, by providing information, efficiency standards, and perhaps incentives to get businesses to adopt higher efficiency choices faster. Specifically, adoption of higher efficiency new buildings (consistent with the LEED rating scheme) would be accelerated, more businesses would undertake more envelope improvement measures, and more businesses would improve the efficiency of their heating and DHW systems.	• Condensing boilers are assumed to be adopted at a rate 13% higher than the current rate, when boilers are replaced at the end of their normal life. • Overall effect of envelope renovations is increased by 5% (either a higher rate of glazing and insulation/sealing projects or greater improvement within projects). • Construction of new buildings built at the LEED gold level more than doubles to approximately 7% of new buildings. • Condensing DHW boilers and tanks, both replacement (at natural rate) and new construction, are assumed to be adopted at 1.5% higher rate than the current rate. These suggested accelerated rates of improvement are based on 25% of the participation rates used in the Most Likely Achievable Potential scenario developed during the 2010 CPR.	Total decrease in EUI by 2031 is approximately 1.1% for these changes.	Decrease in EUI by 2031 is approximately 2.4% compared to the original reference case based on the 2010 CPR.
Renewable thermal & energy efficiency a priority, including the use of "Smart" technology	There would also be an increased switch from natural gas towards renewable supply and district energy. Renewable energy is assumed to displace both natural gas and other fuels such as electricity, but in commercial would mostly target DHW. It is assumed to displace them in approximately the ratio of their initial shares of the end use. District energy is assumed to target both space heating and DHW at the rates indicated in FortisBC's internal study.	• Proposed to reach 1% share of renewables in DHW by 2021 and then stabilize after that. Proposed to reach 0.5% share in existing buildings by 2021 and then stabilize, again just for DHW. • Solarwall did not pass the TRC test in the 2010 CPR, but this analysis will assume that the economics will improve such that it reaches a 1% share of new warehouses by 2021 and then stabilizes. • The share reached by district energy was based on an internal study of market potential done by FortisBC. The study assumed different penetrations for each rate class in four regions. If all this potential is assumed to apply to the	Total decrease in EUI by 2031 is approximately 5.6% for these changes.	Decrease in EUI by 2031 is approximately 8.0% compared to the original reference case based on the 2010 CPR.

	Commercial pools are in the "other" end use and are not specifically addressed here.	commercial portion of each rate class (not the industrials), then the penetration by 2030 reaches 9% in the Lower Mainland and nearly 15% on Vancouver Island, with the other regions in between. Scenario A includes a somewhat less aggressive adoption curve for district energy, so we assumed penetration in 2031 would reach 5% in the Lower Mainland and 7.5% on Vancouver Island, with the other regions in between.		
Energy strategies are consistent within regions, but may be disparate among regions	This input was intended to provide context for the scenario as a whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

1.3 INDUSTRIAL

Scenario A: Abundant supply and decentralized energy markets
Description: Natural gas supply is abundant due to shale gas developments but government policy focuses on strict carbon emission reductions, which drives the development and adoption of new, decentralized low carbon/carbon neutral technologies and limits the market penetration of natural gas
Baseline Scenario: The scenario from which Scenario A is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC industrial customers and their gas consumption in 2011. Energy intensity is not used explicitly in the industrial model, but is tracked as tertiary load (actual useful heat) relative to the level of production and efficiency (tertiary load divided by gas consumed). In the original reference case, tertiary load per unit of production is held constant for all end uses and industry sub-sectors, but efficiency improves over time. In the model developed for the 2010 CPR, efficiency improved by approximately 1% per year. There is documented support for that rate of improvement in the CPR industrial report, but it is also approximately five times the rate of improvement typically assumed in industrial studies in other jurisdictions. For now, the rate of efficiency improvement has been scaled back to 1% per 5-year milestone period, or approximately 0.2% per year. The other factor that is changing in the baseline scenario is the percentage of end uses that is supplied by natural

gas, the natural gas fuel share. In the base year, this ranges from 60% to 100% for different end uses, industries and regions. In the original reference case, these fuel shares are expected to rise during the first milestone and then mainly level off. This reflects the recent increases in gas consumption in industry, because of the price advantage gas currently has compared to other fuels.

Assumptions	Interpretation	Actions Taken	Results for This Assumption	Cumulative Results
Low gas price	Gas prices in this scenario follow the same projected rate of increase that was used to develop the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.) Under Scenario A, gas commodity prices rise to bring the cost with delivery to $8.17/GJ before carbon price.	• The effects of this change in gas cost are combined with the effects of increased carbon price, below.	See below.	No change from the original reference case based on the 2010 CPR. See below.
High carbon price	B.C.'s carbon price is $30/tonne, which works out to 5.7 cents/m^3 or $1.48/GJ out of a total price of about $7.10/GJ.[4] It is proposed to gradually increase this to $120/tonne, bringing the total price of gas to about $14.17/GJ. The price increase, including the change in both commodity and carbon price, would be approximately 5%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.5. Thus, an 5% increase in gas price would tend	• The natural gas fuel share in industry is proposed to decrease by approximately 2.5% for both heating and process loads, with the exception of end uses that are exclusively natural gas using.	Total decrease in gas consumption by 2031 is approximately 2.2% for these changes.	Decrease in total consumption by 2031 is approximately 2.2% compared to the original reference case based on the 2010 CPR.

[4] Rate 2, not including taxes or fixed daily charges.

	to decrease industrial consumption by approximately 2.5% over the long term.[5]			
Strong economic growth	Economic growth would directly increase industrial production growth, though not in every sector. For example, growth in industries that provide building materials follow construction trends. Export industries will tend to experience higher levels of production increase, due to economic growth.	• The industrial sector's response to economic growth can be incorporated either as an increased rate of account growth or as an increase in tertiary load (effectively production per account). • In Scenario A, tertiary load is increased by 0.7% annually from the levels in the original reference case. This increase is applied across the board, to all end uses in all industries in all regions.	Total increase in gas consumption by 2031 is approximately 14.6% for these changes.	Increase in total consumption by 2031 is approximately 12.4% compared to the original reference case based on the 2010 CPR.
Policy focused on carbon reduction	In the industrial sector a policy focused on carbon reduction would result in greater market penetration rates of higher efficiency equipment and implementation of energy conservation measures than in the reference case. Specifically, adoption of higher efficiency boilers, ovens and kilns would be accelerated,	• In the 2010 CPR, the Most Likely achievable scenario developed participation assumptions for a range of industrial measures. Overall, it was assumed that 35% of the equipment that is naturally being replaced would be replaced with a higher-efficiency option, with the exclusion of upgrades to pulp kilns, cement kilns, ore and coal dryers. Most measures were had participation rates in that range, though they went as high as about double that for condensing boilers. This would represent a 40% increase in activity relative to the rate implied by the CPR's 1%	Total increase in efficiency (gas consumption per unit of production) by 2031 is approximately 1.4% for these changes.	Increase in total consumption by 2031 is approximately 11.0% compared to the original reference case based on the 2010 CPR.

[5] Residential price elasticity data is from http://www.nrel.gov/docs/fy06osti/39512.pdf , although http://www.eia.gov/oiaf/analysispaper/elasticity/pdf/tbl.pdf suggests that the long term price elasticity is higher. Additional information on price elasticity can be found at http://www.sustainableprosperity.ca/dl843&display

		annual efficiency improvement. Relative to the lower efficiency rate assumed in this forecast's original reference case, a 35% replacement rate would represent a seven-fold increase in activity level. • For Scenario A, we are assuming that approximately one-quarter of the above rate of replacement would occur, so the replacement activity level would be increased by a factor of about 3. This assumption draws on the findings in the achievable potential chapter of the 2010 CPR.		
Renewable thermal & energy efficiency a priority, including the use of "Smart" technology	There are not likely to be many opportunities to switch from natural gas towards renewable supply or district energy, outside of the use of wood waste, which is captured in the reference case. Solar thermal energy could be used to offset some space heating and water heating, however.	• Proposed to reach 0.5% share of renewables in water heating in newly built plant capacity by 2021 and then stabilize after that. Proposed to reach 0.25% share in existing plants by 2021 and then stabilize, again just for water heating. • Solarwall did not pass the TRC test in the 2010 CPR, but this analysis will assume that the economics will improve such that it reaches a 0.5% share of new plant capacity by 2021 and then stabilizes. In existing plants it reaches a share of 0.25% by 2021 and then stabilizes.	Total decrease in gas consumption by 2031 is approximately 0.1% for these changes.	Increase in total consumption by 2031 is approximately 10.9% compared to the original reference case based on the 2010 CPR.

Energy strategies are consistent within regions, but may be disparate among regions	This input was intended to provide context for the scenario as a whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

2. Explanation of Scenario B

Scenario B is one of four scenarios intended to bound the possible business environments in which the FEU will operate over the next 20 years. Each scenario is constructed by making incremental changes to an original reference case that is based primarily on data developed for the 2010 Conservation Potential Review. Scenario B explanations for each of the residential, commercial and industrial sectors follow below.

2.1 RESIDENTIAL

Scenario B: Constricted supply and decentralized energy markets
Description: Natural gas supply is constrained and new technologies are emerging rapidly to meet future energy needs. Carbon policy is not a driver in this scenario; rather, generalized environmental policies contribute to constricted natural gas supply and support renewable thermal/decentralized energy development.
Baseline Scenario: The scenario from which Scenario A is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC residential customers and their average usage per customer (UPC) in 2011. Including expected changes in natural gas usage over the forecast period, the average residential UPC in the Original Reference Case shows a decline of approximately 1% per year.

Assumptions	Interpretation	Actions Taken	Results for This Assumption	Cumulative Results
Moderate to high gas price	Gas prices in this scenario will increase as compared to the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.) In Scenario B, gas commodity prices rise to bring the cost with delivery to $12.03/GJ before carbon price.	• The effects of this change in gas cost are combined with the effects of increased carbon price, below.	See below.	No change from the original reference case based on the 2010 CPR. See below.
Moderate carbon price	B.C.'s carbon price is $30/tonne, which works out to 5.7 cents/m^3 or $1.48/GJ out of a total price of about $9.75/GJ.[6] It is proposed to gradually increase this to $60/tonne, bringing the total price of gas to about $15.03/GJ. The price increase, including the change in both commodity and carbon price, would be approximately 11%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.2. Thus, a 11% increase in gas price would tend to decrease residential consumption by approximately	• The proportion of new customers choosing to heat with fuels other than gas was increased for all regions and all house types, to result in a 2% reduction in the overall growth in gas-heated dwellings by 2031. The total number of accounts would not be different – just the proportion installing furnaces and boilers. • By 2031, 2% of existing dwellings requiring a replacement furnace are assumed to switch to another fuel (mostly ASHP), at natural rate of furnace replacement. • By 2031, 2% of existing dwellings requiring a replacement gas DHW tank are assumed to switch to	Total decrease in UPC by 2031 is approximately 1.1% for these three changes.	Decrease in UPC by 2031 is approximately 1.1% compared to the original reference case based on the 2010 CPR.

6 Rate 1, including taxes but not fixed daily charges.

	2% over the long term.	electric tanks, at natural rate of DHW replacement. These three fuel choice adjustments, with 2% changes in each case, are introduced gradually, as the commodity and carbon prices gradually change. They produce a total change somewhat smaller than the result suggested by price elasticity, so there may be some additional reduction from the price change. In reality the carbon price may produce a mixture of fuel choice changes and efficiency improvements. For reasons of clarity, we have kept the efficiency changes separate, as a response to carbon reduction policy, below.		
Moderate to strong economic growth	Economic growth would pull population increases in its wake, with a lag of a year or two. (Effects on commercial floor space growth and industrial production would be more direct.) Decision was to make no change in housing starts or housing types.	• None. Strong economic growth is considered an aspect of the planning environment that is needed for the policy and technological changes envisioned as part of this scenario.	No change.	No change.
Policy focused on environmental impacts of energy, not carbon impacts	In the residential sector, this results in movement towards renewable thermals but not specifically gas to electric forms of fuel switching. Specifically, efficiency measures are prioritized but the central focus in this scenario is driving people towards district	• Furnaces are assumed to improve to an average of 92% efficiency instead of the 90% efficiency assumed in the original reference case based on the 2010 CPR. • Overall effect of envelope renovations is increased by 25% (either an average reno results in	These changes result in a total UPC reduction of approximately 1.7% by 2031.	Overall decrease in UPC by 2031 is 2.8% compared to the original reference case based on the 2010 CPR.

	energy systems and alternatives to natural gas.	2.5% reduction in space heating versus the current 2%, or else rate of renos increases). • Adoption of EGH 80 housing in new construction begins in 2020. • 20% of new DHW units, both replacement (at natural rate) and new construction, are assumed to be EF 0.8. (This is relative to nearly 20% of DHW that are either tankless or condensing in post-2005 houses.)		
Strongest market penetration for renewable thermal technologies, compared to other scenarios	There will be a substantial increase in fuel switching from natural gas towards renewable supply and district energy. Renewable energy is assumed to displace both natural gas and other fuels such as electricity. It is assumed to displace them in approximately the ratio of their initial shares of the end use.	• Proposed to reach 1.5% share of renewables in space heating, DHW and pools by 2021 and then stabilize after that. Proposed to reach 0.75% share in existing dwellings by 2021 and then stabilize, for the same end uses. • The share reached by district energy was based on an internal study of market potential done by FortisBC. The study assumed negligible penetration of the residential market before 2021. By 2030 a penetration of up to 0.37% (displacing natural gas) was estimated to be technically possible. Scenario B includes this aggressive adoption curve for district energy.	These two changes result in a further 1.0% decrease in UPC by 2031.	Overall decrease in UPC by 2031 is 3.8% compared to the original reference case based on the 2010 CPR.
Coordinated energy strategies among regions and all levels of government	This input was intended to provide context for the Scenario B as whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

2.2 COMMERCIAL

Scenario B: Constricted supply and decentralized energy markets				
Description: Natural gas supply is constrained and new technologies are emerging rapidly to meet future energy needs. Carbon policy is not a driver in this scenario; rather, generalized environmental policies contribute to constricted natural gas supply and support renewable thermal/decentralized energy development.				
Baseline Scenario: The scenario from which Scenario B is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC commercial customers and their gas consumption in 2011. Energy intensity in the commercial model is expressed as energy utilization intensity (EUI), in MJ of natural gas per m^2 of floor area. Including expected changes in natural gas usage over the forecast period, the average residential EUI in the Original Reference Case shows a decline of approximately 0.3% per year.				
Assumptions	**Interpretation**	**Actions Taken**	**Results for This Assumption**	**Cumulative Results**
Moderate to high gas price	Gas prices in this scenario follow the same projected rate of increase that was used to develop the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.) In Scenario B, gas commodity prices rise to bring the cost with delivery to $12.03/GJ before carbon price.	• The effects of this change in gas cost are combined with the effects of increased carbon price, below.	See below.	No change from the original reference case based on the 2010 CPR. See below.

Moderate carbon price	B.C.'s carbon price is $30/tonne, which works out to 5.7 cents/m^3 or $1.48/GJ out of a total price of about $7.10/GJ.[7] It is proposed to gradually increase this to $60/tonne, bringing the total price of gas to about $15.03/GJ. The price increase, including the change in both commodity and carbon price, would be approximately 11%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.5. Thus, a 11% increase in gas price would tend to decrease commercial consumption by approximately 5.5% over the long term.[8]	• The proportion of new building choosing non-gas heating increased for all regions and all building types, to result in a 5.5% reduction in the overall growth in gas-heated buildings by 2031. The total number of accounts would not be different – just the proportion installing gas heat. • The percentage of existing commercial buildings with roof-top HVAC systems is roughly 30%, with approximately another 10% heated by forced air furnaces. By 2031, the rate at which these buildings are assumed to switch to another fuel (mostly ASHP), at natural rate of RTU/furnace replacement, will have reached 5.5%. • Approximately 40% of existing buildings heat SWH with a gas-fired hot-water tank. By 2031, the rate at which these buildings are assumed to switch to electric tanks, at natural rate of DHW replacement, will have reached 5.5%. • Existing buildings with gas boilers for space heating and/or DHW can also change fuels when they replace equipment, particularly if the cost of gas greatly exceeds the cost of providing the same service with electricity. These fuel choice adjustments, with 5.5% changes in each case, are introduced	Total decrease in EUI by 2031 is approximately 2.9% for these changes.	Decrease in EUI by 2031 is approximately 2.9% compared to the original reference case based on the 2010 CPR.

7 Rate 2, not including taxes or fixed daily charges.
8 Residential price elasticity data is from http://www.nrel.gov/docs/fy06osti/39512.pdf , although http://www.eia.gov/oiaf/analysispaper/elasticity/pdf/tbl.pdf suggests that the long term price elasticity is higher. Additional information on price elasticity can be found at http://www.sustainableprosperity.ca/dl843&display

		gradually, as the commodity and carbon prices gradually change. They produce a change in EUI of approximately 2.8% in 20 years, somewhat less than price elasticity would predict. In reality the carbon price may produce a mixture of fuel choice changes and efficiency improvements. For reasons of clarity, we have kept the efficiency changes separate, as a response to carbon reduction policy, below.		
Moderate to strong economic growth	Economic growth would directly increase commercial floor space growth, though not in every sector. Growth in segments like schools follow population trends, so should not be changed if the residential sector growth was not changed. Growth in segments like restaurants would be faster in a time of high economic growth.	• No change to commercial floor space in response to economic growth assumptions is included in the model.	No change.	No change.
Policy focused on environmental impacts, not carbon reduction	In the commercial sector this results in movement towards renewable thermals but not specifically gas to electric forms of fuel switching. Specifically, efficiency measures are prioritized but the central focus in this scenario is driving people towards district energy systems and alternatives to natural gas.	• Condensing boilers are assumed to be adopted at a rate 5% higher than the current rate, when boilers are replaced at the end of their normal life. • Overall effect of envelope renovations is increased by 2% (either a higher rate of glazing and insulation/sealing projects or greater improvement within projects). • Construction of new buildings built at the LEED gold level increases to approximately 5% of new buildings. • Condensing DHW boilers and tanks, both	Total decrease in EUI by 2031 is approximately 0.4% for these changes.	Decrease in EUI by 2031 is approximately -3.3% compared to the original reference case based on the 2010 CPR.

		replacement (at natural rate) and new construction, are assumed to be adopted at 0.6% higher rate than the current rate. These suggested accelerated rates of improvement are based on 10% of the participation rates used in the Most Likely Achievable Potential scenario developed during the 2010 CPR.		
Strongest market penetration for renewable thermal technologies, compared to other scenarios	There would also be a substantial switch from natural gas towards renewable supply and district energy. Renewable energy is assumed to displace both natural gas and other fuels such as electricity, but in commercial would mostly target DHW. It is assumed to displace them in approximately the ratio of their initial shares of the end use. District energy is assumed to target both space heating and DHW at the rates indicated in FortisBC's internal study. Commercial pools are in the "other" end use and are not specifically addressed here.	• Proposed to reach 1.5% share of renewables in DHW by 2021 and then stabilize after that. Proposed to reach 0.75% share in existing buildings by 2021 and then stabilize, again just for DHW. • Solarwall did not pass the TRC test in the 2010 CPR, but this analysis will assume that the economics will improve such that it reaches a 1.5% share of new warehouses by 2021 and then stabilizes. • The share reached by district energy was based on an internal study of market potential done by FortisBC. The study assumed different penetrations for each rate class in four regions. If all this potential is assumed to apply to the commercial portion of each rate class (not the industrials), then the penetration by 2030 reaches 9% in the Lower Mainland and nearly 15% on Vancouver Island, with the other regions in between. Scenario B includes this same adoption curve for district energy, so we assumed penetration in 2031 would reach 9% in the Lower Mainland and 15% on Vancouver Island, with the other regions in between.	Total decrease in EUI by 2031 is approximately 11.3% for these changes.	Decrease in EUI by 2031 is approximately 14.6% compared to the original reference case based on the 2010 CPR.

Energy strategies are consistent within regions, but may be disparate among regions	This input was intended to provide context for the Scenario as a whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

2.3 INDUSTRIAL

Scenario B: Constricted supply and decentralized energy markets				
Description: Natural gas supply is constrained and new technologies are emerging rapidly to meet future energy needs. Carbon policy is not a driver in this scenario; rather, generalized environmental policies contribute to constricted natural gas supply and support renewable thermal/decentralized energy development.				
Baseline Scenario: The scenario from which Scenario B is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC industrial customers and their gas consumption in 2011. Energy intensity is not used explicitly in the industrial model, but is tracked as tertiary load (actual useful heat) relative to the level of production and efficiency (tertiary load divided by gas consumed). In the original reference case, tertiary load per unit of production is held constant for all end uses and industry sub-sectors, but efficiency improves over time. In the model developed for the 2010 CPR, efficiency improved by approximately 1% per year. There is documented support for that rate of improvement in the CPR industrial report, but it is also approximately five times the rate of improvement typically assumed in industrial studies in other jurisdictions. For now, the rate of efficiency improvement has been scaled back to 1% per 5-year milestone period, or approximately 0.2% per year. The other factor that is changing in the baseline scenario is the percentage of end uses that is supplied by natural gas, the natural gas fuel share. In the base year, this ranges from 60% to 100% for different end uses, industries and regions. In the original reference case, these fuel shares are expected to rise during the first milestone and then mainly level off. This reflects the recent increases in gas consumption in industry, because of the price advantage gas currently has compared to other fuels.				
Assumptions	**Interpretation**	**Actions Taken**	**Results for This Assumption**	**Cumulative Results**
Moderate to high gas price	Gas prices in this scenario follow the same projected rate of increase that was used to develop the original	• The effects of this change in gas cost are combined with the effects of increased carbon price, below.	See below.	No change from the original reference case based on the 2010 CPR.

	reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.) In Scenario B, gas commodity prices rise to bring the cost with delivery to $12.03/GJ before carbon price.			See below.
Moderate carbon price	B.C.'s carbon price is $30/tonne, which works out to 5.7 cents/m^3 or $1.48/GJ out of a total price of about $7.10/GJ It is proposed to gradually increase this to $60/tonne, bringing the total price of gas to about $15.03/GJ. The price increase, including the change in both commodity and carbon price, would be approximately 11%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.5. Thus, a 11% increase in gas price would tend to decrease industrial consumption by approximately 5.5% over the long term.[9] FortisBC industrial customer data shows that some large customers are able to switch fuels very readily, so that total industrial consumption can swing as much as 7 PJ from one year to the next due to gas pricing.	• The price rise in this scenario is assumed to drive several large plants to switch from natural gas to other fuels in the first milestone period. The fuel switch is assumed to persist through the forecast period. Other plants, with less fuel mobility, are assumed to switch more gradually through the forecast period.	Total decrease in gas consumption in 2016 is approximately 11%. By 2031 the decrease in gas consumption is 14.4% relative to the original reference case.	Decrease in total consumption by 2031 is approximately 14.4% compared to the original reference case based on the 2010 CPR.

[9] Residential price elasticity data is from http://www.nrel.gov/docs/fy06osti/39512.pdf , although http://www.eia.gov/oiaf/analysispaper/elasticity/pdf/tbl.pdf suggests that the long term price elasticity is higher. Additional information on price elasticity can be found at http://www.sustainableprosperity.ca/dl843&display

Moderate to strong economic growth	Economic growth would directly increase industrial production growth, though not in every sector. For example, growth in industries that provide building materials follow construction trends. Export industries will tend to experience higher levels of production increase, due to economic growth.	• The industrial sector's response to economic growth can be incorporated either as an increased rate of account growth or as an increase in tertiary load (effectively production per account). • In Scenario B, tertiary load is increased by 0.5% annually from the levels in the original reference case. This increase is applied across the board, to all end uses in all industries in all regions, but only after the initial 2016 decrease described above.	Total increase in gas consumption by 2031 is approximately 6.6% for these changes.	Decrease in total consumption by 2031 is approximately 7.8% compared to the original reference case based on the 2010 CPR.
Policy focused on environmental impacts, not carbon reduction	In the industrial sector this results in movement towards renewable thermals but not specifically gas to electric forms of fuel switching. Specifically, efficiency measures are prioritized according to normal business priorities faced by industrial plants. Policy impacts are limited to encouraging renewable alternatives to natural gas.	• For Scenario B, we are assuming no acceleration of the adoption of industrial efficiency improvements, compared to the original reference case.	No change.	No change.
Strongest market penetration for renewable thermal technologies, compared to	There are not likely to be many opportunities to switch from natural gas towards renewable supply or district energy, outside of the use of wood waste, which is captured in the reference case. Solar thermal energy could be used to offset some space	• Proposed to reach 0.75% share of renewables in water heating in newly built plant capacity by 2021 and then stabilize after that. Proposed to reach 0.5% share in existing plants by 2021 and then stabilize, again just for water heating.	Total decrease in gas consumption by 2031 is approximately 0.1% for these changes.	Decrease in total consumption by 2031 is approximately 7.9% compared to the original reference case based on the 2010 CPR.

other scenarios	heating and water heating, however.	• Solarwall did not pass the TRC test in the 2010 CPR, but this analysis will assume that the economics will improve such that it reaches a 0.75% share of new plant capacity by 2021 and then stabilizes. In existing plants it reaches a share of 0.5% by 2021 and then stabilizes.		
Energy strategies are consistent within regions, but may be disparate among regions	This input was intended to provide context for the scenario as a whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

3. Explanation of Scenario C

Scenario C is one of four scenarios intended to bound the possible business environments in which the FEU will operate over the next 20 years. Each scenario is constructed by making incremental changes to an original reference case that is based primarily on data developed for the 2010 Conservation Potential Review. Scenario C explanations for each of the residential, commercial and industrial sectors follow below.

3.1 RESIDENTIAL

Scenario C: Abundant supply and centralized energy markets
Description: Natural gas supply is abundant due to shale gas developments while new technologies are slow to advance and the energy market remains centralized, leaving natural gas as an important means to meet long term energy needs.

Baseline Scenario: The scenario from which Scenario A is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC residential customers and their average usage per customer (UPC) in 2011. Including expected changes in natural gas usage over the forecast period, the average residential UPC in the original reference case shows a decline of approximately 1% per year.

Assumptions	Interpretation	Actions Taken	Results for This Assumption	Cumulative Results
Low gas price	Gas prices in this scenario will be lower than the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.) In Scenario C, gas commodity prices decline to bring the cost with delivery to $6.14/GJ before carbon price. Since there is no assumed change in carbon price for this scenario (see below), the total gas price is assumed to be $7.64/GJ in 2029, a decrease of 43%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.2. Thus, a 43% decrease in gas price would tend to increase residential consumption by 9% over the long term.	• The proportion of new customers choosing to heat with fuels other than gas was decreased for all regions and all house types, to result in a 9% increase in the overall growth in gas-heated dwellings by 2031. The total number of accounts would not be different – just the proportion installing furnaces and boilers. • By 2031, 9% of existing dwellings with a ducted non-gas heating system requiring replacement are assumed to switch to gas, at natural rate of system replacement. Based on the 2008 REUS, approximately half of electric heating systems are ducted, so the above 9% is reduced by half. • By 2031, 9% of eligible existing dwellings requiring a replacement electric DHW tank are assumed to switch to gas-heated tanks, at natural rate of DHW replacement. Eligibility is reduced by 25% due to possible ducting issues. These three fuel choice adjustments are introduced gradually, as the commodity	Total increase in UPC by 2031 is approximately 1.2% for these three changes.	Increase in UPC by 2031 is approximately 1.2% compared to the original reference case based on the 2010 CPR.

		and carbon prices gradually change. They produce a total change somewhat smaller than the result suggested by price elasticity, so there may be some additional reduction from the price change. In reality the carbon price may produce a mixture of fuel choice changes and efficiency improvements. For reasons of clarity, we have kept the efficiency changes separate, as a response to carbon reduction policy, below.		
Low Carbon Price	B.C.'s carbon price is \$30/tonne, which works out to 5.7 cents/m^3 or \$1.48/GJ out of a total price of about \$9.75/GJ.[10] It is proposed to be maintained at \$30/tonne, in Scenario C.	• None.	No change.	No change.
Moderate economic growth	Economic growth would pull population increases in its wake, with a lag of a year or two. (Effects on commercial floor space growth and industrial production would be more direct.) Decision was to make no change in housing starts or housing types.	• None. Strong economic growth is considered an aspect of the planning environment that is needed for the policy and technological changes envisioned as part of this scenario.	No change.	No change.

[10] Rate 1, including taxes but not fixed daily charges.

Policy focused on economic growth	In the residential sector, there is no specific driver moving people away from using natural gas. Rather, there is some fuel switching to natural gas and many efficiency measures are delayed.	*EX: Move out dates for equipment/appliance replacement; Move out dates for policies (EGH80, DHW regs, etc)* • Furnaces are assumed to remain at the 90% efficiency level assumed in the original reference case based on the 2010 CPR. • Overall effect of envelope renovations remains the same as the 2010 CPR. • Adoption of EGH 80 housing in new construction is delayed until 2025 • New DHW units, both replacement (at natural rate) and new construction, are assumed to be the same efficiency as assumed in the original reference case.	These changes result in modest increases in UPC in the early part of the forecast period, but no net change by 2031 compared to the original reference case.	Overall increase in UPC by 2031 is 1.2% compared to the original reference case based on the 2010 CPR.
Less market penetration for renewable thermal technologies, compared to other scenarios	There will be limited fuel switching from natural gas towards renewable supply and district energy. Renewable energy is assumed to displace both natural gas and other fuels such as electricity. It is assumed to displace them in approximately the ratio of their initial shares of the end use.	• Proposed to reach 0.15% share of renewables in space heating, DHW and pools by 2021 and then stabilize after that. Proposed to reach 0.05% share in existing dwellings by 2021 and then stabilize, for the same end uses. • The share reached by district energy was based on an internal study of market potential done by FortisBC. The study assumed negligible penetration of the residential market before 2021. By 2030 a penetration of up to 0.37% (displacing natural gas) was estimated to be technically	These changes result in a total UPC decrease (compared to the assumptions in the original reference case) of approximately 0.1% by 2031.	Overall increase in UPC by 2031 is 1.1% compared to the original reference case based on the 2010 CPR.

		possible. Scenario C includes 0.10% adoption curve for district energy.		
Disparate energy strategies among regions and all levels of government	This input was intended to provide context for the Scenario C as whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

3.2 COMMERCIAL

Scenario C: Abundant supply and centralized energy markets				
Description: Natural gas supply is abundant due to shale gas developments while new technologies are slow to advance and the energy market remains centralized, leaving natural gas as an important means to meet long term energy needs.				
Baseline Scenario: The scenario from which Scenario C is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC commercial customers and their gas consumption in 2011. Energy intensity in the commercial model is expressed as energy utilization intensity (EUI), in MJ of natural gas per m^2 of floor area. Including expected changes in natural gas usage over the forecast period, the average residential EUI in the original reference case shows a decline of approximately 0.3% per year.				
Assumptions	**Interpretation**	**Actions Taken**	**Results for This Assumption**	**Cumulative Results**
Low gas price	Gas prices in this scenario will be lower than the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.) In Scenario C, gas	• The proportion of new building choosing non-gas heating decreases for all regions and all building types, to result in a 22% increase in the overall growth in gas-heated buildings by 2031. The total number of accounts would not be different – just the proportion installing gas heat.	Total increase in EUI by 2031 is approximately 8.8% for these changes.	Increase in EUI by 2031 is approximately 8.8% compared to the original reference case based on the 2010 CPR.

	commodity prices decline to bring the cost with delivery to $6.14/GJ before carbon price. Since there is no assumed change in carbon price for this scenario (see below), the total gas price is assumed to be $7.64/GJ in 2029, a decrease of 43%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.5. Thus, a 43% decrease in gas price would tend to increase commercial consumption by 22% over the long term.	• The percentage of existing commercial buildings with roof-top HVAC systems is roughly 30%, with approximately another 10% heated by forced air furnaces. By 2031, the rate at which these buildings are assumed to switch to gas from electricity, at natural rate of RTU/furnace replacement, will have reached 22%. • Approximately 40% of existing buildings heat SWH with a gas-fired hot-water tank. By 2031, the rate at which the buildings with electric tanks are assumed to switch to gas tanks, at natural rate of DHW replacement, will have reached 22%. • Existing buildings with electric boilers for space heating and/or DHW can also change fuels when they replace equipment, particularly if the cost of electricity greatly exceeds the cost of providing the same service with gas. These fuel choice adjustments, with 22% changes in each case, are introduced gradually, as the commodity and carbon prices gradually change. They produce a change in EUI of approximately 8.8% in 20 years, somewhat less than price elasticity would predict. In reality the carbon price may produce a mixture of fuel choice changes and efficiency improvements. For reasons of clarity, we have kept the efficiency changes separate, as a response to carbon reduction policy, below.		
Moderate carbon price	B.C.'s carbon price is $30/tonne, which works out to 5.7 cents/m^3 or $1.48/GJ out of a total price of	• None.	No change.	No change.

	about $9.75/GJ.[11] It is proposed to be maintained at $30/tonne, in Scenario C.			
Moderate economic growth	Economic growth would directly increase commercial floor space growth, though not in every sector. Growth in segments like schools follow population trends, so should not be changed if the residential sector growth was not changed. Growth in segments like restaurants would be faster in a time of high economic growth.	• No change to commercial floor space in response to economic growth assumptions is included in the model.	No change.	No change.
Policy focused on economic growth rather than environmental growth	In the commercial sector this results in movement towards increased natural gas use.	• Condensing boilers are assumed to be adopted at a rate 13% lower than the current rate, when boilers are replaced at the end of their normal life. • Overall effect of envelope renovations is decreased by 5% (either a lower rate of glazing and insulation/sealing projects or less improvement within projects). • Construction of new buildings built at the LEED gold level drops to below 3% of new buildings. • Condensing DHW boilers and tanks, both replacement (at natural rate) and new construction, are assumed to be adopted at 1.6% lower rate than the current rate.	Total increase in EUI by 2031 is approximately 1.3% for these changes.	Increase in EUI by 2031 is approximately -10.1% compared to the original reference case based on the 2010 CPR.

[11] Rate 1, including taxes but not fixed daily charges.

		These suggested slowed rates of improvement are based on -25% of the participation rates used in the Most Likely Achievable Potential scenario developed during the 2010 CPR.		
Less renewable thermals compared to other scenarios	There is a minor amount of fuel switching in this scenario. Renewable energy is assumed to displace both natural gas and other fuels such as electricity, but in commercial would mostly target DHW. It is assumed to displace them in approximately the ratio of their initial shares of the end use. District energy is assumed to target both space heating and DHW at the rates indicated in FortisBC's internal study. Commercial pools are in the "other" end use and are not specifically addressed here.	• Proposed to reach 0.15% share of renewables in DHW by 2021 and then stabilize after that. Proposed to reach 0.08% share in existing buildings by 2021 and then stabilize, again just for DHW. • Solarwall did not pass the TRC test in the 2010 CPR, but this analysis will assume that the economics will improve such that it reaches a 0.15% share of new warehouses by 2021 and then stabilizes. • The share reached by district energy was based on an internal study of market potential done by FortisBC. The study assumed different penetrations for each rate class in four regions. If all this potential is assumed to apply to the commercial portion of each rate class (not the industrials), then the penetration by 2030 reaches 9% in the Lower Mainland and nearly 15% on Vancouver Island, with the other regions in between. Scenario C includes a much less aggressive adoption curve for district energy, so we assumed penetration in 2031 would reach 1% in the Lower Mainland and 1.5% on Vancouver Island, with the other regions in between.	Total decrease in EUI by 2031 is approximately 0.5% for these changes.	Increase in EUI by 2031 is approximately 9.6% compared to the original reference case based on the 2010 CPR.
Energy strategies are consistent within regions,	This input was intended to provide context for the Scenario as a whole and was not intended	• None.	No change.	No change.

but may be disparate among regions	to be modeled as a specific variable.			

