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June 18, 2004

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

Attention: Mr. R.J. Pellatt

Dear Sir:

Re: Resource Plan – Terasen Gas (Vancouver Island) Inc. ("TGVI")

In accordance with BCUC Letter No. L-5-04, dated February 6, 2004, TGVI is submitting the attached Resource Plan for the Commission's review. The enclosed Resource Plan, covering the Vancouver Island and Sunshine Coast service areas was prepared in accordance with the Resource Planning Guidelines ("Guidelines") released by the Commission in December 2003.

In addition to the submission of this Resource Plan, TGVI expects to file a CPCN application in late July with the Commission, seeking approval of the Liquefied Natural Gas ("LNG") facility recommended in the Resource Plan.

TGVI anticipates that the Resource Plan and the CPCN application for the LNG project will be reviewed jointly as part of the regulatory review and approval process required.

If there are any questions regarding the content of this letter, please contact James Wong at 604-592-7871

Yours very truly,

TERASEN GAS VANCOUVER ISLAND INC.

Original signed by Scott Thomson

Scott Thomson

/gj
Attachment

Terasen Gas (Vancouver Island) 2004 Resource Plan

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EXECUTIVE SUMMARY

Introduction

Demand for natural gas on Vancouver Island and the Sunshine Coast has seen considerable growth since the construction of the distribution system, with growth expected to continue in the future. Terasen Gas Vancouver Island Inc.'s (TGVI) system currently operates at full capacity and a shortfall in capacity is expected to occur by 2007. The Resource Planning process has reviewed options for addressing this shortfall and concludes that expansion of the existing pipeline system will be required. TGVI believes that the preferred solution to managing the projected shortfall is to construct a LNG facility on Vancouver Island. Without system expansion, the shortfall in 2007 would extend for more than one third of the year, almost an entire winter heating season.

Resource Planning

The Resource Planning process evaluates demand and supply options over a long term 20 year planning horizon and considers their economic, environmental, and social characteristics. The Commission's description of the planning process is:

> *"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."*

Resource Planning is part of an ongoing planning process at Terasen Gas which includes broader regional planning initiatives. Terasen Gas is currently in the process of completing a Regional Resource Planning study that assesses the natural gas infrastructure serving the I-5 Corridor, which encompasses the B.C. Lower Mainland, Vancouver Island, Western Washington and Western Oregon. The study provides the broader context in which Terasen Gas operates and in which this Resource Plan was developed. Furthermore, an integrated regional approach to designing and developing the regional gas delivery infrastructure is required to ensure the secure and reliable supply of energy to consumers throughout the region.

Resource Planning Objectives

TGVI's Resource Planning objectives form the basis for evaluating potential resources in the Resource Plan, including major infrastructure projects, gas supply alternatives, and demand side programs. These objectives are set out in the following table.

Table ES-1. Resource Planning Objectives

Objective	Attribute	Measure
Ensure reliable and secure supply.	System reliability Security of supply	Risk of outages Gas supply diversity
Provide service to customers at least delivered cost.	Financial evaluation of supply side and demand side resources	Net Present Value Total Resource Cost (TRC) Ratepayer Impact (RIM)
Reduce rate volatility.	Expected rates	Risk Trade-offs
Balance socio-economic and environmental impacts.	Social costs / benefits including: Local emissions Greenhouse gas Land use impacts Employment/local economic impacts Stakeholder consultation	 Air pollutants Quantity of CO_2 equivalent Area impacted Jobs created Stakeholder input

The objectives reflect the Utility's commitment to providing the highest level of quality energy services to its customers. Resource portfolios are assessed by determining the degree to which they meet the criteria of each objective. The most desirable resources will rank high on most or all of the objectives.

Gas Supply Overview

Gas supply considerations are a key component in long term Resource Planning for TGVI. When TGVI purchases gas to deliver to distribution customers, it must consider not only the local natural gas market on Vancouver Island and the Sunshine Coast but also the regional market in British Columbia, the U.S. Pacific Northwest, and the continental market of North America. The continental gas supply perspective is important when evaluating the requirement for new facilities that are to be used over their lifetime of thirty or more years. TGVI has reviewed the latest forecasts for gas reserves from a variety of sources and is satisfied that ample supply exists to serve TGVI markets over the planning period.

In planning the gas supply portfolio for TGVI, resources must be put in place to manage the varying demand for gas on an annual basis. TGVI looks at both the design and the normal, or expected demand, for each day in the year. Supply resources are then assembled to ensure that TGVI has sufficient resources to meet the design peak while meeting the normal peak at the least cost.

Future gas supply requirements for TGVI are driven primarily by Core customer growth. Additional pipeline capacity will be required to meet average day growth, but a majority of additional infrastructure needs to be for local storage for the winter to meet peak demand. As demand increases, relatively scarce local storage is expected to become even more important and costly.

Demand Forecast

Higher demand for natural gas will be driven by Core sales customers, the Joint Venture, BC Hydro, and potentially the Whistler region. The five gross demand forecast scenarios developed are characterized by an imminent step change in gross forecasted demand due to continued Core customer growth, long term firm requirements of the Island Cogeneration Plant (ICP), potential impact of the BC Hydro Call for Tenders (CFT) process, potential contract changes for the Joint Venture and the potential conversion of the Whistler region to natural gas service.

Figure ES-2 provides a matrix showing the components of the five gross demand forecast scenarios that have been developed:

Figure ES-2. Gross Demand Scenarios

Gross Demand	*Core Customers*			*Joint Venture*			*Generation (ICP + CFT)*			*Squamish*	*Whistler*	
	High	Base	Low	High	Base	Low	ICP + 0	ICP + 20	ICP + 45	Yes	Yes	No
High-High	•			•					•	•	•	
Base + 45		•			•				•	•		•
Base + 20		•			•			•		•		•
Base + 0		•			•		•			•		•
Low-Low			•			•	•			•		•

Design-day demand from Core customers account for more than half of all customers' design-day demand. For Core customers, three forecast scenarios – Base, High and Low were developed to reflect the range of possible outcomes in customer growth rates.

Customers converting from other energy sources such as oil and electricity comprise the majority of additions recorded in the past. In the future, conversions are expected to stabilize around the 1,200 per year level, reflecting the average number of conversions per year observed in recent years. New construction additions are expected to generally follow economic growth in the Vancouver Island region with total customer growth including conversion and new construction activity slowing to approximately 2% per year, as the Utility matures.

Demand Side Management (DSM) Resources

Demand Side Management refers to "utility activities that modifies or influences the way in which customers utilize energy services." TGVI offers demand side management programs for the Core Market that is targeted to improving the energy efficiency of the residential and commercial customer. TGVI also has arrangements with the major transportation customers, BC Hydro and the Joint Venture, where TGVI can recall or curtail a portion of their firm transport capacity to meet Core peak demands.

A key strategic objective for Terasen Gas is to ensure that the Province remains attractive to new business from a relative energy cost and supply reliability perspective. This means promoting a level playing field with other regions and avoiding the flight of business driven away by high relative energy costs in the region. Opportunities exist to encourage energy efficient gas appliance choices for residential consumers, while building natural gas load and in turn creating cost and supply efficiencies for all customers. These initiatives can help keep gas prices down for customers. Funding for resources that promote such DSM initiatives can be as important as the programs themselves. Through this Resource Plan, TGVI supports a number of provincial initiatives: market transformation relating to more efficient heating systems in residential and commercial applications, fireplace efficiency upgrades, and improvements to building envelopes.

The potential energy savings impact of the new programs targeted to Core customers being considered by TGVI is less than 0.1% of annual customer demand. This relatively low figure is a result of the limited magnitude of energy efficiency opportunities in a new gas market and the small size of the residential and commercial markets as compared to the industrial and electrical generation sectors. To identify and capture DSM opportunities, Terasen Gas – TGVI in particular, believes that it is worthwhile to consider completion of a Conservation Potential Review (CPR) to identify and capture DSM opportunities. TGVI recommends that a CPR should consider all DSM opportunities including cost-effective electric-to-gas fuel substitution.

Terasen Gas is also an engaged stakeholder in the Province's Review of Energy Performance Measures for Buildings in B.C. This Review has culminated in a series of recommended actions that will be presented to the Minister responsible this summer for consideration. A number of the initiatives within this DSM portfolio directly support these recommended actions.

Resource Portfolio Development

Generally, there are three types of "supply side resources" that can be used to increase the physical capacity of a pipeline system: pipeline looping, compression, or on-system storage. In addition, "demand side resources" such as industrial curtailment can be used to limit demand during peak periods.

The supply side components of these portfolios are identified using a computer model that simulates the hydraulic characteristics of the TGVI transmission system and TGVI planning criteria that address the design limitations and operating requirements of the system.

The distinct supply side components identified in the modeling process and used in the various portfolios include; six looping projects on the Mainland and Texada portions of the system, a second marine pipeline crossing of Georgia Straight between Sechelt and Harmac, five compressor station projects, and a LNG storage facility located on Southern Vancouver Island. The details of each of these projects are discussed in detail in the following appendices:

Appendix G: Compressor Additions
Appendix H: Primary Pipeline Looping
Appendix I: LNG Storage

As mentioned earlier, due to the limited magnitude of energy efficiency opportunities in a new gas market and the small size of the residential and commercial markets, Core DSM programs are assumed to have no effect on TGVI's need for additional resources to meet forecast demand requirements.

Concerning curtailment, TGVI currently holds peaking agreements with BC Hydro and the seven large industrial customers represented by the Joint Venture whereby TGVI can recall or curtail a portion of their firm transport capacity and use this to meet Core demand. These agreements will expire concurrently with existing transport agreements. BC Hydro's agreements expire in October 2004, while the Joint Venture agreements could expire as early as December 2005 but otherwise will expire in 2011.

During the Resource Plan stakeholder consultation, both BC Hydro and the Joint Venture have indicated that they are prepared to continue to offer curtailment rights associated with their long term capacity requirements based on agreement of commercial terms. In BC Hydro's case, it is expected ICP and/or any new generation projects would have the ability to switch to oil during periods of curtailment to ensure that dependable generation capacity criteria is met. The industrial mills can also switch a large part of their load to oil and/or other fuels or reduce their production levels if their natural gas supply is curtailed.

On this basis, the supply side portfolios were modeled assuming that curtailment from BC Hydro and the Joint Venture would be available over the planning period, potentially allowing deferment of other supply side alternatives. In developing these long term portfolios, it is assumed that curtailment will not be relied on to meet expected demands in a normal or average winter, but that it will be available to meet peak load requirements in a colder than normal winter. This results in more curtailment potentially being available than is practical for TGVI to consider as part of its resource stack to meet its firm transportation requirements.

From this evaluation process, three types of resource portfolios emerge based on the components employed to meet initial demand growth:

- LNG Storage – a LNG Storage facility followed by phased pipe and compression additions
- Pipe & Compression – phased pipe and compression additions
- Pipe & Compression & Curtailment – phased pipe and compression additions with industrial curtailment

Each of the three portfolio types is evaluated for the three Base cases, Low-Low, and High-High gross demand forecasts outlined earlier.

Resource Portfolio Evaluation

When evaluated against the four Resource Planning objectives (refer to Table ES-2), the LNG Storage resource portfolio is the preferred portfolio. LNG Storage ranks first in reliability and security of supply, cost, and rate impact. LNG is also preferred in terms of employment and land use impacts, and ranks favourably with the other portfolio options in air emissions impacts across the range of demand forecasts.

Table ES-2. Evaluation Summary

TGVI Planning Objective	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Ensure reliable secure supply	✓		
Lowest delivered cost	✓		
Reduce long-term volatility	✓		
Balanced impacts	✓	✓	

Financial evaluation of the different resource portfolios to meet the demand requirements supports the LNG Storage portfolio as the preferred alternative to meet the objective of providing service to customers at the least delivered cost. For the most likely demand forecast scenarios, the LNG Storage portfolio results in the lowest incremental cost and is not dependent on the outcome of BC Hydro's call for new generation capacity on Vancouver Island.

The Resource Planning objective *Balance Socio-Economic and Environmental Impacts* involves measurement and evaluation of emissions factors, land use impacts, and employment impacts for each of the portfolios. The emissions measures for carbon dioxide (CO_2), nitrogen oxide (NOx) and sulphur dioxide (SO_2) are quite similar for all three portfolios across all forecast scenarios. The land use and employment impacts favour the LNG Storage portfolio across all forecasts.

The Resource Planning objective *Ensure Reliable and Secure Supply* was evaluated qualitatively for each of the three resource portfolios. While TGVI is confident that any of the portfolios would deliver an adequate level of reliable and secure supply of gas service to customers, a storage facility on Vancouver Island provides additional protection should an upstream failure occur on the Duke, Terasen Gas mainland or TGVI system. Storage in close proximity to the Utility's major market area adds diversity to the resources available to TGVI.

The Resource Planning objective *Reduce Rate Volatility* measures the relative rate impact of each portfolio and was measured qualitatively. A large storage facility close to the major market helps to mitigate commodity price increases during peak demand periods. A LNG storage facility would also increase regional supply capacity and decrease the risk of a regional price disconnect. Storage can provide a dampening effect on summer versus winter price differentials.

Stakeholder Consultation

Stakeholder needs and concerns are critical to Resource Planning. TGVI consultation activities included workshops in spring 2004 and meetings with select stakeholders seeking input on a range of system expansion needs and DSM alternatives. As well, a background study on the costs and benefits of a possible LNG storage facility on the Island to help meet growing demand has been completed.

Action Plan

As described in the BCUC 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 Action Plan describes what TGVI intends to pursue over the next 4 years based on the information and evaluation provided in this Resource Plan and includes:

- Obtain approvals and construct a Liquefied Natural Gas Storage Facility on Vancouver Island. TGVI will be filing a Certificate of Public Convenience and Necessity (CPCN) in 2004 to support a 2007 in-service date for the LNG storage facility.

- Monitor the BC Hydro Vancouver Island CFT process and develop additional facilities as required to support any new generation requirements. TGVI will identify and develop project plans for these facilities once the outcome of the CFT is known.

- Evaluate potential options to contract for curtailment and/or peaking gas with BC Hydro and the Joint Venture. Evaluation of the different resource portfolios concludes that a LNG facility is a better option as a capacity resource, however the fuel switching capability can offer value as a peaking gas resource to TGVI's Core customers or to other market participants in the region that require peaking gas.

- Examine funding opportunities for the preparation and implementation of marketing plans that will help Terasen Gas reach customer targets and build energy efficient gas load for both new and existing customers. The collective efforts will help to maintain a very competitive position for natural gas, benefiting the entire regional energy outlook in keeping with the provincial Energy Policy.

- Conduct a Conservation Potential Review to fully understand the future potential market for DSM programs. TGVI will be applying to the BCUC for funding to conduct a Conservation Potential Review (CPR) and will be seeking participation from BC Hydro and other partners interested in jointly funding this initiative.

- Continue with Existing and Implement New Demand Side Management Initiatives. TGVI believes there is significant potential for strategic load building DSM programs in the residential and commercial markets. The Utility is recommending continuing three successful strategic load building programs: the Home Builders' Grand, the Build Smart, and the Conversion Program and, where applicable, to introduce four new conservation and efficiency programs currently offered or planned for the Terasen Gas mainland service area.

- Retain and Upgrade the Texada Compressor. The current arrangements with BC Hydro contemplate retention of the Texada compressor once a long term transportation arrangement is in place to serve the ICP generation facility.

- Monitor the Resource Planning process for Terasen Gas (Whistler) Inc. and assess the feasibility of providing natural gas service to Whistler. If natural gas service to Whistler is supported by the Whistler Resource Plan, it is anticipated that TGVI would build a pipeline lateral to connect Whistler to the TGVI transmission system at Squamish in 2007. This may require the filing of a CPCN for approval as early as third quarter 2004.

1 INTRODUCTION AND BACKGROUND

1.1 Introduction to Terasen Gas (Vancouver Island) Inc.

Terasen Gas (Vancouver Island) Inc. (TGVI) provides natural gas transmission and distribution services to approximately 80,000 residential, commercial, and industrial customers on Vancouver Island and the Sunshine Coast. Service is provided through approximately 640 km of high pressure transmission pipeline, including three compressor stations, and over 3,200 km of distribution mains. TGVI's largest customers are the Vancouver Island Gas Joint Venture (Joint Venture) representing seven large pulp and paper mills and British Columbia Hydro & Power Authority (BC Hydro) serving the Island Cogeneration Project (ICP).

Figure 1-1. Terasen Gas Vancouver Island System

TGVI, formerly Centra Gas British Columbia, is a wholly owned subsidiary of Terasen Inc., a private, shareholder-owned company whose shares trade on the Toronto Stock Exchange under the symbol TER. Terasen Inc. also owns and operates the following British Columbia based gas utilities:

- Terasen Gas (Whistler) Inc., formerly Centra Gas Whistler Inc.,
- Terasen Gas (Squamish) Inc., formerly Squamish Gas, and;
- Terasen Gas Inc., formerly BC Gas Utility, which serves the Lower Mainland and the Interior

In total, Terasen Gas (including Vancouver Island, Sunshine Coast, Whistler, Squamish, Lower Mainland, Interior) is the largest natural gas distribution utility in the Pacific Northwest, serving more than 862,000 customers in British Columbia. Terasen Gas employs 1,400 people spread over more than 125 communities and operates more than 43,000 km of natural gas transmission and distribution pipelines. Terasen's utility operations, including TGVI, are regulated by the British Columbia Utilities Commission (BCUC).

In response to the provincial government's Energy Policy[1], the BCUC has directed energy utilities to file Resource Plans in 2004 and to update them periodically thereafter. To assist the development of these plans, the BCUC also issued a set of Resource Planning Guidelines (refer to Appendix A) which have been used in the development of this document. In response to this directive, Terasen Gas plans to complete Resource Plans for each of its gas utility operations by November 2004. In the case of TGVI, however, an earlier submission is desirable to help support decisions related to:

- The Joint Venture's option to renew their transportation service agreement. This option must be exercised by December 31, 2004.
- Gas transportation that may be needed to resolve reliability concerns associated with BC Hydro's high voltage direct current (HVDC) cables system serving Vancouver Island.
- BC Hydro's Call for Tenders (CFT) process for competitive bids from independent power producers. The outcome of the CFT process and its impact on gas demand will likely not be known until the end of 2004.

1.2 Regulatory Context

Section 45 of the Utilities Commission Act, amended in 2003, implements the provincial government's Energy Policy of November 2002, "Energy for Our Future: A Plan for BC", setting out the requirements under the Act for utilities to complete Resource Plans. In December 2003,

[1] Energy For Our Future: A Plan for BC - http://www.gov.bc.ca/em/popt/energyplan.htm#eof

the BCUC issued Resource Planning Guidelines to help guide utilities in the submission of Resource Plans under Section 45 of the Act.

The Commission's Resource Planning Guidelines outline the process, summarized below, to be followed by utilities in developing their Resource Plans.

1. Identify the planning context and objectives of a Resource Plan – planning horizon of 15 to 20 years.
2. Develop a range of gross (pre-DSM[2]) demand forecasts.
3. Identify supply & demand resources.
4. Measure supply & demand resources against Resource Plan objectives.
5. Develop a range of multiple-resource portfolios.
6. Evaluate resource portfolios against Resource Plan objectives and select a portfolio.
7. Develop an action plan to implement the selected portfolio.
8. Obtain stakeholder input during the planning process.
9. Consider government policy and seek regulatory input during the Resource Plan preparation.
10. Submit the Resource Plan for regulatory review.

The Commission's guidelines form the basis of the Resource Planning processes undertaken by Terasen Gas (Vancouver Island) Inc. as described in this document.

1.3 Planning Context and Objectives

The Resource Planning process evaluates demand and supply options and considers their economic, environmental and social characteristics. The Commission's description of the planning process is:

> *"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."*

Resource Planning is part of an ongoing planning process at Terasen Gas which includes project-specific planning, service territory planning (the Resource Plan) and broader regional planning initiatives. Terasen Gas is in the process of completing a Regional Resource Planning

[2] DSM = Demand Side Management

study that assesses the natural gas infrastructure serving the I-5 Corridor, which encompasses the B.C. Lower Mainland, Vancouver Island, Western Washington and Western Oregon, for the purpose of determining the ability of the infrastructure to reliably serve the needs of the market. The Regional Resource Plan forms the broader context in which Terasen Gas operates and in which this Resource Plan was developed. The key activities which encompass the Resource Planning process are embedded in the overall planning processes which the Company undertakes in providing the highest standards of service to our customers.

In keeping with the provincial government's Energy Policy, effective Resource Planning requires that consumers have access to the information needed to make the best choices among all available energy sources. The delivery of an effective marketing strategy and programs to assist consumers in making appropriate energy choices is a key component of the Resource Planning process.

The product of the Resource Planning process is a long-term plan for the acquisition of resources to meet forecasted customer needs for natural gas over the long term (20 years), together with a detailed four-year action plan for acquiring resources to meet customer requirements in the near term. It is a planning document that analyzes financial, environmental and social impacts and incorporates stakeholder input. The last formal Integrated Resource Plan for Vancouver Island and Sunshine Coast was filed in May 1996 by Centra Gas. A consolidated Resource Plan which includes all of Terasen Gas' operations in British Columbia will be filed with the Commission by November of 2004.

1.3.1 Overview of the Resource Planning Process

The Resource Planning process at TGVI consists of the following activities:

1. Establish Objectives

The first step in the Resource Planning process is to develop the objectives. The objectives form the basis for deciding which resources will be acquired to provide service to customers both in the near term and over the planning period.

2. Review the Regional Context

TGVI operates in a greater regional area from which the company derives its gas supplies and which influences the availability, reliability, security and cost of those supplies. Key considerations related to the greater regional context and to the North American gas market as a whole are embedded in the process of identifying possible resource options for inclusion in alternative resource portfolios. In developing the TGVI Resource Plan, TGVI also reviewed the *Integrated Electricity Plan* submitted by BC Hydro to the Commission in March, 2004.

3. Develop a Range of Possible Demand Forecasts

The TGVI system is relatively new and has experienced considerable growth in capacity additions to serve an expanding customer base since its inception in 1991. TGVI employed a range of alternative assumptions related to new industrial loads and residential and commercial customer additions in developing a range of demand forecasts which bracket the possible future service requirements on the TGVI system. Three (3) distinct "probable" forecasts are selected from this range against which alternative resource portfolios can be developed and compared.

4. Identify Potential Supply and Demand Side Resources

The TGVI system is connected to the mainland and to potential supply sources throughout North America. While this ensures access to sufficient supplies of gas, increased demand for gas service on the TGVI system has resulted in the need for additional capacity to transport gas from the supply regions to the consumption areas. Providing sufficient capacity to meet future customer demand can be accomplished through combinations of additional piping, compression and storage. On the demand side, programs which encourage customers to modify their energy consumption volumes or patterns, or to substitute gas for alternative energy sources have an impact on overall demand requirements.

5. Group Resources into Resource Portfolios to meet the Demand Forecasts

Once the possible supply resources have been identified, they are grouped into distinct portfolios which are capable of delivering the required service to customers for one or more of the demand forecasts. The most effective portfolios will be scalable allowing flexibility in meeting changes in demand over time, thereby reducing the risk of over or under supply for the market.