3.3 INDUSTRIAL

Scenario C: Abundant supply and centralized energy markets
Description: Natural gas supply is abundant due to shale gas developments while new technologies are slow to advance and the energy market remains centralized, leaving natural gas as an important means to meet long term energy needs.
Baseline Scenario: The scenario from which Scenario C is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC industrial customers and their gas consumption in 2011. Energy intensity is not used explicitly in the industrial model, but is tracked as tertiary load (actual useful heat) relative to the level of production and efficiency (tertiary load divided by gas consumed). In the original reference case, tertiary load per unit of production is held constant for all end uses and industry sub-sectors, but efficiency improves over time. In the model developed for the 2010 CPR, efficiency improved by approximately 1% per year. There is documented support for that rate of improvement in the CPR industrial report, but it is also approximately five times the rate of improvement typically assumed in industrial studies in other jurisdictions. For now, the rate of efficiency improvement has been scaled back to 1% per 5-year milestone period, or approximately 0.2% per year. The other factor that is changing in the baseline scenario is the percentage of end uses that is supplied by natural gas, the natural gas fuel share. In the base year, this ranges from 60% to 100% for different end uses, industries and regions. In the original reference case, these fuel shares are expected to rise during the first milestone and then mainly level off. This reflects the recent increases in gas consumption in industry, because of the price advantage gas currently has compared to other fuels.

Assumptions	Interpretation	Actions Taken	Results for This Assumption	Cumulative Results
Low gas price	Gas prices in this scenario follow the same projected rate of increase that was used to develop the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029.	• The natural gas fuel share in industry is proposed to increase by approximately 22% for both heating and process loads, with the exception of end uses that are exclusively natural gas using. • In cases where the fuel share is	Total increase in gas consumption by 2031 is 4.9% for these changes.	Increase in total consumption by 2031 is 4.9% compared to the original reference case based on the 2010 CPR.

	(Prices in the model vary by region.) In Scenario C, gas commodity prices decline to bring the cost with delivery to \$6.14/GJ before carbon price. Since there is no assumed change in carbon price for this scenario (see below), the total gas price is assumed to be \$7.64/GJ in 2029, a decrease of 43%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.5. Thus, a 43% decrease in gas price would tend to increase industrial consumption by 22% over the long term.	already approaching 100% in the model, the increase is limited to 22% of the non-gas fuel share that remains to be captured. Hence, the increase in consumption is, in most cases, much smaller than 22%. • FortisBC data on industrial demand indicates that low gas prices can prompt relatively large movements in consumption for a few large customers. In addition to the modest change in consumption that results from 22% of the remaining non-gas fuel share for some end uses, this scenario enlarges on this change by adding tertiary load – in effect, plants are assumed to add to their capacity to use gas in their production.		
Moderate carbon price	B.C.'s carbon price is \$30/tonne, which works out to 5.7 cents/m^3 or \$1.48/GJ out of a total price of about \$9.75/GJ.[12] It is proposed to be maintained at \$30/tonne, in Scenario C.	• None.	No change.	No change.
Moderate economic growth	Economic growth would directly increase industrial production growth, though not in every sector. For example, growth in industries that provide building materials follow construction trends. Export industries will tend to experience higher levels	• The industrial sector's response to economic growth can be incorporated either as an increased rate of account growth or as an increase in tertiary load (effectively production per account).	Total increase in gas consumption by 2031 is approximately 5.4% for these changes.	Increase in total consumption by 2031 is 10.3% compared to the original reference case based on the 2010 CPR.

[12] Rate 1, including taxes but not fixed daily charges.

	of production increase, due to economic growth.	• In Scenario C, tertiary load is increased by 0.25% annually from the levels in the original reference case. This increase is applied across the board, to all end uses in all industries in all regions.		
Policy focused on economic growth rather than environmental growth	In the industrial sector this results in movement towards increased natural gas use.	• In the 2010 CPR, the Most Likely achievable scenario developed participation assumptions for a range of industrial measures. Overall, it was assumed that 35% of the equipment that is naturally being replaced would be replaced with a higher-efficiency option, with the exclusion of upgrades to pulp kilns, cement kilns, ore and coal dryers. Most measures were had participation rates in that range, though they went as high as about double that for condensing boilers. This would represent a 40% increase in activity relative to the rate implied by the CPR's 1% annual efficiency improvement. Relative to the lower efficiency rate assumed in this forecast's original reference case, a 35% replacement rate would represent a seven-fold increase in activity level. • For Scenario C, we are assuming that the rate at which equipment is improved when replaced would slow down, so more equipment was replaced by the same efficiency. The replacement activity level from the original reference	Total increase in gas consumption by 2031 is approximately 1.5% for these changes.	Increase in total consumption by 2031 is 11.8% compared to the original reference case based on the 2010 CPR.

		case would be decreased by a factor of about 3. These suggested slowed rates of improvement are based on -25% of the participation rates used in the Most Likely Achievable Potential scenario developed during the 2010 CPR.		
Less renewable thermals compared to other scenarios	There are not likely to be many opportunities to switch from natural gas towards renewable supply or district energy, outside of the use of wood waste, which is captured in the reference case.	• None.	No change.	No change.
Energy strategies are consistent within regions, but may be disparate among regions	This input was intended to provide context for the scenario as a whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

4. Explanation of Scenario D

Scenario D is one of four scenarios intended to bound the possible business environments in which the FEU will operate over the next 20 years. Each scenario is constructed by making incremental changes to an original reference case that is based primarily on data developed for the 2010 Conservation Potential Review. Scenario D explanations for each of the residential, commercial and industrial sectors follow below.

4.1 RESIDENTIAL

Scenario D: Constricted supply and decentralized energy markets				
Description: Natural gas supply is constricted and a slower economy minimizes technological development and decentralization, limiting the energy alternatives available to meet consumers' long term needs.				
Baseline Scenario: The scenario from which Scenario A is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC residential customers and their average usage per customer (UPC) in 2011. Including expected changes in natural gas usage over the forecast period, the average residential UPC in the original reference case shows a decline of approximately 1% per year.				
Assumptions	**Interpretation**	**Actions Taken**	**Results for This Assumption**	**Cumulative Results**
Moderate gas price	Gas prices in this scenario are higher than the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.) In Scenario D, gas commodity prices rise to bring the cost with delivery to $10.04/GJ before carbon price.	• The effects of this change in gas cost are combined with the effects of increased carbon price, below.	See below.	No change from the original reference case based on the 2010 CPR. See below.
Moderate Carbon Price	B.C.'s carbon price is $30/tonne, which works out to 5.7 cents/m^3 or $1.48/GJ out of a total price of about $9.75/GJ.[13] It is proposed to	• The proportion of new customers choosing to heat with fuels other than gas was decreased for all regions and all house types, to result	Total increase in UPC by 2031 is approximately 0.3% for these three changes.	Increase in UPC by 2031 is approximately 0.3% compared to the original

[13] Rate 1, including taxes but not fixed daily charges.

	increase to $45/tonne, in Scenario D, bringing the total price of gas to about $12.29/GJ. The price decrease, including the change in both commodity and carbon price, would be approximately 9%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.2. Thus, an 9% decrease in gas price would tend to increase residential consumption by approximately 2% over the long term	in a 2% increase in the overall growth in gas-heated dwellings by 2031. The total number of accounts would not be different – just the proportion installing furnaces and boilers. • By 2031, 2% of existing dwellings with a ducted non-gas heating system requiring replacement are assumed to switch to gas, at natural rate of system replacement. Based on the 2008 REUS, approximately half of electric heating systems are ducted, so the above 2% is reduced by half. • By 2031, 2% of eligible existing dwellings requiring a replacement electric DHW tank are assumed to switch to gas-heated tanks, at natural rate of DHW replacement. Eligibility is reduced by 25% due to possible ducting issues. These three fuel choice adjustments are introduced gradually, as the commodity and carbon prices gradually change. They produce a total change somewhat smaller than the result suggested by price elasticity, so there may be some additional reduction from the price change. In reality the carbon price may produce a mixture of fuel choice changes and efficiency improvements. For reasons of clarity, we have kept the efficiency changes separate, as a response to carbon reduction policy, below.For reasons of clarity, we have kept the efficiency changes separate, as		reference case based on the 2010 CPR.

		a response to carbon reduction policy, below.		
Slow economic growth	Economic growth would pull population increases in its wake, with a lag of a year or two. (Effects on commercial floor space growth and industrial production would be more direct.) Decision was to make no change in housing starts or housing types.	• None. Strong economic growth is considered an aspect of the planning environment that is needed for the policy and technological changes envisioned as part of this scenario.	No change.	No change.
Policy focused on economic growth with some advancement of carbon regulations	In the residential sector, the high price and limited development of decentralized energy systems results in a prioritization of energy efficiency. Specifically, adoption of the EGH 80 homes would be accelerated, more people would undertake more envelope improvement measures, and more people would improve the efficiency of their furnaces and DHW.	• Furnaces are assumed to improve to an average of 95% efficiency instead of the 90% efficiency assumed in the original reference case based on the 2010 CPR. • Overall effect of envelope renovations is increased by 60% (either an average reno results in 3.2% reduction in space heating versus the current 2%, or else rate of renos increases). • Adoption of EGH 80 housing in new construction begins in 2013. • 50% of new DHW units, both replacement (at natural rate) and new construction, are assumed to be EF 0.8. (This is relative to nearly 20% of DHW that are either tankless or condensing in post-2005 houses.)	These changes result in a total UPC reduction of approximately 4.2% by 2031.	Overall decrease in UPC by 2031 is 3.9% compared to the original reference case based on the 2010 CPR.

Slower market penetration for renewable thermal technologies, compared to other scenarios	There will be a limited increase in fuel switching from natural gas towards renewable supply and district energy as natural gas prices are high. Renewable energy is assumed to displace both natural gas and other fuels such as electricity. It is assumed to displace them in approximately the ratio of their initial shares of the end use.	• Proposed to reach 0.25% share of renewables in space heating, DHW and pools by 2021 and then stabilize after that. Proposed to reach 0.10% share in existing dwellings by 2021 and then stabilize, for the same end uses. • The share reached by district energy was based on an internal study of market potential done by FortisBC. The study assumed negligible penetration of the residential market before 2021. By 2030 a penetration of up to 0.37% (displacing natural gas) was estimated to be technically possible. Scenario D includes 0.20% adoption curve for district energy.	These two changes result in a further 0.3 decrease in UPC by 2031.	Overall decrease in UPC by 2031 is 4.2% compared to the original reference case based on the 2010 CPR.
Disparate energy strategies among regions and all levels of government	This input was intended to provide context for the Scenario D as whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

4.2 COMMERCIAL

Scenario D: Constricted supply and decentralized energy markets
Description: Natural gas supply is constricted and a slower economy minimizes technological development and decentralization, limiting the energy alternatives available to meet consumers' long term needs.
Baseline Scenario: The scenario from which Scenario D is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC commercial customers and their gas consumption in 2011. Energy intensity in the commercial

model is expressed as energy utilization intensity (EUI), in MJ of natural gas per m^2 of floor area. Including expected changes in natural gas usage over the forecast period, the average residential EUI in the original reference case shows a decline of approximately 0.3% per year.				
Assumptions	**Interpretation**	**Actions Taken**	**Results for This Assumption**	**Cumulative Results**
Moderate gas price	Gas prices in this scenario are higher than the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from \$7/GJ in 2011 to approximately \$13.50/GJ in 2029. (Prices in the model vary by region.) In Scenario D, gas commodity prices rise to bring the cost with delivery to \$10.04/GJ before carbon price.	• The effects of this change in gas cost are combined with the effects of increased carbon price, below.	See below.	No change from the original reference case based on the 2010 CPR. See below.
Moderate Carbon Price	B.C.'s carbon price is \$30/tonne, which works out to 5.7 cents/m^3 or \$1.48/GJ out of a total price of about \$9.75/GJ.[14] It is proposed to increase to \$45/tonne, in Scenario D, bringing the total price of gas to about \$12.29/GJ. The price decrease, including the change in both commodity and carbon price, would be approximately 9%. Literature on price elasticity is limited, but does suggest that	• The proportion of new building choosing non-gas heating decreases for all regions and all building types, to result in a 4.5% increase in the overall growth in gas-heated buildings by 2031. The total number of accounts would not be different – just the proportion installing gas heat. • The percentage of existing commercial buildings with roof-top HVAC systems is roughly 30%, with approximately another 10% heated by forced air furnaces. By 2031, the rate at which these buildings are assumed to switch to gas from	Total increase in EUI by 2031 is approximately 2.3% for these changes.	Increase in EUI by 2031 is approximately 2.3% compared to the original reference case based on the 2010 CPR.

[14] Rate 1, including taxes but not fixed daily charges.

	values are low, e.g., perhaps -0.5. Thus, a 9% decrease in gas price would tend to increase commercial consumption by approximately 4½% over the long term.[15]	electricity, at natural rate of RTU/furnace replacement, will have reached 4.5%. • Approximately 40% of existing buildings heat SWH with a gas-fired hot-water tank. By 2031, the rate at which the buildings with electric tanks are assumed to switch to gas tanks, at natural rate of DHW replacement, will have reached 4.5%. • Existing buildings with electric boilers for space heating and/or DHW can also change fuels when they replace equipment, particularly if the cost of electricity greatly exceeds the cost of providing the same service with gas. These fuel choice adjustments, with 4.5% changes in each case, are introduced gradually, as the commodity and carbon prices gradually change. They produce a change in EUI of approximately 7.2% in 20 years, somewhat less than price elasticity would predict. In reality the carbon price may produce a mixture of fuel choice changes and efficiency improvements. For reasons of clarity, we have kept the efficiency changes separate, as a response to carbon reduction policy, below.		
Slow economic growth	Slow economic growth would limit the increase in commercial floor space growth, though not in every sector. Growth in segments like schools follow population trends, so should not be changed if the	• No change to commercial floor space in response to economic growth assumptions is included in the model.	No change.	No change.

[15] Residential price elasticity data is from http://www.nrel.gov/docs/fy06osti/39512.pdf , although http://www.eia.gov/oiaf/analysispaper/elasticity/pdf/tbl.pdf suggests that the long term price elasticity is higher. Additional information on price elasticity can be found at http://www.sustainableprosperity.ca/dl843&display

	residential sector growth was not changed. Growth in segments like restaurants would be slower in a time of poor economic growth.			
Policy focused on economic growth with some advancement of carbon regulations	In the commercial sector, the high price and limited development of decentralized energy systems results in a prioritization of energy efficiency.	• Condensing boilers are assumed to be adopted at a rate 26% higher than the current rate, when boilers are replaced at the end of their normal life. • Overall effect of envelope renovations is increased by 10% (either a higher rate of glazing and insulation/sealing projects or greater improvement within projects). • Construction of new buildings built at the LEED gold level more than triples to approximately 11% of new buildings. • Condensing DHW boilers and tanks, both replacement (at natural rate) and new construction, are assumed to be adopted at 3% higher rate than the current rate. These suggested accelerated rates of improvement are based on 50% of the participation rates used in the Most Likely Achievable Potential scenario developed during the 2010 CPR.	Total decrease in EUI by 2031 is approximately 2.4% for these changes.	Decrease in EUI by 2031 is approximately -0.1% compared to the original reference case based on the 2010 CPR.
Low renewable thermals compared to other scenarios	There is a minor amount of fuel switching in this scenario. Renewable energy is assumed to displace both natural gas and other fuels such as electricity, but in commercial would mostly	• Proposed to reach 0.25% share of renewables in DHW by 2021 and then stabilize after that. Proposed to reach 0.1% share in existing buildings by 2021 and then stabilize, again just for DHW. • Solarwall did not pass the TRC test in the	Total decrease in EUI by 2031 is approximately 2.6% for these changes.	Decrease in EUI by 2031 is approximately 2.7% compared to the original reference case based on the

	target DHW. It is assumed to displace them in approximately the ratio of their initial shares of the end use. District energy is assumed to target both space heating and DHW at the rates indicated in FortisBC's internal study. Commercial pools are in the "other" end use and are not specifically addressed here.	2010 CPR, but this analysis will assume that the economics will improve such that it reaches a 0.25% share of new warehouses by 2021 and then stabilizes. • The share reached by district energy was based on an internal study of market potential done by FortisBC. The study assumed different penetrations for each rate class in four regions. If all this potential is assumed to apply to the commercial portion of each rate class (not the industrials), then the penetration by 2030 reaches 9% in the Lower Mainland and nearly 15% on Vancouver Island, with the other regions in between. Scenario D includes a much less aggressive adoption curve for district energy, so we assumed penetration in 2031 would reach 2.5% in the Lower Mainland and 3.75% on Vancouver Island, with the other regions in between.		2010 CPR.
Energy strategies are consistent within regions, but may be disparate among regions	This input was intended to provide context for the Scenario as a whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

4.3 INDUSTRIAL

Scenario D: Constricted supply and decentralized energy markets				
Description: Natural gas supply is constricted and a slower economy minimizes technological development and decentralization, limiting the energy alternatives available to meet consumers' long term needs.				
Baseline Scenario: The scenario from which Scenario D is developed, the original reference case from the 2010 Conservation Potential Review, was recalibrated to match the number of FortisBC industrial customers and their gas consumption in 2011. Energy intensity is not used explicitly in the industrial model, but is tracked as tertiary load (actual useful heat) relative to the level of production and efficiency (tertiary load divided by gas consumed). In the original reference case, tertiary load per unit of production is held constant for all end uses and industry sub-sectors, but efficiency improves over time. In the model developed for the 2010 CPR, efficiency improved by approximately 1% per year. There is documented support for that rate of improvement in the CPR industrial report, but it is also approximately five times the rate of improvement typically assumed in industrial studies in other jurisdictions. For now, the rate of efficiency improvement has been scaled back to 1% per 5-year milestone period, or approximately 0.2% per year. The other factor that is changing in the baseline scenario is the percentage of end uses that is supplied by natural gas, the natural gas fuel share. In the base year, this ranges from 60% to 100% for different end uses, industries and regions. In the original reference case, these fuel shares are expected to rise during the first milestone and then mainly level off. This reflects the recent increases in gas consumption in industry, because of the price advantage gas currently has compared to other fuels.				
Assumptions	**Interpretation**	**Actions Taken**	**Results for This Assumption**	**Cumulative Results**
Moderate gas price	Gas prices in this scenario follow the same projected rate of increase that was used to develop the original reference case based on the 2010 CPR. Including the carbon price, Lower Mainland gas prices were expected to rise from $7/GJ in 2011 to approximately $13.50/GJ in 2029. (Prices in the model vary by region.) In Scenario D, gas commodity prices rise to bring the cost with delivery to $10.04/GJ before carbon price.	• The effects of this change in gas cost are combined with the effects of increased carbon price, below.	See below.	No change from the original reference case based on the 2010 CPR. See below.

Moderate carbon price	B.C.'s carbon price is \$30/tonne, which works out to 5.7 cents/m^3 or \$1.48/GJ out of a total price of about \$9.75/GJ.[16] It is proposed to increase to \$45/tonne, in Scenario D, bringing the total price of gas to about \$12.29/GJ. The price decrease, including the change in both commodity and carbon price, would be approximately 9%. Literature on price elasticity is limited, but does suggest that values are low, e.g., perhaps -0.5. Thus, a 9% decrease in gas price would tend to increase industrial consumption by approximately 4½% over the long term.[17]	• The natural gas fuel share in industry is proposed to increase by approximately 4.5% for both heating and process loads, with the exception of end uses that are exclusively natural gas using. • In cases where the fuel share is already approaching 100% in the model, the increase is limited to 4.5% of the non-gas fuel share that remains to be captured. Hence, the increase in consumption is, in most cases, much smaller than 4.5%. • In the original reference case, a recent rapid rise in industrial consumption mostly associated with fuel switching in certain large plants was continued into the first milestone period. This increase has not been included in Scenario D, despite its relatively low gas prices, because Scenario D is a slow growth scenario. An adjustment to tertiary load was used to make this change.	Decrease in consumption by 2016 is about 10% and after that there is a subsequent increase in gas consumption by 2031 is approximately 0.4% in response to the price signal. Net is a decrease of 9.6%.	Decrease in total consumption by 2031 is approximately 9.6% compared to the original reference case based on the 2010 CPR.
Slow economic growth	Economic growth would directly increase industrial production growth, though not in every sector. For example, growth in industries that provide building materials follow	• The industrial sector's response to economic growth can be incorporated either as an increased rate of account growth or as an increase in tertiary load	No change.	Increase in total consumption by 2031 is 9.6% compared to the original reference case

16 Rate 1, including taxes but not fixed daily charges.
17 Residential price elasticity data is from http://www.nrel.gov/docs/fy06osti/39512.pdf , although http://www.eia.gov/oiaf/analysispaper/elasticity/pdf/tbl.pdf suggests that the long term price elasticity is higher. Additional information on price elasticity can be found at http://www.sustainableprosperity.ca/dl843&display

	construction trends. Export industries will tend to experience higher levels of production increase, due to economic growth.	(effectively production per account). • In Scenario D, tertiary load is unchanged from the original reference case, other than the change noted above.		based on the 2010 CPR.
Policy focused on economic growth with some advancement of carbon regulations	In the industrial sector, the high price and limited development of decentralized energy systems results in a prioritization of energy efficiency.	• In the 2010 CPR, the Most Likely achievable scenario developed participation assumptions for a range of industrial measures. Overall, it was assumed that 35% of the equipment that is naturally being replaced would be replaced with a higher-efficiency option, with the exclusion of upgrades to pulp kilns, cement kilns, ore and coal dryers. Most measures were had participation rates in that range, though they went as high as about double that for condensing boilers. This would represent a 40% increase in activity relative to the rate implied by the CPR's 1% annual efficiency improvement. Relative to the lower efficiency rate assumed in this forecast's original reference case, a 35% replacement rate would represent a seven-fold increase in activity level. • For Scenario D, we are assuming that approximately one-half of the above rate of replacement would occur, so the replacement activity level would be increased by a	Total decrease in gas consumption by 2031 is approximately 2.3% for these changes.	Decrease in total consumption by 2031 is 11.9% compared to the original reference case based on the 2010 CPR.

		factor of about 4.5. This assumption draws on the findings in the achievable potential chapter of the 2010 CPR.		
Low renewable thermals compared to other scenarios	There are not likely to be many opportunities to switch from natural gas towards renewable supply or district energy, outside of the use of wood waste, which is captured in the reference case.	• None.	No change.	No change.
Energy strategies are consistent within regions, but may be disparate among regions	This input was intended to provide context for the scenario as a whole and was not intended to be modeled as a specific variable.	• None.	No change.	No change.

Appendix C

DEMAND-SIDE RESOURCES

Appendix C-1

2014-2018 EEC PROGRAM DESCRIPTIONS

APPENDIX C-1 – EEC 2014-2018 PROGRAM DESCRIPTIONS

Program Area	Program Name	Description
Residential	Energy Efficient Home Performance Program	This program will promote energy-efficiency home retrofits in collaboration with utility partners as well as provincial, federal and municipal governments. In addition to incentives, initiatives include capacity building for weatherization and educational opportunities to promote the new Home Energy Rating System.
	Furnace Replacement Program	This program will target customers with functioning furnaces (standard or mid-efficiency) or boilers and, through a combination of marketing and incentives, will encourage them to replace the equipment now, rather than waiting for it to fail at some point in the future.
	EnerChoice Fireplace Program	This program will promote the purchase and installation of energy-efficient EnerChoice fireplaces. The program will emphasize consumer and dealer education about the importance of selecting natural gas fireplaces based on energy-efficient performance attributes rather than just decorative features. Program awareness and participation will be promoted through a combination of customer and dealer incentives.
	Appliance Service Program	This program will provide customer education related to the importance of regular appliance maintenance to ensure efficient operation of natural gas appliances. This program will also create opportunities for contractors to dialogue with customers about upgrading appliances to more efficient models.
	ENERGY STAR® Water Heater Program	This program promotes the replacement of standard efficiency water heaters with efficient ENERGY STAR® models. As part of a longer term market transformation strategy, the program will introduce 0.67 EF storage tank water heaters and new technologies with energy factors (EF) greater than 0.80. The new technologies include condensing and non-condensing tankless water heaters, hybrids and condensing storage tanks. The program is available to both retrofit and new construction markets. The program supports upcoming federal and provincial Efficiency Act Standards for natural gas- and propane-fired water heaters.
	Low-Flow Fixtures	This program will develop partnership opportunities that promote the installation of low-flow fixtures that reduce hot water consumption in houses, row houses and MURBS

Program Area	Program Name	Description
	New Home Program	This program will provide education and financial incentives in support of energy-efficient building practices for the Residential sector. This program supports the pending efficiency updates to the BC Building Code (2013) and also educates consumers about the benefits of purchasing energy-efficient new homes. The Companies are collaborating with the BC Hydro Power Smart New Home and FortisBC PowerSense programs. Future program design is under development, pending the outcome of Building Code efficiency upgrade announcements and the introduction of new Home Energy Rating Systems, including NRCan's EnerGuide revisions, R2000, and ENERGY STAR® for New Homes.
	New Technologies Program	This program will operate in conjunction with the Innovative Technologies Program by introducing technologies that are cost effective but with initially low market penetration. Market adoption will be increased by educating the trades and consumers about the potential of the new energy-saving technologies.
	Customer Engagement Tool for Conservation Behaviors	This program will provide customers with reports that show them their energy consumption in comparison to their neighbours. The reports will include energy saving tips and offers to reduce their energy bills. Promotional activities will include online tools and paper-based reporting.
	Financing Pilot	This program will facilitate customer access to energy-efficiency financing, both utility-funded on-bill financing and financing through third-party financial institutions. Both on-bill financing and financing through third-party financial institutions will require interest rate buy-downs and incur administration costs. In the case of on-bill financing, most promotion is anticipated to be through contractors. In the case of financial institution partnerships, most promotion will be undertaken by the financial institution. There is much that is unknown, including the measure savings and the Net-to-Gross ratio.

Program Area	Program Name	Description
Commercial	Space Heat Program	This program will provide rebates for the installation of high-efficiency space heating equipment in Commercial sector applications. This includes rebates for high-efficiency boilers currently delivered to the market via the Efficient Boiler program. Based on the results of the Condensing Gas-Fired Ventilation Unit pilot program undertaken by Innovative Technologies, rebates for condensing rooftop units are expected to be introduced to the program in 2016 or 2017. Note that condensing rooftop unit assumptions may change based on the actual results of the pilot program. Promotional activities will include print and online communications, tradeshows, and leveraging FortisBC Energy Solution Managers and Energy Specialists to increase program uptake with Commercial sector customers while also garnering program support through industry associations.
	Water Heating Program	This program provides rebates for the installation of high-efficiency commercial water heaters with thermal efficiencies greater than or equal to 84%. Promotional activities will include print and online communications, tradeshows, and leveraging FortisBC Energy Solution Managers and Energy Specialists to increase program uptake with Commercial sector customers while also garnering program support through industry associations.
	Commercial Food Service Program	This program, launched in September 2012, offers a suite of rebates for the installation of high-efficiency commercial cooking appliances. Promotional activities will include print and online communications, tradeshows, and leveraging FortisBC Energy Solution Managers and Energy Specialists to increase program uptake with Commercial sector customers while also garnering program support through industry associations.
	Customized Equipment Upgrade Program	This program provides eligible customers with funding towards the completion of a detailed energy study, aimed at identifying customized energy saving opportunities within their facilities, and subsequent capital incentive funding to encourage the implementation of any cost-effective measures identified in the study. The program will capture energy savings associated with measures that are otherwise difficult to incent as part of a prescriptive program because they are complex, and one project may include multiple measures with interactive effects. Interactive effects are situations where changes made to one energy using system may have a direct influence on the energy consumption of another system. For example, reduced lighting power may lead to an increased requirement for space heating. The required energy study must account for these effects where applicable. The expected energy savings, measures, capital cost, incentives etc., will necessarily vary depending on the customer. Each project will be submitted to a TRC test and must be approved by the utility.

Program Area	Program Name	Description
Commercial	EnerTracker Program	This 3-year pilot program is a subset of the continuous optimization (C.Op) program. It provides participants who are otherwise unable or unwilling to participate in the full C.Op program with access to an Energy Management Information System (EMIS). EMIS software provides customers with a detailed picture of their natural gas consumption in "near time". Timely access to this information is expected to speed up fault detection, thereby enabling more rapid corrective action to avoid wasted gas consumption, as well as to assist in the identification of additional potential natural gas conservation measures. Note that this pilot program slated to end December 31, 2015. If the program proves successful, it may be extended past 2015.
	Continuous Optimization Program	Hidden building operational problems can result in inefficiencies and increased natural gas consumption. The Continuous Optimization Program (C.Op.), in partnership with BC Hydro's Power Smart, is designed to help Commercial sector building owners identify and correct energy wasting operational faults and continuously monitor building performance to help maintain and improve energy efficiency, resulting in reduced operating costs. Eligible customers will receive funding towards the cost of re-commissioning services to study their building and recommend energy-efficiency improvements, as well as access to an EMIS to assist in tracking their building's performance after the re-commissioning work is complete. In return, participants must agree to implement, at their own cost, measures identified by the re-commissioning study that, when combined, will have a payback of two years or less.
	Commercial Energy Assessment Program	This program identifies inefficiencies at the participant's facilities via an on-site walkthrough assessment by an energy-efficiency consultant. The consultant then produces a report that describes the observed inefficiencies, outlines proposed solutions, and identifies any applicable incentive programs. FortisBC then forwards the report to the participant. The program for 2014-2018 reflects revisions made in 2013 to: • Provide dual-fuel energy assessments in the shared service territory; • Increase FortisBC brand permeation and emphasis on FortisBC Commercial sector programs in energy assessment reports; • Install an element of accountability to encourage a greater implementation of energy saving measures post-assessment • Diversify service providers and ensure fair market value; and • Re-evaluate program target audience(s) and ensure program offering is aligned with their needs

Program Area	Program Name	Description
	Energy Specialist Program	This program will fund energy specialist positions, whose key priority is to identify opportunities for their organization to participate in FortisBC's EEC programs. The energy specialist reports to and supports the BC Hydro-funded energy manager on holistic energy reduction projects, while also focusing on identifying opportunities to use natural gas more efficiently. Energy specialist positions are funded by FortisBC up to $60,000 for a period of one year. This program is funded as an enabling program but claims natural gas savings for those projects completed by energy specialists that are not claimed by another EEC program and are verified by a third-party engineering firm through the annual Energy Specialist Program evaluation study. No promotional activities are planned for this program other than a presence on the FortisBC web site. New participation will be solicited through direct communications utilizing existing FortisBC and BC Hydro account management channels.
	Mechanical Insulation Pilot	The Mechanical Insulation Retrofit project is expected to commence in 2013, and is designed to identify and evaluate the energy savings associated with mechanical insulation retrofits in multi-family residential buildings. The project will be a collaboration among FortisBC, building owners and managers, and consultants. Failure to comply with mechanical insulation building codes and best practices results in wasted or excess natural gas consumption. Mechanical insulation retrofits will include the following measures: heating pipes insulated with 1 ½" thick fiberglass; domestic hot water systems pipes 2" and larger will be insulated with 1 ½" thick fiberglass insulation; piping less than 2" will be insulated with 1" thick fiberglass insulation; all insulation will be covered with service jackets and PVC fitting covers; and valves for both the heat and hot water systems will be insulated with the same thickness as the adjoining pipes. An estimated 1,400,000 GJ could be saved annually by performing mechanical insulation retrofits and improving practices and standards on new multi-unit residential buildings. This pilot is planned to commence in 2013 and is projected to deliver validated measurement data by 2015. This may provide input for a potential prescriptive Commercial program to launch in 2016.
Industrial	Industrial Optimization Program	This program provides financial incentives towards identifying, assessing and implementing customized cost-effective energy-efficiency projects for industrial processes using natural gas as process heat or an energy source. Three options will be available to Industrial clients to identify saving opportunities. Two implementation programs will be available to small, medium and large Industrial customers.

Program Area	Program Name	Description
	Specialized Industrial Process Technology Program	This program provides prescriptive incentives to Industrial customers to encourage the implementation of specific technologies and best practices targeted at particular industrial processes using natural gas as process heat or an energy source.
Low Income	Energy Savings Kit	The goal of this program is to reach a broad audience of low income customers and enable them to take some simple steps towards saving energy by installing a bundle of easy-to-install items that are delivered to their door. Promotional activities will include bill inserts, print ads, direct mail, and partnerships with government ministries and non-profits that serve the low income population.
	Energy Conservation Assistance Program	This program will enable deep energy savings in low income customer facilities that have moderate to high energy consumption. Promotional activities will include bill inserts, print ads, customer endorsements, and partnerships with government ministries, housing providers, and other organizations that serve the low income populations.
	REnEW	The goal of this program is to ensure that the energy-efficiency trade in BC is built in a way that enhances communities by enriching the skills of people that are facing barriers to employment. This program provides energy-efficiency trade training by industry experts at no cost to participants.
	Low Income Space Heat Top-Ups	This program will encourage non-profit housing societies to replace standard efficiency boilers with high-efficiency boilers. The program will piggyback on the Commercial boiler program; however, it will provide an incentive that is about 30% better. Due to the fact that this program will piggyback on the Commercial space heat program, all cost, energy savings and measure life assumptions are based on the Commercial space heat program. The 30% bump to the customer incentive will come from the Low Income program budget. As such, the incremental costs shown here are only 30% of the full incremental costs, the incentive amounts reflect only the 30% bump, and the gas savings only reflect 30% of the total savings from the measure. Promotional activities will be delivered primarily through partnerships with BC Housing, BC Non-Profit Housing Association and other non-profit housing societies.

Program Area	Program Name	Description
	Low Income Water Heating Top-Ups	This program will encourage non-profit housing societies to replace standard efficiency water heaters with high-efficiency water heaters. This program will piggyback on the Commercial water heating program; however, it will provide an incentive that is about 30% better. Due to the fact that this program will piggyback on the Commercial water heating program, all costs, energy savings, and measure life assumptions are based on the Commercial water heating program. The 30% bump to the customer incentive will come from the Low Income program budget. As such, the incremental costs shown here are only 30% of the full incremental costs, the incentive amounts reflect only the 30% bump, and the gas savings only reflect 30% of the total savings from the measure. Promotional activities will be delivered primarily through partnerships with BC Housing, BC Non-Profit Housing Association and other non-profit housing societies
	Non-Profit Custom Program	This program will encourage non-profit housing societies to replace inefficient equipment and systems with high-efficiency solutions. This program will involve an energy study and will provide incentives based on the recommendations of the study. Incentives under this program will cover all of the incremental cost of the cost-effective measures. Promotional activities will include outreach to non-profit housing societies, partnerships with non-profit housing associations, and partnerships with other service organizations working within the non-profit housing sector.