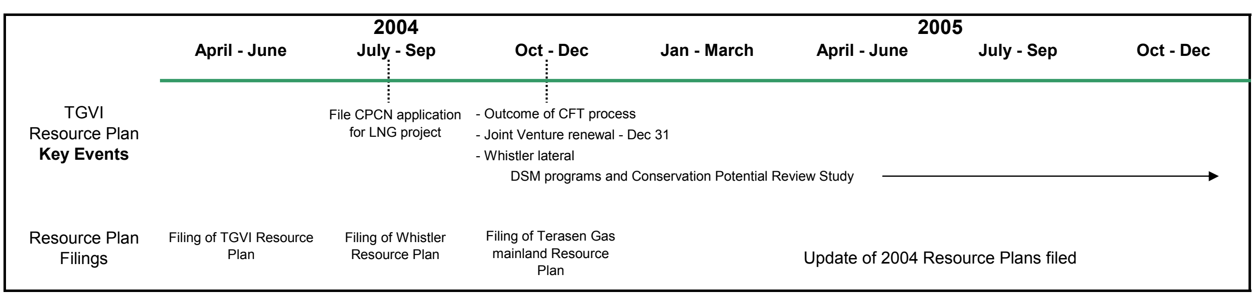
6. Review the Process and Alternative Portfolios with Interested Stakeholders

A key part of Resource Planning is communication with interested stakeholders on the process undertaken by the company. This is accomplished through meetings and information sessions with stakeholders such as customers and municipalities.

7. Recommend a Preferred Portfolio

The final part of the Resource Planning process is the selection of a Preferred Portfolio of Resources which satisfies the requirements of the demand forecasts while ranking high against the Resource Planning objectives. The recommendation of a Preferred Portfolio leads to a four year Action Plan for resource acquisition over the near term of the long term planning period addressed by the Resource Plan (normally 20 years).

1.3.2 Resource Planning Process Timeline



TGVI expects to file its Resource Plan for the Vancouver Island and Sunshine Coast with the Commission for their review by mid June 2004. Following this, TGVI will be filing a CPCN application in the summer of 2004 with the Commission to seek approval of the Liquefied Natural Gas (LNG) facility proposal. In addition, a Resource Plan for the Whistler region will be filed in the third quarter, culminating with the filing of a separate Resource Plan for the mainland by November 30, 2004. Before filing the Whistler and mainland Resource Plans, Terasen Gas will be consulting with stakeholders and providing information through meetings and workshops.

Key upcoming events in the fourth quarter include the outcome of the BC Hydro Call for Tenders process on Vancouver Island, the decision on the feasibility of providing gas service to Whistler and the Joint Venture's decision to renew their transportation service agreement. The option must be exercised by December 31, 2004.

1.3.3 TGVI Resource Planning Objectives

TGVI's Resource Planning objectives form the basis for evaluating all potential resources in the Resource Plan including major infrastructure projects, gas supply alternatives and demand side programs. The objectives reflect the Utility's commitment to providing the highest level of quality energy services to its customers.

TGVI's Resource Planning objectives are outlined below.

Ensure reliable and secure gas supply.

A secure energy supply is essential for all of TGVI'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 Utility.

Provide service to customers at least delivered cost.

Customers and regulators expect the Utility to procure and deliver energy in the most cost-effective and efficient manner possible. The most desirable resource options will provide cost effective service solutions both in the near term and into the future in the context of reliability and security. Demand Side Management strategies which are cost-effective can add value to customers through more effective use of the gas delivery infrastructure and more efficient use at the burner tip.

Reduce rate volatility.

Another important objective of the Utility is to dampen rate volatility and allow gas to remain competitive with other energy sources. Customers value consistent, predictable rates which allow them to budget for their energy service requirements.

Balance socio-economic and environmental impacts.

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

The Resource Plan objectives form the basis for evaluating potential resource portfolios. Resource portfolios are assessed by determining the degree to which they meet the criteria of each objective. The most desirable resources will rank high on most or all of the objectives. The relative ranking of resource portfolios against the objectives is determined using both quantitative and qualitative techniques. To be meaningful, objectives must be measurable and differentiate between resources.[3]

The following table provides a summary of the objectives, associated attributes and measures used to assess alternative resource portfolios against those objectives.

Table 1-1. Resource Planning Objectives

Objective	**Attribute**	**Measure**
Ensure reliable and secure supply.	System reliability Security of supply	Risk of outages Gas supply diversity
Provide service to customers at least delivered cost.	Financial evaluation of supply side and demand side resources	Net Present Value Total Resource Cost (TRC) Ratepayer Impact (RIM)
Reduce rate volatility.	Expected rates	Risk Trade-offs
Balance socio-economic and environmental impacts.	Social costs / benefits including: Local emissions Greenhouse gas Land use impacts Employment/local economic impacts Stakeholder consultation	 Air pollutants Quantity of CO_2 equivalent Area impacted Jobs created Stakeholder input

The resource portfolio selection process involves ranking each portfolio for each of the four (4) Resource Planning objectives. The relative ranking of each of the resource portfolios forms the basis for selection of a preferred portfolio.

As indicated in the Resource Planning objectives table, the measures attached to attributes associated with each objective include both quantitative and qualitative measures.

[3] An example for TGVI is the objective "*ensuring adequate returns for our shareholders*". It was determined that, while key to the viability of our business, it was not possible to unambiguously differentiate between resource portfolios using this objective.

The objective *Ensure Reliable and Secure Supply* is measured qualitatively by ranking the alternative resource portfolios according to their relative susceptibility to upstream outages and the overall diversity of their respective supply resources.

Provide Service to Customers at Least Delivered Cost is evaluated for supply side resources based on the Net Present Value (NPV) of the costs of those resources in each portfolio. For demand side resources, the standard DSM measures are used to evaluate programs: the Total Resource Cost[4] (TRC) is used for conservation and efficiency programs; the Ratepayer Impact Measure (RIM) test is used for load addition programs.

The objective *Reduce Rate Volatility* is evaluated qualitatively by ranking the resource portfolios according to their expected impact on customer rates.

The objective *Balance Socio-Economic and Environmental Impacts* is measured using three quantitative measures: expected impacts of air emissions (local and global); land area affected; and employment created. Stakeholder input, discussed in Section 7, is also considered within the context of this objective.

Using these criteria in the portfolio selection process involves consideration of both inter-relationships between attributes and judgements on the relative weightings assigned to each attribute. The results of the trade-off process for TGVI and selection of a preferred Resource Portfolio are discussed in detail in Section 6 Resource Portfolio Evaluation.

4 **Ratepayer Impact Measure (RIM) test** – a measure of the distribution of equity impacts of DSM programs on non-participating rate-payers. From this perspective, a program is cost effective if it reduces a utility's rates. This can be expressed as a ratio or in dollars of net benefits. **Total Resource Cost (TRC) Test** – a test used to evaluate the economic benefits and costs of utility DSM program from the perspective of all utility customers. The test can be expressed as a ratio or dollars of net benefits.

2 TGVI GAS SUPPLY OVERVIEW

2.1 TGVI Gas Supply Obligations

From a gas supply perspective, TGVI has two types of customers. Distribution customers consist of residential, commercial and small industrial customers that have gas delivered to their home or business. These customers are also referred to as “Core Market” or “Core” customers. On behalf of Core customers, TGVI purchases natural gas and recovers this cost in a bundled sales rate. This requires holding natural gas pipeline and storage assets upstream of the TGVI system on behalf of these customers.

Core customers typically use a significant portion of their gas requirements for heating applications. Consequently, gas demand for the Core Market is weather sensitive. Due to the weather dependency, sufficient gas supplies must be purchased to meet the requirements for the Core Market based on the coldest day of each year.

The second type of customer is transportation customers. These customers are large industrial customers possessing the ability to manage their own gas supply requirements. Transportation customers purchase their own gas in the wholesale market and provide it to TGVI at the interconnect of Duke pipeline and the Terasen Gas Inc. system near Huntingdon, B.C. TGVI then transports the gas from Huntingdon to the customers’ facilities. Currently, TGVI has the option to interrupt service to these customers on the coldest days and divert their gas to the Core Market. This provision limits the need to build pipeline capacity to serve Core demands that are only required on the coldest days.

2.2 Gas Supply Market Considerations

Gas supply considerations are a key component in long term Resource Planning for TGVI. When TGVI purchases gas to deliver to distribution customers, it must consider not only the local natural gas market on Vancouver Island and the Sunshine Coast but also the regional market in British Columbia, the U.S. Pacific Northwest and the continental market of North America.

The continental gas supply perspective is important when evaluating the requirement for new facilities which are to be used over their lifetime of thirty or more years. TGVI has reviewed the latest forecasts for gas reserves from a variety of sources and is satisfied that ample supply exists to serve TGVI markets over the planning period. A more detailed discussion is included in Appendix B.

The regional market is centered on the Huntingdon/Sumas market hub at the B.C. / Washington border, southeast of Vancouver. Most of the gas used in the region originates in Northeastern British Columbia but the regional market also can access production in Alberta and the Western United States. Gas is delivered to the market through a network of gas pipelines and storage facilities.

2.3 Gas Supply Portfolio Planning

In planning the gas supply portfolio for TGVI, resources must be put in place to manage the varying demand for gas on an annual basis as outlined in Figure 2.1. From this, a load duration curve is modeled depicting annual consumption arranged in order of magnitude (refer to Figure 2.2). TGVI looks at both the design and the normal, or expected demand, for each day in the year[5]. Supply resources are then assembled to ensure that TGVI has sufficient resources to meet the design peak while meeting the normal peak at the least cost.

The basic resources that TGVI has available are pipeline, gas storage and curtailment or fuel switching resources. The cost and characteristics of each resource dictate where they best fit in the supply portfolio. Pipeline capacity is best used for demand that is constant throughout the year. This is because pipeline capacity is fixed and must be paid for based on the peak capacity that is reserved for the user.

Gas storage is typically limited to a shorter time span. Storage is most cost effective when it is located close to the market it serves as this limits the amount of pipeline capacity that is required to deliver gas from the storage facility to the market.

There are two basic types of storage, underground and liquefied natural gas storage. Underground storage is generally located in depleted gas or oil reservoirs. Gas is pressurized and pushed into the reservoir for delivery at a later date. Underground storage is typically less expensive on a unit cost basis but is dependent on having the available geology. Liquified gas storage is extremely convenient because it can be located very close to the market but there are higher costs associated with building the storage tanks and converting the gas to a liquid. Underground storage is typically used for serving load of 30 to 120 days duration whereas LNG is used for shorter durations.

Finally, curtailment or fuel switching can be used as a supply resource. This involves interrupting a large customer and using their gas supply to meet peak demand. Typically, the large customer has a backup fuel supply that it can use to replace the lost gas supply. Curtailment is typically used for very short duration peaks in demand. The reasons for a shorter duration include limitations in terms of the supply of the alternate fuel, the cost of the fuel, and local environmental concerns that limit the amount of alternate fuel that can be consumed. From a gas supply perspective, there must be confidence that the customer will have the firm gas supply to make available and will in fact be in a position to switch when called upon.

5 **Design day, design day demand (see also: peak day)** – the maximum demand for natural gas a utility expects it must provide over a single day. As core demand is weather dependent, design day is forecast based upon the coldest weather observed in the last 25 years . For transportation customers, the design day is equivalent to the firm contract demand.

Normal demand – the expected demand during a year of 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.

Figure 2-1. Annual Supply Portfolio Profile – 2003 / 04

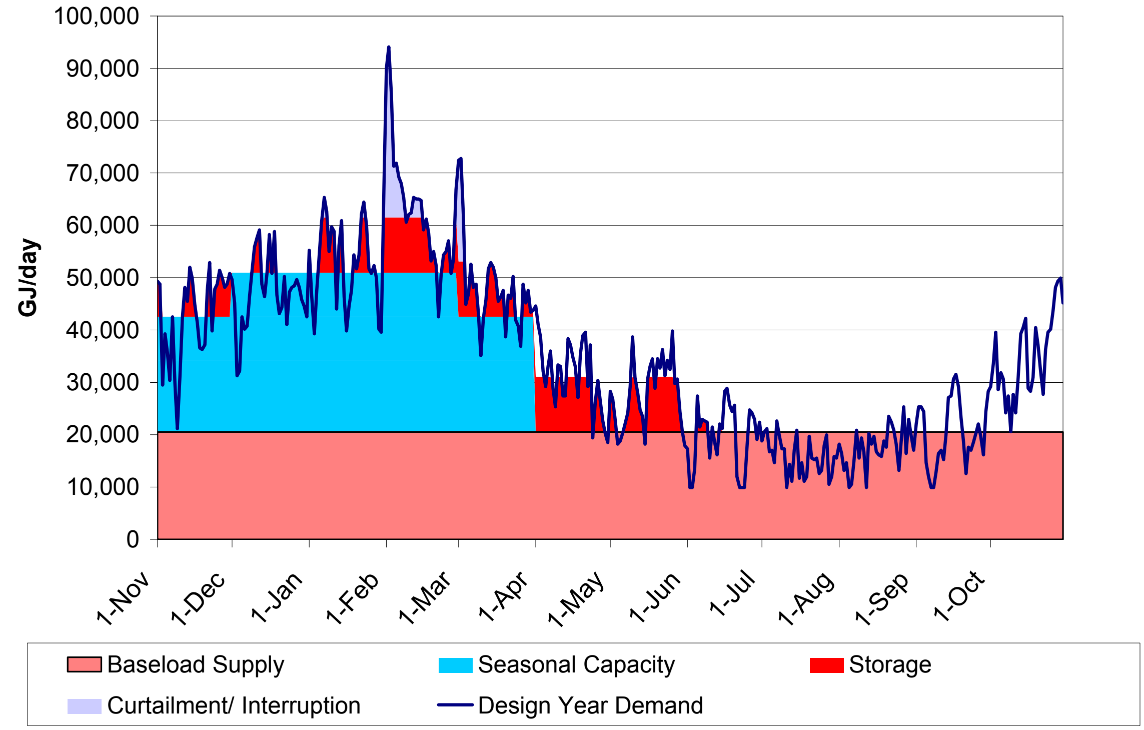
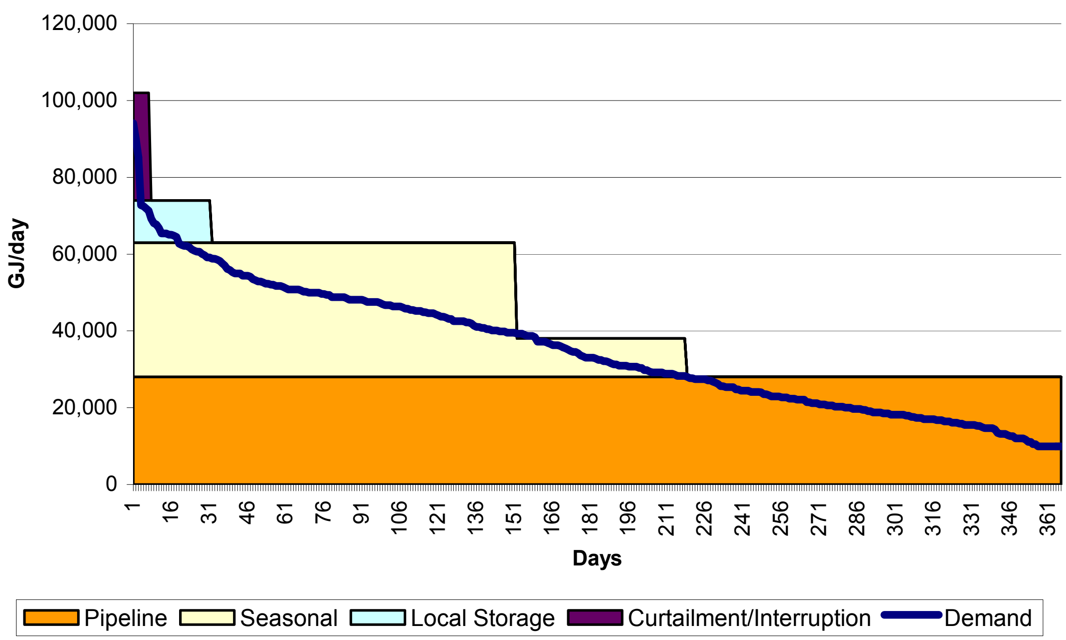


Figure 2-2. TGVI Core Market Design Load Duration Curve – 2003 / 04



As shown in the load duration curve, gas supply requirements vary significantly through-out the year, reflecting the significant weather sensitive demand of TGVI's Core Market. In assembling a gas supply portfolio to meet this demand, TGVI balances the objective of least cost against the other objectives of ensuring supply reliability and security and reducing rate volatility.

Least Cost

TGVI assembles a portfolio that on an expected basis represents least delivered cost. This is done by using a mix of supply sources that minimizes the assets required to serve the load. For example, storage capacity is substituted for pipeline capacity to serve demand that is infrequent. Pipeline capacity is used during the summer when demand is low to transport gas to storage reservoirs. This increases the utilization of pipeline capacity. TGVI uses computer modeling tools and industry experience to establish least cost portfolios.

Supply Reliability and Security

Two of the major risks affecting supply reliability and security are infrastructure failure and supplier failure. Infrastructure failure can occur for a variety of reasons due to the mechanical nature of the gas delivery system. Problems can occur with pipelines, compressors, gas wells, or gas plants. Suppliers can fail for a variety of reasons including financial difficulties such as bankruptcy or failure to deliver due to lack of reserves, contract disputes, errors in nominating gas or failing to contract for adequate plant or delivery capacity. TGVI addresses these risks by diversifying its supply portfolio.

Rate Volatility

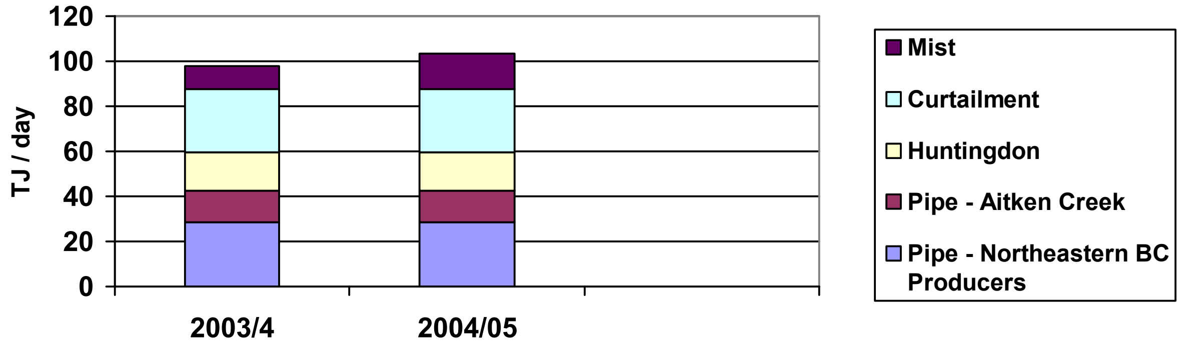
Rate volatility is a result of both increases in absolute prices and in daily or seasonal price volatility related to short term events. TGVI manages the portfolio to track long term market trends while minimizing short term volatility. In Southwestern B.C., the major source of volatility has been the result of regional capacity limitations during periods of peak demand. When demand is high, usually due to cold weather, and there is a lack of additional supply sources, the only way to balance the market is to increase the price to the point that demand is reduced. This can lead to very high prices.

2.4 Managing Risks

To the greatest extent possible, TGVI builds supply diversity into its gas portfolio to limit exposure to any one facility or supplier. TGVI supports regional infrastructure planning, working cooperatively with other utilities in the region to understand forces in the market and to plan infrastructure required to serve the market over the long term, ensuring adequate and reliable supply and reducing price and rate volatility for its customers.

In order to manage price risk, TGVI uses gas storage and financial tools. Gas is stored in summer when it is less expensive and withdrawn for use in the winter. Financial tools allow TGVI to lock-in gas prices in advance so the gas purchase price is known.

Figure 2-3. Terasen Gas Vancouver Island Supply Sources



All the gas used in the TGVI system originates in Northeastern B.C. As shown on Figure 2.3, TGVI currently holds approximately 42 terajoules per day (TJ/day) of pipeline capacity to bring gas from the supply area to Huntingdon. This capacity is equivalent to the average daily demand on the TGVI system during the winter. In addition, TGVI sources approximately 1/3 of this supply from the Aitken Creek storage field in Northeastern B.C. The remaining 2/3 is sourced from several Northeast B.C. producers (in the summer this latter supply is redirected to refill the Aitken Creek storage). Another 15 TJ/day of supply is sourced as seasonal supply from suppliers directly at Huntingdon. TGVI sources 10 TJ/day of local storage from the Mist storage facility in Oregon. This will increase to 15 TJ/day in the 2004/05 gas year due to increasing peak day demand in the Core Market related to customer additions. Finally, approximately 30 TJ/day of industrial curtailment is currently used to meet peak day Core requirements.

2.5 Conclusions

Future gas supply requirements for TGVI are driven primarily by Core Market growth. Additional pipeline capacity will be required to meet average day growth, but a majority of required infrastructure will be local storage for the winter to meet peak demand. As demand increases, relatively scarce local storage is expected to become even more important and more costly.

TGVI will continue to focus on its objectives of long term access to secure, reliable, competitively priced supply to meet Core customer requirements.

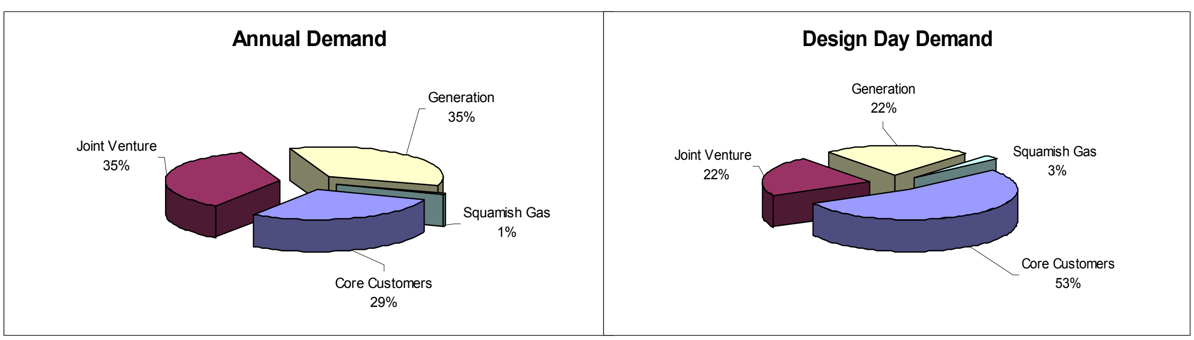
3 GROSS DEMAND FORECASTS

3.1 Introduction to Demand Forecasts

Forecasted demand scenarios have been prepared for a planning horizon of 20 years, in accordance with the requirements of the Resource Planning process outlined in a previous section of this report, reflecting the long term nature of Resource Planning. In addition, to reflect the uncertainties about the future associated with a long planning horizon of 20 years, TGVI has prepared a range of forecasted gross demand scenarios to account for such uncertainties and to facilitate a comprehensive understanding of the potential resource portfolios that it might employ to balance supply and demand.

TGVI provides natural gas service to approximately 80,000 residential and commercial customers (Core Market) on Vancouver Island and the Sunshine Coast where it provides both a delivery and commodity service. TGVI also provides transportation of natural gas service to industrial customers, an electric generation facility and a small natural gas utility. The transportation customers are represented by large end-users that generally provide their own natural gas commodity. Transportation customers consist of the seven large pulp mills that form part of the Joint Venture, the Island Cogeneration Project (ICP) and Terasen Gas (Squamish). Figure 3.1 provides the profiles of the Annual Demand and Design-Day Demand for customers of TGVI.

Figure 3-1. Customer Profiles – 2004 Annual Demand and Design-Day Demand



For the purpose of this Resource Plan, a gross demand forecast scenario is comprised of the sum of the different individual customer demand components that make up the gross demand. The individual customer demand components include Core Sales Customers (Residential, Commercial, Small Industrial), Transport Customers (BC Hydro for gas-fired generation of electricity and the Joint Venture of pulp mills), and demand from local distribution companies (Terasen Gas Squamish and potentially Terasen Gas Whistler).