Program Area	Program Name	Description
Conservation Education & Outreach	Residential Education Program	This program will provide information to Residential customers and the general public on natural gas conservation and energy literacy by seeking opportunities to engage with customers directly (either face-to-face or through online programs). This audience will also include low income and ethnic customers. Promotional activities will include print and online communications and engagement campaigns as well as educational seminars, participation in home shows and community events. The Program also includes the cost of production of materials for events and prizing for audience engagement such as 5-minute shower timers or weather stripping samples that are utilized at events targeting Residential customers and children. In addition, continuing partnerships with the regional Canadian Home Builders' Associations and local sports organizations will expand outreach opportunities to engage with Residential customers. Furthermore, FEU will continue to focus on behavioural change opportunities that may result in energy savings. Lastly, collaborations between internal departments and with other utilities will be sought to achieve cost efficiencies in the budget, particularly for advertising and for outreach events.
	Commercial Education Program	This program will provide ongoing communication and education about energy conservation initiatives as well as encouraging behavioural changes that help Commercial customers reduce their organization's energy consumption. The Commercial sector is made up of small and large businesses in a variety of sub sectors such as retail, offices, multi-family residences, schools, hospitals, hospitality services and municipal/institutions. Promotional activities will include print and online communications, event support of industry trade shows, industry association meetings, award events, and development of online tools to assist with education and engagement such as the Cut the Carbon ("C3") online community web site, which engages employees at health authorities and health organizations in carbon-cutting actions and environmental conservation. In addition, the Companies will be furthering partnerships with organizations such as Small Business of BC and Business Improvement Associations of BC, which work with small to medium-sized businesses, and working with Natural Resources Canada to deliver education workshops on natural gas equipment. Lastly, this area will also guide and support behaviour education campaigns delivered by energy specialists (or an energy manager) in their respective organizations. Collaborations between internal departments, as well as with other utilities, will be pursued to achieve cost efficiencies in the budget, in particular on advertising and outreach events.

Program Area	Program Name	Description
	School Education Program	This program responds to section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), where a public utility's plan portfolio is adequate if it includes an education program for students enrolled in [K-12] schools and post-secondary schools in the Companies' service area. Activities will include building partnerships and funding support for a variety of in-class and online programs related to conserving energy for K-12 students, delivered both internally and externally by third parties such as non-profit organizations or local sports teams. Some of these programs may include, but are not limited to: Energy is Awesome, Destination Conservation, BC Green Games, Green Bricks, Energy Champion assembly presentations, Vancouver Aquarium Aquaguide, and Beyond Recycling. Some of these programs may also include distribution of low-flow fixtures, shower timers, colouring books, and educational playing cards as part of the program. Partnerships and funding support for post-secondary programs would include in-class programs, in-residence and on-campus education campaigns.

Appendix C-2

CONSERVATION POTENTIAL REVIEW 2010
SUMMARY REPORT

Conservation Potential Review – 2010 FortisBC

Residential, Commercial and Industrial Sectors: Energy-efficiency, Alternate Energy & Customer Behaviour Opportunities (2010-2030)

Summary Report

Submitted to
FortisBC

Submitted by
ICF Marbek

In association with
Habart Associates
The Cadmus Group
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May 2011

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List of Exhibits

1 Introduction

1.1 Objectives

This Conservation Potential Review (CPR) provides FortisBC with a comprehensive planning document that the company can use on an ongoing basis to:

- Develop a long-range energy-efficiency strategy
- Design and implement energy-efficiency programs
- Assess the impact of energy-efficiency programs on both peak and annual loads
- Set annual energy-efficiency targets and budgets.
- Determine contribution energy-efficiency programs can make towards meeting greenhouse gas (GHG) reduction targets

However, it should be emphasized that this report does not aim to either set specific program targets or provide program design.

1.2 Scope

Sector Coverage: The study addresses three sectors: Residential, Commercial and Industrial. In contrast to the 2006 CPR, which excluded FortisBC's (then Terasen Gas's) 300 largest manufacturing accounts, this CPR includes all of FortisBC's customers.

Geographical Coverage: The study results are presented for the total FortisBC service region and for the five service areas of: Lower Mainland, Vancouver Island, Whistler, Northern Interior and Southern Interior.

Study Period: The Base Year for this study is calendar year 2010. The time period covered by this study is to 2030, with milestones at the intervening years of 2015, 2020 and 2025.

Technologies: The study addresses energy-efficiency, customer behaviour and alternative energy options such as renewables and combined heat and power technologies.

Relation to Previous B.C. CPRs: This study builds on the substantial body of information and modelling work prepared in previous CPR studies conducted for FortisBC (then Terasen Gas) (2006) and BC Hydro (2007). The 2006 FortisBC study was intended to mesh with the BC Hydro study from 2007 and therefore included all customers of either utility, not just FortisBC customers. This study includes only FortisBC natural gas customers because this permitted the study to make better use of the recently completed energy end-use studies.

1.2.1 *Data Caveat*

As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current penetration of energy-efficient technologies, the rate of future economic growth and customer willingness to implement new energy-efficiency measures are particularly influential. Wherever possible, the assumptions used in this study are consistent with those used by FortisBC and are based on best available information, which in many cases includes the professional judgement of the consultant team, FortisBC personnel and/or local experts. The reader should use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout the report.

1.3 Study Organization

The study has been organized into the following areas:[1]

- **Three individual sector reports** (Residential, Commercial and Industrial) that provide an assessment of the technical opportunities for more efficient use of natural gas within each sector. A summary report will bring together the findings of all three sectors.

- **A commercial end-use survey (CEUS)** that provides insight into current natural gas equipment efficiency levels, fuel share and annual consumption levels within key Commercial sub sectors. The CEUS results were used to refine the Commercial sector building archetypes employed in the assessment of technical opportunities.

- **An options paper** that outlines alternative approaches to the assessment of cost-effective levels of DSM activity outside of the California Standard Practice tests.

1.4 This Report

This report brings together the findings of the Residential, Commercial, and Industrial sectors, together with an estimate of the net job creation and other economic effects attributable to the achievable efficiency results within the three sectors. The report is organized as follows:

- **Section 2** presents a summary of the total study results, including the total Base Year, Reference Case, Economic and Achievable Potential results for the Residential, Commercial, and Industrial sectors.

- **Section 3** presents a summary of the Residential sector results for the study period 2010 to 2030.

- **Section 4** presents a summary of the Commercial sector results for the study period 2010 to 2030.

- **Section 5** presents a summary of the Industrial sector results for the study period 2010 to 2030.

- **Section 6** presents a summary of the economic impacts associated with the identified Achievable Potential savings.

[1] **Note:** A separate Customer Preferences study was prepared in parallel with this CPR. The two studies were, however, implemented in a coordinated manner and the results of the Customer Preferences study contributed to the results of this CPR.

1.5 Definitions

This study employs numerous terms that are unique to analyses such as this one and consequently it is important to ensure that all readers have a clear understanding of what each term means when applied to this study. Below is a brief description of some of the most important terms.

Base Year

The Base Year is the starting point for the analysis. It provides a detailed description of "where" and "how" energy is currently used in the existing Residential, Commercial, and Industrial sectors. Creation of the Base Year required the development of profiles of natural gas use within each sector, sub sector and service area.

Reference Case (includes Natural Conservation)

The Reference Case estimates the expected level of natural gas consumption that would occur over the study period in the absence of new demand side management (DSM) program initiatives. It provides the point of comparison for the subsequent calculation of "Economic" and "Achievable" savings potentials. Creation of the Reference Case required the development of detailed profiles for new buildings and plants in each of the sub sectors, estimation of the expected stock growth, estimation of the likely impacts of new building, appliance and equipment standards and, finally an estimation of "natural" changes affecting energy consumption over the study period.

Technology Assessment

Energy-efficiency, customer behaviour, and alternative energy options were identified that met the criteria, as outlined above, in the study's scope. Technology cost and performance data were compiled relative to the base line technology and the measure total resource cost (TRC) was calculated for each option.

Measure Total Resource Cost

The conventional measure TRC calculates the net present value of energy savings that result from an investment in an efficiency, behaviour, or alternative energy technology or measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and operating and maintenance (O&M) costs. This calculation includes, among others, the following inputs: the avoided natural gas and electricity supply costs, the life of the technology, and the selected discount rate, which in this analysis has been set at 7.38% for most of the regions and 6.87% for Vancouver Island. Societal impacts are not included in the TRC.

Economic Potential Forecasts

The Economic Potential Forecast is the level of energy consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective, from FortisBC's perspective, when using lifecycle costing with the long-run avoided cost of new natural gas supply. All the energy-efficiency, behaviour, and alternative energy options included in the technology assessment that had a positive measure TRC, which is the conventional DSM screen, were incorporated into the Economic Potential Forecast.

Two Economic Potential Forecasts were prepared 1) energy efficiency and alternative energy, and 2) behaviour.

Achievable Potential The Achievable Potential is the proportion of the savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all the energy-efficiency/alternative energy or behaviour options that meet the criteria defined by the Economic Potential Forecast. The results are presented as a range, defined as *most likely* and *aggressive*.

Estimates provided were developed in a workshop involving FortisBC energy-efficiency program personnel, trade allies, selected external experts and the consulting team.

Peak Day Load Impacts Load factors provided by FortisBC were used to derive peak day load impacts from the energy consumption values contained in each of the potential estimates noted above.

Residential Customers For the purposes of this study, residential customers are categorized under Rate 1 in most of the FortisBC service region, RGS in the Vancouver Island region, and RES SGS1/SGS2 in the Whistler region. Multi-storey apartment and strata buildings are addressed in the Commercial sector report.

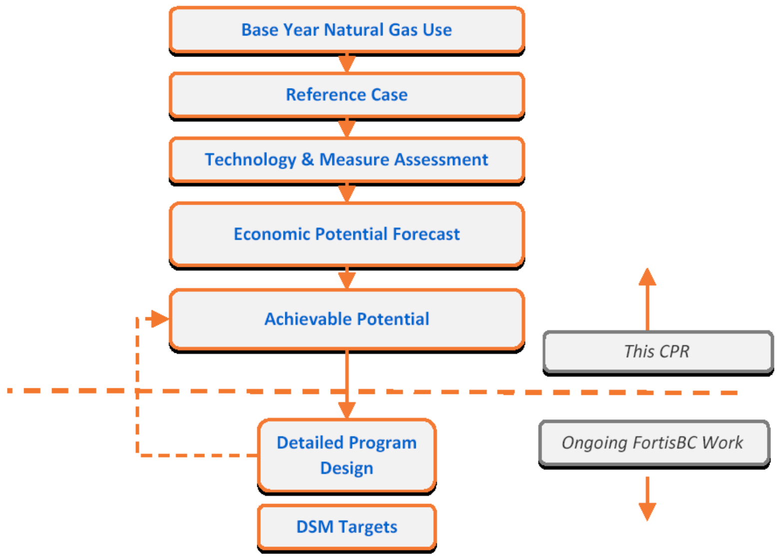
Commercial Customers For the purposes of this study, commercial customers are categorized under Rates 2, 3, 23, 22, 25, and 27 in most of the FortisBC service region. Note that this study classifies “Commercial” and “Industrial” facilities based on building/plant attributes, as represented by NAICS codes. This approach, which is consistent with CPR best practices throughout North America, is in contrast with the rate class approach employed by FortisBC. The rate-based approach tends to classify customers based on annual sales volumes. For example, light manufacturing facilities are typically included within FortisBC’s small commercial rate class; however, in this study these customers are included in the Industrial sector. Commercial customers also include multi-storey apartment and strata buildings.

Industrial Customers For the purposes of this study, industrial customers are categorized under Rates 2, 3, 5, 7, 23, 22, 25, and 27 in most of the FortisBC service region.

1.6 Overview of Approach

To meet the objectives outlined above, the study was conducted within an iterative process that involved a number of well-defined steps, as outlined in Exhibit 1. At the completion of each step, FortisBC reviewed the results and, as applicable, revisions were identified and incorporated into the interim results. The study then progressed to the next step.

Exhibit 1 Major Study Steps



A summary of these steps is presented below.

Step 1: Develop Base Year Calibration Using Actual FortisBC Sales Data

- Compile and analyze available data on British Columbia's existing building stock and plants.
- Develop detailed technical descriptions of the existing building stock and plants.
- Undertake computer simulations of energy use in each building type and compare these with actual building billing and audit data.
- Compile actual FortisBC billing data.
- Create sector model inputs and generate results.
- Calibrate sector models results using actual billing data.

Step 2: Develop Reference Case

- Compile and analyze building design, equipment and operations data, and develop detailed technical descriptions of the new building stock.
- Develop computer simulations of energy use in each new building type.
- Compile data on forecast levels of building stock growth and "natural" changes in equipment efficiency levels and/or practices.
- Define sector model inputs and create forecasts of energy use for each of the milestone years.
- Calibrate with FortisBC load forecast.

Step 3: Develop and Assess Energy-efficiency, Alternate Energy and Behaviour Measures

- Develop list of energy-efficiency, alternate energy and customer behaviour measures.
- Compile detailed cost and performance data for each measure.
- Identify the baseline technologies employed in the Reference Case.
- Compile FortisBC and BC Hydro economic data on current and forecast costs for new supply of natural gas and electricity generation.
- Determine the measure TRC for each energy-efficiency and fuel choice option.

Step 4: Estimate Economic Energy-efficiency, Alternative Energy Potential and Behaviour Measures

- Screen the identified energy-efficiency and alternative energy measures from Step 3 against the economic data.
- Identify the combinations of energy-efficiency measures and building types where the measure TRC is positive.
- Apply the economically attractive energy-efficiency measures from Step 3 within the energy-use simulation model developed previously for each building type.
- Determine annual natural gas consumption in each building and plant type when the economic efficiency measures are employed.
- Compare the consumption levels when all economic efficiency and alternate energy measures are used with the Reference Case consumption levels and calculate the natural gas consumption impacts.

Step 5: Estimate Achievable Savings Potential

- “Bundle” the energy-efficiency, alternative energy and customer behaviour options identified in the Economic Potential Forecast into a set of Actions.
- Create “Action Profiles” for each of the identified Actions that provide a high level rationale and direction, including target technologies and sub markets as well as key barriers and a broad intervention strategy.
- Review historical Achievable program results and prepare preliminary Action Assessment Worksheets.
- Consult with FortisBC personnel, review preliminary estimates and reach general agreement on *most likely* and *aggressive* range of Achievable Potential.

Step 6: Estimate Peak Day Load Impacts of Economic and Achievable Savings Potential

- Annual energy decreases/increases contained in each of the energy-efficiency/fuel choice scenarios were converted to average daily values based on annual load profile data provided by FortisBC.
- Load factors that correlate “average” to “peak” consumption were provided by FortisBC for each rate class and service area.
- Peak day load impacts were calculated for each of the energy-efficiency and fuel choice scenario results by applying the above load factors.

2 Summary of Total Study

2.1 Total Natural Gas Savings Potential

The study findings confirm the existence of significant remaining cost-effective natural gas DSM opportunities in the Residential, Commercial, and Industrial sectors within FortisBC's service area.

Exhibit 2 and Exhibit 3 summarize the total combined natural gas savings for the Residential, Commercial and Industrial sectors that have been identified in each of the individual sector technical reports. Selected highlights include:

- In the Reference Case, total natural gas consumption in the total FortisBC service area decreases from approximately 167.6 million GJ/yr. in 2010 to approximately 162.6 million GJ/yr. by 2030, a decrease of about 3%. As noted in Section 1.5, the Reference Case includes an estimation of the expected stock growth, the likely impacts of new building, appliance and equipment standards and, finally an estimation of "natural" changes affecting energy consumption over the study period.

- In the Economic Potential scenario, natural gas savings in the total FortisBC service area are approximately 17 million GJ/yr. in 2015 and increase to approximately 22.6 million GJ/yr. by 2030. The potential natural gas savings in 2030 would result in a decrease of gas consumption to approximately 140 million GJ/yr., a decrease of approximately 14%, relative to the Reference Case.

- In the *most likely* Achievable scenario, natural gas savings in the total FortisBC service area would be approximately 2.2 million GJ/yr. in 2015 and would increase to approximately 10.3 million GJ/yr. by 2030. The potential natural gas savings in 2030 would result in a decrease of gas consumption to approximately 152.4 million GJ/yr., a decrease of approximately 6%, relative to the Reference Case, and a reduction in GHG emissions of approximately 516 thousand tonnes CO_2e/yr.

- In the *aggressive* Achievable Potential scenario, natural gas savings in the total FortisBC service area would be approximately 3.6 million GJ/yr. in 2015 and would increase to approximately 15.2 million GJ/yr. by 2030. The potential natural gas savings in 2030 would result in a decrease of gas consumption to approximately 147.4 million GJ/yr., a decrease of approximately 9%, relative to the Reference Case, and a reduction in GHG emissions of approximately 764 thousand tonnes CO_2e/yr.

Exhibits 4, 5 and 6 provide additional details. Exhibit 4 shows the distribution of natural gas savings by scenario, sector and milestone year, while Exhibits 5 and 6 show the resulting impacts of those savings on FortisBC's peak day capacity requirement and the reduction of greenhouse gas (GHG) emissions.

Exhibit 2 Summary of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, 3 Sectors

Milestone Year	Annual Consumption, All 3 Sectors (1000 GJ/yr.)				Potential Annual Savings, All 3 Sectors (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Most Likely	Aggressive		Most Likely	Aggressive
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2010	167,626						
2015	159,582	142,597	157,409	155,954	16,985	2,173	3,629
2020	161,489	141,895	156,775	153,360	19,594	4,714	8,129
2025	161,995	140,350	154,611	149,958	21,644	7,383	12,037
2030	162,630	140,037	152,376	147,436	22,593	10,254	15,194

Exhibit 3 Graphic of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, 3 Sectors

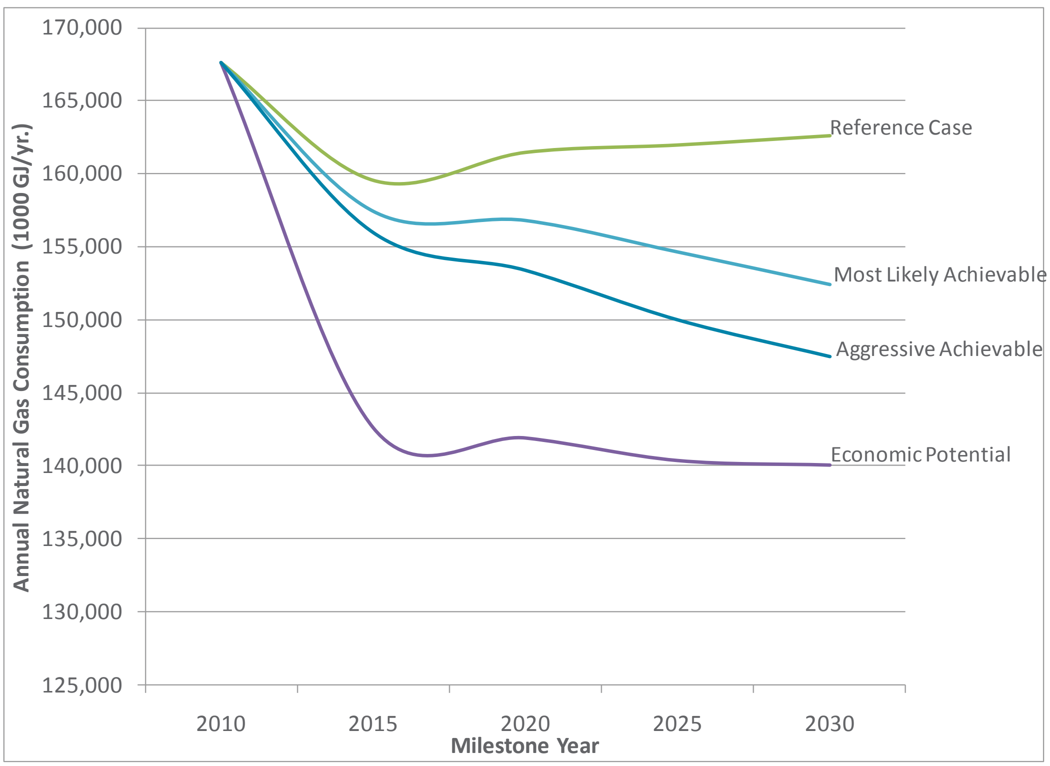


Exhibit 4 Graphic of Achievable Natural Gas Savings for the Total FortisBC Service Area by Scenario, Sector, and Milestone Year (1000 GJ/yr.), 3 Sectors

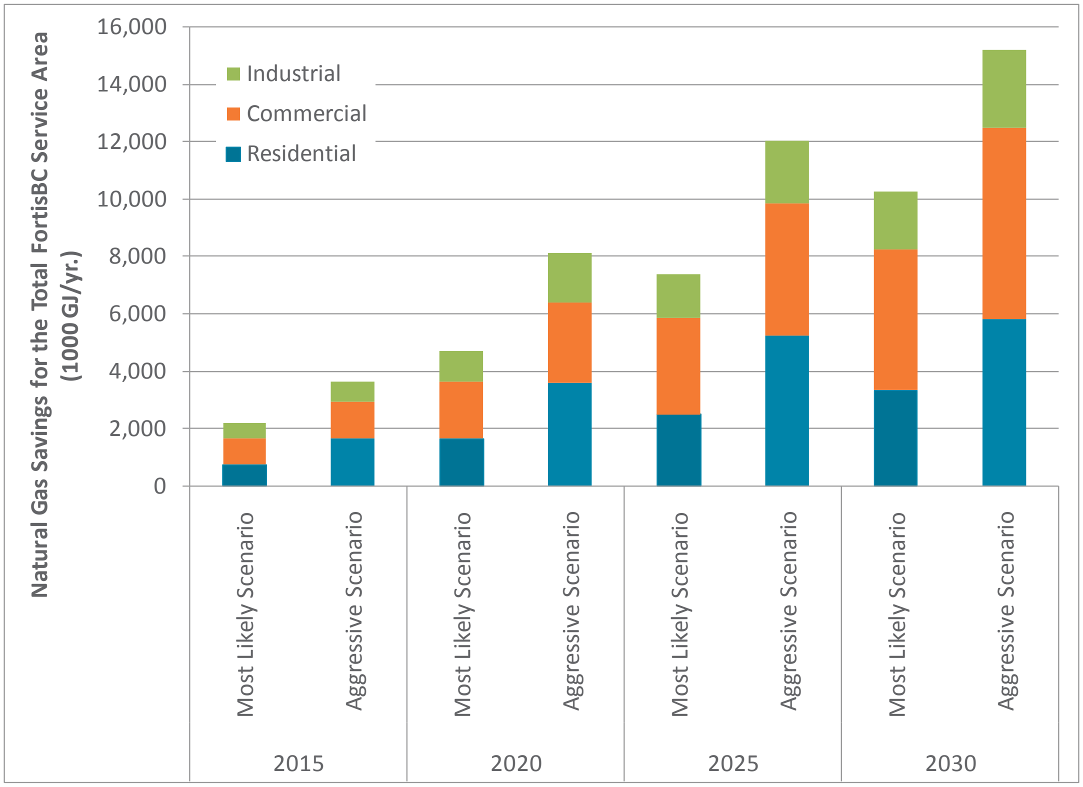


Exhibit 5 Graphic of Achievable Peak Day Capacity Impact by Scenario, Sector, and Milestone Year (GJ)

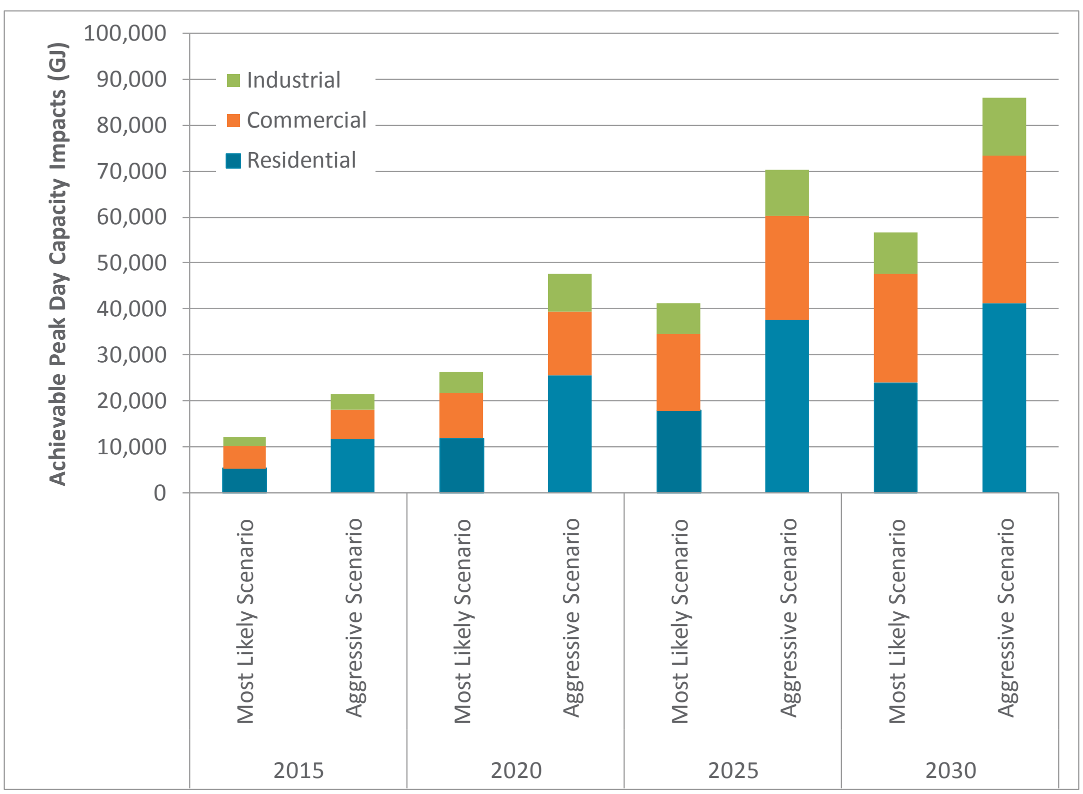
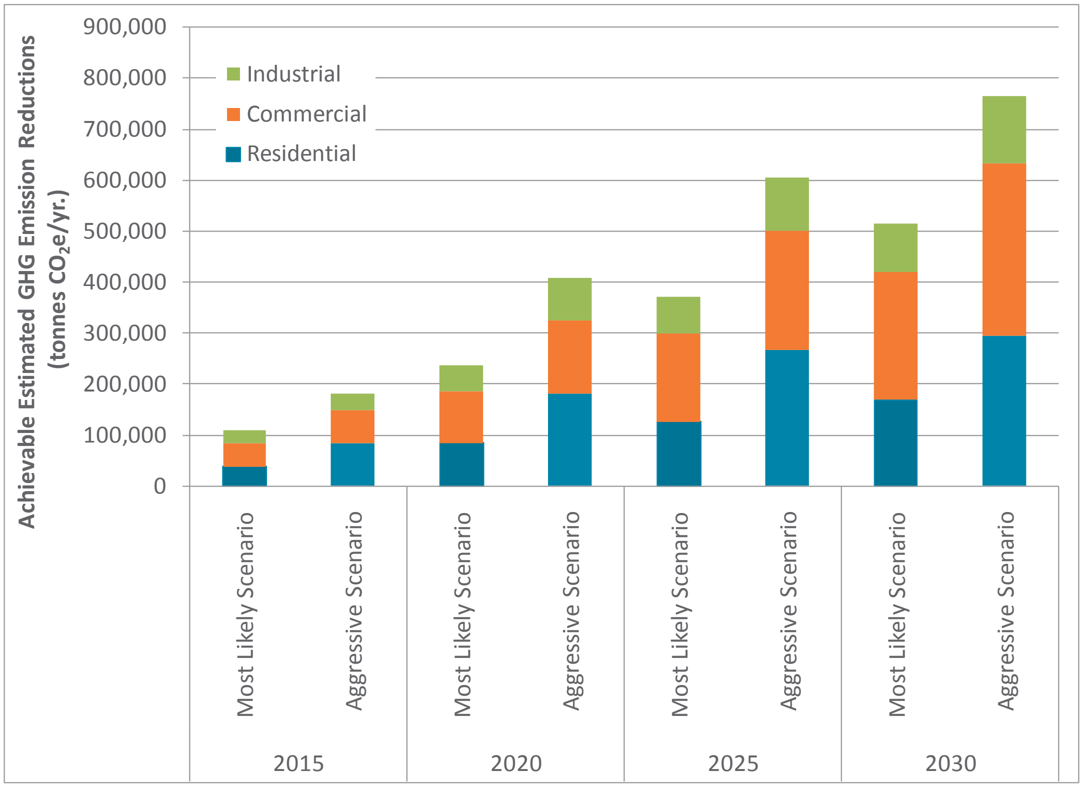


Exhibit 6 Graphic of Achievable Estimated GHG Emission Reductions by Scenario, Sector, and Milestone Year (tonnes CO_2e/yr.)



2.2 Key Observations

As was illustrated in the preceding exhibits, despite a decade of successful relatively small-scale DSM program implementation, there remains significant cost-effective DSM potential within FortisBC's service area. This remaining opportunity reflects, in part, how the continued technology cost and performance improvements have increased the availability of energy efficiency options. Key study observations are highlighted below.

Achievable Potential

Relative to the Reference Case forecast for 2030, the Achievable Potential savings range from 10.3 million GJ/yr. in the *most likely* Achievable scenario to approximately 15.2 million GJ/yr. in the *aggressive* scenario, which represent 45% and 67%, respectively, of the Economic Potential savings.

Key Technologies and Measures

In the Residential sector, space heating accounts for nearly 80% of the total energy savings. The largest contributor to these savings is the early retirement of gas furnaces, which accounts for approximately half of the total Achievable Potential savings. The remaining space heating savings are from programmable thermostats, homeowner air sealing, and improved insulation in basements, attics and walls. Fireplaces account for a further 12-13% of total energy savings; these savings are all from upgrading to more efficient fireplaces at the natural rate of replacement or new purchase.

In the Commercial sector, the most significant opportunities are actions that reduce space and water heating loads in existing buildings. Four measures account for approximately two-thirds of the savings. They are, in order of their contribution; O&M measures, advanced building automation systems, recommissioning, high-efficiency boilers, and low-flow plumbing fixtures.

In the Industrial sector, the most significant opportunities involve replacing medium size standard efficiency boilers in the food processing and manufacturing sub sectors with condensing models. For large boilers, such as in pulp mills, and for large process equipment such as cement kilns, lime kilns and coal driers, the most significant opportunities involve upgrading the equipment with better controls and heat recovery equipment. Improving the air heating efficiency of large industrial fabrication workspaces is another significant opportunity.

2.3 Additional Information

The summary of potential natural gas savings presented in this report are based on the detailed data and analysis contained in the CPR 2010 reports listed below. The reader is referred to these reports for additional information.

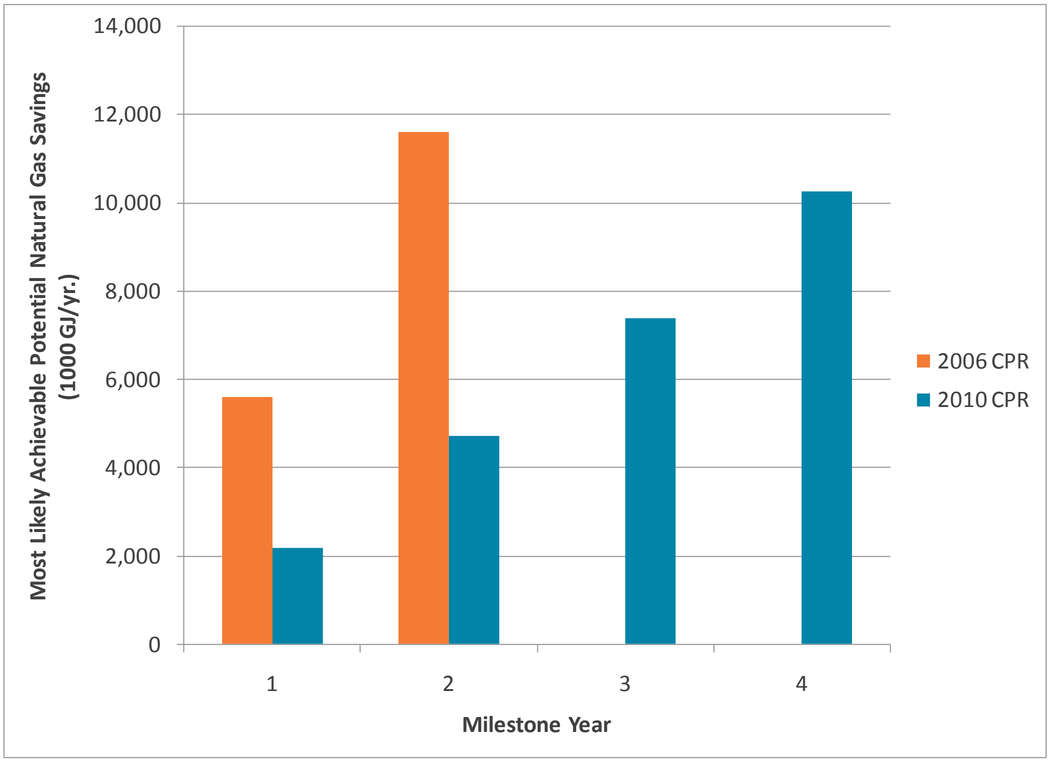
- Conservation Potential Review – 2010 FortisBC; Residential Sector Energy-efficiency, Alternative Energy and Customer Behaviour Opportunities (2010-2030).
- Conservation Potential Review – 2010 FortisBC; Commercial Sector Energy-efficiency and Alternative Energy Opportunities (2010-2030).
- Conservation Potential Review – 2010 FortisBC; Industrial Sector Energy-efficiency and Alternative Energy Opportunities (2010-2030).
- Conservation Potential Review – 2010 FortisBC; Impact of CPR 2010 Natural Gas Savings on the B.C. Economy (2010-2030).

2.3.1 Comparison of 2006 CPR Results to 2010 CPR Results

Both the 2006 and 2010 CPR results are calculated and presented at 5-year intervals, or milestone years. The milestone years in the 2006 CPR were 2011 and 2016; the milestone years in the 2010 are 2015, 2020, 2025, and 2030.

A comparison of the 2006 CPR results and the 2010 CPR results, according to milestone year is provided in Exhibit 7, overleaf.

Exhibit 7 Comparison of Annual Savings at 5-year Milestone Periods, Most Likely Achievable Potential Scenario, 2006 CPR vs 2010 CPR



The most significant contribution to the reduced level of Achievable Potential savings in the 2010 CPR relative to the 2006 CPR is the impact of energy performance standards. More specifically, the Reference Case for the 2010 CPR incorporates the expected natural gas savings from new space and water heating equipment performance standards as well as those due to new residential and commercial construction standards. These standards, which were introduced since the 2006 CPR, provide significant natural gas savings. This means that natural gas savings attributed to the new standards have been removed from the potential FortisBC program induced impacts, thus reducing the overall achievable potential.

In addition to the above market changes, there are some changes in the scope and structure of the 2010 CPR compared to the 2006 CPR:

- In contrast to the 2006 CPR, which excluded FortisBC's (then, Terasen Gas) 300 largest manufacturing accounts, the 2010 CPR includes all of FortisBC's customers, thus increasing the industrial share.

- The 2010 CPR examined only FortisBC customers whereas the 2006 CPR included all B.C. facilities, including non-FortisBC customers. The inclusion of non-FortisBC customers in the 2006 study was to facilitate a fuel choice analysis. However fuel choice was not within the scope of the 2010 CPR and, additionally, the focus on FortisBC customers (only) in the 2010 CPR enabled the study to use recent FortisBC customer market survey information.

- The approach to Commercial and Residential sector segmentation employed in the 2010 CPR differs from that employed in the 2006 CPR. The 2010 CPR includes Medium and Large Apartments in the Commercial sector; the 2006 study included them in the Residential sector. These changes were introduced to better accommodate the scope and objectives of the 2010 CPR.

- Commercial sector building profiles were also changed to incorporate more recent data. The net impact of the updates made to the 2006 CPR commercial sector building profiles for use in the 2010 CPR was an increase in “base load” (non-heating) gas consumption, especially for domestic hot water heating.

3 Residential sector

The Residential sector includes single-family detached/duplex houses, attached/row housing, and mobile/other homes. Multi-storey apartment and strata buildings are included in the Commercial sector.

3.1 Approach

The analysis of the Residential sector employed three modelling platforms:

- **HOT2000,** a commercially-supported, residential building simulation software.
- **RSEEM** (Residential Sector Energy End Use Model), a Marbek in-house spreadsheet based macro model.
- **RETScreen**, a commercially-supported, renewable energy systems modelling tool.

The major steps in the general approach to the study are outlined in Section 1.6 above (Overview of Approach). Specific procedures for the Residential sector were as follows:

- **Modelling of Base Year** – ICF Marbek used the FortisBC customer data to break down the Residential sector using four factors:

  - Type of dwelling (single detached, attached, apartment, etc.)
  - Heating category (natural gas or electric heat)
  - Building age
  - Service area.

  To estimate the natural gas used for space heating, the consultants factored in building characteristics such as insulation levels, floor space and air tightness using a variety of data sources, including the Ontario EnerGuide for Houses database, FortisBC billing data, local climate data and discussions with local contractors. They also used the results of FortisBC customer surveys that provided data on type of heating system, number and age of household appliances, renovation activity, etc. Based on the available data sources, the consultants calculated an average natural gas use by end use for each dwelling type. The consultant's models produced a close match with actual FortisBC sales data.

- **Reference Case Calculations** – For the Residential sector, the consultants developed profiles of new buildings for each type of dwelling. They estimated the growth in building stock using the same data as that contained in FortisBC's most recent load forecast and estimated the amount of natural gas used by both the existing building stock and the projected new buildings and appliances. As with the Base Year calibration, the consultant's projection closely matches FortisBC's own forecast of future natural gas requirements.

- **Assessment of DSM Measures** – To estimate the Economic and Achievable energy savings potentials, the consultants assessed a wide range of commercially available energy-efficiency measures and technologies such as:

  - Thermal upgrades to the walls, roofs and windows of existing buildings
  - More efficient space heating equipment and controls
  - More efficient water heating equipment and measures to reduce usage
  - Improved designs for new buildings.

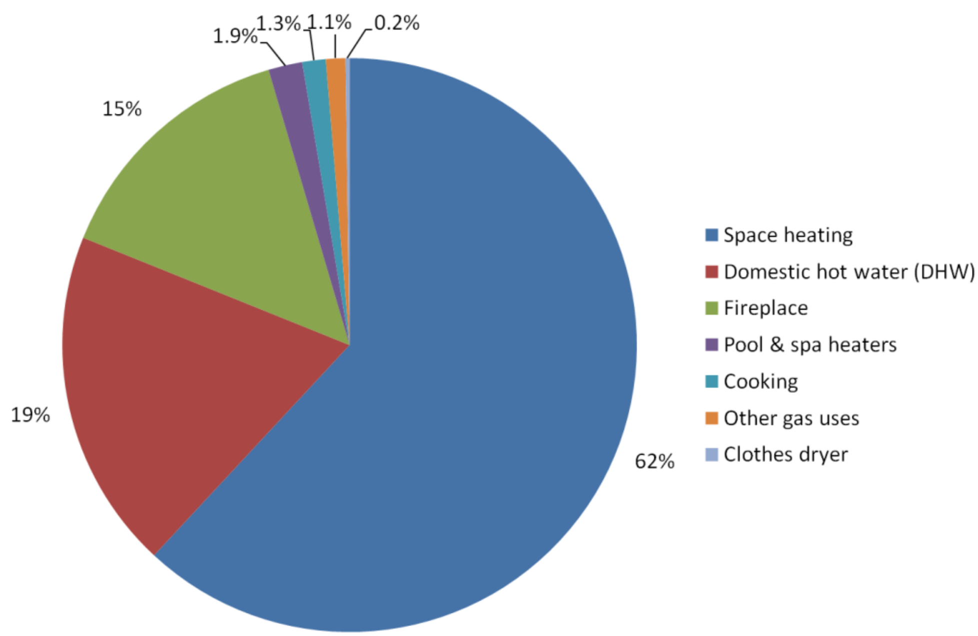
3.2 Base Year Natural Gas Use[2]

In the Base Year of 2010, FortisBC's Residential sector customers consumed approximately 74.4 million GJ of natural gas. Exhibit 8 and Exhibit 9 provide additional details on natural gas consumption by major end use and sub sector, respectively.

Exhibit 8 shows that space heating accounts for approximately 62% of the total residential natural gas use. Domestic hot water (DHW) is the next largest residential end use, accounting for approximately 19% of total residential natural gas use, followed by fireplaces (15%). Cooking, swimming pool heaters, clothes dryers, and other gas uses, combined, account for about 4% of residential natural gas use. The "Other gas uses" end use includes a variety of residential uses such as gas barbecues, outdoor fireplaces, garage or patio heaters, and outdoor lights.

Exhibit 9 shows that single-family dwellings (SFD) and duplexes account for about 92% of residential natural gas consumption followed by attached/row houses at 6%. Mobile/other dwellings account for the remaining 2% of residential natural gas use.

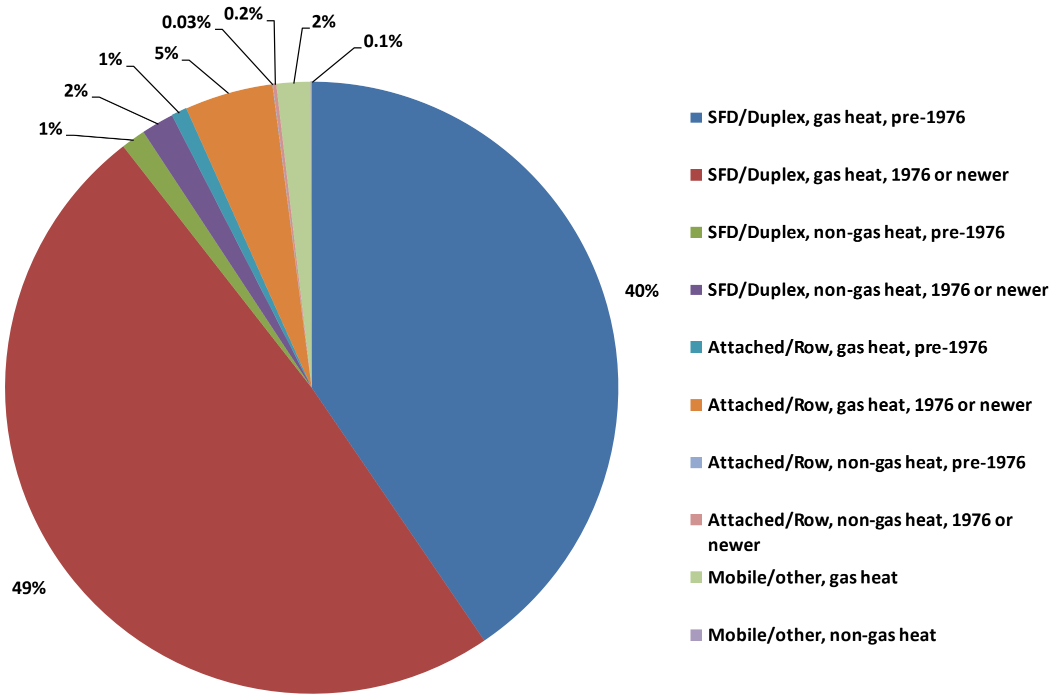
Exhibit 8 Base Year Residential Natural Gas Consumption for the Total FortisBC Service Area by End Use



[2] Readers attempting to compare these results with the CPR study completed for FortisBC (then Terasen Gas) in 2006 should be aware of two key difference between this study and the earlier one:

- The 2006 CPR was intended to complement a CPR completed for BC Hydro and therefore included all Residential sector customers of both utilities. This current study includes only those dwellings that have natural gas accounts with FortisBC.
- The 2006 CPR included high-rise multi-family buildings in the Residential sector, again for compatibility with the BC Hydro study. This study includes them in the Commercial sector, to be consistent with FortisBC's customer rate classes.

Exhibit 9 Base Year Residential Natural Gas Consumption for the Total FortisBC Service Area by Sub Sector



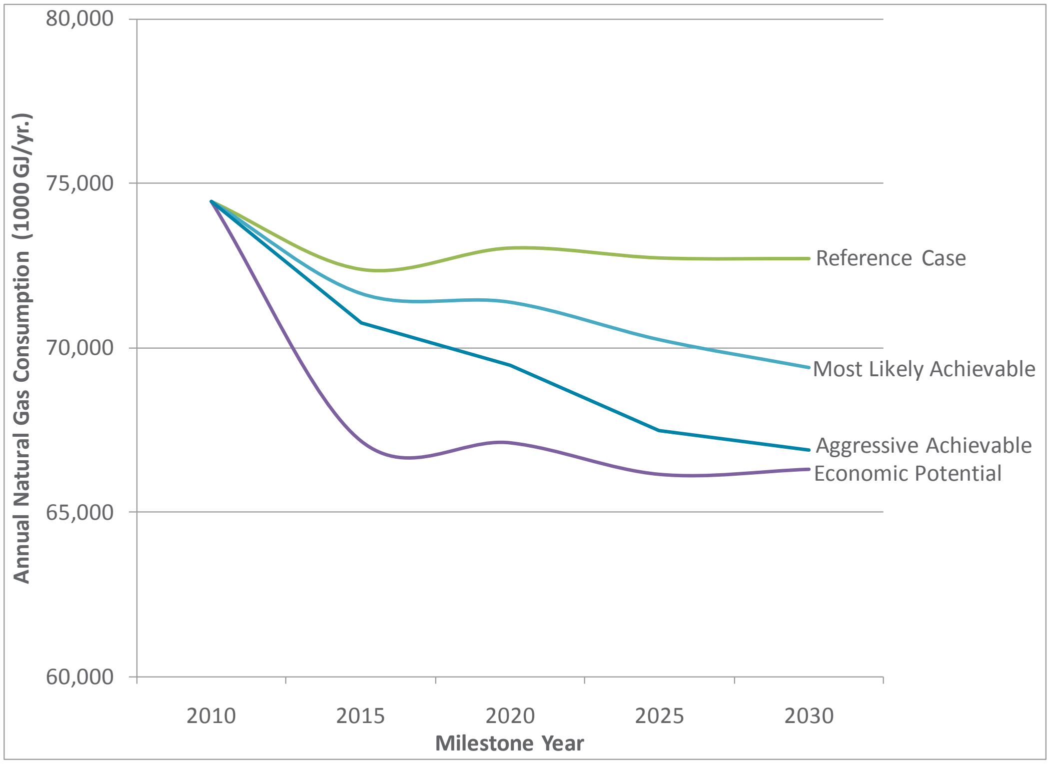
3.3 Results and Findings

A summary of the levels of annual natural gas consumption contained in the Reference Case and each of the energy-efficiency forecasts by milestone year is presented in Exhibit 10 and Exhibit 11 and discussed briefly in the paragraphs below.

Exhibit 10 Summary of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Residential Sector

Milestone Year	Annual Consumption, Residential sector (1000 GJ/yr.)				Potential Annual Savings, Residential sector (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Most Likely	Aggressive		Most Likely	Aggressive
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2010	74,440						
2015	72,382	67,173	71,638	70,742	5,209	744	1,640
2020	73,027	67,110	71,369	69,453	5,917	1,658	3,574
2025	72,726	66,152	70,226	67,474	6,574	2,500	5,252
2030	72,707	66,306	69,378	66,871	6,401	3,329	5,836

Exhibit 11 Graphic of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Residential Sector



Reference Case

In the absence of continued DSM initiatives, the study estimates that natural gas consumption in the Residential sector will decline from the Base Year (2010) consumption of approximately 74.4 million GJ/yr. to 73.0 million GJ/yr. by 2020 and 72.7 million GJ/yr. by 2030. This represents an overall decrease of about 2% in the period. Gas consumption per customer is expected to decline over the study period, partly because of the natural replacement of furnaces and water heaters with more efficient models, as required by new mandatory minimum efficiency standards, and partly because of new minimum performance standards for the construction of new homes. The decline in consumption per customer is expected to more than compensate for the increasing number of customers over the period, so that the overall residential gas consumption will decline.

Economic Potential Forecast

Under the conditions of the Economic Potential Forecast, the study estimated that consumption in the Residential sector would decline to about 66.3 million GJ/yr. by 2030. Annual savings relative to the Reference Case are about 6.4 million GJ/yr. or about 9%. The Economic Potential annual savings are about 5.9 million GJ/yr. in 2020.

Achievable Potential – Energy-efficiency Scenario

A selection of the natural gas savings opportunities identified in the Economic Potential Forecast were discussed in a full-day workshop. The guided participant discussions provided estimated levels of participation under a *most likely* scenario of program activity and an *aggressive* scenario of program activity. These levels were applied to the Economic Potential savings to estimate the Achievable Potential for these two scenarios. For technologies not specifically discussed in the workshops, participation levels were estimated through extrapolation from the technologies that were discussed. The results are presented in Exhibit 12 and Exhibit 13 by action and by milestone year.

Exhibit 12 Most Likely Achievable Natural Gas Savings for the Total FortisBC Service Area by Technology and Milestone Year (1000 GJ/yr.), Residential Sector[3]

End Use	Measure	2015	2020	2025	2030	% Savings 2030 Relative to Total 2030 Savings	Average B/C Ratio
Domestic hot water	DHW pipe insulation	11	18	20	20	1%	17.1
Domestic hot water	Showerheads	35	49	47	38	1%	9.5
Space heating	Prog. thermostats	198	292	303	256	8%	7.1
Domestic hot water	faucet aerators	21	29	28	22	1%	5.0
Fireplace	Gas fireplaces	23	111	336	391	12%	3.5
Pool & spa heaters	Solar pool heaters	12	50	116	210	6%	1.2
Space heating	Wall insulation	8	24	46	74	2%	1.2
Domestic hot water	DHW tank insulation	2	4	5	5	0%	1.2
Space heating	Attic insulation	44	85	123	159	5%	1.2
Space heating	Basement insulation	25	71	136	217	7%	1.1
Space heating	Homeowner air sealing	60	116	169	218	7%	1.1
Domestic hot water	ESTAR clothes washers	11	29	36	26	1%	1.0
Space heating	Early retire gas furnaces	294	780	1,134	1,693	51%	0.3
Grand Total		744	1,658	2,500	3,329	100%	1.7

Exhibit 13 Aggressive Achievable Natural Gas Savings for the Total FortisBC Service Area by Technology and Milestone Year (1000 GJ/yr.), Residential Sector[3]

End Use	Measure	2015	2020	2025	2030	% Savings 2030 Relative to Total 2030 Savings	Average B/C Ratio
Domestic hot water	DHW pipe insulation	22	36	41	41	1%	17.1
Domestic hot water	Showerheads	55	78	75	60	1%	9.5
Space heating	Prog. thermostats	396	580	599	505	9%	7.0
Domestic hot water	Faucet aerators	33	46	44	35	1%	5.0
Fireplace	Gas fireplaces	46	222	667	753	13%	3.4
Pool & spa heaters	Solar pool heaters	22	90	207	377	6%	1.2
Space heating	Wall insulation	16	48	92	149	3%	1.2
Domestic hot water	DHW tank insulation	5	8	10	10	0%	1.2
Space heating	Attic insulation	88	170	247	318	5%	1.2
Space heating	Basement insulation	49	142	272	434	7%	1.1
Space heating	Homeowner air sealing	120	233	338	437	7%	1.1
Domestic hot water	ESTAR clothes washers	22	58	73	52	1%	1.0
Space heating	Early retire gas furnaces	766	1,864	2,588	2,668	46%	0.3
Grand Total		1,640	3,574	5,252	5,836	100%	1.8

[3] Early retirement of gas furnaces is included in Exhibit 12 and Exhibit 13 at the request of FortisBC. This is because, although the measure is not considered cost effective when viewed through conventional DSM screens (it does not pass the TRC test as applied in this study), fully 76% of FortisBC's customers (or 91% of those who heat with gas furnaces) have standard- and mid-efficiency furnaces. It is the desire of FortisBC to offer its customers a program to encourage these customers to replace their standard- and mid-efficiency furnaces at or before the end of equipment life with high-efficiency furnaces. Thus, FortisBC wanted to discover through this study the impacts of such a program on the savings available from the Residential sector.

Peak Day Load Impacts – Energy-efficiency Scenarios

The peak day savings associated with each of the Achievable energy-efficiency scenarios were calculated using load factor data provided by FortisBC. The results are summarized in Exhibit 14 and Exhibit 15. As illustrated, the Achievable peak day savings in 2030 range from a decrease of about 34,000 GJ/day (*most likely* scenario) to a decrease of approximately 59,000 GJ/day (*aggressive* scenario) for the total FortisBC service region.

Exhibit 14 Most Likely Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Residential Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	5,294	1,224	747	256	17	7,539
2020	11,830	2,670	1,695	575	29	16,800
2025	17,913	3,840	2,543	995	28	25,319
2030	23,904	5,182	3,398	1,215	25	33,724
Savings 2030 Relative to Total 2030 Savings	71%	15%	10%	4%	0.1%	100%

Exhibit 15 Aggressive Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Residential Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	11,686	2,683	1,676	530	39	16,614
2020	25,557	5,711	3,705	1,181	60	36,214
2025	37,702	8,034	5,410	1,997	54	53,196
2030	41,351	9,632	5,890	2,205	47	59,126
Savings 2030 Relative to Total 2030 Savings	70%	16%	10%	4%	0.1%	100%

Electricity Impacts

The natural gas savings associated with the Economic Potential scenario shown in Exhibit 10 would also result in collateral electricity savings as some efficiency measures affect both energy sources. The study estimated that in 2030 the natural gas efficiency measures contained in the Economic Potential scenario would result in additional electrical savings of 24 GWh/yr.

Greenhouse Gas Impacts – Energy-efficiency Scenarios

The natural gas savings associated with each of the Achievable energy-efficiency scenarios shown in Exhibit 12 and Exhibit 13 would result in significant greenhouse gas reductions. The study estimated that in 2030 the natural gas efficiency measures contained in the *aggressive* and *most likely* Achievable Potential scenarios would reduce GHG emissions by 296,000 and 169,000 of CO_2e/yr., respectively. Further details are provided in Exhibit 16 and Exhibit 17. The electricity savings associated with the natural gas efficiency measures would also result in additional GHG reductions, which have not been included in this calculation.

Exhibit 16 Most Likely Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Residential Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	26,603	6,032	3,681	1,322	85	37,724
2020	59,447	13,156	8,352	2,966	146	84,067
2025	90,014	18,917	12,530	5,139	138	126,737
2030	120,118	25,530	16,741	6,270	126	168,785
Savings 2030 Relative to Total 2030 Savings	71%	15%	10%	4%	0.1%	100%

Exhibit 17 Aggressive Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Residential Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	58,723	13,220	8,255	2,738	192	83,129
2020	128,426	28,136	18,252	6,096	301	181,211
2025	189,455	39,580	26,653	10,307	268	266,263
2030	207,792	47,455	29,016	11,384	236	295,883
Savings 2030 Relative to Total 2030 Savings	70%	16%	10%	4%	0.1%	100%

Achievable Potential - Customer Behaviour

The study also assessed potential from customer behaviours changes. Exhibit 18 presents a summary of the results for both the *aggressive* and *most likely* achievable potential scenarios.

It should be noted that there is significant potential overlap with the reported savings from energy efficiency technologies. Consequently, the behaviour savings shown in Exhibit 18 have not been added to those for the energy efficiency technologies.

Exhibit 18 Achievable Potential from Customer Behaviour Changes, Aggressive and Most Likely Achievable Natural Gas Savings, by Milestone Year (1000 GJ/yr.)

Achievable Scenario	Energy Impact (1000 GJ/yr.)			
	2015	**2020**	**2025**	**2030**
Aggressive	383	975	1,727	2,649
Most Likely	199	518	930	1,439

3.4 Summary of Findings

The study findings confirm the existence of potential cost-effective natural gas efficiency improvements in British Columbia’s Residential sector, but highlight the increasing challenges in finding opportunities. In the *most likely* and *aggressive* Achievable scenarios energy-efficiency improvements would provide between 3,329,000 and 5,836,000 GJ/yr. of savings in 2030 as well as peak day load reductions of approximately 34,000 to 59,000 GJ.

These potential savings are smaller than those found in previous studies, both because of the success of previous program initiatives on the part of FortisBC and other utilities, and because of new standards for furnaces, water heaters, and new home construction. Consequently, there is a need to look beyond the “easy” and the “conventional” to more innovative approaches to seeking continued energy-efficiency and GHG reduction opportunities.

As an example of one possible approach, this study explored the potential offered by early retirement of gas furnaces. This measure was included in the Achievable Potential at the request of FortisBC. This is because although the measure is not considered cost effective when viewed through conventional DSM screens (it does not pass the measure TRC test as applied in this study), fully 76% of FortisBC’s customers (or 91% of those who heat with gas furnaces) have standard and mid-efficiency furnaces. It is the desire of FortisBC to offer its customers a program to encourage these customers to replace their standard and mid-efficiency furnaces before the end of equipment life with high-efficiency furnaces.

Partly because of the inclusion of the furnace early retirement measure, space heating accounts for nearly 80% of the total energy savings in the two Achievable Potential scenarios. The largest contributor to these savings is the early retirement of gas furnaces, which accounts for approximately half of the total Achievable Potential savings. Improvements in gas fireplace efficiency offer 12-13% of the total energy savings in the two Achievable Potential scenarios, swimming pool heater efficiency offers 6%, and water heating efficiency offers 3% of the savings.

4 Commercial Sector

The Commercial sector includes office and retail buildings, hotels and motels, restaurants, high-rise and mid-rise apartments, warehouses and a variety of small buildings. In this study, it also includes buildings that are often classified as "institutional," such as hospitals and nursing homes, schools and universities.

Throughout this report, use of the word "commercial" includes both commercial and institutional buildings, unless otherwise noted.

4.1 Approach

The detailed end-use analysis of energy-efficiency opportunities in the Commercial sector employed two linked modelling platforms: **CEEAM** (Commercial Energy and Emissions Analysis Model), an ICF Marbek in-house simulation model developed in conjunction with Natural Resources Canada (NRCan) for modelling natural gas use in commercial/institutional building stock, and **CSEEM** (Commercial sector Energy End-use Model), an in-house spreadsheet-based macro model.

The major steps in the general approach to the study were outlined in Section 1.6. Specific procedures for the Commercial sector were as follows:

- **Modelling of Base Year** – ICF Marbek compiled data that defines "where" and "how" natural gas is currently used in existing commercial buildings. The consultants then created building energy-use simulations for each type of commercial building and calibrated the models to reflect actual FortisBC customer sales data. Estimated savings for the Other Commercial Buildings category were derived from the results of the modelled segments. They did not directly model that category because it is extremely diverse and the natural gas use of individual facility types is relatively small. The consultant's model produced a close match with actual FortisBC sales data.

- **Reference Case Calculations** – For the Commercial sector, ICF Marbek developed detailed profiles of new buildings in each of the building segments, estimated the growth in building stock and estimated "natural" changes affecting natural gas consumption over the study period. As with the Base Year calibration, the consultant's projection closely matches the FortisBC 2010 forecast of future natural gas requirements.

- **Assessment of DSM Measures** – To estimate the Economic and Achievable natural gas savings potentials, the consultants assessed a wide range of commercially available DSM measures and technologies such as:

    - Measures to improve building envelope efficiency
    - Measures to reduce domestic hot water use, including solar hot water systems
    - Upgraded heating and ventilating systems
    - Improved construction in new buildings
    - Efficient cooking appliances.

4.2 Base Year Natural Gas Use

In the Base Year of 2010, FortisBC's Commercial sector customers consumed approximately 57 million GJ. Exhibit 19 and Exhibit 20 provide additional details on natural gas consumption by major end use and sub sector, respectively.

Exhibit 19 shows that space heating accounts for approximately 59% of the total Commercial sector natural gas use. Domestic hot water heating is the next largest end use, accounting for approximately 25% of total commercial natural gas use, followed by commercial cooking (15%). Other end uses such as dehumidification, steam system distribution losses, laundry equipment, and pool heating account for about 7% of commercial natural gas use.

Exhibit 20 shows that Small Commercial buildings account for about 30% of natural gas consumption followed by Large and Medium Apartments, (approximately 25% combined). No other sub sector accounts for more than 10% of Commercial sector natural gas use.

Exhibit 19 Base Year Commercial Natural Gas Consumption for the Total FortisBC Service Area by End Use

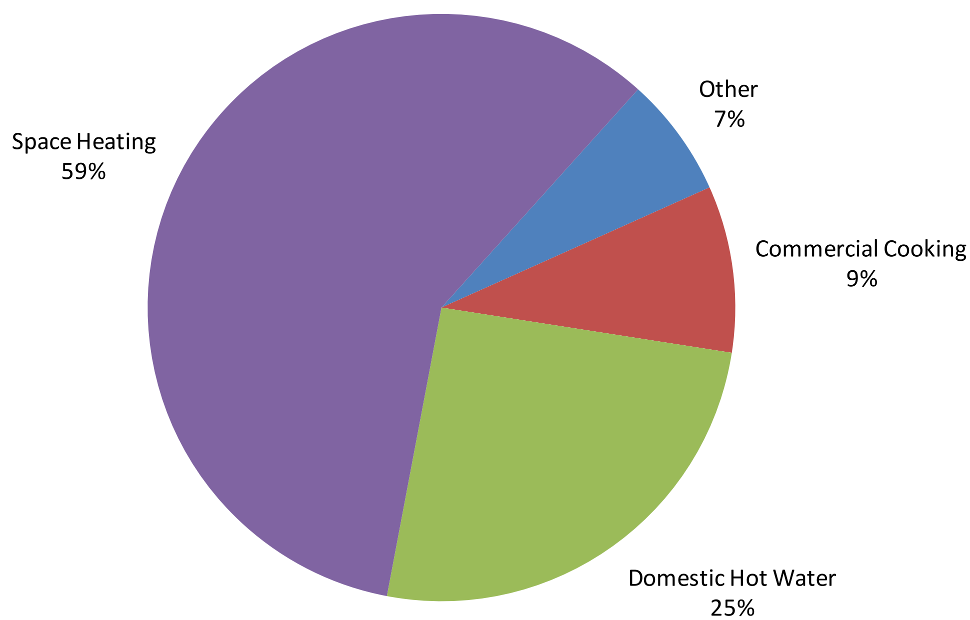
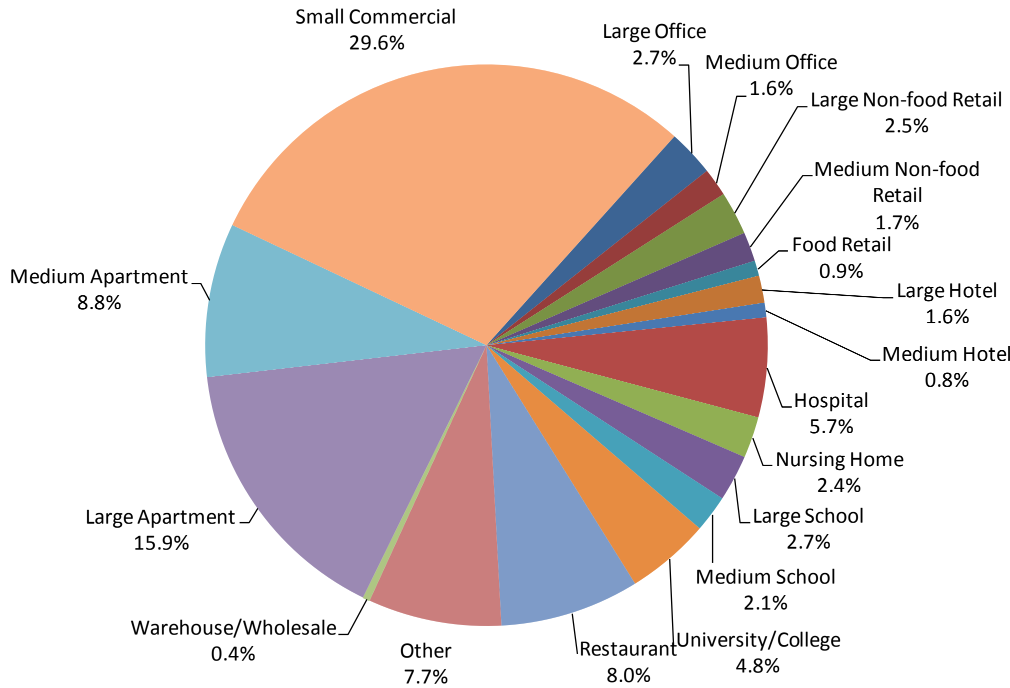


Exhibit 20 Base Year Commercial Natural Gas Consumption for the Total FortisBC Service Area by Sub Sector



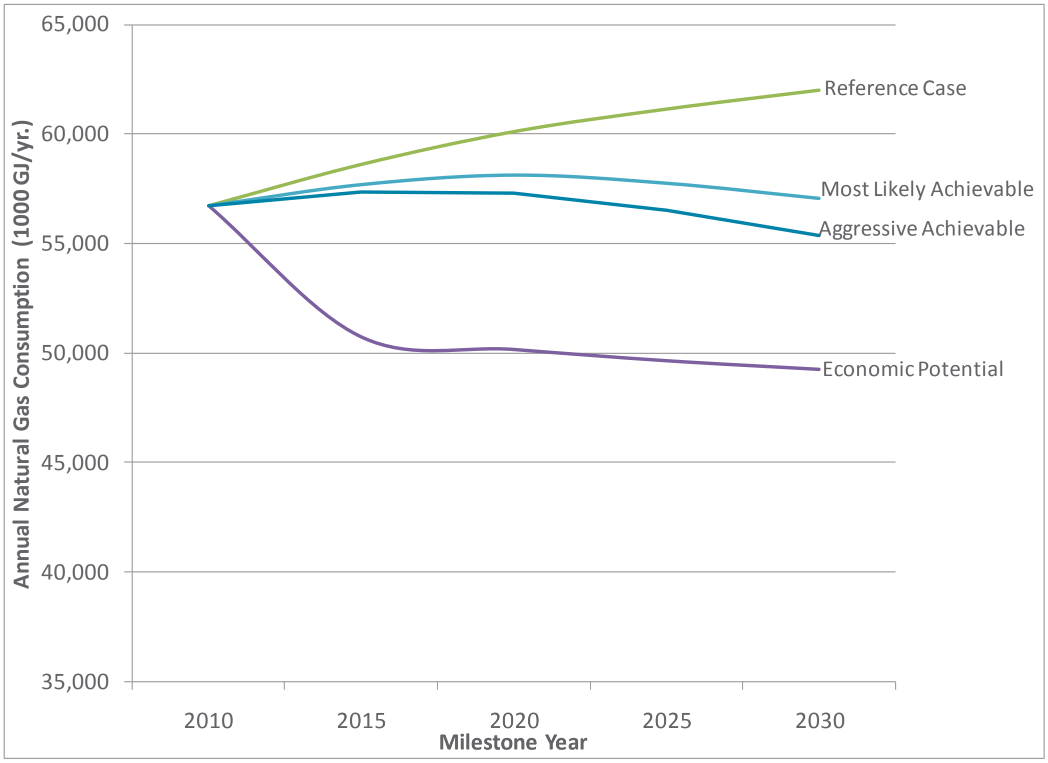
4.3 Results and Findings

A summary of the levels of annual natural gas consumption contained in the Reference Case and each of the energy-efficiency forecasts by milestone year is presented in Exhibit 21 and Exhibit 22 and discussed briefly in the paragraphs below.

Exhibit 21 Summary of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Commercial Sector

Milestone Year	Annual Consumption, Commercial sector (1000 GJ/yr.)				Potential Annual Savings, Commercial sector (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Most Likely	Aggressive		Most Likely	Aggressive
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2010	56,730						
2015	58,607	50,714	57,676	57,332	7,893	930	1,275
2020	60,095	50,137	58,104	57,286	9,958	1,991	2,809
2025	61,118	49,622	57,739	56,498	11,496	3,379	4,619
2030	61,977	49,225	57,062	55,344	12,752	4,915	6,633

Exhibit 22 Graphic of Forecast Results for the Total FortisBC Service Area Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Commercial Sector



Reference Case

In the absence of continued DSM initiatives, the study estimates that natural gas consumption in the Commercial sector will increase from the Base Year (2010) consumption of approximately 56.7 million GJ/yr. to 60.1 million GJ/yr. by 2020 and 62.0 million GJ/yr. by 2030. This represents an overall increase of about 9% in the period.

Economic Potential Forecast

Under the conditions of the Economic Potential Forecast, the study estimated that consumption in the Commercial sector would decline to about 49.2 million GJ/yr. by 2030. Annual savings relative to the Reference Case are about 12.8 million GJ/yr. or about 22%. The Economic Potential annual savings are about 10 million GJ/yr. in 2020.

Achievable Potential – Energy-efficiency Scenario

A selection of the natural gas savings opportunities identified in the Economic Potential Forecast was discussed in a full-day workshop. The guided participant discussions provided estimated levels of participation under a *most likely* scenario of program activity and an *aggressive* scenario of program activity. These levels were applied to the Economic Potential savings to estimate the Achievable Potential for these two scenarios. For technologies not specifically discussed in the workshops, participation levels were estimated through extrapolation from the technologies that were discussed. Results by sub sector and end use are presented in Exhibit 23 and Exhibit 24 for both Achievable scenarios.