Figure 3.2 below provides a matrix showing the components of the five gross demand forecast scenarios that have been developed:

- High-High [High case scenario to bracket the full range of possible forecasts]
- Base + 0 [Likely demand scenario with zero impact from CFT process]
- Base + 20 [Likely demand scenario with 20 TJ / day impact from CFT process]
- Base + 45 [Likely demand scenario with 45 TJ / day impact from CFT process]
- Low-Low [Low case scenario to bracket the full range of possible forecasts]

Figure 3-2. Matrix of Gross Demand Scenarios

Gross	Core Customers			Joint Venture			Generation (ICP + CFT)			Squamish	Whistler	
Demand	High	Base	Low	High	Base	Low	ICP + 0	ICP + 20	ICP + 45	Yes	Yes	No
High-High	•			•					•	•	•	
Base + 45		•			•				•	•		•
Base + 20		•			•			•		•		•
Base + 0		•			•		•			•		•
Low-Low			•			•	•			•		•

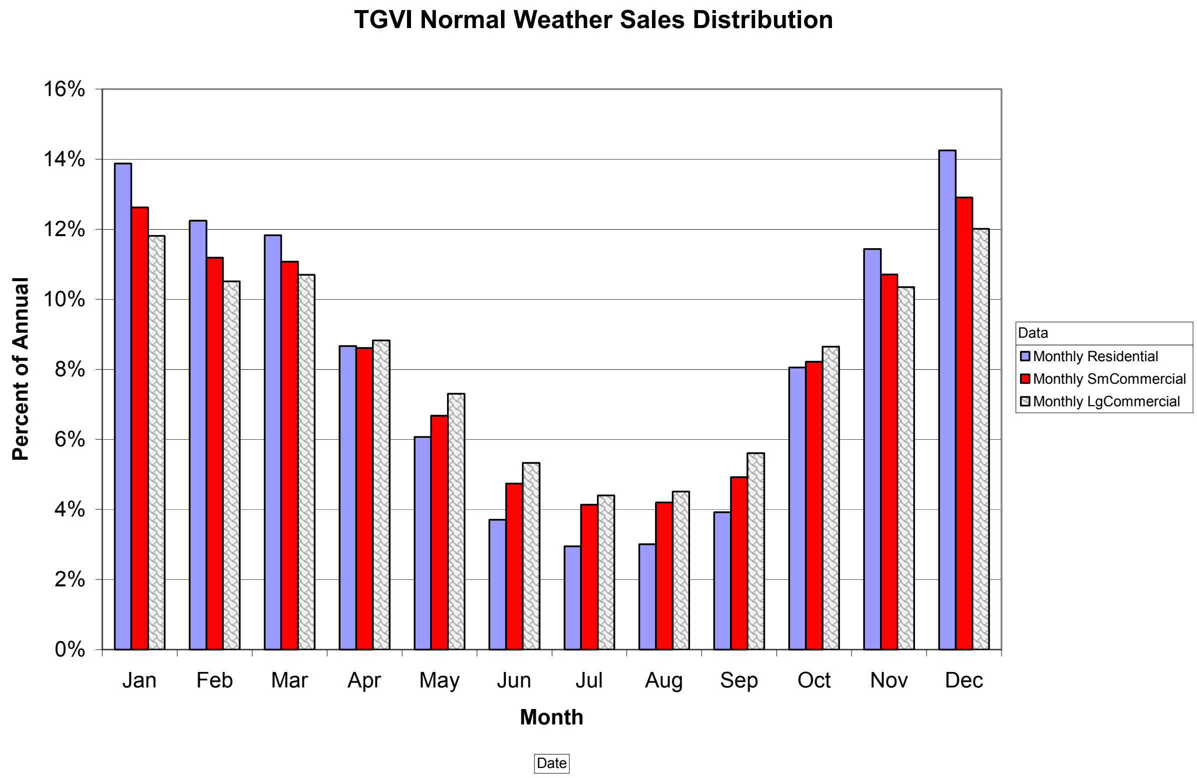
The next sections of this report will discuss the different customer demand components of the forecasted demand scenarios, the key drivers and the assumptions incorporated.

3.2 Customer Demand Components

3.2.1 Core Sales Customers

For 2004, Core customers' consumption represents approximately 29% of the annual gas volumes and approximately 53% of the design-day demand. Residential and commercial customer annual consumption profiles are illustrated in Figure 3-3. The profile illustrates the "peakiness" of the consumption and its high correlation to colder temperatures usually experienced during the winter period.

Figure 3-3. Residential and Commercial Customer Annual Consumption Profile



Factors or drivers affecting the Core customers' forecasted demand for gas are:

- growth in the number of customers
- usage patterns of the customers, impacted by technology and economic factors
- weather

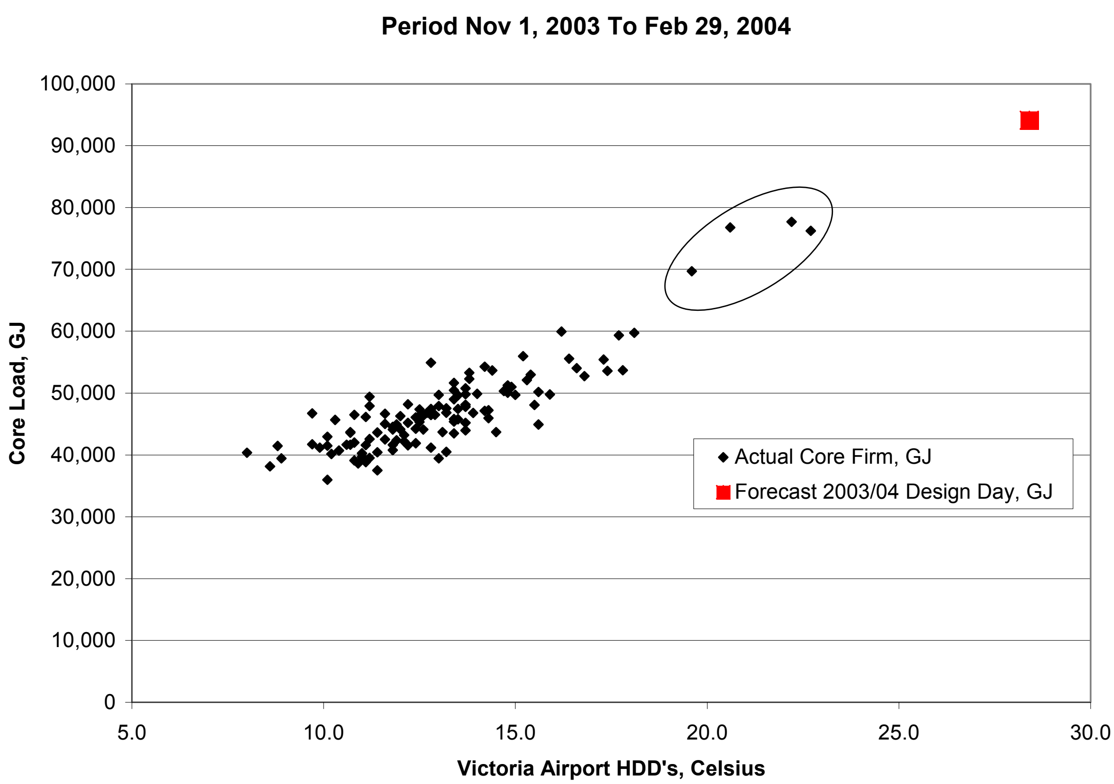
Variations in the first two drivers can lead to a number of potential outcomes with growth in the number of Core Market customers being the primary determinant of the demand forecast. To address this uncertainty, three forecast scenarios were developed to bracket the probable combinations. A Base forecast was developed to represent the expected outcome, as well as a High and a Low forecast to bracket the range of probable outcomes. The variability of the third factor, weather, was accounted for by utilizing design and normal weather conditions for determining demand requirements.

3.2.1.1 Weather Sensitivity

Load planning for the purpose of Resource Planning is driven primarily by the peak day or design-day demand. Design-day demand represents the maximum expected amount of gas in any one day required by customers on the TGVI system. For TGVI, since Core customers' demand is primarily weather dependent, design-day demand is forecast based upon the coldest weather observed in the last 25 years, which over the last 25 years has been minus 10.4 degrees Celcius or 28.4 heating degree days (HDD)[6].

Recent experience in early 2004 provides support to the validity of the existing design-day demand model. Figure 3.4 illustrates the observed relationship between Core customer load and heating degree days recorded this past winter. The cold weather experienced from January 3 to 6th of minus 4 degrees Celcius led to daily sendout for Core customers of over 70,000 GJs per day during the noted time period. The four days of observations recorded correspond closely with the demand that would have been predicted by the heating degree day demand model.

Figure 3-4. TGVI Core Consumption to Heating Degree Days



6 A heating degree day is 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 Celcius.

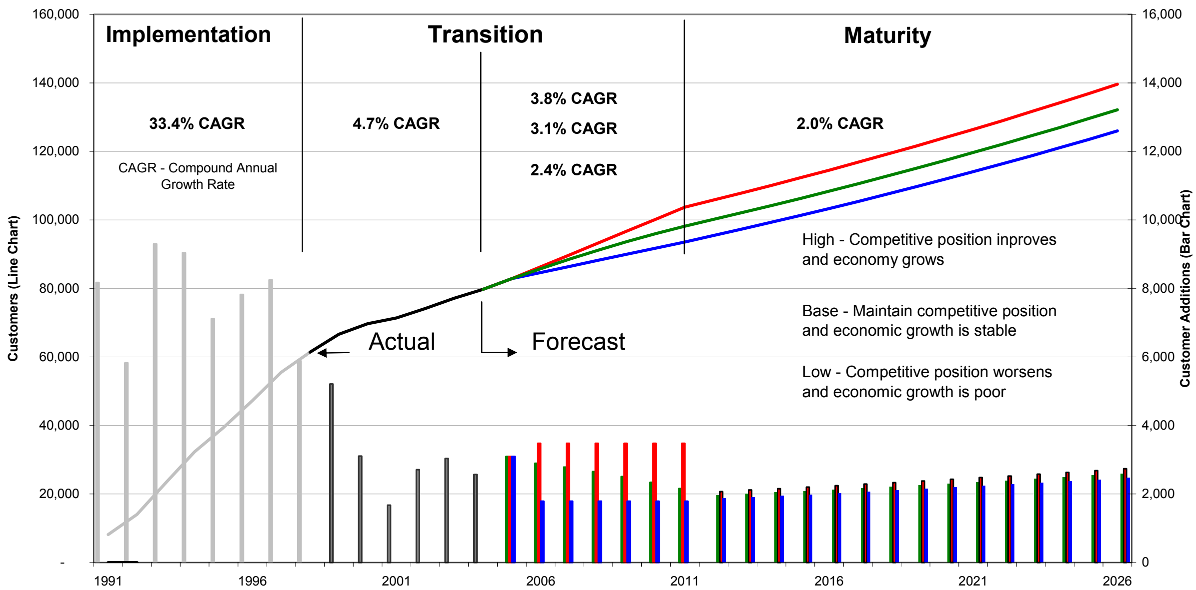
For Terasen Gas Inc. mainland load planning, a slightly different design-day methodology is used. The methodology is based on analysis of historical weather recorded, using a statistical approach of 1 in 20 probability of the coldest day weather event occurring to determine the design-day temperature. Application of the mainland design methodology to TGVI though leads to a similar result from TGVI existing methodology. In the future, Terasen Gas will be reviewing the two methodologies currently employed at TGVI and Terasen Gas Inc. mainland to ensure consistency where appropriate in the selection of design-day criteria for system planning purposes.

In addition to design-day demand, annual demand defined as the total gas forecasted to be consumed each day over a year, is required for system supply planning purposes. The relationship between the design-day demand and annual demand is called the load duration. As mentioned in section 2.3, Gas Supply Portfolio Planning, the load duration is typically depicted in graphical format as a load duration curve, representing the daily forecasted demand over each day of the year, ordered from the highest demand day to the lowest demand day. In planning the gas supply portfolio for TGVI, resources must be put in place to meet the projected design-day demand and manage the varying demand for gas on an annual basis.