Exhibit 23 Most Likely Achievable Natural Gas Savings for the Total FortisBC Service Area by Measure and Milestone Year (GJ/yr.), Commercial Sector

End Use	Measure	2015	2020	2025	2030	% Savings Relative to Total 2030 Savings	Average B/C Ratio
Domestic Hot Water	Pre-Rinse Spray Valves	57,607	84,693	110,297	107,352	2.2%	16.70
Domestic Hot Water	Ultra Low-Flow Fixtures	195,943	288,323	376,043	366,771	7.5%	8.61
Space Heating	Demand Ctrl Kitchen Vent.	4,091	7,913	11,414	14,537	0.3%	5.27
Domestic Hot Water	Condensing DHW (Boiler)	1,665	12,285	39,274	89,919	1.8%	3.08
Multiple	New Construction 40% Better	1,429	10,292	31,621	70,396	1.4%	3.07
Space Heating	Programmable T'stats	54,957	107,153	155,816	200,101	4.1%	2.77
Domestic Hot Water	Condensing DHW (Tank Type)	1,815	13,390	42,773	73,296	1.5%	2.58
Multiple	BAS and Recommissioning	162,255	316,967	461,728	593,864	12.1%	2.49
Space Heating	Air Sealing	895	3,522	7,737	13,290	0.3%	1.86
Space Heating	Condensing Rooftop Units	847	3,268	7,025	11,780	0.2%	1.83
Space Heating	Condensing Boilers	35,149	135,083	290,443	490,417	10.0%	1.70
Commercial Cooking	HE Cooking	3,188	24,210	54,931	98,972	2.0%	1.62
Space Heating	Air-Air Heat Recovery	54,621	105,301	151,557	192,958	3.9%	1.52
Multiple	O&M Measures	50,292	197,566	436,475	761,752	15.5%	1.38
Space Heating	Roof Insulation	1,981	14,928	48,739	112,200	2.3%	1.26
Space Heating	Condensing Unit Heater	60	232	496	832	0.0%	1.21
Domestic Hot Water	Drainwater Heat Recovery	335	1,234	2,614	4,439	0.1%	1.19
Space Heating	HVLS Fans	687	1,322	1,896	2,394	0.0%	1.19
Space Heating	Demand Ctrl Vent.	953	1,831	2,610	3,264	0.1%	1.17
Space Heating	Infrared Heaters	0	1,360	2,589	3,666	0.1%	1.16
Multiple	Small Commercial	241,293	527,453	911,955	1,357,598	27.6%	-
Multiple	Other	60,181	132,367	230,676	345,306	7.0%	-
Grand Total		930,246	1,990,692	3,378,709	4,915,107	100%	3.20

Exhibit 24 Aggressive Achievable Natural Gas Savings for the Total FortisBC Service Area by Measure and Milestone Year (GJ/yr.), Commercial Sector

End Use	Measure	2015	2020	2025	2030	% Savings Relative to Total 2030 Savings	Average B/C Ratio
Domestic Hot Water	Pre-Rinse Spray Valves	41,645	81,398	119,287	155,341	2.3%	16.7
Domestic Hot Water	Ultra Low-Flow Fixtures	141,808	277,565	407,352	531,248	8.0%	8.61
Space Heating	Demand Ctrl Kitchen Vent.	5,599	10,760	15,463	19,670	0.3%	5.27
Domestic Hot Water	Condensing DHW (Boiler)	3,129	22,869	72,630	163,162	2.5%	3.08
Multiple	New Construction 40% Better	9,819	37,046	77,103	129,782	2.0%	3.07
Space Heating	Programmable T'stats	68,187	132,389	192,234	243,154	3.7%	2.77
Domestic Hot Water	Condensing DHW (Tank Type)	3,418	24,969	79,015	131,989	2.0%	2.58
Multiple	BAS and Recommissioning	201,268	391,471	569,360	699,843	10.6%	2.49
Space Heating	Air Sealing	4,262	8,345	12,163	15,573	0.2%	1.86
Space Heating	Condensing Rooftop Units	1,155	4,405	9,364	15,529	0.2%	1.83
Space Heating	Condensing Boilers	48,013	182,990	391,328	660,997	10.0%	1.7
Commercial Cooking	HE Cooking	4,959	37,659	85,447	153,957	2.3%	1.62
Space Heating	Air-Air Heat Recovery	74,708	143,060	205,251	262,327	4.0%	1.52
Multiple	O&M Measures	241,403	474,158	698,360	914,103	13.8%	1.38
Space Heating	Roof Insulation	3,442	25,847	84,415	195,136	2.9%	1.26
Space Heating	Condensing Unit Htr.	82	313	665	1,109	0.0%	1.21
Domestic Hot Water	Drainwater Heat Recovery	630	2,292	4,797	7,910	0.1%	1.19
Space Heating	HVLS Fans	939	1,793	2,554	3,207	0.0%	1.19
Space Heating	Demand Ctrl Vent.	1,298	2,464	3,469	4,295	0.1%	1.17
Space Heating	Infrared Heaters	0	1,838	3,474	4,884	0.1%	1.16
Multiple	Small Commercial	334,939	753,649	1,263,001	1,846,194	27.8%	-
Multiple	Other	84,288	191,639	322,624	473,670	7.1%	-
Grand Total		1,274,993	2,808,920	4,619,354	6,633,079	100%	3.32

Peak Day Load Impacts – Energy-efficiency Scenarios

The peak day savings associated with each of the Achievable energy-efficiency scenarios were calculated using load factor data provided by FortisBC. The results are summarized in Exhibit 25 and Exhibit 26. As illustrated, the Achievable peak day savings in 2030 range from a decrease of about 38,000 GJ in the *most likely* Achievable scenario to a decrease of approximately 51,000 GJ in the *aggressive* Scenario for the total FortisBC service region.

Exhibit 25 Most Likely Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Commercial Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	4,714	744	802	849	31	7,141
2020	9,904	1,675	1,753	1,883	66	15,281
2025	16,637	2,977	3,012	3,197	113	25,936
2030	23,786	4,537	4,502	4,740	164	37,729
Savings 2030 Relative to Total 2030 Savings	63%	12%	12%	13%	0.4%	100%

Exhibit 26 Aggressive Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Commercial Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	6,424	1,058	1,061	1,202	42	9,787
2020	13,983	2,461	2,401	2,623	94	21,562
2025	22,688	4,212	4,092	4,314	154	35,459
2030	32,115	6,298	6,100	6,182	221	50,917
Savings 2030 Relative to Total 2030 Savings	63%	12%	12%	12%	0.4%	100%

Greenhouse Gas Impacts – Energy-efficiency Scenarios

The natural gas savings associated with each of the Achievable energy-efficiency scenarios shown in Exhibit 27 and Exhibit 28 would result in significant GHG reductions. The study estimated that in 2030 the natural gas efficiency measures contained in the *aggressive* and *most likely* Achievable Potential scenarios would reduce GHG emissions by 338,000 and 250,000 of CO_2e/yr., respectively.

Exhibit 27 Most Likely Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Commercial Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	31,274	4,933	5,321	5,635	206	47,369
2020	65,701	11,108	11,626	12,493	440	101,368
2025	110,366	19,747	19,978	21,209	747	172,047
2030	157,787	30,100	29,865	31,444	1,087	250,283
Savings 2030 Relative to Total 2030 Savings	63%	12%	12%	13%	0.4%	100%

Exhibit 28 Aggressive Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Commercial Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	42,613	7,020	7,035	7,974	282	64,924
2020	92,758	16,325	15,927	17,402	620	143,033
2025	150,501	27,939	27,145	28,617	1,021	235,222
2030	213,041	41,776	40,468	41,012	1,468	337,765
Savings 2030 Relative to Total 2030 Savings	63%	12%	12%	12%	0.4%	100%

4.4 Summary of Findings

The study findings confirm the existence of significant potential cost-effective natural gas efficiency improvements in British Columbia's Commercial sector. In the *most likely* and *aggressive* Achievable scenarios those energy-efficiency improvements would provide between 4,915,000 and 6,633,000 GJ/yr. of savings in 2030 as well as peak day load reductions of approximately 38,000 to 51,000 GJ. Savings are primarily associated with the space heating and water heating end uses, with approximately two-thirds of the savings in both Achievable scenarios associated with space heating measures.

Four measures each account for more than 10% of the savings in both the *most likely* and *aggressive* Achievable scenarios. These are, in order of their contribution: O&M measures, advanced building automation systems/recommissioning, high-efficiency boilers, and low-flow plumbing fixtures. These four measures represent a total of 69% of the *most likely* Achievable scenario savings and 65% of the *aggressive* Achievable scenario savings.

5 Industrial Sector

The Industrial sector consists of the eight largest natural gas consuming Industrial sub sectors within the FortisBC service area, an additional category (Other) that combines the remaining smaller industry groups, and the agriculture sub sector. The largest natural gas consuming Industrial sub sectors within the FortisBC service area, which are the primary focus of this study, are: Chemical, Fabricated Metal, Food & Beverage, Mining, Miscellaneous Manufacturing, Non-Metal Manufacturing, Pulp & Paper, and Wood Products.

This study includes analysis of the interruptible natural gas loads for large customers and the savings measures associated with their process requirements. As a result the Mining and Pulp and Paper sub sectors have been added for the 2010 review, compared to those sub sectors previously studied in the 2006 CPR.

5.1 Approach

The analysis of the Industrial sector employed a customized spreadsheet model. The model applies appropriate end-use technologies to each sub sector in each service area. The input energy-use information and equipment efficiencies are organized by service area, major sub sector, major end use, and technology.

The major steps in the general approach to the study were outlined in Section 1.6. Specific procedures for the Industrial sector were as follows:

- **Modelling of Base Year** – The consultants compiled data that defines "where" and "how" natural gas is currently used in industry. The primary input variables affecting the consumption of natural gas, based on industrial process, are:
  - Type and efficiency of specific major processing equipment
  - Energy consumption and operating hours for heating equipment
  - Economic activity levels within each sub sector (useful heat requirement)
  - Production processes employed.

- The average natural gas consumption for June through August provided the basis for the annual process heat load for the industries, with process consumption not affected by climate.

- **Reference Case Calculations** – The energy-use changes that would occur without utility programs are in the Reference Case. A constant rate of improvement was applied for each technology that reflects the natural rate of equipment replacement and upgrades seen in B.C.'s Industrial sector. The natural gas sales were calculated for each sub sector and service area along with the useful heat based on the conversion efficiencies of technologies for both comfort and process heating.

- **Assessment of DSM Measures** – To estimate the Economic and Achievable natural gas savings potentials, the consultants assessed a wide range of commercially available DSM measures and technologies such as:
  - Controls and high-efficiency burners (bundled standard upgrades)
  - Heat recovery (off of boiler)
  - Insulation – equipment and distribution systems
  - Heat recovery (off of process)
  - Optimized heat balance and control
  - Steam trap maintenance.

5.2 Base Year Natural Gas Use

In the Base Year of 2010, FortisBC's Industrial sector customers consumed approximately 36,456,000 GJ. Exhibit 29 and Exhibit 30 provide additional details of the Industrial sector natural gas consumption by major end uses and sub sector, respectively.

Exhibit 29 shows that boilers account for approximately 43% of the total industrial natural gas use. Most of the boiler load involves process steam use. Furnaces for air heating large industrial areas account for about 12% of the industrial consumption and another 12% is used in kilns at pulp and paper sites, and for manufacturing lime for the Kraft pulping process. The remaining natural gas is used in a variety of industrial processes, including lumber kilns, coal driers, and cement kilns.

Exhibit 30 indicates the distribution among the sub sectors. The Pulp and Paper sector dominates at 32%, followed by Agriculture, Food & Beverage at 12% each, Chemical at 10%, Wood Products at 9%, Mining at 8%, and Fabricated Metal at 6%.

Exhibit 29 Base Year Industrial Natural Gas Consumption for the Total FortisBC Service Area by End Use

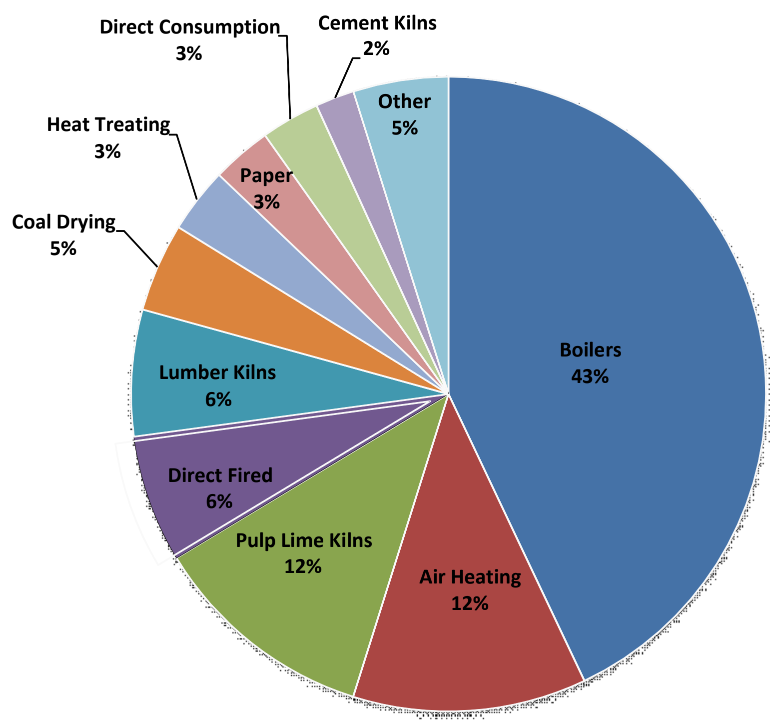
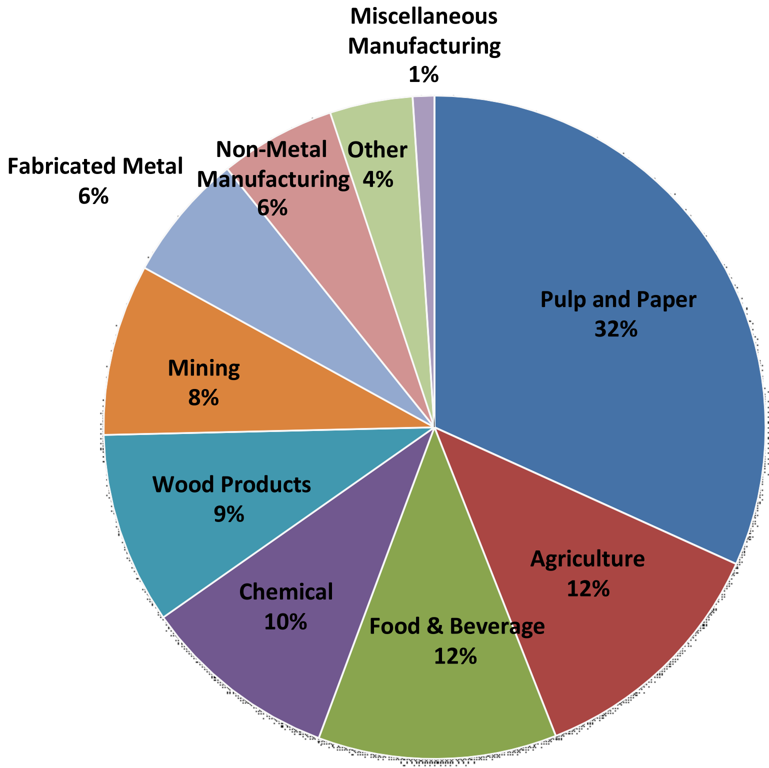


Exhibit 30 Base Year Industrial Natural Gas Consumption for the Total FortisBC Service Area by Sub Sector



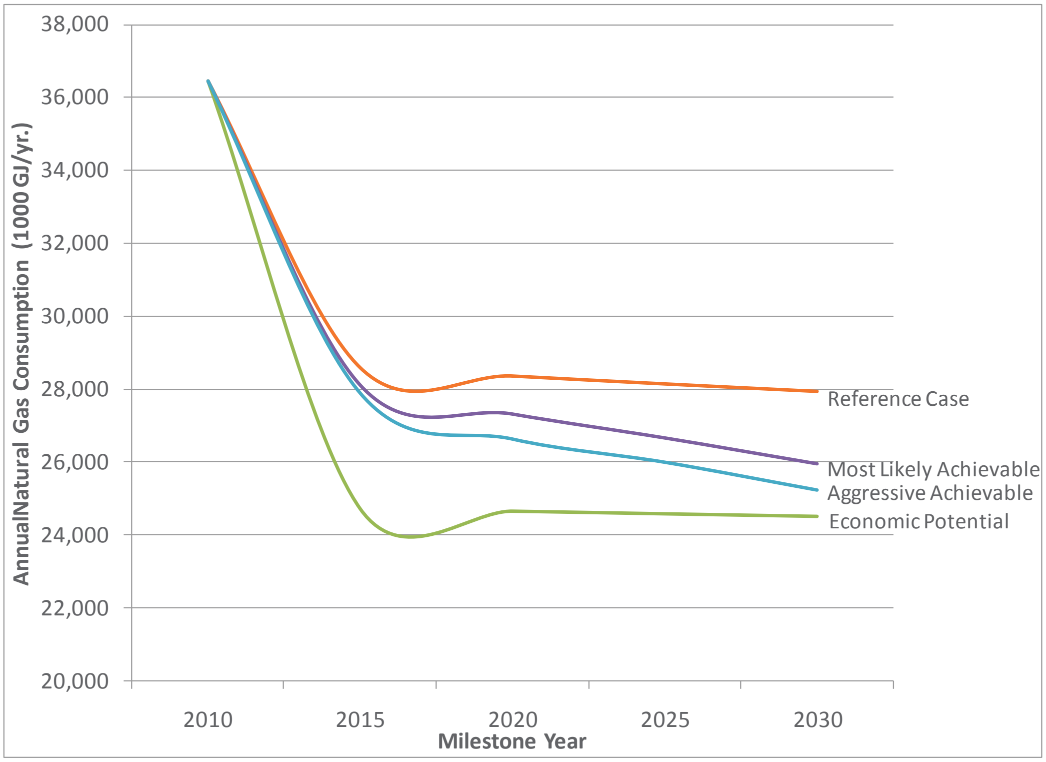
5.3 Results and Findings

A summary of the levels of annual natural gas consumption contained in the Reference Case and each of the energy-efficiency forecasts by milestone year is presented in Exhibit 31 and Exhibit 32 and discussed briefly in the paragraphs below.

Exhibit 31 Summary of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Industrial Sector

Milestone Year	Annual Consumption, Industrial sector (1000 GJ/yr.)				Potential Annual Savings, Industrial sector (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Most Likely	Aggressive		Most Likely	Aggressive
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2010	36,456						
2015	28,594	24,710	28,095	27,880	3,884	499	714
2020	28,367	24,648	27,302	26,621	3,719	1,065	1,746
2025	28,151	24,576	26,646	25,985	3,575	1,505	2,166
2030	27,946	24,506	25,936	25,221	3,440	2,010	2,725

Exhibit 32 Graphic of Forecast Results for the Total FortisBC Service Area Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Industrial Sector



Reference Case

In the absence of continued DSM initiatives, the study estimates that natural gas consumption in the Industrial sector will decline from the base year (2010) consumption of approximately 36.5 million GJ/yr. to 28.4 million GJ/yr. by 2020 and 27.9 million GJ/yr. by 2030. This represents an overall decrease of about 23% in the period. The forecast decrease is due to an expected continued decline in the wood products and pulp and paper industry as well as a continuation of the move to wood waste from natural gas. The move to wood waste will be mainly due to the provincial government policy of encouraging a reduction of GHG emissions.

Economic Potential Forecast

Under the conditions of the Economic Potential Forecast, the study estimated that consumption in the Industrial sector would decline to about 24,506,000 GJ/yr. by 2030. Annual savings relative to the Reference Case are about 3,439,000 GJ/yr. or about 12%. The Economic Potential is obtained relatively quickly due to the analysis indicating that, from a strictly economic perspective, most of the inefficient equipment could be replaced by more efficient alternatives within the next five years.

Achievable Potential – Energy-efficiency Scenario

A selection of the natural gas savings opportunities identified in the Economic Potential Forecast were discussed in a full-day workshop. The guided participant discussions provided estimated levels of participation under a *most likely* scenario of program activity and an *aggressive* scenario of program activity. These levels were applied to the Economic Potential savings to estimate the Achievable Potential for these two scenarios. For technologies not specifically discussed in the workshops, participation levels were estimated through extrapolation from the technologies that were discussed. The results are presented in Exhibit 33 and Exhibit 34 by technology and by milestone year for the *most likely* and *aggressive* Achievable Potential scenarios, respectively.

Exhibit 33 Most Likely Achievable Natural Gas Savings for the Total FortisBC Service Area by End Use and Milestone Year (GJ/yr.), Industrial Sector

End Use	2015	2020	2025	2030	% Savings 2030 Relative to Ref Case	% Savings 2030 Relative to Total 2030 Savings
Boilers	256,269	527,267	823,065	1,153,094	9%	57%
Air heating	88,567	174,994	259,343	341,709	11%	17%
Ovens	470	4,134	6,278	8,748	1%	0.4%
Heat treating	1,809	16,439	23,073	29,753	6%	1%
Lumber kilns	48,534	97,260	140,724	180,165	29%	9%
Veneer dryers	6,116	12,044	17,723	23,097	1%	1%
Pulp lime kilns	2,884	8,117	15,777	25,538	6%	1%
Cement kilns	6,395	13,015	17,758	21,494	3%	1%
Ore drying	1,016	2,435	2,639	2,964	0%	0.1%
Coal drying	53,356	127,832	110,862	124,497	24%	6%
Direct fired	34,172	81,391	88,010	98,828	6%	5%
Grand Total	499,589	1,064,929	1,505,251	2,009,988	7%	100%

Exhibit 34 Aggressive Achievable Natural Gas Savings for the Total FortisBC Service Area by Technology and Milestone Year (GJ/yr.), Industrial Sector

End Use	Sub Sector	2015	2020	2025	2030	% Savings 2030 Relative to Total 2030 Savings	Average B/C Ratio
Coal drying	High-efficiency coal and ore dryers	55,388	132,701	116,140	130,425	5%	15 (coal)
Ore drying	High-efficiency kilns	2,558	23,427	33,149	42,988	2%	9.1
Cement kilns	High-efficiency kilns	7,211	20,293	39,441	63,846	2%	7
Direct fired	Direct-fired heating - gypsum	68,344	162,783	176,021	197,856	7%	5.5
Ovens	High-efficiency ovens	940	8,268	12,555	17,497	1%	5.4
Heat treating	Heat treating furnace with sequential firing, high-velocity burners	3,619	32,879	46,145	59,507	2%	5.4
Veneer dryers	Advanced veneer dryer	9,785	19,271	28,357	36,955	1%	5.4
Air heating	Radiant tube heating	110,709	218,743	324,178	427,137	16%	4.4
Lumber kilns	High-efficiency kilns	64,712	129,680	187,632	240,220	9%	4.2
Boilers	Efficient boilers	373,963	950,508	110,661	1,367,177	50%	~4
Process water heating	Direct-fired water heating	7,988	24,561	50,261	81,010	3%	N/A
Pulp lime kilns	Direct-fired paper drying	8,871	23,500	41,621	60,576	2%	N/A
Grand Total		714,089	1,176,613	2,166,162	2,725,193	100%	

Peak Day Load Impacts – Energy-efficiency Scenarios

The peak day savings associated with each of the Achievable energy-efficiency scenarios were calculated using load factor data provided by FortisBC. The results are summarized in Exhibit 35 and Exhibit 36. As illustrated, the Achievable peak day savings in 2030 range from a decrease of 16,990 GJ in the *most likely* Achievable scenario to a decrease of 23,080 GJ/day in the *aggressive* scenario for the total FortisBC service region.

Exhibit 35 Most Likely Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Industrial Sector

Year	Lower Mainland	Northern Interior	Southern Interior	Vancouver Island	Grand Total
2015	2,197	936	971	110	4,213
2020	4,633	1,936	2,150	227	8,973
2025	6,749	2,978	2,659	328	12,715
2030	9,055	4,064	3,462	409	16,990
Savings 2030 Relative to Total 2030 Savings	53%	24%	20%	2%	100%

Exhibit 36 Aggressive Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Industrial Sector

Year	Lower Mainland	Northern Interior	Southern Interior	Vancouver Island	Grand Total
2015	3,250	1,398	1,228	162	6,093
2020	8,064	3,367	2,990	373	14,794
2025	10,003	4,424	3,442	476	18,346
2030	12,544	5,694	4,285	556	23,080
Savings 2030 Relative to Total 2030 Savings	54%	25%	19%	2%	100%

Greenhouse Gas Impacts – Energy-efficiency Scenarios

The natural gas savings associated with each of the Achievable Potential scenarios would also result in a reduction of GHG emissions.[4] As illustrated in Exhibit 37 and Exhibit 38, by 2030 the GHG reductions are estimated to be in the range of 96,000 to 130,000 tonnes CO_2e per year, depending on the scenario.

[4] GHG impacts are estimated based on an emissions factor of 48kg of CO_2e/GJ of natural gas. This is the B.C. Natural Gas Emission Factor.

Exhibit 37 Most Likely Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Industrial Sector

Year	Lower Mainland	Northern Interior	Southern Interior	Vancouver Island	Grand Total
2015	11,361	5,809	6,027	783	23,980
2020	23,960	12,187	13,352	1,617	51,117
2025	34,906	18,493	16,509	2,343	72,252
2030	46,833	25,233	21,494	2,920	96,479
Savings 2030 Relative to Total 2030 Savings	49%	26%	22%	3%	100%

Exhibit 38 Aggressive Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Industrial Sector

Year	Lower Mainland	Northern Interior	Southern Interior	Vancouver Island	Grand Total
2015	16,809	8,681	7,627	1,159	34,276
2020	41,707	20,903	18,563	2,665	83,837
2025	51,735	27,468	21,374	3,399	103,976
2030	64,876	35,357	26,607	3,969	130,809
Savings 2030 Relative to Total 2030 Savings	50%	27%	20%	3%	100%

5.4 Summary of Findings

The study findings indicated that even with a declining load there are significant potential cost-effective natural gas efficiency improvements in the Industrial sector. This potential is due to the existence of older inefficient boilers, lumber kilns, lime kilns, and a variety of other industrial process equipment that could be economically replaced. It would be cost effective for this replacement to occur by 2015, but due to other market barriers, it is estimated that in the *most likely* scenario and *aggressive* scenario it will take until 2030 to obtain the savings.

The major market barriers constraining faster market penetration include:

- Higher capital cost of efficient product(s)
- Need to recover investment costs in a short period (payback)
- Lack of product performance information
- Lack of available product.

In the *most likely* and *aggressive* Achievable scenarios these energy-efficiency improvements would provide between 2,010,000 and 2,725,000 GJ/yr. of savings in 2030 as well as peak day load reductions of approximately 16,990 to 23,080 GJ.

A variety of efficient boiler technologies accounts for nearly 57% of the total energy savings in the two Achievable Potential scenarios. The major opportunity involves replacing standard efficiency boilers in the 68% to 80% efficiency range with condensing boilers in the plus 90% efficiency range. This opportunity is mainly applicable to medium size boilers in the food processing and manufacturing sectors.

For large boilers, such as in pulp mills, and for large process equipment such as cement kilns, lime kilns and coal driers, the *most likely* opportunities will involve upgrading the equipment with better controls or heat recovery equipment rather than replacing the complete unit.

Another significant energy saving opportunity is improving the air heating efficiency of large industrial fabrication work spaces. Generally, these spaces are now heated with unit heaters. In some cases, inefficient unit heaters could be replaced by more efficient unit heaters but a larger opportunity is with replacing the unit heaters with gas radiant heaters.

6 Economic Impacts

6.1 Introduction

In addition to energy savings, FortisBC's investment in DSM programs can have broad impacts on the provincial economy as measured through metrics such as employment, GDP, and industrial output. Impacts arise from short term investment activities, such as building retrofits, and longer term changes in household/business spending, which can be attributed to the persistence of energy savings.

This analysis uses the results from the FortisBC Conservation Potential Review (CPR) Update 2010 to provide an estimate of the net macroeconomic impacts expected from implementing the *most likely* and *aggressive* Achievable Potential scenarios outlined in each of the main sector reports.

Three sets of economic impacts are reported in this analysis:

- Changes in output (total industry revenues)
- Changes in GDP at factor cost (total value added at producers' prices, or total output minus costs of production)
- Changes in employment (number of jobs).[5]

The above economic impacts are reported for three sectors (Residential, Commercial and Industrial) under the *most likely* and *aggressive* Achievable Potential scenarios at two milestone years: 2021 (10 years out) and 2030 (19 years out).

6.2 Approach

The economic analysis is based on the application of economic multipliers, which are a set of proportionality constants that relate changes in domestic production in a particular sector to its impacts on the entire B.C. economy. BC Stats released a report in March 2008 documenting the British Columbia provincial economic multipliers based on 2004 economic data. These multipliers were applied to various activities across all sectors from the energy-efficiency strategy and totalled to determine the net impacts, which are relative to the scenario where no energy-efficiency strategy is implemented.

6.3 Results and Conclusion

The study concludes that:

- The impacts on output, GDP, and employment are all positive across all sectors for every scenario
- Impacts increase over time and are larger for the *aggressive* Achievable scenario
- The Residential sector, in every scenario, accounts for the greatest share of economic impacts
- By 2021, the net employment gains from CPR activities will range between 362 - 682 jobs, depending on the scenario
- By 2031 the net employment gains from CPR activities would grow to between 580 - 881 jobs, depending on the scenario.

[5] BC Stats and BC Ministry of Advanced Education and Labour Market Development (2010). *A Guide to the BC Economy and Labour Market.*

Exhibit 39 and Exhibit 40 present a summary of the impacts in the milestone year 2021 for the *most likely* and the *aggressive* Achievable Potential scenarios. Additional results are provided in the main report.

Exhibit 39 Economic Impacts, 2021, Most Likely Achievable Scenario

Sector	Output	GDP	Employment
Residential	$31,935,141	$9,173,163	197
Commercial	$11,419,118	$3,211,087	118
Industrial	$4,545,079	$1,212,245	47
Total	$47,899,339	$13,596,496	362

Exhibit 40 Economic Impacts, 2021, Aggressive Achievable Scenario

Sector	Output	GDP	Employment
Residential	$72,915,818	$20,923,741	441
Commercial	$16,260,403	$4,592,314	166
Industrial	$7,328,959	$1,951,239	75
Total	$96,505,181	$27,467,294	682

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Appendix C-3

FEU COMMERCIAL AND INDUSTRIAL EEC SAVINGS

APPENDIX C-3 – FEU COMMERCIAL AND INDUSTRIAL EEC SAVINGS

The FEU Commercial and Industrial EEC Savings appendix describes the highest, lowest and Reference Case scenarios in terms of annual EEC program savings by measure and by scenario. Each scenario is constructed by making incremental changes to a reference case, which is based primarily on data developed for the 2009 Conservation Potential Review (consult Appendix B-3 for a detailed description of each scenario and Appendix C-1 for EEC program descriptions). Figures 1 and 2 are intended to present the widest range of potential energy savings under scenarios of different future planning environments over the next 20 years. The estimated program savings in Tables 1A, 1B, 2A and 2B below display the anticipated annual savings of EEC programs for the two milestone years 2016 and 2033 respectively.