3.2.1.2 Customer New Account Growth Forecast

Three forecast scenarios – Base, High and Low were developed to reflect the range of possible outcomes in anticipated customer growth rates. To assist the development of these growth scenarios, TGVI segmented the growth of the Core Market into three distinct phases of growth: **Implementation**, **Transition** and **Maturity**. Each of these phases has different characteristics and an associated customer growth rate, representing the past, present and future in the evolution of the Utility. While it does not contain any forecast material, the information presented in the Implementation phase provides a historical perspective, helping put into context the assumptions incorporated into the Transition and Maturity phases.

Figure 3-5. Core Customer New Account Growth in Three Market Phases



During the Implementation phase, customers converting from other energy sources such as oil and electricity made up the majority of the customer additions recorded. In the Transition phase, conversion activity has slowed and is expected to stabilize around the 1,200 conversions per year level, reflecting the actual average number of conversions per year observed from 2001 to 2003. The remainder of the customer additions during the Transition phase is comprised of new construction related additions which are expected to generally follow economic growth in the Vancouver Island region. In the final phase, the Maturity phase, customer growth is expected to slow to an annual growth rate of approximately 2% per year, consisting of a base level of conversion activity and new construction additions driven by economic growth.

3.2.1.3 Implementation Phase - Customer Additions

Prior to commissioning the natural gas transmission and distribution system in 1991 on Vancouver Island and the Sunshine Coast, consumers utilized alternative energy sources such as electricity, oil and to a smaller extent, wood and propane. After the commissioning of the TGVI system, a large proportion of these consumers chose to convert to natural gas. The economics of converting to natural gas was attractive based upon existing pricing structures at that time. At the same time, new residential and commercial construction activity predominately chose natural gas to meet their energy needs.

The combination of the conversion of customers from alternative energy sources and the addition of new construction created initial high growth rates for TGVI. Annual growth as illustrated in Figure 3.5 from the period 1991 through 1998 was 34% per year. Growth could have been higher if the Company had not been limited by its ability to attach customers economically and efficiently.

3.2.1.4 Transition Phase - Customer Additions

The Transition phase is defined as the period from 1999 to 2011. Customer growth during this period is expected to decline significantly from that experienced during the Implementation phase. Annual growth is expected to range only in the 2% to 4% per year, reflecting a reduced level of conversion activity from that experienced in the Implementation phase.

Base Forecast

The Base forecast shown in Figure 3.5 with an annual growth rate of 3.1% per year for Core customer additions was developed assuming the relative competitive position of natural gas against alternative fuel sources in the marketplace is maintained and that overall economic growth and household formations continue at growth rates experienced in recent years.

In the Base scenario, TGVI forecasted that customer additions due to new construction will generally follow the trend of growth rates projected for household formations by BC Stats[7], with annual customer additions forecasted to average approximately 1,900 per year on a declining basis year over year from the period 2005 to 2011. Even though household formations statistics suggest an uptrend in economic activity during this period, TGVI erred on the conservative side in its forecast by incorporating a declining trend from levels experienced in recent years, as it expects new construction additions to gravitate to an annual growth level associated with a utility in the Maturity phase. This has been reflected in the forecast from 2012 onwards.

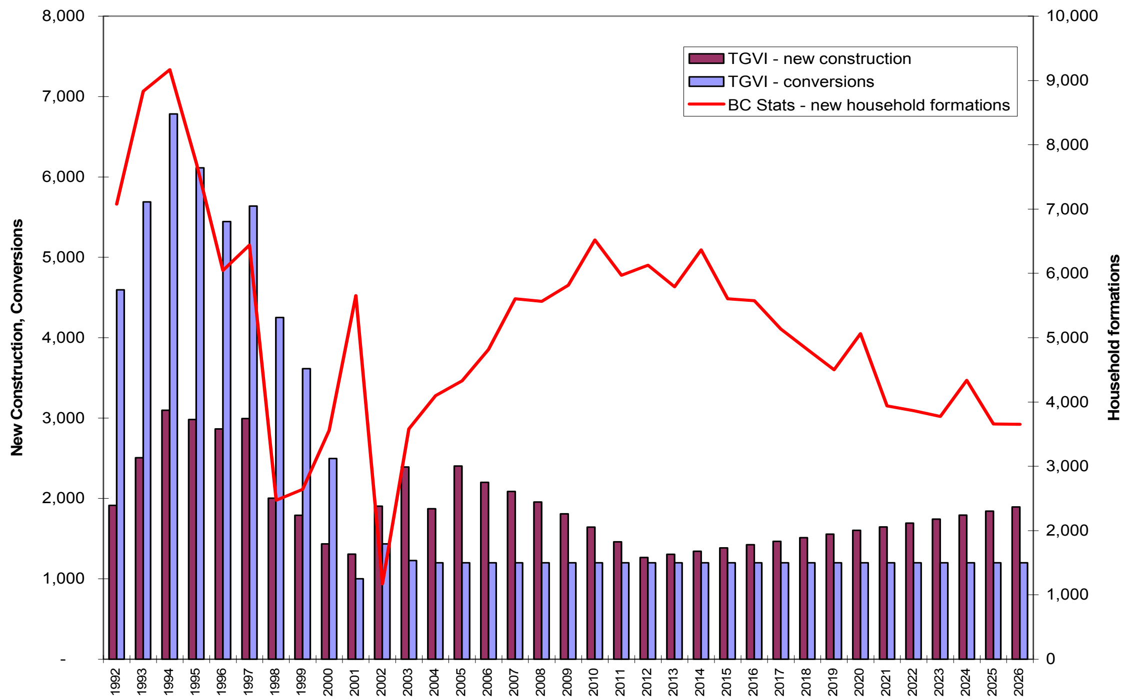
As shown on Figure 3.6, there is a general correlation between the number of customer additions due to new construction and the number of household formations (or housing starts) reported during the period 1992 – 2003. This relationship is typically observed in most mature gas utilities such as Terasen Gas Inc. where new construction activities are driven primarily by general economic growth. In the case of TGVI, the observed correlation during the Implementation phase when natural gas service was first introduced is not as strong, primarily because of its limited ability during that time to attach customers. Otherwise, customer additions due to new construction could have been higher during the Implementation phase.

Forecasting customer growth for TGVI is further complicated by the significance of the number of conversion customers that make up the total number of customer additions. Conversion activity is forecasted to remain in the 1,200 per year range, a reflection of the conversion activity levels experienced between 2001 – 2003. This may turn out to be conservative as there is a significant conversion market still available with only 60% of the residential homes “on the main” (with natural gas nearby) having gas service. In total, there is an estimated 55,000 number of potential non-gas users “on main” to be converted. When contrasted to Terasen Gas Inc. Mainland’s saturation rate of 85% to 90%, TGVI’s saturation rate is extremely low, providing further evidence to support continued activity in the conversion sector.

No natural gas commodity price spikes are anticipated in the Base scenario. An occurrence of a significant natural gas price commodity spike similar to that experienced in 2000 / 2001 will likely have the same dampening effect on customer growth.

7 BC Stats Household Formations Projections, updated January 2004

Figure 3-6. Base Scenario for Customer Addition Activities – New Construction and Conversions

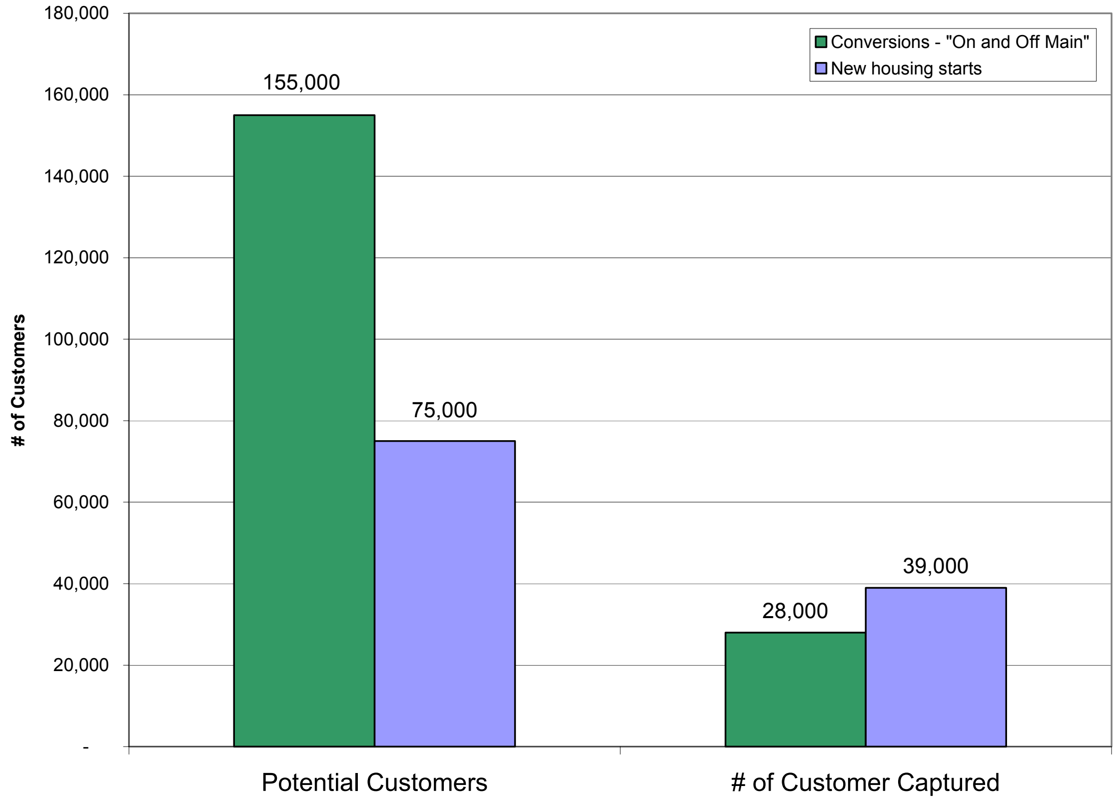


In summary, illustrated in Figure 3.7, is the Base scenario for the forecast period of 2004 to 2026. TGVI expects gross customer additions of approximately 39,000 due to new construction and 28,000 due to conversion activity, for a total of 67,000 gross customer additions. In aggregate, the 67,000 forecasted customer additions represent only a 29% capture rate of the total potential number of customers available during the forecast period. Customer additions due to new construction represent 52% of the potential number of customers[8] with conversions accounting for 18% of the potential number of conversion customers – both "on and off main".

As stated earlier, TGVI has been conservative in its assumption of the projected number of new customers. The above macro analysis provides support and validates that the overall load forecast is reasonable.

[8] The potential number of customers due to new construction is determined by assuming that for each new household formation projected by BC Stats, there is 0.65 of a housing start (ratio determined based on historical relationship between housing starts and household formations – the Canadian Housing Market Corporation does not provide long term housing start forecasts). The total number of forecasted housing starts forms the basis for the potential customers from new construction.

Figure 3-7. Total Forecasted Gross Customer Additions compared to Potential Additions – 2004 to 2026



High Forecast

For the High growth scenario of 3.8% per year annual growth, TGVI considered a more competitive position of natural gas relative to alternative energy coupled with stronger economic growth. In this scenario, the attachments are assumed to continue at today's levels, which are consistent with the median of growth rates during the initial years of the Transition phase. The number of conversion customers is also higher along with a greater rate of new construction market capture.

Low Forecast

The Low scenario of 2.4% per year annual growth represents a situation of poor economic growth and a weaker competitive position for natural gas. Customer additions drop to a level consistent with the 10th percentile of growth in the initial years of the Transition phase.

3.2.1.5 Maturity Phase - Customer Additions

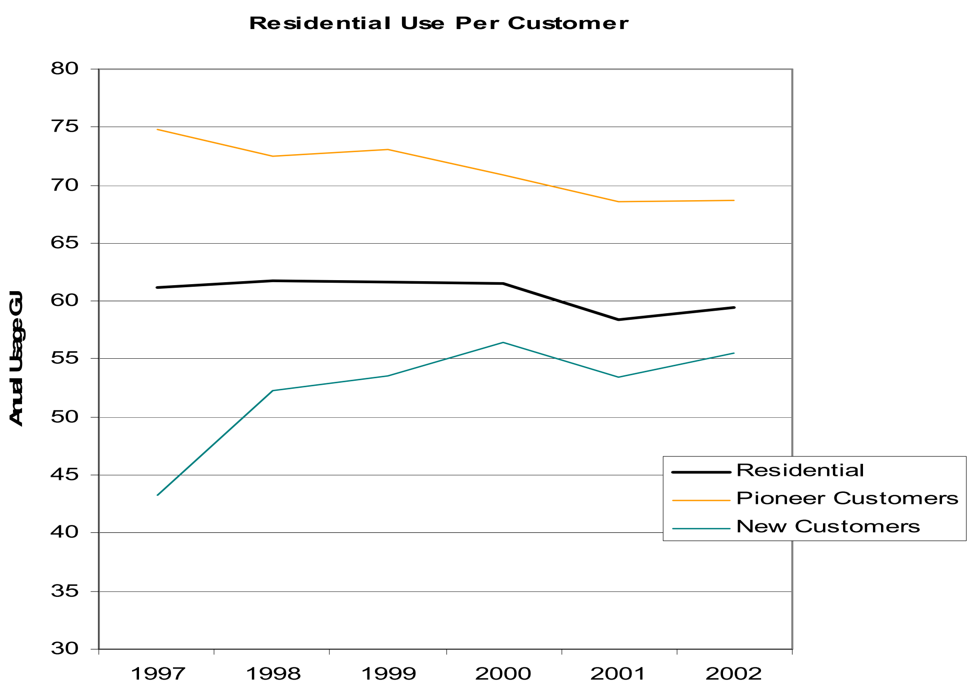
Post - 2011 is defined as the Maturity phase. In this phase, customer growth is forecasted to slow to an annual growth rate of 2% per year, for all three scenarios; Base, High and Low. It has been assumed that the level of customer conversions stabilize at 1,200 per year and new construction related customer additions track the general health of the economy. The assumed annual growth rate of approximately 2% per year forecasted for the Maturity phase is consistent with the rates observed at other mature utilities in Canada.

3.2.1.6 Core Customer Gross Energy Demand Forecast

Building from the previous customer growth scenarios, estimates of customer use rates by rate class were developed for the Core Market using historical consumption data. These estimated used rates are required in order to calculate and forecast total design-day demand and annual demand of Core Market customers.

For each class of customer, the annual demand was analyzed to develop an understanding of how the customers might consume in the future. Data and experience indicate that Core customer usage patterns are relatively constant. While factors such as the relative competitive position of alternate fuel choices, technology and Demand Side Management programs had an effect on consumption, the impact was not and is not expected to be material for the forecast period.

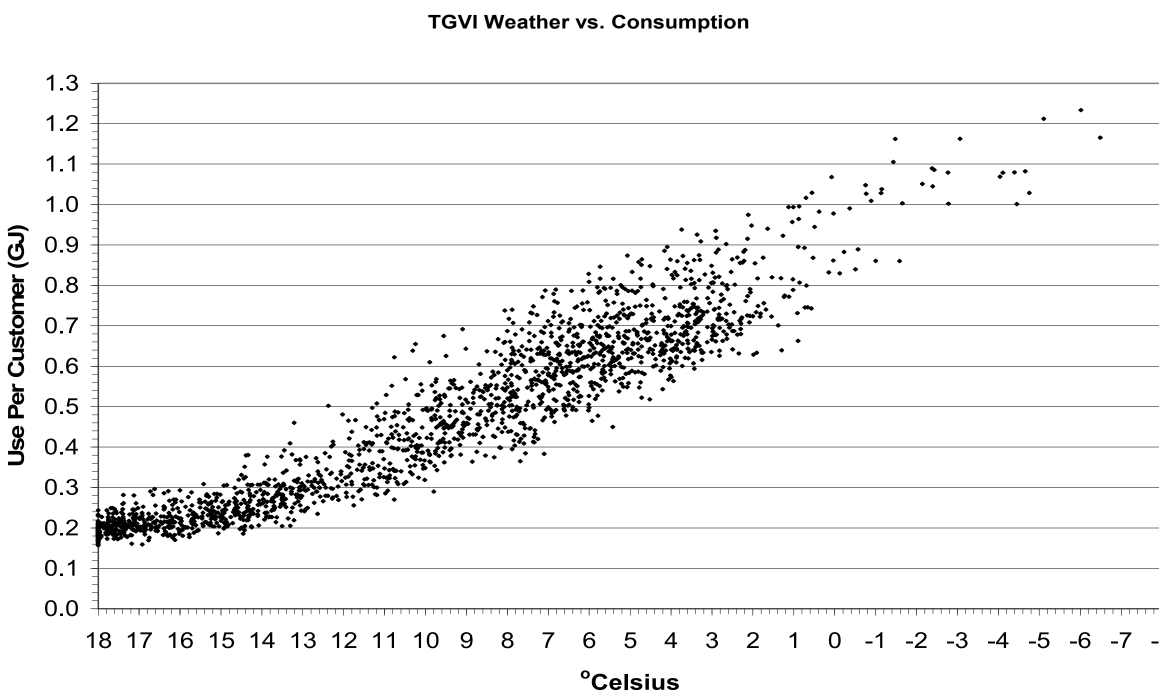
Figure 3-8. Annual Use Rate Per Residential Customer



Introduction of natural gas to Vancouver Island and the Sunshine Coast is relatively recent. As a result, the TGVI market consists primarily of new and efficient end-use equipment installed during this initial period of growth. As shown on Figure 3.8, existing or pioneer residential customers (those customers that switched to natural gas use in the early stages of Implementation phase of growth) have been reducing the average consumption rate per customer over the years as less efficient equipment are being replaced by higher efficiency end-use equipment. Offsetting this reduced load though has been higher average use rates of new customers, as new customers find more end uses for natural gas within their homes and facilities. The net effect is that overall annual average consumption per customer is relatively stable and predictable.

Therefore, the primary determinant of Core customers' consumption is weather. The correlation of a Core customer's demand to weather is shown in Figure 3.9. TGVI used a statistical analysis technique called regression analysis to compare historical Core customer demand to weather observed (or heating degree days). The results of this analysis yielded the design-day demand contributions per customer.

Figure 3-9. Statistical Analysis of Weather vs. Gas Consumption



The design-day demand is highly correlated to the coldness of weather conditions experienced and is highly price inelastic, meaning that during the design-day, the demand is insensitive to price, driven primarily by the weather. As mentioned earlier, the design-day is a single event based upon the coldest weather observed in the last 25 years. The Utility must plan to be able to serve the firm requirements of all customers on such a day.

Using the usage characteristics of the design-day weather event and annual demand per customer determined by analysing annual and daily historical demand compared to weather, forecasts for the design-day and annual demand requirements for Core customers are prepared for each of the three customer growth scenarios; Base, High and Low.

3.2.2 Transportation Customers

Transportation customers' requirements represent approximately 71% of the annual gas volumes and approximately 47% of the design-day demand. The TGVI transportation market is dominated by a few large industrial and electric generation customers. Unlike the Core market, demand for the transportation market is not all weather related and thus not necessarily coincident with the overall TGVI design-day demand.

There are three categories of transportation end-use customers on TGVI's system: industrial, generation and distribution utility. The particular requirements of each of these categories of customers are unique and require different approaches to forecast gross demand. Furthermore, because of their relative size, demand variations for` transportation customers result in step changes in demand on the TGVI system.[9] To properly assess the magnitude of these forecasted step changes, consultation with the specific transportation customers is necessary as the circumstances of each customer's needs are unique.

3.2.2.1 Industrial (Joint Venture) Customers

There are seven pulp mills on Vancouver Island and the Sunshine Coast that comprise the Vancouver Island Gas Joint Venture (Joint Venture) which as a single legal entity contracts for transportation service from TGVI. The Joint Venture began transporting and consuming natural gas when the pipeline was commissioned in 1991. Joint Venture members generally utilize natural gas as an energy alternative to oil, hog fuel or coal. The Joint Venture is currently served through a long-term contract that expires at the end of 2005 with a provision for an extension to January 1st, 2011. The decision for the contract extension election however must be made by December 31, 2004.

At present, there is uncertainty as to the level of contract demand that the Joint Venture will enter into with TGVI. Therefore, three scenarios; a Base, High and Low forecast have been prepared based on consultation with the Joint Venture partners to address this uncertainty in the analysis for Resource Planning. In order to assess the firm contract demand requirements for the Joint Venture, TGVI formally requested their input as to reasonable Base, High and Low levels of natural gas demand that they expected over the forecast horizon of 20 years.

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9 For example, when the Island Cogeneration Plant that generates electricity and steam in Elk Falls was commissioned, it required and contracted for 38,000 GJ/day of capacity. This represented almost 30% of the contracted TGVI system capacity prior to the commissioning of the plant.

Base Forecast – 34 TJ / day

In the Base case, the demands of the Joint Venture are assumed to be slightly below the levels experienced today. This reflects the recent consumption experience TGVI has with the Joint Venture and includes the impact of the price shift in commodities observed in recent years.

High Forecast – 40 TJ / day

For the High case, TGVI assumed demand to be equivalent to the maximum levels experienced during the early to mid 1990s. This scenario reflects a stronger pulp market but no new mills in the forecast period.

Low Forecast – 20 TJ / day

The Low case reflects the lowest plausible demand scenario that TGVI may face with the Joint Venture in the forecast period. In this scenario, the pulp industry is in a period of decline.

3.2.2.2 Gas- Fired Generation Customer (BC Hydro)

Currently, TGVI provides natural gas transportation to a cogeneration facility, the Island Cogeneration Plant, located at Elk Falls near Campbell River. Calpine Canada owns and operates the facility, however BC Hydro has a long term electricity purchase agreement in place whereby BC Hydro provides the gas supply and contracts for all of the electricity output. In addition, BC Hydro's recent Integrated Electricity Plan views the ICP capacity as a long term resource for meeting the electricity requirement for Vancouver Island. Consequently, although BC Hydro currently has a short term contract for gas transportation service to the ICP, it is expected that TGVI will continue to serve the ICP load over the long term. It is also expected that ICP's firm contract demand will increase from 38 TJ/day to 45 TJ/day which is representative of the full operating requirement of the plant.

BC Hydro has identified a gap between electricity supply and demand in the future on Vancouver Island of between 150 megawatts (MW) and 300 MW. In order to fill this supply gap, BC Hydro has recently issued a CFT for competitive bids from independent power producers. The majority of the proposed projects that have qualified for this process have incremental demands for natural gas.

The outcome of the CFT process and its impact on gas demand will not be known likely until the end of 2004. To address this uncertainty, TGVI has created three demand scenarios based on the potential outcomes of the CFT and the long-term requirements of the ICP.

Base Forecast – 65 TJ / day

The Base case is designed to provide 65 TJ/day of gross demand, which includes firm ICP demand at 45 TJ/day and an additional 20 TJ/day of demand (equivalent to 100 – 150 MW of new gas-fired generation) to support the outcome of the CFT process. This scenario represents a step change in demand of almost 30 TJ/day by 2007.

High Forecast – 90 TJ / day

The High case assumes a firm total gross demand for the ICP at 45 TJ/day plus an additional generation facility of similar size from the CFT process (250 - 300 MW), for a total of 90 TJ/day. This represents a step change in demand for generation of over 50 TJ/day by 2007.

Low Forecast – 45 TJ / day

The Low case reflects ICP at 45 TJ/day and no additional demand resulting from the CFT process. This scenario represents a step change of almost 10 TJ/day in demand over the current situation.

As reflected in the above three scenarios, there exists significant uncertainty in total demand from generation customers. However, TGVI expects the outcome of decisions impacting the ICP and CFT will be a step change in gross demand ranging from just under 10 TJ/day to over 50 TJ/day.

3.2.2.3 Squamish & Whistler

Terasen Gas (Squamish) Inc. and Terasen Gas (Whistler) Inc. are wholly owned subsidiaries of Terasen Inc. serving the Squamish and Whistler distribution markets. Currently, Squamish is a transportation customer of TGVI while Whistler is evaluating the feasibility of replacing its existing propane system with a natural gas system. Due to the relatively small impact on the TGVI system, detailed analysis of demand scenarios for Squamish and Whistler have not been included in the TGVI Resource Plan.