FEU Commercial EEC Savings

Figure 1: FEU Commercial Annual EEC Savings by Scenario

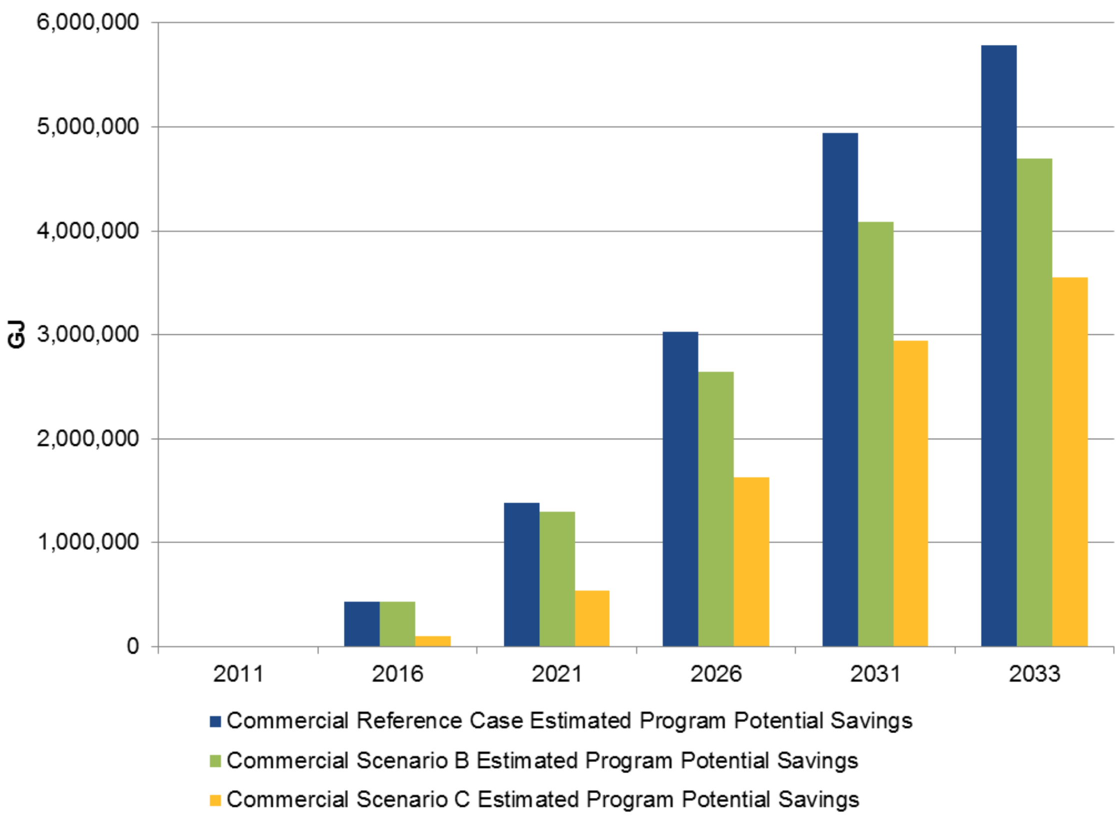


Table 1A: FEU Commercial Annual EEC Savings by Measure and Scenario, 2016

Measure	Reference Case	Scenario B		Scenario C	
	Est. Program Potential Savings (GJ)	Est. Program Potential Savings (GJ)	% Change from Ref Case	Est. Program Potential Savings (GJ)	% Change from Ref Case
Advanced Veneer Dryer	826.5	743.9	-10.0%	848.6	2.7%
Aggregate savings	180,862.7	182,126.0	0.7%	32,618.7	-82.0%
BAS and RCx	132,622.0	132,496.1	-0.1%	0.0	-100.0%
Boiler upgrades	5,721.4	5,135.9	-10.2%	5,836.9	2.0%
Condensing Boiler	754.4	677.2	-10.2%	758.7	0.6%
Condensing Boilers	51,303.3	51,257.6	-0.1%		-100.0%
Condensing DHW (Boiler)	704.8	702.4	-0.3%	463.5	-34.2%
Condensing DHW (Tank Type)	21,487.5	21,393.1	-0.4%	21,705.8	1.0%
Condensing UH	1,039.8	1,040.5	0.1%	0.0	-100.0%
DCKV	1,439.7	1,438.9	-0.1%	1,441.4	0.1%
Direct-fired Paper Drying	2.5	2.2	-10.0%	2.5	1.9%
Direct-fired Water Heating	1.2	1.1	-10.0%	1.2	2.1%
Drainwater HR	565.2	562.6	-0.5%	571.1	1.0%
Efficient Oven	168.0	151.2	-10.0%	174.7	4.0%
Enclosure Upgrade	797.5	717.8	-10.0%	816.5	2.4%
HE Air Handling Units and Heaters	377.1	126.5	-66.5%	0.0	-100.0%
HE Cement Kiln	0.5	0.4	-10.0%	0.5	1.9%
HE Cooking	9,041.4	9,041.4	0.0%	4,802.5	-46.9%
HE Kiln	641.7	577.5	-10.0%	660.0	2.8%
HE Ore Dryer	0.2	0.2	-10.0%	0.2	1.9%
HE Pulp Lime Kilns	0.4	0.4	-10.0%	0.4	1.9%
Heat Treating Furnace	92.0	82.8	-10.0%	96.2	4.6%
HVLS Fans	1,739.9	1,739.2	0.0%	0.0	-100.0%
Low-Flow Aerators	8,169.8	8,146.0	-0.3%	8,249.4	1.0%
Misc Efficient Equipment	4.5	4.0	-10.0%	0.0	-100.0%
Near Condensing Boiler	5,353.0	4,841.0	-9.6%	5,473.3	2.2%
New Construction 40% Better	10,288.5	10,282.5	-0.1%	10,344.9	0.5%
Pre-Rinse Spray Valves	1,638.5	1,630.3	-0.5%	1,655.0	1.0%
Radiant Tube Heating	496.7	446.9	-10.0%	614.2	23.7%
Grand Total	**436,140.6**	**435,365.6**	**-0.2%**	**97,136.1**	**-77.7%**

Table 1B: FEU Commercial Annual EEC Savings by Measure and Scenario, 2033

Measure	Reference Case	Scenario B		Scenario C	
	Est. Program Potential Savings (GJ)	Est. Program Potential Savings (GJ)	% Change from Ref Case	Est. Program Potential Savings (GJ)	% Change from Ref Case
Advanced Veneer Dryer	3,889.4	3,629.6	-6.7%	4,311.5	10.9%
Aggregate savings	1,774,658.4	1,403,056.5	-20.9%	942,322.7	-46.9%
BAS and RCx	573,459.9	480,208.1	-16.3%	0.0	-100.0%
Boiler upgrades	26,478.2	24,645.3	-6.9%	29,502.8	11.4%
Condensing Boiler	3,074.3	2,861.2	-6.9%	3,456.8	12.4%
Condensing Boilers	938,003.1	765,614.1	-18.4%		-100.0%
Condensing DHW (Boiler)	53,113.5	41,353.3	-22.1%	42,063.1	-20.8%
Condensing DHW (Tank Type)	767,661.0	595,965.1	-22.4%	934,158.3	21.7%
Condensing UH	3,946.5	3,224.2	-18.3%	0.0	-100.0%
DCKV	5,945.0	4,902.0	-17.5%	6,818.3	14.7%
Direct-fired Paper Drying	14.5	13.5	-6.7%	16.0	10.4%
Direct-fired Water Heating	28.4	26.4	-7.0%	35.3	24.5%
Drainwater HR	9,738.1	7,940.0	-18.5%	11,142.3	14.4%
Efficient Oven	296.8	277.0	-6.7%	304.4	2.5%
Enclosure Upgrade	3,561.1	3,310.3	-7.0%	4,145.7	16.4%
HE Air Handling Units and Heaters	1,674.6	594.5	-64.5%	0.0	-100.0%
HE Cement Kiln	8.5	7.9	-6.7%	9.3	9.7%
HE Cooking	378,614.4	378,614.4	0.0%	200,723.4	-47.0%
HE Kiln	3,345.7	3,122.2	-6.7%	3,813.4	14.0%
HE Ore Dryer	2.1	1.9	-6.7%	2.0	-2.3%
HE Pulp Lime Kilns	54.1	50.5	-6.7%	59.7	10.3%
Heat Treating Furnace	131.1	122.4	-6.7%	150.6	14.9%
HVLS Fans	6,883.8	5,712.5	-17.0%	0.0	-100.0%
Low-Flow Aerators	15,965.6	12,491.0	-21.8%	18,980.0	18.9%
Misc Efficient Equipment	45.6	42.6	-6.7%	0.0	-100.0%
Near Condensing Boiler	26,359.2	24,748.4	-6.1%	29,436.6	11.7%
New Construction 40% Better	1,148,818.9	901,646.2	-21.5%	1,292,671.2	12.5%
Pre-Rinse Spray Valves	3,162.5	2,408.5	-23.8%	3,747.5	18.5%
Radiant Tube Heating	1,520.5	1,413.0	-7.1%	2,023.1	33.1%
Grand Total	**5,750,454.7**	**4,668,002.6**	**-18.8%**	**3,529,894.1**	**-38.6%**

FEU Industrial EEC Savings

Figure 2: FEU Industrial Annual EEC Savings by Scenario

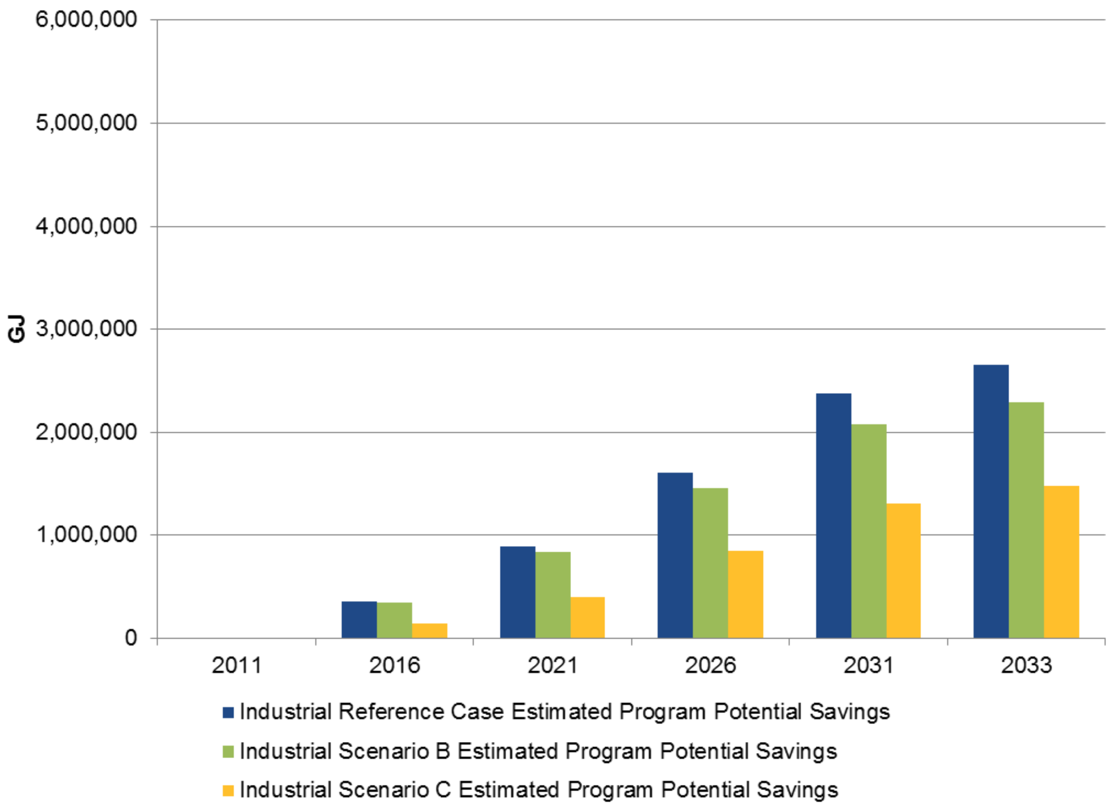


Table 2A: FEU Industrial Annual EEC Savings by Measure and Scenario, 2016

Measure	Reference Case	Scenario B		Scenario C	
	Est. Program Potential Savings (GJ)	Est. Program Potential Savings (GJ)	% Change from Ref Case	Est. Program Potential Savings (GJ)	% Change from Ref Case
Advanced Veneer Dryer	19,396.3	17,456.7	-10.0%	19,918.0	2.7%
Aggregate savings	116,595.4	120,530.7	3.4%	22,589.9	-80.6%
BAS and RCx	94,783.2	94,789.7	0.0%	0.0	-100.0%
Boiler upgrades	33,061.1	29,677.7	-10.2%	33,758.9	2.1%
Condensing Boiler	2,570.5	2,307.4	-10.2%	2,642.0	2.8%
Condensing Boilers	22,982.4	22,988.0	0.0%		-100.0%
Condensing DHW (Boiler)	327.6	327.1	-0.1%	164.2	-49.9%
Condensing DHW (Tank Type)	3,594.3	3,583.4	-0.3%	3,626.9	0.9%
DCKV	379.8	380.0	0.0%	380.3	0.1%
Direct-fired Paper Drying	177.4	159.7	-10.0%	180.9	1.9%
Direct-fired Water Heating	19.1	17.2	-10.0%	19.5	2.1%
Drainwater HR	487.9	486.4	-0.3%	492.9	1.0%
Efficient Oven	542.5	488.2	-10.0%	547.4	0.9%
Enclosure Upgrade	1,444.8	1,300.4	-10.0%	1,479.1	2.4%
HE Air Handling Units and Heaters	1,158.9	198.5	-82.9%	0.0	-100.0%
HE Cement Kiln	3.1	2.8	-10.0%	3.1	1.9%
HE Cooking	3,218.0	3,218.0	0.0%	1,387.1	-56.9%
HE Kiln	15,223.2	13,700.9	-10.0%	15,657.0	2.8%
HE Ore Dryer	2.5	2.3	-10.0%	2.6	1.9%
HE Pulp Lime Kilns	27.2	24.4	-10.0%	27.7	1.9%
Heat Treating Furnace	1,226.0	1,103.4	-10.0%	1,192.8	-2.7%
Low-Flow Aerators	2,952.8	2,950.0	-0.1%	2,978.7	0.9%
Misc Efficient Equipment	1.0	0.9	-10.0%	0.0	-100.0%
Near Condensing Boiler	26,989.6	23,341.9	-13.5%	26,419.1	-2.1%
New Construction 40% Better	4,363.6	4,375.6	0.3%	4,383.5	0.5%
Pre-Rinse Spray Valves	473.6	472.1	-0.3%	478.4	1.0%
Radiant Tube Heating	1,591.9	1,432.5	-10.0%	1,638.2	2.9%
Grand Total	**353,593.3**	**345,315.7**	**-2.3%**	**139,968.1**	**-60.4%**

Table 2B: FEU Industrial Annual EEC Savings by Measure and Scenario, 2033

Measure	Reference Case	Scenario B		Scenario C	
	Est. Program Potential Savings (GJ)	Est. Program Potential Savings (GJ)	% Change from Ref Case	Est. Program Potential Savings (GJ)	% Change from Ref Case
Advanced Veneer Dryer	79,381.0	74,078.4	-6.7%	87,989.6	10.8%
Aggregate savings	1,000,809.6	868,422.6	-13.2%	508,383.6	-49.2%
BAS and RCx	352,624.8	299,415.0	-15.1%	0.0	-100.0%
Boiler upgrades	113,656.6	105,789.0	-6.9%	127,164.2	11.9%
Condensing Boiler	6,658.6	6,197.2	-6.9%	8,834.8	32.7%
Condensing Boilers	364,517.8	302,779.5	-16.9%		-100.0%
Condensing DHW (Boiler)	22,236.7	17,867.8	-19.6%	13,571.4	-39.0%
Condensing DHW (Tank Type)	149,519.6	118,804.0	-20.5%	181,661.5	21.5%
DCKV	1,461.6	1,223.0	-16.3%	1,676.3	14.7%
Direct-fired Paper Drying	780.6	728.4	-6.7%	862.1	10.4%
Direct-fired Water Heating	358.6	333.5	-7.0%	444.8	24.0%
Drainwater HR	7,382.5	6,163.6	-16.5%	8,451.2	14.5%
Efficient Oven	922.8	861.2	-6.7%	906.6	-1.8%
Enclosure Upgrade	5,014.5	4,661.8	-7.0%	5,838.0	16.4%
HE Air Handling Units and Heaters	3,910.1	717.9	-81.6%	0.0	-100.0%
HE Cement Kiln	44.4	41.4	-6.7%	48.7	9.7%
HE Cooking	112,562.5	112,562.5	0.0%	48,522.9	-56.9%
HE Kiln	68,292.7	63,730.9	-6.7%	77,835.9	14.0%
HE Ore Dryer	19.7	18.4	-6.7%	21.8	10.4%
HE Pulp Lime Kilns	2,134.2	1,991.6	-6.7%	2,354.6	10.3%
Heat Treating Furnace	2,103.3	1,962.8	-6.7%	2,045.2	-2.8%
Low-Flow Aerators	5,160.4	4,162.2	-19.3%	6,034.2	16.9%
Misc Efficient Equipment	8.4	7.8	-6.7%	0.0	-100.0%
Near Condensing Boiler	86,701.4	81,157.3	-6.4%	97,003.9	11.9%
New Construction 40% Better	261,366.1	212,817.6	-18.6%	290,063.6	11.0%
Pre-Rinse Spray Valves	848.3	664.7	-21.6%	1,003.8	18.3%
Radiant Tube Heating	4,277.6	3,977.2	-7.0%	6,441.0	50.6%
Grand Total	**2,652,754.5**	**2,291,137.3**	**-13.6%**	**1,477,159.6**	**-44.3%**

Appendix D

SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Appendix D-1

DISCUSSION OF THE LOWER MAINLAND SYSTEM SUSTAINMENT PLAN

APPENDIX D-1 – DISCUSSION OF THE LOWER MAINLAND SYSTEM SUSTAINMENT PLAN

Appendix D-1 provides background information to transmission and intermediate pipeline planning issues highlighted in Section 5.2 and an additional area (Burns Bog) which requires further analysis. With the exception of CNG and LNG customers, gas delivery to FEU customers in the Lower Mainland is via gas pipelines and moves from high to low pressure. Gas flows through transmission pressure (TP) pipelines, which supply gas to intermediate pressure (IP) systems, which in turn supply gas to distribution pressure (DP) pipelines. Regulating stations control pressure between the higher and lower pressure systems. In some cases TP pipelines supply DP systems directly.

Describing these systems can be complex since the systems are often interlinked and can have multiple higher pressure supply points. This discussion reviews concerns and opportunities associated with the lower pressure IP systems. These concerns are then amalgamated and the combined effect, if any, on the higher pressure (e.g. TP) systems can be considered. Often, solutions on the higher pressure TP pipeline system will address multiple issues identified on the lower pressure IP pipelines.

The Coastal Transmission System (CTS) is a TP pipeline system that provides gas to all customers in the Lower Mainland. The Lower Mainland IP system is supplied from the CTS at multiple delivery points. In order to continue delivering gas safely and reliably to FEU customers, system reinforcements are required on the IP system(s) and on several sections of the CTS. Determining reinforcement strategies involves consideration of a number of main factors including:

- **Security of supply**
  The reinforcement must provide an improvement in the security of supply by:
  - Improving operability (e.g. increasing line pack, providing operational opportunities to isolate pipelines without interruptions in service)
  - Eliminating single points of failure (e.g. looping critical single pipelines, providing additional supply points)
- **Integrity**
  The reinforcements must improve integrity of the pipeline system by:
  - Addressing known integrity issues (e.g. known corrosion problems)
  - Enhancing the FEU's capability to evaluate the integrity of the pipelines using in-line inspection (ILI) or other inspection methods
- **Capacity**

Where capacity constraints have been identified, the reinforcements must address the capacity constraint

1. Lower Mainland Intermediate Pressure System

The Lower Mainland IP System is fed primarily from Fraser Gate and Coquitlam Gate stations, and is part of an integrated network that delivers gas to the regulator stations throughout Vancouver, Burnaby, New Westminster and Coquitlam. A third feed via the Pattullo Gate station also supplies this system but is not discussed here. Three main issues must be addressed on the Lower Mainland IP System:

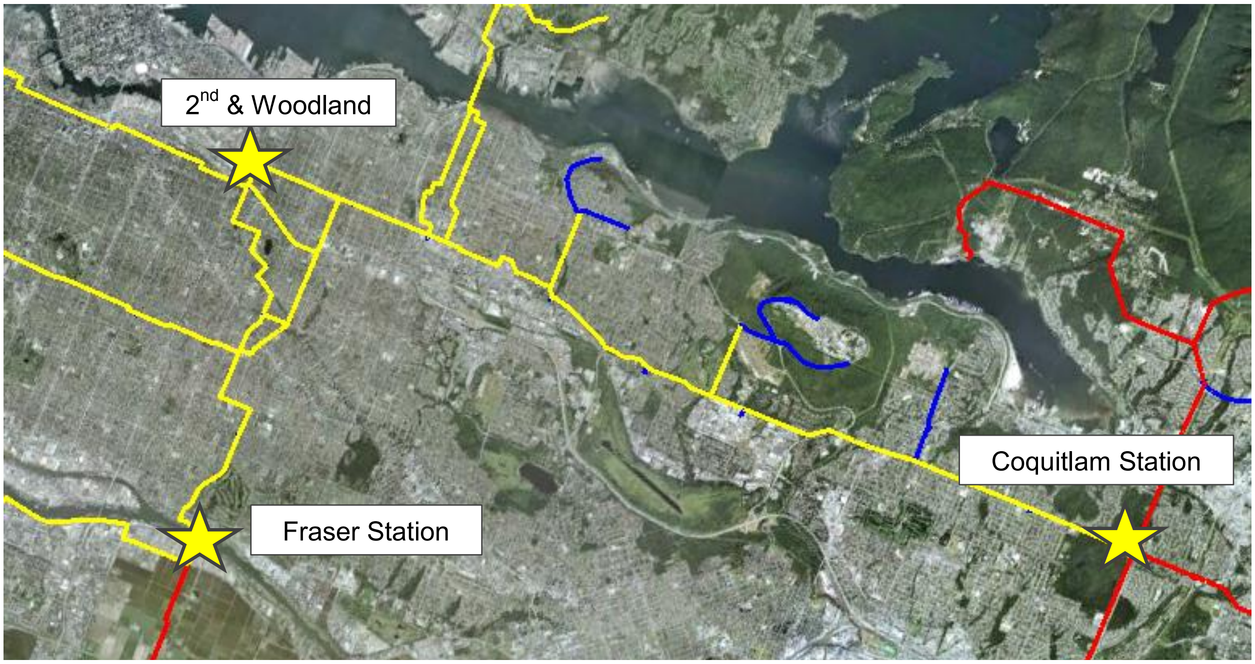
- Integrity concerns on the Coquitlam IP pipeline out of Coquitlam Gate,
- Seismic vulnerability concerns on the IP pipeline out of Fraser Gate, and
- Previously identified capacity reinforcements on the IP pipeline out of Fraser Gate.

Each of these concerns is discussed in further detail below.

1.1 COQUITLAM GATE IP PIPELINE

The Lower Mainland IP system relies on two primary pipelines. The first is a 508 mm (NPS 20) pipeline that originates at the Coquitlam Gate Station on the southeast corner of Mariner Way and Como Lake Avenue in Coquitlam and extends west to the 2nd & Woodland Distribution Station at the southwest corner of Woodland Drive and 2nd Avenue in Vancouver (Figure 1). Here, it joins with a 762 mm (NPS 30) pipeline that originates at Fraser Gate Station at the 2700 Block of East Kent Avenue in Vancouver and extends north to 2nd & Woodland.

Figure 1: Aerial Photo Showing Two Primary Pipelines (508 mm and 762 mm) Joining at 2nd and Woodland on the Lower Mainland IP System



Source: FEU data overlaid on Google Earth mapping

- Transmission pressure pipelines operating at 300 psi or greater
- Intermediate pressure pipelines operating at 100 psi up to 300 psi
- Intermediate pressure pipelines operating at 100 psi up to 300 psi

Since 2010, there have been ten corrosion leaks on the 508 mm pipeline. These leaks have been attributed to external corrosion under field-applied pipeline coatings. In response to those leaks, a number of exploratory investigations were completed to better understand the condition of the pipe and the causes of the leaks. Of the thirteen sections of pipeline that were examined between 2011 and 2012, nine of them showed evidence of corrosion. At six of those nine sections, the corrosion was active and continuing to degrade the integrity of the pipe. All leaks and instances of corrosion examined occurred at the girth welds where field-applied coating had disbonded from the pipe, creating the environment for corrosion growth.

Based on historical increases in the rate of leaks on the pipeline, the corrosion examined, and the causal factors associated with the corrosion, the pipeline has been assessed as nearing the end of its effective service life and must be replaced. An engineering assessment has shown that this pipeline is suitable for continued service and is being operated in accordance with the requirements of CSA Z662-11.[1] Through implementation of an Integrity Management Program,

[1] In response to Order 2013-25, FEI made a submission to the B.C. Oil and Gas Commission identifying the ten corrosion leaks and indicating that the 508 mm pipeline is suitable for continued service and is being operated in

FEI manages and mitigates system hazards. This has resulted in incremental mitigation activities, including increased leak survey frequency of this pipeline. In addition, FEI has outlined a replacement plan for this pipeline, which is currently planned for submission to the BC Utilities Commission in 2014. Replacing this 508 mm pipeline will reduce and potentially eliminate the frequency of leaks, avoid any unplanned shut downs of this pipeline, and address concerns of uncontrolled migration of leaking gas which could result in accumulation of gas. Replacing the pipeline also addresses the FEU's requirement under Section 37(1)(a) of the B.C. *Oil and Gas Activities Act* to prevent spillage.

A CPCN application is expected to be submitted by the second quarter of 2014. Nevertheless, with a decision reached to replace the pipeline, FEI must look beyond the 508 mm section and the immediate pipeline condition concern to ensure that the planned upgrades help to optimize other system sustainment and planning solutions required in the region.

1.2 FRASER GATE IP PIPELINE

In the 1990s, work was completed to stabilize the transmission pipelines supplying Fraser Gate and to stabilize the station site itself against earthquake induced ground movement. This was done in response to a seismic vulnerability study that predicted loss of service through these assets if a significant seismic event should occur. However, the 762 mm outlet pipe from Fraser Gate, forming the southerly end of the Coquitlam, Burnaby, Vancouver IP pipeline system, was not stabilized and remains at high risk of failure due to ground movement associated with an earthquake as small as a one in 475-year return period event. Loss of service of that pipeline could result in service disruption of up to 170,000 customers. Consequently, the 762 mm IP pipeline from Fraser Gate to Marine & Elliott Station must be replaced to bring it up to current seismic standards and a CPCN application is expected to be brought forward in 2014. However, due to the reasons outlined below, the Coquitlam 508 mm IP pipeline must be reinforced first to enable this work.

Hydraulic modeling has confirmed that it is not practical to shut in[2] the Fraser Gate IP outlet to correct the identified seismic vulnerability. Shutting in this pipeline for extended periods of time would lead to a loss of service to a significant number of customers. Barring shut in of the Fraser Gate IP pipeline, two other options are available to upgrade the 700 m of 762 mm pipeline while continuing to provide service to customers supplied from Fraser Gate:

(1) The first option involves installing a temporary bypass thereby allowing gas to continue to flow from Fraser Gate. Unfortunately, installing a bypass is not considered feasible due to the railway crossing depicted below in Figure 2.

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accordance with the requirements of CSA Z662-11. Nevertheless, plans to replace this pipeline address the FEU's requirement under Section 37(1)(a) of the B.C. *Oil and Gas Activities Act* to prevent spillage.

[2] A pipeline "shut in" refers to removing the pipeline from service.

(2) The second option involves increasing the back-feed capacity through the Coquitlam pipeline such that Fraser Gate could be taken out of service. This option effectively "back flows" gas from Coquitlam Gate to those customers served from Fraser Gate.

Previous analyses had indicated a potential capacity constraint on the 762 mm Fraser Gate pipeline. One potential solution for this capacity constraint would be to loop this pipeline; however, given the necessity to replace the existing 508 mm Coquitlam IP pipeline, there is an opportunity to *increase* the capacity of the Coquitlam IP pipeline which negates the previously forecast need to loop the 762 mm Fraser Gate pipeline.

Increasing capacity through the Coquitlam IP Pipeline has a number of benefits including: aligning with the planned replacement of the Coquitlam IP pipeline, the ability to provide a second feed to the Lower Mainland (basically allowing gas to flow from either Fraser or Coquitlam gates), and increasing operational flexibility due to multiple supply points.

Figure 2: Aerial Photo Showing Railway Crossing Obstacle to Potential Bypass Construction on Fraser Gate to Marine & Elliott 762 mm IP Pipeline

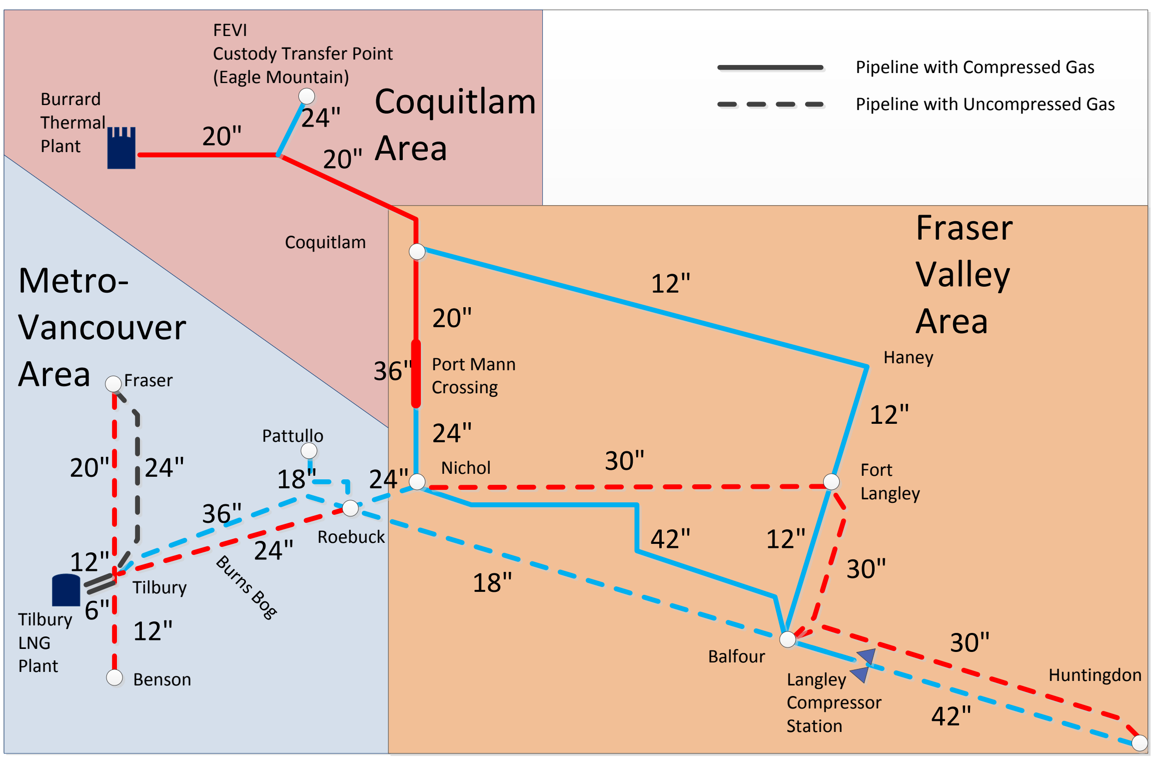
Source: FEU data overlaid on Google Earth mapping

In summary, reinforcing the Coquitlam IP would address identified integrity concerns on this pipeline. Sufficient reinforcement (e.g. potentially upsizing this pipeline) would provide a means to address the seismic risk on the Fraser IP pipeline by allowing the 762 mm pipeline to be taken out of service. In addition, reinforcing the Coquitlam IP pipeline would also indefinitely defer previously identified capacity reinforcements on the Fraser IP 762 mm pipeline.

2. Coastal Transmission System

The 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 and Metro Vancouver. There are two, primary transmission-related facilities on the CTS: the Langley Compressor Station and the Tilbury LNG storage facility. The CTS delivers gas to the core market distribution networks in the Lower Mainland and provides transportation service to BC Hydro's Burrard Thermal Generating Station (BT) and to the FEVI transmission system at Eagle Mountain in Coquitlam. The layout of the CTS is shown in Figure 3.

Figure 3: Schematic of the Coastal Transmission System Including the Langley Compressor Station and Tilbury LNG Storage Facility



2.1 NICHOL TO COQUITLAM

Security of Supply and Pipeline Capacity

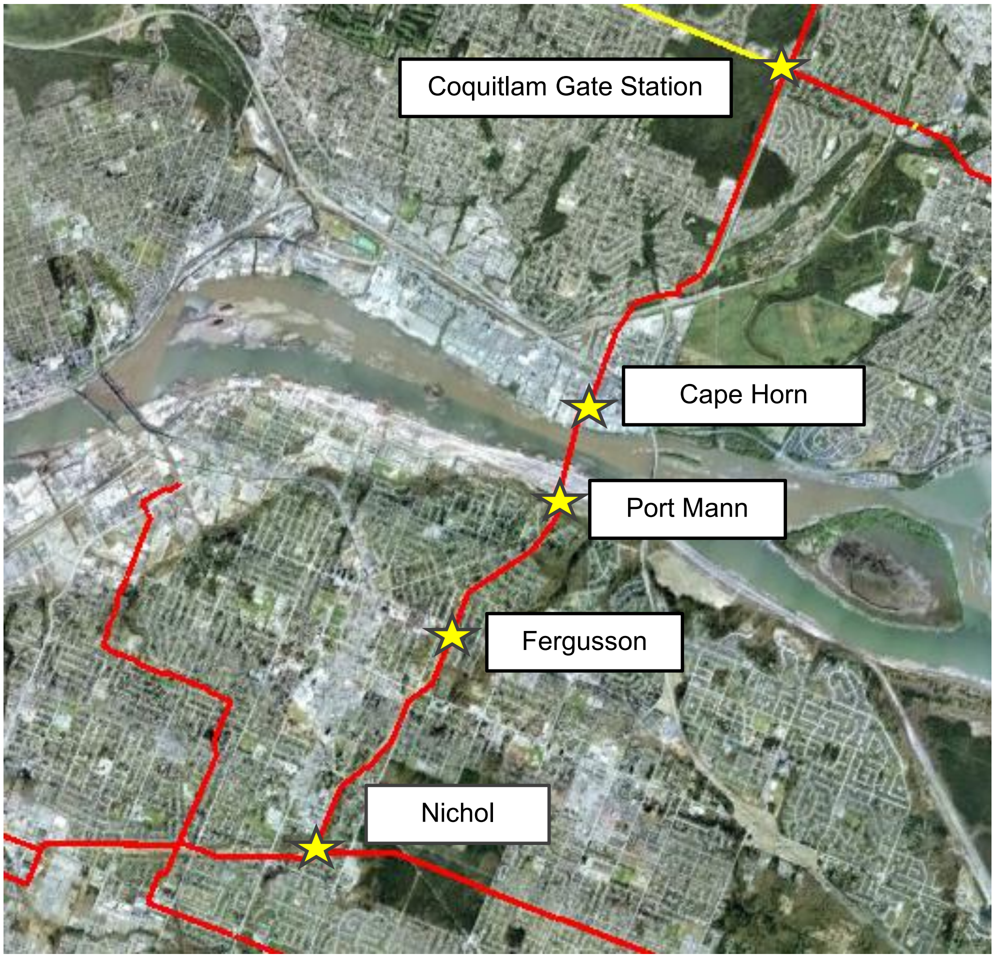
Long range system capacity planning has identified a need to reinforce the CTS in approximately 2027. These reinforcements are planned to occur on the Nichol to Coquitlam pipeline(s) and could include replacement, looping, load reduction (via Burrard Thermal contractual agreements) or a combination thereof. This is a known and identified capacity constraint on the CTS.

To support the strategy of IP back feed from Coquitlam Gate station (refer to previous section) TP reinforcements are required on the CTS. Potential reinforcements on this transmission corridor from Nichol Control Station north towards Coquitlam Gate station could include:

- Looping or replacing the existing 508 mm TP pipeline from the Cape Horn Valve Assembly to the Coquitlam Gate Station; and/or
- Looping or replacing the existing 610 mm TP pipeline from Nichol Control Station to the south bank of the Port Mann crossing of the Fraser River.

These reinforcements increase the supply pressure and capacity to Coquitlam Station, thereby enabling back feed towards Fraser Gate on the IP pipeline. Providing additional capacity to Coquitlam Gate station through the 323 mm Livingstone to Coquitlam TP pipeline from the east has also been considered; however, analysis completed to date indicates that upgrading 35 kilometers of this 323 mm pipeline would be cost prohibitive when compared to reinforcing the 11 kilometers of pipeline from Nichol to Coquitlam. Consequently, transmission reinforcements of the Nichol to Coquitlam pipeline(s) are required to address the need to strengthen the Fraser to Marine and Elliot IP Pipeline and to support security of supply to Coquitlam, Burnaby and Vancouver customers.

Figure 4: Aerial Photo Showing Coquitlam Gate Station and Potential Project Areas from Nichol to Coquitlam



Source: FEU data overlaid on Google Earth mapping

In-Line Inspection between Fergusson Station and Port Mann Station

ILI is a critical aspect of the FEU system integrity program that provides an opportunity to identify pipeline defects that cannot be otherwise detected. In 2003, a Horizontal Directional Drill (HDD) crossing was completed of the Fraser River on the Nichol to Coquitlam pipeline downstream of the Port Mann Bridge and to meet anticipated future growth, the new crossing was installed using 914 mm pipe. Baseline ILI of the 914 mm river crossing is planned for 2016 and work is currently underway to relocate the receiving barrel on the 610 mm pipeline to allow ILI from the Nichol Valve Assembly to the Port Mann crossing. Previous ILI inspections on the 610 mm pipeline have been conducted from Nichol to Ferguson.

Loss of the 610 mm pipeline between Ferguson and Port Mann or the river crossing between Port Mann and Cape Horn could result in the loss of service of up to 170,000 customers. Moving the receiver from Fergusson Station to Port Mann would provide the capacity to conduct an ILI on the entire length of the Nichol to Port Mann 610 mm pipeline. However, the Port Mann location is a city park and securing property rights at that location may be difficult to impossible.

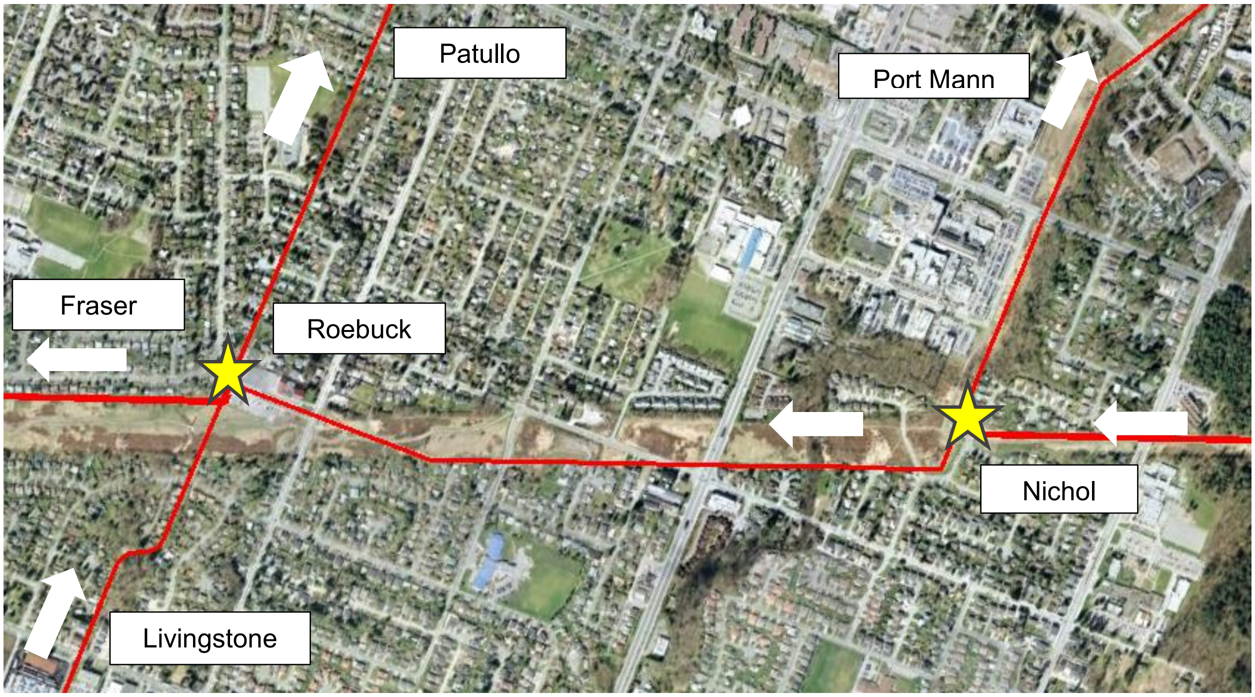
These pipeline inspection challenges can be resolved by looping the Nichol to Port Mann pipeline with a with a 914 mm loop, which would enable joining the 914 mm proposed pipeline with the existing 610 mm pipeline at a location anywhere between Fergusson Station and Port Mann that a suitable site can be located. This solution would permit full ILI from Nichol to Cape Horn and provide increased confidence in the ability to maintain the integrity of this critical pipeline. As a result of the current impracticality of completing in-line inspections on the Port Mann crossing, the Nichol to Port Mann loop should be completed before the Cape Horn to Coquitlam loop.

2.2 NICHOL TO ROEBUCK

Two pipelines supply gas to the Nichol Valve Assembly, a 1067 mm and 762 mm. From Nichol gas can flow north to Coquitlam or west to Fraser Gate and Vancouver. Between Nichol and the Roebuck Valve Assembly at the 9100 Block of 132 Street in Surrey (Figure), all flow is through a single 610 mm pipeline. At Roebuck the system is increased to 762 mm and 914 mm pipelines that run to Fraser Gate. A limited supply also intersects the system at Roebuck with the 457 mm TP pipeline between Livingstone Station and Patullo Station; however, the capacity of this pipeline would have little effect on the overall loss of supply if the Nichol to Roebuck pipeline was disrupted.

Loss of the Nichol to Roebuck section of 610 mm transmission pipeline could result in the loss of service of up to 320,000 customers. While FEI manages pipeline integrity through an active Integrity Management Program (including activities such as pipeline inspection and leak survey reports), it is prudent and in alignment with the Security of Supply strategy to reduce risk by installing a second line at this location. Correspondingly, looping Nichol to Roebuck with a 1067 mm transmission pipeline is required. A CPCN application specific to this work is expected to be filed in 2014.

Figure 5: Aerial Photo of the Nichol to Roebuck 610 mm Transmission Pipeline Showing Flow Directions



Source: FEU data overlaid on Google Earth mapping

2.3 BURNS BOG

The gas supply to Delta, Richmond and Vancouver is transported through Burns Bog between Delta Valve Assembly and Tilbury Valve Assembly by the same 914 mm and 762 mm pipelines as run west from Roebuck Valve Assembly. When these pipelines were first installed, there was limited activity in the area. However, in recent years, landfilling and construction adjacent to the right of way (ROW) has resulted in soil movement causing pipeline damage at three different sites. Repair of the pipeline at these sites required that the pipelines be moved to bypasses and the ROW preloaded to compress and stabilize the soil. Following adequate compaction, the pipelines were reinstated in their original alignment.

A similar system of bypasses and preload was used during construction of the South Fraser Perimeter Road along the north side of the ROW. Pipeline and soil monitoring during construction of the South Fraser Perimeter Road indicated that one section of the northerly 914 mm pipeline may have had a deflection of up to 700 mm over a 300 meter length. ILI performed in 2013 has since provided a more accurate assessment. Additional ILI runs are being considered for 2014 to further assess whether settling of these pipelines is an issue requiring mitigation.

Appendix D-2

FEI 5-YEAR CAPITAL PLAN

APPENDIX D-2 – FEI 5-YEAR CAPITAL PLAN

PREAMBLE

FEI has segmented its 5 Year Capital Plans as follows:

Regular Capital Plan

- Sustainment Capital – Consists of expenditures for meter recall or meter exchange programs; system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load; replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and expenditures for mains and service renewals and alterations.
- Growth Capital – Consists of expenditures for the installation of new mains, services and meters.
- Other Capital – Consists of expenditures for Bio-methane Interconnections, Equipment, Facilities, and IT.

Major Capital Plan

- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital is defined as forecast Capital Expenditures that are under $5 million (excluding AFUDC) and have been categorized into Sustainment, Growth and Other capital. This category excludes Capitalized Overheads and AFUDC.

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. Typically, major capital projects for FEI in excess of $5 million have required a CPCN.

FEI's 5 Year Capital Plans for the period 2014 to 2018 are presented to provide additional background and context for the Resource Plan. These Capital Plans are not included for the purposes of approval by the BCUC in its review of the FEI Resource Plan, since FEI believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. FEI's 2014-2018 Performance Based Ratemaking Revenue Requirements Application included detailed capital expenditures that were submitted on June 10, 2013. Consistent with past practice, FEI continues to believe that the appropriate forum for review of its Capital Expenditures is in its Revenue Requirements Application proceedings.

As FEI's 5 Year Regular Capital Plan and Major Capital Plans include all planned capital expenditures, FEI believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the *Utilities Commission Act*.

FEI has endeavored to provide a comprehensive 5 Year Capital Plan 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 the Company's next Revenue Requirements Application filing, which is anticipated in 2018.

5 YEAR REGULAR CAPITAL PLAN

The following table identifies the cost projections for regular capital expenditures from 2014-2018. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

- Sustainment Capital – System Integrity and Reliability
  - Meter Recalls / Exchanges
  - Transmission System Reinforcements / Integrity and Reliability
  - Distribution System Reinforcements / Integrity and Reliability
  - Distribution Mains and Service Renewals and Alterations
- Growth Capital – Mains, Services & Meters
  - New Customer Mains
  - New Customer Services
  - New Customer Meters
- Other Capital – All Other Plant
  - Biomethane - Interconnect
  - Equipment
  - Facilities
  - IT
- Contributions In Aid of Construction

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 1 identifies the cost projections for regular capital expenditures in 2014-2018.

Table 1: Forecast of Regular Capital Expenditures ($ thousands)

	2013 Projection	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	25,062	25,967	26,852	25,869	24,225	25,085
Transmission System Reinforcements	18,005	16,555	20,479	15,537	14,221	14,298
Distribution System Reinforcements	8,691	10,112	7,282	7,546	8,073	8,653
Distribution Mains & Service Renewals & Alt.	20,500	25,815	24,433	28,245	34,059	34,304
Total Sustainment Capital	72,258	78,449	79,045	77,198	80,578	82,340
Growth Capital						
New Customer Mains	5,033	5,374	5,462	5,561	5,664	5,798
New Customer Services	16,791	18,360	19,502	20,214	20,337	20,363
New Customer Meters	1,438	1,664	1,805	1,876	1,877	1,862
Total Growth Capital	23,262	25,398	26,769	27,651	27,878	28,022
Other						
Biomethane - Interconnect	1,100	3,908	1,100	1,864	1,864	1,864
Equipment	3,875	6,818	7,328	7,127	7,358	6,702
Facilities	7,549	3,904	4,026	4,122	4,269	4,626
IT	21,600	20,105	20,105	20,106	20,102	20,098
Total Other	34,124	34,735	32,560	33,218	33,593	33,289
Total Gross Capex	129,644	138,582	138,374	138,067	142,050	143,652
CIAC	(5,864)	(5,821)	(5,821)	(5,821)	(5,820)	(5,819)
Total Net Capex	123,781	132,762	132,554	132,247	136,230	137,833

5 YEAR MAJOR CAPITAL PLAN

1. Major Capital Projects that do not require a CPCN

Table 2 identifies the cost projections for major capital projects that are included in Regular Capital but are not subject to CPCN applications for the period 2010-2014.

Table 2: Forecast of Major Capital Projects not requiring a CPCN ($ thousands)

Project Description	Project Category	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
($000's)							
Transmission Plant							
2731m of 1957 vintage 273mm OD Savona Nelson Mainline	Pipeline Location Upgrades		4,100				
697m of 1957 vintage 323mm OD Savona Nelson Mainline	Pipeline Location Upgrades			1,200			
2206m of 1957 vintage 114mm OD Williams Lake Lateral	Pipeline Location Upgrades			3,300			
765m of 1975 vintage 323m OD East Kooenay Link Mainline	Pipeline Location Upgrades				1,300		
1291m of 1957 vintage 168mm OD Prince George #1 Lateral	Pipeline Location Upgrades				1,900		
1319m of 2000 vintage 610mm OD Southern Crossing Pipeline	Pipeline Location Upgrades					2,000	
2782m of 2000 vintage 610mm OD Southern Crossing Pipeline	Pipeline Location Upgrades						4,500
Pitt River Pipeline Crossing Replacement	Natural Hazards Mitigation				3,500		
Electrical Equipment	Tilbury LNG Plant Upgrades		2,700				
Inlet & Outlet Pipelines Replacement	Tilbury LNG Plant Upgrades			2,000			
Second Pump for Loading Tankers	Tilbury LNG Plant Upgrades			1,000			
Air Cooler	Tilbury LNG Plant Upgrades						3,000
Buildings	Tilbury LNG Plant Upgrades						1,000
Tilbury Expansion Project	Tilbury LNG Plant Upgrades	5,000	102,388	159,606	133,005		
Distribution Plant							
Trenton Gate Station Replacement - Port Coquitlam	Upgrade/Enhancement		1,200				
Lougheed Hwy Main Replacement Project - Burnaby	Upgrade/Enhancement		1,300				
Penticton Second Supply	Upgrade/Enhancement						
Pattullo Bridge Replacement - Surrey/New Westminster	Upgrade/Enhancement			2,700			
IT							
GIS Refresh Project	Upgrade/Enhancement	428	1,733				
E-Forms Project	Upgrade/Enhancement	405	1,575				
Intranet Project	Upgrade/Enhancement	360	720				
SharePoint Migration and Upgrade Project	Upgrade/Enhancement	810	360				
SharePoint Business New Builds Project	Upgrade/Enhancement	720	630				
Finance Consolidation and Enterprise Report / Gas Cost Forecasting	Upgrade/Enhancement	1,080	387				
Project Portfolio Management	Upgrade/Enhancement		180				
Customer Service Enhancement Project	Upgrade/Enhancement	1,575	1,215	1,215	1,215	1,215	1,215
Network and Security Enhancements Program	Upgrade/Enhancement	1,440	1,890	1,350	1,350	1,350	1,350
Server, Storage and Data Centre Enhancements Program	Upgrade/Enhancement	1,350	1,710	1,350	1,350	1,350	1,350
Unified Communications Program	Upgrade/Enhancement	2,160	1,350	900	900	900	900

1.1 PIPELINE CLASS LOCATION UPGRADES

Clause 4.3.2 of CSA Standard Z662, *Oil and gas pipeline systems*, defines limitations on operating stress (safety factor) based on the number of dwellings within 200m of the pipeline. An increase in the density of dwellings adjacent to a pipeline may result in the class location being changed leading to a requirement to reduce the operating stress of the pipeline and thus increase the factor of safety. CSA Z662 also requires annual assessments of the class location to recognize and accommodate development near the pipeline. In instances where the class location is changed as a result of development FEI must change the operating parameters of the pipeline. This may require reducing the operating pressure which leads to a loss of capacity and may limit the ability to meet customer demand. In instances where reducing operating pressure is unacceptable, the impacted section of pipeline must be replaced to meet the required safety factor while maintaining customer supply.

The projects listed below involve the replacement of sections of pipelines due to adjacent development and are anticipated to exceed $1 million over the 2014-2018 forecast period:

- 2731m (6 segments) of 1957 vintage 273mm OD Savona Nelson Mainline, East of Oliver (2014) – approx. $4.1 million;
- 697m (10 segments) of 1957 vintage 323mm OD Savona Nelson Mainline, West of Kamloops and West of Vernon (2015) – approx. $1.2 million;
- 2206m (4 segments) of 1957 vintage 114mm OD Williams Lake Lateral, Williams Lake (2015) – approx. $3.3 million;
- 765m (9 segments) of 1975 vintage 323mm OD East Kootenay Link Mainline, Salmo and Creston (2016) – approx. $1.3 million;

1.2 NATURAL HAZARDS MITIGATION

FEI's operating programs monitor depth of cover at water crossings, the stress on pipelines at sites of moving or unstable slopes, and the resistance of pipelines with regard to seismic events. The following project is required to prevent the loss of pipeline integrity as a result of natural hazards.

Pitt River Pipeline Crossing Replacement, 323mm OD Livingstone to Coquitlam Pipeline, Port Coquitlam & Pitt Meadows (2016). The pipeline crossing of this river is both shallow and susceptible to high stresses as a result of ground movement due to a moderate seismic event. Options have been considered and a 900m long horizontally directionally drilled pipeline crossing is proposed. The approximate cost is $3.5 million.

1.3 TILBURY LNG PLANT UPGRADES

A number of projects that exceed $1 million have been identified that will ensure the continued reliable and safe operation of the Tilbury LNG Plant over the 2014-2018 forecast period.

Electrical Equipment (2014) – estimated $2.7 million

Recent changes to the provincial Electrical Code as well as some deterioration and obsolescence necessitate the need to upgrade the electrical supply for the plant.

Inlet and Outlet Pipelines Replacement (2015) – estimated $2 million

The two pipelines operating as the inlet and outlet for the plant (323mm and 168mm) pass through an area that is known to have a high potential for seismically induced liquefaction. This would result in significant lateral spreading and potential failure of both pipelines under a moderate seismic event. Replacement of 550m sections of the pipelines at a greater depth (approx. 20m) by horizontally directional drilling is proposed.

Second Pump for Loading Tankers (2015) – estimated $1 million

Only one pump exists for loading LNG tankers and if this pump failed the repair or replacement likely could not be accomplished in a timely manner. A second pump is proposed to be installed as a standby pump to ensure the ability to fill LNG tankers, respond to requests for emergency LNG supply, and to provide LNG for planned distribution system alterations.

Air cooler (2018) – estimated $3 million

Replacement is required as age related deterioration is not preventable. Failure generally occurs due to fins lodging to tubing without warning and results in a complete loss of liquefaction capability. An unplanned repair would likely take significant time and would reduce supply for emergency and planned distribution alterations and peak shaving.

Buildings (2018) – estimated $1 million

Upgrade of control and administration building to current standards including ensuring design to post significant seismic event operability.

1.4 TILBURY LNG FACILITY EXPANSION PROJECT

In November 2013, the Province signed a Special Direction directing the BCUC to allow the Corporation to expand the LNG facilities at Tilbury Island in Delta, BC. The Expansion Project will increase the LNG production and storage capabilities at the Tilbury LNG Facility. The Special Direction set out a number of requirements for the BCUC as follows:

- To exempt the Expansion Project from a CPCN process;
- To impose an upper limit of $400 million on costs related to the Expansion Project;
- To allow for recovery of the costs of the Expansion Project from customers;
- To allow FEI to provide CNG and LNG service as part of its natural gas service; and
- To approve a permanent LNG sales and dispensing service for FEI at the rate set out in the Special Direction.

The Expansion Project is expected to be put in service in 2016.

1.5 DISTRIBUTION SYSTEM REINFORCEMENT, INTEGRITY AND RELIABILITY CAPITAL

Trenton Gate Station Replacement – Port Coquitlam (2014)

The replacement of the Trenton Gate Station is to address undersized piping, an unreliable line heater, and add a station inlet filter and telemetry. This station supplies both DP and IP systems and thus is larger than a typical community gate station. The replacement has been proposed since 2006, but has been deferred due to nearby transportation projects, including the upgrade to the intersection of the Mary Hill Bypass with the Lougheed Highway and the construction of the new Pitt River Bridge, in order to determine the impact of this work upon the station site. As well, deferral of construction has occurred in order to undertake negotiations for additional land as the existing site is an odd shape and use is restricted by overhead power lines and adjacent wet lands. Approximate cost is $1.2 million.

1.6 DISTRIBUTION MAINS, SERVICE RENEWALS AND ALTERATIONS CAPITAL

Lougheed Highway Main Replacement Project – Burnaby (2014)

The Lougheed Highway Main Replacement project consists of replacing approximately 4.5km of existing 168mm steel main with polyethylene pipe along the existing route or along another, as the existing pipe was installed in the original shoulder of the road and was installed on supports. With subsequent widening of the road over the pipeline and repeated flexing of the pipe due to traffic load, there have been a number of failures of the oxy-acetylene welds, the most recent in 2008 when 500 homes were evacuated. The installation of new pipe will also reduce the probability of a significant interruption to the operation of the Skytrain and interference with Lougheed Highway. Other sections of the steel main have been replaced in the past. Design and community relations activities have been undertaken and the first phase of the replacement is occurring in 2013 ($410 thousand). The proposed expenditure in 2014 is $1.3 million.

Penticton Second Supply – Penticton (2015)

The distribution system in and adjacent to the City of Penticton is presently served by one gate station. The configuration of the distribution piping exiting and heading away from the station is such that a failure of one major branch, for example, from third party damage, will result in the interruption of service to a significant portion of the town. There are approximately 13,000 customers served by the existing station and it is proposed that a second gate station be installed along with a large supply main into the central portion of town. This will reduce the likelihood of a single event affecting a majority of the entire customer base. The plan to install a second source of supply to the City of Penticton has been in existence for many years. In about 1980 the site for the second gate station was purchased in the NE corner of Penticton. The estimated cost for installing an additional gate station and the distribution system improvements is $2.4 million (approx. 10 percent will be incurred in 2014).

Pattullo Bridge Replacement – Surrey / New Westminster (2015)

The replacement of the Pattullo Bridge that crosses the Fraser River between the cities of Surrey and New Westminster is planned by Translink. FEI has a 508mm OD pipeline on this bridge (installed about 1970) currently operating at 700kPa (with a potential to operate at 1200kPa). The pipeline supplies a large portion of New Westminster and the eastern portion of Burnaby. FEI has confirmed that a pipeline crossing at this location is required and preliminary agreement has been obtained for approval to install a new gas line on the new bridge. In this instance the existing pipeline is subject to the conditions of a “Highways Permit” which includes the requirement that FEI is responsible for any alterations to the gas line as a result of work on the bridge. At the present time it is our understanding that FEI may have to install a new pipeline on the new bridge during 2015; however, this could be deferred as a result of decisions by other parties. The estimate for the total project is $2.7 million.

2. Major Capital Projects that require a CPCN

At this time, there are no major (estimated value exceeding $5 million) capital pipeline projects that have already been approved and will come into service during the PBR Period.

2.1 ANTICIPATED CPCN - HUNTINGDON STATION BYPASS

FEI's Huntingdon Station is the sole source of supply to FEI's Coastal Transmission System (CTS) and the interconnected FEVI transmission system and controls gas supply to communities in the Lower Mainland, Squamish, Whistler, the Sunshine Coast, and Vancouver Island. Loss of functionality of certain sections of the Huntingdon Station can lead to the complete outage on both the CTS and FEVI systems, thereby triggering a potential gas supply service outage to 660,000 customers. A new station bypass at Huntingdon Station is necessary to reduce the risk of a service outage. FEI anticipates filing a CPCN for this project and completing this project during the PBR period.

2.2 ANTICIPATED CPCN - PRELOAD AND STABILIZE REMAINING RIGHT OF WAY BETWEEN DELTA STATION AND TILBURY STATION

As a result of operational issues that have been experienced, work has been undertaken over the past several years to stabilize most of the Right of Way in the Burns Bog area through which two transmission pipelines run. There are still sections that remain to be stabilized to mitigate the risk of ground movement and associated pipe damage. FEI anticipates filing a CPCN for this project and completing this project during the PBR period.

2.3 ANTICIPATED CPCN - COASTAL TRANSMISSION SYSTEM UPGRADE PLAN

The CTS is comprised of approximately 260 kilometers of pipelines that provide natural gas transportation from the Huntingdon-Sumas trading point to various metering and regulating stations throughout the Fraser Valley and Metro Vancouver areas. It also supplies the FEVI transmission system at Eagle Mountain in Coquitlam.

Analysis of the CTS has indicated there are a number of projects that may be required in order to ensure the ongoing safety, integrity, and reliability of the system. FEI is developing an overall plan that will include those projects, and anticipates filing those projects in the form of CPCNs during the course of this PBR period. Currently, this plan includes the following projects:

1. *Looping the 610mm OD Nichol to Port Mann Transmission Pipeline with 914mm OD in Surrey;*
2. *Looping the 610mm OD Nichol to Roebuck Transmission Pipeline with 1067mm OD in Surrey;*
3. *Replacing and upgrading the 508mm OD Coquitlam to Vancouver Intermediate Pressure Pipeline (the actual size and delivery pressure are still to be determined) and,*

4. *Looping the 508mm OD Cape Horn to Coquitlam Transmission Pipeline with 914mm OD in Coquitlam.*

LOOP THE 610MM OD NICHOL TO PORT MANN TRANSMISSION PIPELINE WITH 914MM OD IN SURREY:

Looping the Nichol to Port Mann transmission pipeline is required to:

Improve supply to Coquitlam Station and improve security of supply to 170,000 customers. Allow redirection of pipeline flows to meet operational needs; Provide the ability to manage ILI operations on the pipeline and Port Mann crossing; and assist in managing the reverse flow operation of the Mt. Hayes LNG facility.

FEI anticipates filing a CPCN for this project and completing this project during the PBR period.

LOOP THE 610MM OD NICHOL TO ROEBUCK TRANSMISSION PIPELINE WITH 1067MM OD IN SURREY:

This transmission pipeline loop is required to provide improved security for supply for up to 320,000 customers that currently depend on a single 610 mm pipeline.

FEI anticipates filing a CPCN for this project and completing this project during the PBR period.'

REPLACE AND UPGRADE 508MM OD COQUITLAM TO VANCOUVER INTERMEDIATE PRESSURE PIPELINE:

Replacement of this pipeline is required to mitigate risks to identified corrosion and ensure security of supply to up to 41,000 customers.

FEI anticipates filing a CPCN for this project and completing this project during the PBR period.

LOOP THE 508MM OD CAPE HORN TO COQUITLAM TRANSMISSION PIPELINE WITH 914M OD IN COQUITLAM:

This pipeline loop is required to enable improved supply through Coquitlam station and to provide improved security of supply to up to 150,000 customers.

FEI anticipates filing a CPCN for this project and completing this project during the PBR period.

2.4 ANTICIPATED CPCN - KINGSVALE-OLIVER REINFORCEMENT PROJECT (KORP)

The KORP consists primarily of a 161 km, 24-inch expansion project from Kingsvale to Oliver, BC. The reinforcement would further integrate and expand service using available capacity on T-South and SCP. The KORP provides an opportunity to deliver a growing supply of British Columbia gas to the Pacific Northwest and California markets. Removing pipeline capacity constraints would build on the T-South Enhanced Service offering for FEI customers, including additional demand charge revenue, T-South toll savings, and improved access to competitively prices and reliable gas supply, as well as additional security of supply and liquidity in the region.

FEI customers have received accumulated financial benefits of $25 million from the T-South Enhanced Service offering. This is forecasted to grow to $36 million by 2014. The T-South Enhanced Service has provided shippers with the optionality of delivering to Sumas or the Kingsgate market. Expansion of the bi-directional Southern Crossing system would also aid in increasing capacity at Sumas during peak demand periods.

Appendix D-3

FEVI 5-YEAR CAPITAL PLAN

APPENDIX D-3 – FEVI 5-YEAR CAPITAL PLAN

1 PREAMBLE

FEVI has segmented its 5 Year Capital Plans as follows:

Regular Capital Plan

- Sustainment Capital – Consists of expenditures for meter recall or meter exchange programs; system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load; replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and expenditures for mains and service renewals and alterations.
- Growth Capital – Consists of expenditures for the installation of new mains, services and meters.
- Other Capital – Consists of expenditures for Equipment, Facilities, and IT.

Major Capital Plan

- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital is defined as forecast Capital Expenditures that are under $5 million (excluding AFUDC) and have been categorized into Sustainment, Growth and Other capital. This category excludes Capitalized Overheads and AFUDC.

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. Typically, major capital projects for FEI in excess of $5 million have required a CPCN.

FEVI's 5 Year Capital Plans for the period 2014 to 2018 are presented to provide additional background and context for the Resource Plan. These Capital Plans are not included for the purposes of approval by the BCUC in its review of the FEVI Resource Plan, since FEVI believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. FEVI's 2014 Revenue Requirements Application included detailed capital expenditures that were submitted on September 25, 2013. Consistent with past practice, FEVI continues to believe that the appropriate forum for review of its Capital Expenditures is in its Revenue Requirements Application proceedings.

As FEVI's 5 Year Regular Capital Plan and Major Capital Plans include all planned capital expenditures, FEVI believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the Utilities Commission Act.

FEVI has endeavored to provide a comprehensive 5 Year Capital Plan 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 the Company's next Revenue Requirements Application filing, which is anticipated in 2014.

2 5 YEAR REGULAR CAPITAL PLAN

The following table identifies the cost projections for regular capital expenditures from 2014-2018. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

- Sustainment Capital – System Integrity and Reliability
    - Meter Recalls / Exchanges
    - Transmission System Reinforcements / Integrity and Reliability
    - Distribution System Reinforcements / Integrity and Reliability
    - Distribution Mains and Service Renewals and Alterations
- Growth Capital – Mains, Services & Meters
    - New Customer Mains
    - New Customer Services
    - New Customer Meters
- Other Capital – All Other Plant
    - Equipment
    - Facilities
    - IT
- Contributions In Aid of Construction

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 1 identifies the cost projections for regular capital expenditures in 2014-2018.

Table 1: Forecast of Regular Capital Expenditures ($ thousands)

	2013 Projection	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	1,344	1,358	1,515	1,613	1,648	1,816
Transmission System Reinforcements	6,328	7,541	12,699	5,768	7,241	4,215
Distribution System Reinforcements	1,296	2,215	2,153	1,639	1,860	1,070
Distribution Mains & Service Renewals & Alt.	5,803	4,529	4,730	5,344	5,732	7,453
Total Sustainment Capital	14,771	15,643	21,097	14,364	16,481	14,554
Growth Capital						
New Customer Mains	2,400	2,518	2,568	2,619	2,672	2,725
New Customer Services	5,162	5,983	6,570	6,874	6,823	6,960
New Customer Meters	270	300	330	345	342	349
Total Growth Capital	7,833	8,801	9,467	9,838	9,837	10,034
Other						
Equipment	4,230	1,566	1,185	1,188	1,187	986
Facilities	616	642	642	643	643	643
IT	2,400	2,222	2,219	2,224	2,223	2,225
Total Other	7,246	4,430	4,046	4,054	4,053	3,854
Total Gross Capex	29,850	28,875	34,611	28,257	30,371	28,442
CIAC	(845)	(853)	(852)	(854)	(853)	(854)
Total Net Capex	29,006	28,022	33,759	27,403	29,518	27,588

At this time, there are no major capital pipeline projects exceeding $1 million or approved/ anticipated CPCN projects that have been identified during the 2014-2018 period.

Appendix D-4

FEW 5-YEAR CAPITAL PLAN

1 APPENDIX D-4 – FEW 5 YEAR CAPITAL PLAN

1 PREAMBLE

FEW has segmented its 5-Year Capital Plans as follows:

Regular Capital Plan

- Sustainment Capital – Consists of expenditures for meter recall or meter exchange programs; system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load; replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and expenditures for mains and service renewals and alterations.
- Growth Capital – Consists of expenditures for the installation of new mains, services and meters.
- Other Capital – Consists of expenditures for Equipment, Facilities, and IT.

Major Capital Plan

- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital is defined as forecast Capital Expenditures that are under $5 million (excluding AFUDC) and have been categorized into Sustainment, Growth and Other capital. This category excludes Capitalized Overheads and AFUDC.

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. Typically, major capital projects for FEI in excess of $5 million have required a CPCN.

FEW's 5 Year Capital Plans for the period 2014 to 2018 are presented to provide additional background and context for the Resource Plan. These Capital Plans are not included for the purposes of approval by the BCUC in its review of the FEW Resource Plan, since FEW believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. Consistent with past practice, FEW continues to believe that the appropriate forum for review of its Capital Expenditures is in its Revenue Requirements Application proceedings.

As FEW's 5 Year Regular Capital Plan and Major Capital Plans include all planned capital expenditures, FEW believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the Utilities Commission Act.

FEW has endeavored to provide a comprehensive 5 Year Capital Plan 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 the Company's next Revenue Requirements Application filing.

2 5 YEAR REGULAR CAPITAL PLAN

The following table identifies the cost projections for regular capital expenditures from 2014-2018. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

- Sustainment Capital – System Integrity and Reliability
    - Meter Recalls / Exchanges
    - Transmission System Reinforcements / Integrity and Reliability
    - Distribution System Reinforcements / Integrity and Reliability
    - Distribution Mains and Service Renewals and Alterations
- Growth Capital – Mains, Services & Meters
    - New Customer Mains
    - New Customer Services
    - New Customer Meters
- Other Capital – All Other Plant
    - Equipment
    - Facilities
    - IT
- Contributions In Aid of Construction

Regular Capital excludes Capital Projects which are subject to CPCN applications. Table 1 identifies the cost projections for regular capital expenditures in 2014-2018.

Table 1: Forecast of Regular Capital Expenditures ($ thousands)

	2013 Projection	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	27	27	28	28	29	29
Transmission System Reinforcements	0	0	0	0	0	0
Distribution System Reinforcements	0	423	0	0	0	0
Distribution Mains & Service Renewals & Alt.	15	30	30	30	30	30
Total Sustainment Capital	42	480	58	58	59	59
Growth Capital						
New Customer Mains	61	62	64	65	66	68
New Customer Services	170	185	195	205	203	200
New Customer Meters	9	10	11	11	11	11
Total Growth Capital	240	258	269	281	280	279
Other						
Equipment	60	10	60	60	10	10
Facilities	13	54	204	279	14	14
IT						
Total Other	73	64	264	339	24	24
Total Gross Capex	355	802	591	679	363	362
CIAC	(17)	(17)	(17)	(17)	(17)	(17)
Total Net Capex	338	785	574	662	346	346

At this time, there are no major capital pipeline projects exceeding $1 million or approved/ anticipated CPCN projects that have been identified during the 2014-2018 period.

Appendix E

FEI-FEVI 2013-2014 ANNUAL CONTRACTING PLAN EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

1 INTRODUCTION

The Annual Contracting Plan (ACP) is a short term gas supply planning document filed with the Commission in the spring of each year. The ACP sets out the anticipated demand for natural gas by core customers and outlines the Companies' strategy to contract for gas commodity, storage, and pipeline transportation resources to meet demand for the upcoming gas contract year. The ACP also includes a review of regional marketplace developments that provides context for the overall portfolio strategy.

This submission outlines the proposed ACPs to meet the respective natural gas requirements of FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) for the upcoming gas year, commencing on November 1, 2013 and ending on October 31, 2014. The Annual Contracting Plan for FEI also incorporates the natural gas requirements for FortisBC Energy (Whistler) Inc. (FEW). FEI, FEW, and FEVI are collectively known as the "FortisBC Energy Utilities" or the "FEU" or the "Companies". This submission incorporates the FEI and FEVI Annual Contracting Plans into a single filing. The content of this submission is consistent with previous years' filings, including topics of special interest as directed by the Commission in the acceptance letters of the 2012/13 ACPs[1].

Within the FEU's Common Rates, Amalgamation and Rate Design Application submitted to the Commission on April 11, 2012, the FEU sought approval for amalgamating FEI, FEVI, and FEW in order to implement "postage stamp" or harmonized rate structures across the entire FEU service area. Accordingly, in the FEU's submission on May 1, 2012, incorporating the FEI and FEVI's 2012/13 ACPs, the FEU assessed the requirements to implement a single gas portfolio following amalgamation. On February 25, 2013, the Commission issued its decision denying the proposal for amalgamation. As such, as provided in this document, FEI and FEVI will continue to maintain separate gas supply portfolios and develop separate price risk management strategies. Maintaining separate gas supply portfolios and price risk management strategies will enable FEVI to address and mitigate its unique challenges. While the FEI and FEVI ACPs will remain separate for 2013/14, both continue to take into consideration regional market developments that impact both utilities.

1.1 Objectives of the FEU 2013/14 ACPs

The objectives for the 2013/14 ACPs are consistent with those of the 2012/13 ACPs that were accepted by the Commission. They continue to be appropriate and are as follows:

[1] Commission Order No. L-45-12 dated August 2, 2012 for FEI and Commission Order No. L-46-12 dated August 9, 2012 for FEVI.

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 portfolio mix that incorporates flexibility in the contracting of resources based on short term and long term planning, and evolving market dynamics.

The ACPs have been successful in meeting these objectives in the past and the proposed 2013/14 ACP will continue to enable the FEU to meet these objectives for the upcoming gas year and beyond.

1.2 Follow up from the Filing of the 2012/13 ACPs

The Commission accepted the recommendations outlined in the FEI 2012/13 ACP in Commission Letter No. L-45-12 dated August 2, 2012 and in the FEVI 2012/13 ACP in Commission Letter No. L-46-12 dated August 9, 2012. Included in these Letters, the Commission directed FEI and FEVI to provide the following information as part of their 2013/14 ACP:

- An update to the Northeastern BC study with the scope and detail of the update to be determined by FEI.
- A review and analysis of the experience with the Mt. Hayes and Tilbury LNG peaking resources for the 2012/13 contract year, including an analysis of the impact of Rate Schedule 16 service on the availability of those peaking resources for providing peaking supply for core natural gas customers.
- A review of the storage and transportation alternatives for the 2013/14 and 2014/15 contract years and an analysis to optimize the amounts of pipeline and storage to be contracted in future years, taking into account the regional infrastructure and market developments currently in place and anticipated to be in place in the future.

The Appendices included in this submission provide additional information describing regional market developments of significance for the FEU, considerations for resource contracting, and portfolio optimization outlooks.

The FEU trust that the information included in this filing helps to provide insight into contracting considerations that were taken into account in the development of this ACP, as well as providing an update on significant developments that affect the regional marketplace. These developments do not significantly impact the recommended portfolios for the coming winter 2013/14, but are important to monitor because they could affect the portfolio strategy in the future.

2 FEI 2013/14 ACP

This section provides an overview of significant topics that are discussed in detail in the FEI 2013/14 ACP, including the forecast design peak day and annual normal loads, changes in contracting for resources from the previous year, operational and long term planning considerations. Key elements of FEI's porfiolio include:

- **Forecast Design Peak Day Demand for 2013/14**

  Forecast at 1,218 TJ/d for 2013/14, which represents a net decrease of 0.5 percent or 6 TJ/d from 1,224 TJ/d in 2012/13. The reduction in the design peak day is mainly attributable to a drop in the actual use per customer combined with a slightly lower forecast customer growth rate.

- **Annual Normal Demand for 2013/14**

  Forecast at 117.3 PJ for 2013/14, resulting in an average daily normal load of 321 TJ/d. In 2012/13 the total annual normal demand was forecast at 113.8 PJ, which had resulted in a daily normal load of 312 TJ/d. The increase of 9 TJ/d in 2013/14 for the annual normal load is mainly attributable to an increase in commercial and small industrial volumes.

- **Commodity Portfolio**

  For 2013/14 FEI proposes to change the baseload supply receipt point allocation by increasing Station 2 from 70 percent to 75 percent, decreasing Huntingdon from 15 percent to 0 percent, and increasing AECO/NIT from 15 percent to 25 percent in 2013/14 compared to previous years' allocations (see Appendix C for details). This change is primarily due to the concerns with future Huntingdon supply reliability given the significant amount of decontracting of Westcoast firm T-South capacity by shippers.

  FEI recommends continuing with a balanced mix of daily and monthly priced commodity supply in the portfolio to mitigate adverse price movements and provide operating flexibility.

  FEI also recommends consideration of longer term supply contracts with BC gas producers, up to ten years in length, in the interests of supply security at the Station 2 market hub.

- **Midstream Portfolio**

  Due to the changes in the Commodity baseload supply receipt point allocation percentages, FEI will be required to contract for incremental T-South and NGTL and Foothills capacity effective November 1, 2013. FEI has also made changes to its seasonal supply within the Midstream portfolio to account for the changes in market conditions and in the interests of meeting the objectives.

2.1 Resource Contracting in the FEI 2013/14 ACP

FEI must not only meet forecast design peak day demand[2], but also manage loads rising well above normal over extended periods of colder weather and mitigate interruptions in delivery capacity related to both transportation and storage. Conversely, FEI also must manage load swings and resources requirements during spells of warmer than normal weather in the winter months. FEI strives to procure and deliver natural gas in the most reliable manner possible. This responsibility includes the need to to identify, monitor, and mitigate potential operational and market-related risks. In addition, the minimization of costs related to the annual portfolio, while ensuring the delivery of gas each day, is an important key objective. Balancing the need for cost minimization while meeting reliability, diversity, and flexibility objectives do not necessarily always result in the selection of the least cost alternative for inclusion in the portfolio.

The recommended portfolio is based on a balance of resources that meets the objectives of the plan. The portfolio selected each year is based on the objectives of the ACP that take into account the market data available to FEI at that time. However, it must be recognised that due to the many factors influencing natural gas supply and demand, the market for natural gas is always changing. Not only are there absolute price changes, but also changes in market factors (premiums or discounts) for securing physical supply. These changes are driven by the relationship between pricing points and the availability of resources.

The contracting strategy for the FEI's Commodity and Midstream portfolios include a combination of monthly and daily priced supply for price diversification, in addition to contracting at multiple storage facilities and associated transportation resources. Daily priced supply can be resold in the market at the same price as it is bought and, therefore, remove any price exposure compared to monthly priced supply. This strategy helps FEI to remain cost neutral when reselling gas on the day. Monthly priced supply helps reduce exposure to market price volatility during the winter months.

FEI takes a longer term outlook when contracting for some resources, like transportation and storage assets, and may be restricted to some degree in changing these particular resources in the portfolio in a particular year. However, customers realize any benefit associated with such resources since they provide security of supply and increased portfolio diversity. Gas from various storage facilities in the winter provides the portfolio with diversity and intraday flexibility, as well as summer-priced supply.

Further details about these consideration are provided in the confidential components of the 2013/14 ACP.

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[2] The total system demand based on the usage from the total forecast number of accounts on the system on the coldest day expected to occur.

2.2 Demand Forecast (Design Peak Day and Normal Load)

The forecast of design peak day demand for the 2013/14 contract year is 1,218 TJ/d, which represents a decrease of 0.5 percent or 6 TJ/d over the 2012/13 contract year. Table 1 sets out the forecast design peak day and normal loads during the winter and summer season projected for the next five years. This table also sets out the forecast 2012/13 design peak day and normal loads that were used in the 2012/13 ACP.

Table 1: Forecast Design Peak Day and Normal Volumes by Service Region

Contract Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
	(TJ/d)	*(TJ/d)*	*(TJ/d)*	*(TJ/d)*	*(TJ/d)*	*(TJ/d)*
Columbia	28	28	28	29	29	29
Lower Mainland	900	892	898	905	910	915
Ft. Nelson	5	5	5	5	6	6
Inland	284	285	287	289	292	293
Whistler	7	7	7	7	7	7
Total Peak Day Load	**1,224**	**1,218**	**1,226**	**1,235**	**1,243**	**1,250**
Change	n/a	-6	8	9	8	7
% Change	n/a	-0.5%	0.7%	0.7%	0.6%	0.6%
Winter Normal Load	**485**	**512**	**516**	**519**	**523**	**526**
Summer Normal Load	**190**	**187**	**188**	**190**	**191**	**192**
Average Daily Normal Load	**312**	**321**	**324**	**327**	**328**	**330**
	(PJ/yr)	*(PJ/yr)*	*(PJ/yr)*	*(PJ/yr)*	*(PJ/yr)*	*(PJ/yr)*
Annual Normal Load	**113.8**	**117.3**	**118.1**	**119.5**	**119.8**	**120.4**

For the 2013/14 contract year, the annual normal load is forecast to increase to 117.3 PJ from 113.8 PJ in 2012/13, resulting in an average daily normal load of 321 TJ/d in 2013/14 compared to 312 TJ/d in 2012/13. The 321 TJ/d will be the new daily baseload supply that will be received by FEI on behalf of the Commodity Providers, which includes FEI in its role as default commodity provider for customers who are not enrolled with marketers, in accordance with the ESM. The increase in normal loads in 2013/14 over 2012/13 is primarily attributable to an increase in forecast demand from commercial and small industrial customers.

2.3 Commodity Portfolio Overview: 2013/14

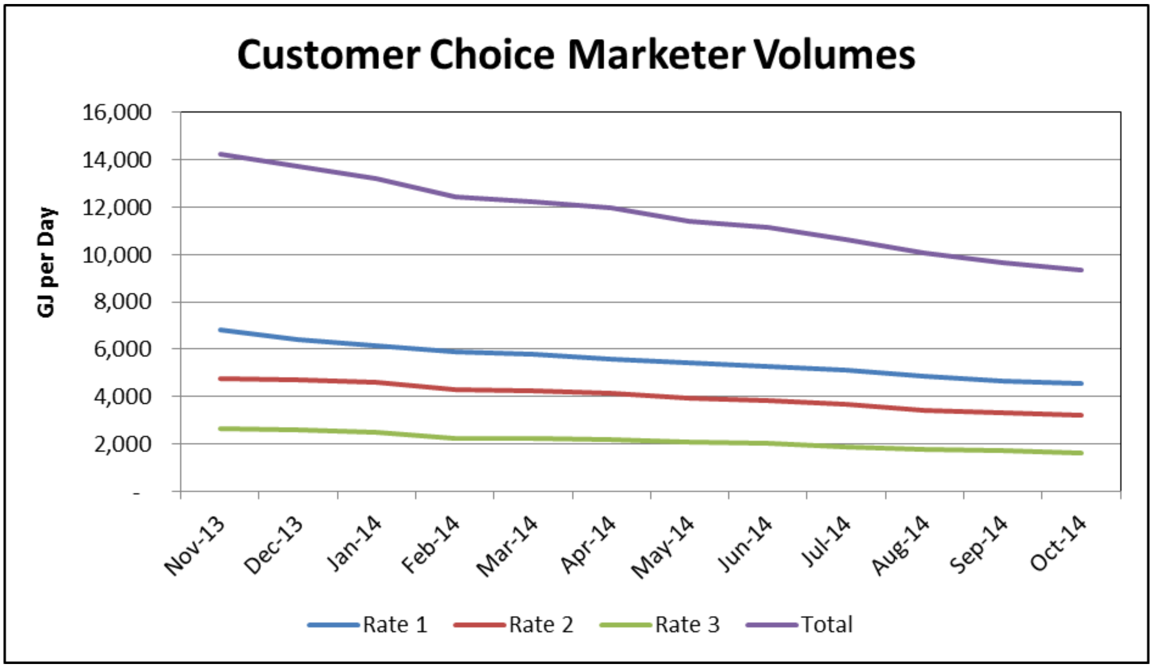
Commodity Providers, , supply the daily baseload volume that is equivalent to the normalized annual demand, which itself is derived from the normal load forecast. Commodity Providers must provide the normalized annual load requirement of 321 TJ/d, plus fuel, effective November 1, 2013.

Baseload supply for the 2013/14 contract year will be based on the following receipt point allocation percentages: 75 percent at Station 2, 25 percent at AECO/NIT, and 0 percent at Huntingdon. The percentage allocations have changed from previous years and are discussed in detail in Appendix C. Since the inception of the Customer Choice Program, the allocations for the provision of daily supply from Commodity Providers had been set as follows: 70 percent at Station 2; 15 percent at AECO/NIT and 15 percent at Huntingdon.

The Customer Choice Program was opened up to residential customers starting on May 1, 2007 with enrolments for an entry date of November 1, 2007. At that time, a large portion of residential unbundling contracts with Gas Marketers were termed up by customers for five years and the majority of these expired on October 31, 2012. Commencing on November 1, 2012, there was a significant reduction in the number of customers that decided to continue with Gas Marketers and instead opted to return to FEI as their commodity supplier based on the standard variable rate that is offered by the utility. FEI had estimated a high and a low case of gas volumes that would be supplied by Gas Marketers serving residential and commercial customers for the 2012/13 contract year as 40 TJ/d and 30 TJ/d in the 2012/13 ACP. However, after the 2012/13 ACP was filed, FEI significantly lowered its projection to 21 TJ/d as a more reasonable estimate for the 2012/13 contract year.

For the 2013/14 contract year, FEI expects that the volume supplied by Gas Marketers serving residential and commercial customers will drop even further. The average daily volume provided by Gas Marketers is expected to average 12 TJ/d while 309 TJ/d will be provided by FEI out of the total daily baseload supply of 321 TJ/d. As a result, the Gas Marketer supplied volume will represent less than 4 percent of daily baseload supply requirements while FEI will provide over 96 percent of the total daily supply. Gas Marketer supplied baseload volumes forecasted in this ACP are illustrated in Figure 1 below.

Figure 1: 2013/14 Estimate of Gas Marketer Volumes[3]



The estimated average daily consumption of 12 TJ/d is determined by taking the number of customers remaining with marketers per month multiplied by the use rate per customer that is then averaged for the November 1, 2013 to October 31, 2014 period. After netting Gas Marketer supplied baseload volumes from total forecast baseload volumes, means FEI will be required to provide the following amounts at the specified delivery points starting November 1, 2013:

Station 2:	(321 TJ/d – 12 TJ/d) x 75% plus 3.1% fuel	= 239 TJ/d
Alberta:	(321 TJ/d – 12 TJ/d) x 25% plus 1% fuel	= 78 TJ/d

The methodology used to calculate the fuel percentages that are used above for 2013/14 is consistent with the previous year's approach, which is described in FEI's letter to the Commission dated February 7, 2008. The fuel rates that are used above have remained unchanged since the start of the 2011/12 contract year[4]. FEI will continue to monitor the Fuel Gas account and will report the results of its review of the Fuel Gas Percentages to the Commission by the end of the 2013 summer, including a request to modify the fuel rates if necessary.

2.4 FEI Midstream Portfolio Overview: 2012/13

FEI Midstream's annual evaluation of its portfolio considers critical factors such as security of supply, reliability, delivered cost of supply, and availability of alternative incremental resources.

3 This estimate is based on actual enrollments in the Customer Choice Program taken in January 2013.
4 Approved via Commission Order G-120-12, dated September 11, 2012.

To replace expiring resources and/or meet future growth requirements, FEI Midstream assessed a number of alternatives for 2013/14 including:

- Station 2 supply and associated T-South transportation capacity;
- seasonal winter storage;
- shorter duration market area storage;
- Huntingdon and/or Stanfield, spot and peaking supply; and
- Kingsgate and/or Alberta supply..

Additionally, FEI also has on-system gas supply from resources such as the Tilbury and Mt. Hayes LNG storage facilities that can provide high volume supply on short demand during periods of cold and extreme winter weather or emergency situations.

FEI performed a review of the supply options available for the upcoming winter period, taking into account key market developments which have affected regional pricing and supply sourcing dynamics in the Pacific Northwest (PNW). After evaluation of the new peak and normal day load forecasts, current portfolio mix, and market developments, FEI Midstream recommends the following resource portfolio for 2013/14:

Table 2: Planned Peak Day Portfolio for 2013/14 vs. 2012/13 Actual Portfolio

FEI PEAK DAY PORTFOLIO (TJ/d)	2013/14 Planned Portfolio	2012/13 Portfolio
Fort Nelson Division	**5**	**5**
Huntingdon Baseload Supply (CCRA gas & Mktrs)	-	47
Alberta Baseload Supply (CCRA gas & Mktrs)	80	47
Station 2 Baseload Supply (CCRA gas & Mktrs)	241	218
Total Commodity Supply	**321**	**312**
Seasonal Supply	93	106
Seasonal Storage	182	182
Market Area Storage	188	188
Peaking Supply	-	6
Spot Supply	91	91
Mt. Hayes LNG	142	142
Tilbury LNG	166	166
Industrial Curtailment/Other	30	27
Total Midstream Supply	**892**	**908**
Total Resources (TJ/day)	**1,218**	**1,224**
Peak Day Demand (TJ/day)	**1,218**	**1,224**

Notes:
- *Volumes stated in this table do not include fuel required for delivery of supply to the FEI system.*
- *Market area and seasonal storage categories have been updated from 2012/13.*
- *Amounts may not sum due to rounding.*

FEI recommends a forecast peak day value for 2014/14 of 1,218 TJ/d, a decrease of 0.5 percent from the 2012/13 value of 1,224 TJ/d.

1. Incremental storage contracts and third party storage redelivery service agreements that have been or will be negotiated will be outlined in greater detail within the confidential sections of the 2013/14 ACP.

2. Contracting at Station 2, Alberta, and Kingsgate supply is outlined in greater detail within the confidential sections of the 2013/14 ACP.

3 FEVI 2013/14 ACP

FEVI strives to procure and deliver natural gas in the most reliable manner possible which includes the responsibility to identify, monitor and mitigate potential operational and market-related risks. In addition, the minimization of costs related to the annual portfolio, while ensuring the delivery of gas each day, is a key objective.

Significant topics that follow in the FEVI 2013/14 ACP include the forecast design peak day and annual normal loads, changes in contracting of resources from the previous year, and long term contracting considerations. Key elements of FEVI's porfiolio include:

- **Forecast Design Peak Day Demand for 2013/14**

  A decrease of 2.5 TJ or 2.3 percent in 2013/14 over the 2012/13 contract year is attributable mainly to a decline in the forecast use per customer.

- **Annual Normal Demand for 2013/14**

  A decrease of 0.3 PJ or 2.5 percent in 2013/14 over the 2012/13 contract year is also attributable mainly to a decline in the forecast use per customer.

- **Commodity Supply**

  For 2013/14 FEVI proposes changes to its seasonal supply to account for changes in market conditions.

- **Storage and Transportation Contracting**

  FEVI will adjust its pipeline transportation contracting according to the changes to its commodity supply for 2013/14. Storage resources remain unchanged from 2012/13.

3.1 Demand Forecast (Design Peak Day and Normal Load)

FEVI's forecast 2013/14 design peak day supply requirement is estimated at 106.2 TJ/d, excluding system gas and fuel, which equates to approximately 111.4 TJ/d with system gas and fuel. FEVI's forecast design peak day has decreased from the prior year's forecast primarily as a result of a decrease in use per customer. The forecasting methodology is consistent with that used to forecast the demand for other FEI regions.

Table 3 sets out the forecast design peak day and normal loads during the winter and summer season projected for the next five years starting with the 2013/14 gas year. This table also sets out the forecast 2012/13 design peak day and normal loads that was used in the 2012/13 ACP.

Table 3: FEVI's Forecast Design Peak Day and Normal Volumes.

Contract Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
	(TJ/d)	(TJ/d)	(TJ/d)	(TJ/d)	(TJ/d)	(TJ/d)
Total Peak Day Load in	108.7	106.2	108.2	110.2	112.1	113.6
Change	n/a	-2.5	2.0	2.0	1.9	1.44
% Change	n/a	-2.3%	1.9%	1.8%	1.8%	1.3%
Winter Normal Load	47	47	48	49	50	51
Summer Normal Load	23	21	21	22	22	22
Average Daily Normal Load	32.6	31.8	32.6	33.2	33.7	34.0
	(TJ/yr)	(TJ/yr)	(TJ/yr)	(TJ/yr)	(TJ/yr)	(TJ/yr)
Annual Normal Load in TJs	11.9	11.6	11.9	12.1	12.3	12.4

The decrease in 2013/14 annual normal load forecast, compared to last year's forecast, is attributable primarily to a decrease in the use per customer. However, the total annual forecast demand increases in future years, after the 2013/14 contract year, as a result of a projected increase in total customers (when multiplied with the same use per customer that was used to calculate the 2013/14 normal load).

3.2 FEVI Portfolio Overview

Table 4 that follows sets out FEVI's design peak day portfolio for 2013/14 and compares it to that from 2012/13.

Table 4: FEVI 2013/14 Recommended Peak Day Portfolio

FEVI PEAK DAY PORTFOLIO (TJ/d)	2013/14 Planned Portfolio	2012/13 Portfolio
Baseload Supply	19	19
Total Commodity Supply	**19**	**19**
Seasonal Supply	26	26
Seasonal Storage	13	13
Market Area Storage	25	25
Peaking Supply	-	4
Spot Supply	-	-
Mt. Hayes LNG	19	19
Industrial Curtailment/Other	3	3
Total Midstream Supply	**86**	**90**
Total Resources (TJ/day)	**106**	**109**
Peak Day Demand (TJ/day)	**106**	**109**

Notes:
- *Volumes stated in this table do not include fuel required for delivery of supply to the FEVI system.*
- *Amounts may not sum due to rounding.*

4 REGIONAL DEVELOPMENTS

Significant changes are occurring in the natural gas marketplace in western Canada. These changes will likely impact traditional supply and demand dynamics and regional gas flows as well as regional market prices. The major supply potential in northeast BC has prompted the development of infrastructure initiatives that will be needed to serve new sources of demand. With declining gas supplies in Alberta and increasing demand from industrial, power generation and oil sands demand, TransCanada is expanding into northeast BC to access the significant new production basins that are being developed there. Furthermore, numerous LNG export projects have been announced for the west coast of BC. In addition, several projects have been proposed in the US PNW to move more gas to the growing I-5 market. The FEU are monitoring these developments as they will impact future resource availability and its cost effectiveness.

The proposed BC LNG export projects could significantly impact regional gas flows by the end of the decade. The recent announcement by the provincial government of British Columbia that four additional proponents are interested in potentially locating LNG liquefaction terminals at a new site, Grassy Point north of Prince Rupert, bring to eleven the projects considered for development in northern BC. Separately, Pacific Energy Corp. announced plans to develop a smaller scale LNG export project on the FEVI system near Squamish. These projects are driven primarily by an interest in accessing large supplies of reliable natural gas required to serve growing demand in key Asian markets that include Japan, South Korea, and China. These markets are seeking to diversify their sources of supply and are attracted by the political stability and mature market structure for accessing natural gas that Canada offers. LNG exports from BC represent the most significant new market opportunity that the Western Canadian Sedimentary Basin (WCSB) has seen and comes at a time when production from this basin is being increasingly pushed from traditional markets in eastern North America by new shale gas developments located closer to those markets.

BC is poised to be in the forefront of various developments surrounding pipeline, infrastructure and potentially significant volumes export of LNG to Asian markets over the next few years. However, the growth of natural gas production in BC is also subject to various influences such as pricing of commodity, influence of changing demand dynamics and cost of production. Continued expansion of gas production should benefit consumers in BC as this provides opportunities for increased supplies to be available in BC markets well into the future.

Developments on the regulatory front will also impact regional gas flow patterns. Earlier this year the NEB reach a decision on TransCanada's Mainline Restructuring and Komie North applications, denying key aspects of each application, while approving others. It is unclear at this point how TransCanada will respond to these decisions, which makes the business impacts uncertain.

Based on these developments, the FEU will continue to act to ensure secure, reliable and cost effective supply for its customers.

- The FEU will continue to actively participate in pipeline infrastructure developments, tolling proceedings and other initiatives to ensure that the marketplace in BC offers supply liquidity and competitive pricing compared to neighbouring regional markets.
- The FEU will continue to establish key relationships with major producers who plan to develop gas supply in the Horn River, Montney and other producing regions of BC over the long term including producers actively involved in attempting to develop an export LNG market to Asian markets.
- The FEU will evaluate opportunities within their own operating region to improve infrastructure that will provide greater access to markets leading to better diversity and reliability within the portfolio over the long term.

The FEU believe that any increase in gas production in BC should provide a level of direct benefit to consumers in the province, which can be achieved by enhancing the liquidity and flow of gas at the Station 2 market hub. Therefore, the FEU will continue to proactively monitor developments and foster relationships with key producers in order to help ensure that accessible supply and competitive pricing are available at Station 2 over the long term.

The FEU are actively involved in NEB proceedings that affect the FEU's access to supply and are also actively involved in developing solutions with regional stakeholders to help ensure issues related to third party pipeline infrastructure are favourably resolved. These activities are important because they help to ensure that customers in BC will continue to have access to cost effective supply over the long term.

5 CONCLUSION

The key objectives of the FEU are to contract for gas supply that offer security and diversity within the portfolio while minimizing overall portfolio costs over the short and long term. Therefore, the FEU continually evaluate developments in the regional marketplace such as infrastructure developments, regional pricing, cost and availability of resources, and growth opportunities in order to meet these objectives.

FEI and FEVI will continue to meet normal and peak day loads through diverse, flexible and cost effective portfolios of resources. While the forecast normal and peak day load requirements have changed only slightly from the previous year, other market factors are driving more significant changes in the FEI and FEVI portfolios for 2013/14. The FEU will continue to make appropriate changes to their portfolios as market conditions change in order to meet the objectives.

The FEU will continue to actively monitor and participate in pipeline infrastructure developments, tolling proceedings and other initiatives that will affect gas flows and pricing in the region. The FEU will also explore infrastructure improvements within its own service regions to promote liquidity and supply availability over the long term. The FEU will attempt to ensure that they continue to be able to access secure and reliable gas supply in a cost effective manner for core customers.

Appendix F

ABORIGINAL RIGHTS AND FEU STATEMENT OF ABORIGINAL PRINCIPLES

APPENDIX F – ABORIGINAL RIGHTS AND FEU'S STATEMENT OF ABORIGINAL PRINCIPLES

The FEU are leaders in developing and building mutually beneficial working relationships with Aboriginal and First Nations communities. Understanding, respect, open communication and trust are key values that guide the Companies' work with First Nations groups throughout the province. This appendix provides a brief background on Aboriginal rights in B.C., describes how the Utilities are affected by and abide by Aboriginal law, and includes the FEU Statement of Aboriginal Principles.

1. Aboriginal Rights in B.C.

Aboriginal peoples of Canada hold aboriginal and treaty rights that are expressly recognized and affirmed by section 35 of the *Constitution Act, 1982*. British Columbia recognizes 285 different First Nations, Bands and Tribal Councils. The large majority of these First Nations are not signatories to a treaty (historic or modern) and most land in British Columbia is not covered by a treaty. As a result, many Aboriginal land and rights claims in B.C. remain outstanding. In addition, there can be competing claims from different First Nations over the same piece of land.

Since 2002, in the B.C. Courts and the Supreme Court of Canada, there have been a number of significant court cases that have discussed when consultation is necessary and the scope of the consultation that is required. These cases deal with those situations where the Government is considering approving or permitting projects that may negatively impact an asserted or proven Aboriginal or treaty right. In those situations, the Crown will typically owe a 'duty to consult' with affected First Nations and, depending on the strength of the aboriginal group's claim and the degree of impact, there may be a need to accommodate those Aboriginal interests. Although the duty to ensure that proper consultation has taken place ultimately rests with the Crown, in the majority of cases, the procedural aspects—that is, the actual on-the-ground work of information sharing, learning about potential impacts and planning for mitigation—is delegated to the project proponent. The project proponent is also affected by the pace and nature of any dealings between the Crown and the First Nation, and any court decision that halts a project for lack of adequate consultation.

The FEU are directly affected by this dynamic. For instance:

- The B.C. Court of Appeal ruled in March 2009 that BCUC decisions could affect Aboriginal rights, and that the BCUC must determine the adequacy of Aboriginal consultation and accommodation before making decisions. By Order G-50-10, the Commission CPCN Guidelines were modified to specify that public utility CPCN applications include consideration of First Nations consultation. Since that time, FEU project applications have addressed First Nations consultation.

- The FEU comply with the Consultation and Notification Regulation created pursuant to B.C.'s *Oil and Gas Activities Act,* which prescribes a formal process for pipeline companies that are seeking Oil and Gas Commission (OGC) permits to formally notify and/or consult with individuals or organizations that may be affected by OGC permits.

The area of Aboriginal law, particularly in the area of consultation and accommodation, is evolving, with new cases being heard by the courts on a regular basis. The outcome of these cases, whether or not they relate specifically to public utilities, can have a bearing on the Companies' business as they can impact government policy and processes of permitting authorities.

2. FEU Statement of Aboriginal Principles

The FEU is committed to building effective Aboriginal relationships and to ensure that the Companies have the structure, resources and skills necessary to maintain these relationships. In order to meet this commitment, the Companies' actions and its employees are guided by the following principles:

- The Companies acknowledge, respect and understand that Aboriginal people have unique histories, cultures, protocols, values, beliefs and governments.
- The Companies support fair and equal access to employment and business opportunities within FortisBC companies for Aboriginal people.
- The Companies will develop fair, accessible employment practices and plans that ensure Aboriginal people are considered fairly for employment opportunities within FortisBC.
- The Companies will strive to attract Aboriginal employees, consultants and contractors and business partnerships.
- The Companies are committed to dialogue through clear and open communication with Aboriginal communities on an ongoing and timely basis for the mutual interest and benefit of both parties.
- The Companies encourage awareness and understanding of Aboriginal issues within its work force, industry and communities where it operates.
- To achieve better understanding and appreciation of Aboriginal culture, values and beliefs, the Companies are committed to educating its employees regarding Aboriginal issues, interests and goals.
- The Companies will ensure that when interacting with Aboriginal peoples, its employees, consultants and contractors demonstrate respect, and understanding Aboriginal people's culture, values and beliefs.
- To give effect to these principles, each of the Companies' business units will develop, in dialogue with Aboriginal communities, plans specific to their circumstances.

Appendix G

GLOSSARY OF TERMS AND ACRONYMS

APPENDIX G – GLOSSARY OF TERMS AND ACRONYMS

Acronym or Term	Definition
ACP	Annual Contracting Plan
AECO/NIT	Alberta Energy Company/Nova Inventory Transfer - refers to an important storage and exchange point for Canadian natural gas. AECO/NIT is commonly used to refer to the benchmark pricing index for the Alberta natural gas marketplace.
AFUDC	Allowance for funds used during construction - an allowance for the cost of debt and equity funding of capital projects before they are completed and placed into service and included in rate base; the AFUDC recorded for a project is added to the overall project cost.
Annual demand	The cumulative daily demand for natural gas over an entire year.
Bcf	Billion cubic feet
BCH	BC Hydro
BCUC	British Columbia Utilities Commission, or Commission - the BCUC is the provincial body regulating utilities in British Columbia.
BTU	British thermal units
Burrard Thermal	Burrard Thermal Generating Station (BC Hydro)
CAPP	Central Appalachian
CEA	Clean Energy Act
CEO	Conservation Education, and Outreach
CGA	Canadian Gas Association
CIAC	Contributions in aid of construction
CNG	Compressed natural gas
Commission	*see British Columbia Utilities Commission, BCUC*
CO_2e	Carbon dioxide-equivalent - a unit to express an amount of greenhouse gas emission in terms of carbon dioxide (CO_2) based on the relative global warming potential of each gas. Commonly expressed in million tonnes, i.e. $MtCO_2e$.
CPCN	Certificate of Public Convenience and Necessity - a certificate obtained from the British Columbia Utilities Commission under Section 45 of the *Utilities Commission Act* for the construction and/or operation of a public utility plant or system, or an extension

	of either, that is required, or will be required, for public convenience and necessity.
CPR	Conservation Potential Review - a comprehensive economic analysis of energy conservation potential that looks at where energy savings opportunities exist.
CTS	Coastal Transmission System
Daily demand	The amount of natural gas consumed by the Utilities' customers throughout each day of the year.
Demand forecast	A prediction of the demand for natural gas into the future for a given period and under a specified set of expected future conditions.
DES	District Energy System
DHW	Domestic Hot Water
DSM	Demand-side management - commonly defined as any utility activity that modifies or influences the way in which customers utilize energy services.
Design day, or design hour demand	The maximum expected amount of gas in any one day or hour required by customers on the utility system. Since core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1-in-20-year return period. For transportation customers, the design-day is equivalent to the firm contract demand. (*See also Peak day*)
DLE	Diesel litre-equivalents
EEC	Energy Efficiency and Conservation
EECAG	Energy Efficiency and Conservation Advisory Group
EF	Energy Factor or Efficiency Factor
EGH	EnerGuide for Houses
EIA	Energy Information Administration (U.S.) - a division of the U.S. Department of Energy that provide statistics, data and analysis on resources, supply, production, consumption of energy.
FBC	FortisBC Inc.
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission
FEU	Fortis Energy Utilities - refers collectively to FEI, FEVI, and FEW
FEI	FortisBC Energy Inc.

FEVI	FortisBC Energy (Vancouver Island) Inc.
FEW	FortisBC Energy (Whistler) Inc.
FortisBC	Refers to FortisBC Inc. (Electric) when used alone in the context of this LTRP
GDP	Gross domestic product
GGRR	Greenhouse Gas Reduction (Clean Energy) Regulation
GGRTA	Greenhouse Gas Reduction Targets Act
GHG	Greenhouse gas
GJ	Gigajoule - a unit of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).
GLJ	GLJ Petroleum Consultants Ltd. - 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.
GWh	Gigawatt hour - a unit of energy equal to 1 million kilowatt-hours
HDD	Heating degree day - a measure of the coldness of the weather experienced. The number of heating degree days for a given day is calculated based on the extent to which the daily mean temperature falls below a reference temperature, 18 degrees Celsius.
Huntingdon/Sumas	Gas flow regulating stations on either side of the British Columbia /Washington state (U.S.) border through which much of the regional gas supply is traded.
I-5 Corridor	The natural gas regional market area served by infrastructure located along Interstate-5 in the northwestern U.S. The I–5 corridor includes B.C.'s Lower Mainland and Vancouver Island, Western Washington and Western Oregon.
IG	Island Generation (BC Hydro) - a cogeneration plant located at Elk Falls, Campbell River that supplies electricity and thermal energy on Vancouver Island.
ILI	In-line inspection
IP	Intermediate pressure
IRP	Integrated resource plan - a document that details the resource planning process and outcomes that guide a utility in planning to serve its customers over the long term. *(See also LTRP.)*
IRR	Internal rate of return
IT	Information technology

ITS	Interior Transmission System
JPS	Jackson Prairie Storage
KORP	Kingsvale Oliver Reinforcement Project
kPa	Kilopascal - a metric measurement unit of pressure. Gauge pressure is often given in units with a 'g' appended, e.g. 'kPag'.
kW	kilowatt (a unit of energy equal to one thousand watts) - the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.
kWh	kilowatt hour (equal to one thousand watts used for a period of one hour) - the basic unit of measurement of electric energy. On average, residential customers in B.C. use about 10,000 kWh per year.
LNG	Liquefied Natural Gas - natural gas stored under high pressure, which turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state; however, specialized storage facilities must be constructed.
Load	The total amount of gas demanded by all customers at a given point in time.
LTRP	Long Term Resource Plan - the FEU's LTRP examines future demand and supply resource conditions over the next 20 years and recommends actions needed to ensure customers' energy needs are met over the long term. *(See also IRP)*
LTSP	Long Term Sustainment Plan - an asset management process/planning approach that assists in creating and supporting long term asset replacement plans and capital expenditures.
MMscfd	one million standard cubic feet per day
MOP	Maximum operating pressure
mTRC	Modified Total Resource Cost - a modification to the Total Resource Cost test that is set out in the B.C. Demand-side Measures Regulation to recognize the environmental value of energy conservation
MW	Megawatt - a unit of power equal to one million watts or one thousand kilowatts, commonly used to measure both the capacity of generating stations and the rate at which electric energy can be delivered.
NEB	National Energy Board
NGT	Natural gas for transportation
NGTL	Nova Gas Transmission Ltd.

NGV	Natural gas vehicles
Normal demand, *also called* **annual demand**	When considering historical normal demand, this is the actual demand experience that has been adjusted to account for weather that has been colder/warmer than normal, i.e. the expected demand during a year of normal weather conditions. When considering forecast normal demand, this is the expected demand under normal weather conditions. Normal weather conditions are based on a rolling 10-year average of heating degree days experienced during each of the 10 years.
NRCan	Natural Resources Canada
NWGA	Northwest Gas Association - a trade organization of the Pacific Northwest natural gas industry. Its members include six natural gas utilities, including FortisBC, serving communities in Idaho, Oregon, Washington and British Columbia, and three interstate pipelines that move natural gas from supply basins into and through the region.
NWP	Northwest Pipeline
NYMEX	New York Mercantile Exchange
PBR	Performance Based Ratemaking or PBR, also frequently called incentive regulation - an approach to determining a utility's rates or revenue requirements that includes incentives for the utility to achieve greater levels of efficiency in managing and operating its utility system, while maintaining (or in some cases improving) its customer service quality. Depending on the desired objectives, PBR can be narrowly focused on a particular aspect of utility service or more broadly based encompassing many aspects of the utility's operations.
Peak day, peak demand, peak day demand	The maximum expected amount of gas in any one day or hour required by customers on the FEI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. For transportation customers, the design-day is equivalent to the firm contract demand. (*See also: design day*)
PJ	Petajoule - a unit of energy equal to 1,000 terajoules or 10^6 gigajoules
PNW	Pacific Northwest - a region that is commonly referred to as the three northwestern states of Washington, Oregon, Idaho and the Province of B.C.
PRMP	Price Risk Management Plan
Psig	Pounds per square inch gauge - a measurement of pressure.
Rate volatility	The amount to which natural gas rates fluctuate and the frequency

	of those fluctuations.
Resources	The demand-side and supply-side means available to meet forecasted energy needs. Examples of supply-side resources within the context of resource planning are pipeline looping, compression and storage.
REUS	Residential End Use Study
RIB	Residential Inclining Block rate (BC Hydro)
RNG	Renewable natural gas
ROW	Right of way
RPAG	Resource Planning Advisory Group
RRA	Revenue Requirement Application
SCP	Southern Crossing Pipeline
Shut in	A pipeline “shut in” refers to removing a pipeline from service.
Tcf	Trillion cubic feet
TCPL	TransCanada Pipeline
TJ	Terajoule - a unit of energy equal to 1,000 gigajoules
TP	Transmission pressure
TRC	Total Resource Cost - a standard cost-benefit test for energy efficiency initiatives that compares the present value of all costs of efficiency for all members of society with the present value of benefits in order to assess the impacts of a portfolio of energy efficiency initiatives on the economy at large.
TSA	Transportation Service Agreement
UCA	Utilities Commission Act
UPC	Use per customer
Utilities	*see Fortis Energy Utilities (FEU)*
VIGJV	Vancouver Island Gas Joint Venture - a joint venture of industrial customers (primarily large mills) on Vancouver Island who contract for transportation services as a single entity.
WCSB	Western Canadian Sedimentary Basin