Terasen Gas (Squamish) Inc.

Squamish is located near the upstream compressor station at Eagle Mountain on the TGVI system and represents approximately only 3% of design-day demand for TGVI and 1% of annual demand for TGVI. Given the relatively small impact of the demand, instead of preparing Base, High and Low forecasts, only a Base forecast was prepared to represent the needs of Squamish in the TGVI Resource Plan.

Terasen Gas (Whistler) Inc.

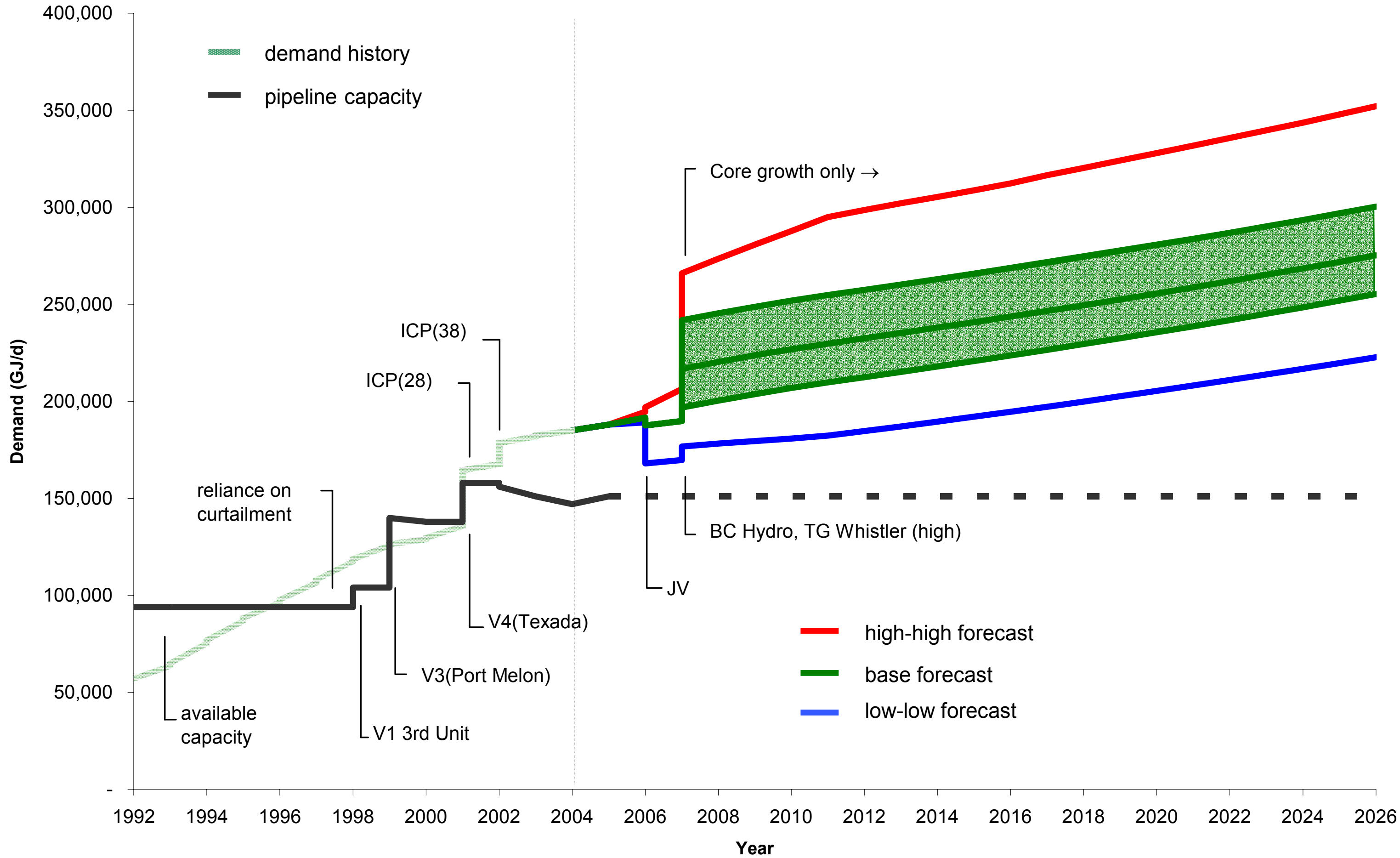
The customers of the Whistler distribution system are currently connected to a propane distribution grid, however the Whistler system is nearing its capacity and will require additional facilities. One alternative being considered is the conversion of the propane system to natural gas. In this scenario, it is anticipated that TGVI would apply to construct a pipeline lateral connecting Whistler to the high pressure transmission system at Squamish as early as 2007.

Current design-day demand is 6,500 GJ/day and if natural gas service is introduced, it is expected to grow to 11,000 GJ/day by the end of the planning period. Whistler represents a relatively small potential load for TGVI at approximately 5% of design-day demand and approximately 2% of annual demand. Due to the uncertainty of the Whistler load, inclusion of Whistler in the demand forecasts occur in only the High scenario and represents a step change in demand occurring in 2007.

3.3 Gross Demand Scenarios

The sum of the different customer demand components of design-day demand for each of the five gross demand scenarios (i.e. High-High, 3 Base scenarios, Low-Low) outlined in Figure 3.2 results in five gross system design-day demand forecasts.

Figure 3-10. Gross Design-Day Demand Scenarios



The gross design-day demand forecasts are characterized by large step changes in demand related to transportation customers' demand and by the continuing growth of the Core customers' demand.

As shown in Figure 3.10, the outcome of the CFT process is the most influential event in the forecast period affecting gross design-day demand. To capture this uncertainty, three Base forecasts have been prepared modeling the potential outcomes of the CFT process. The range of these Base demand scenarios by the end of the forecast period amounts to approximately 50 TJ/day. Also, as outlined earlier in Figure 3.2, a High-High and a Low-Low scenario have been included to bracket the full range of forecast combinations to assess the sensitivity of the forecast scenarios under extreme demand assumptions. Details of the composition of each gross design-day demand scenario are provided in Appendix F for reference.

3.4 Conclusions

At TGVI, the demand for natural gas is growing and is expected to continue growing, driven by demand from Core sales customers, the Joint Venture, BC Hydro and potentially the Whistler region. The five gross demand forecast scenarios presented are characterized by an imminent step change in gross forecasted demand due to continued Core customer growth in the Transition period, long term firm requirements of the ICP, potential impact of the CFT, potential contract changes for the Joint Venture and the potential conversion of the Whistler region to natural gas service.

4 CORE MARKET DEMAND SIDE MANAGEMENT

Demand Side Management refers to "utility activities that modifies or influences the way in which customers utilize energy services." TGVI offers demand side management programs for the Core Market that is targeted to improving the energy efficiency of the residential and commercial customer. TGVI also has arrangements with the major transportation customers, BC Hydro and the Joint Venture, where TGVI can recall or curtail a portion of their firm transport capacity to meet Core peak demands. This curtailment option is discussed in Section 5 *Resource Portfolio Development*. This next section deals with demand side programs targeted at the Core Market.

4.1 Background

TGVI and its predecessor, Centra Gas, have pursued a number of customer programs since natural gas was first delivered to the Island and the Sunshine Coast in 1991. The objective in all of the programs was to increase the energy utilization of the gas delivery network, with the provincial government providing significant funding for many of the initiatives.

Now that the market territory has matured to its present level of utilization and with the potential for increased on-island electricity generation, the customer program focus will shift towards increasing the utilization of the delivery system and the overall system efficiency. While the need remains to increase on-main saturation (on-main saturation is currently at approximately 60%), energy efficiency programs can play an important role in reducing peak day impacts, leading to lower overall cost of gas commodity and delivery services for customers. Efficiency programs also play an important role in reducing the overall cost of energy services through cost effective energy efficiency investments.

Among Terasen Gas' responsibilities is the need to help ensure that the region remains attractive to new businesses from a relative energy cost and supply reliability perspective. For industry, this means promoting a level playing field with other regions and avoiding the flight of businesses driven by high relative energy costs in this region. For residential consumers, opportunities exist to encourage energy efficient gas appliance choices, while building natural gas load and in turn creating cost and supply efficiencies for all customers. These initiatives can help keep gas prices down for customers. Funding for resources that promote DSM initiatives can be as important as the programs themselves. Furthermore, such resources also need to be considered within the Resource Planning context across all energy alternatives using an integrated energy approach.

TGVI is committed to working with industry partners, other utilities and all levels of government to ensure cost effective delivery of its programs and consideration of interdependencies among fuel choices. Through this Resource Plan, TGVI supports a number of provincial initiatives: market transformation relating to more efficient heating systems in residential and commercial applications, fireplace efficiency upgrades, and improvements to building envelopes.

4.2 Role of Demand Side Management

From TGVI's perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources. To accomplish this, TGVI has been working with the provincial government and with BC Hydro to ensure that builders and developers, and end-use customers understand the benefits of natural gas over alternative energy choices for uses such as space and water heating, cooking, and clothes drying.[10]

Other benefits that DSM programs can generate include:

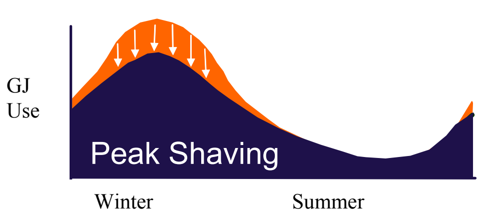
Table 4-1. Benefits of Demand Side Programs

Benefits of DSM
• Meet customer expectations by assisting them with managing their energy use • Enhance the safety and improve the operating characteristics of customers' energy utilization systems • Support climate change initiatives • Overcome barriers to market transformation of efficient technology • Support job creation • Defer transmission facility improvements through targeted DSM

4.3 Load Management Strategies

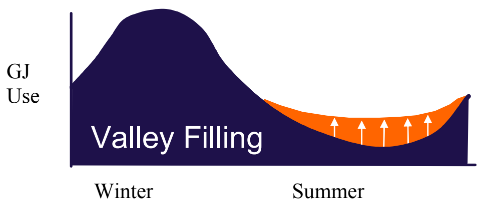
There are four primary load shaping strategies that DSM can employ to meet various utility objectives. The following diagrams represent the changing customer gas demands throughout the year:

Figure 4-1. Primary Load Shaping Strategies

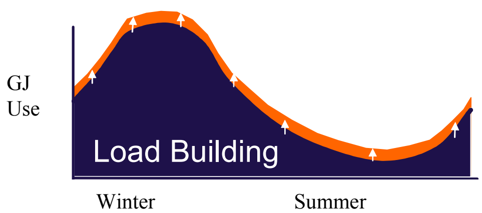


Peak shaving reduces peak day load requirements. Customer energy costs are reduced by decreasing demand on the delivery system, thereby reducing the need to expand the system. In addition, the need to purchase the most expensive gas is reduced.

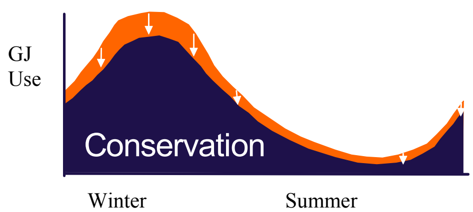
[10] A description of specific programs offered by BC Hydro, in conjunction with Terasen Gas, which provide incentives for customers to choose natural gas can be found in the BC Hydro 2004/05 and 2005/06 Revenue Requirements Application, Vol. 2, Appendix "N" *Power Smart Program Summaries*.



Valley filling is a load building strategy to add load during the summer months when demand is low. The primary effect of valley filling is rate reduction for all customers by increasing the recovery of fixed costs through higher load during periods of low demand.



Strategic load building adds load throughout the year. It increases delivery system utilization and therefore also contributes to rate reductions. To maximize the cost effectiveness of this strategy, the energy efficiency of new heating loads should be optimized.



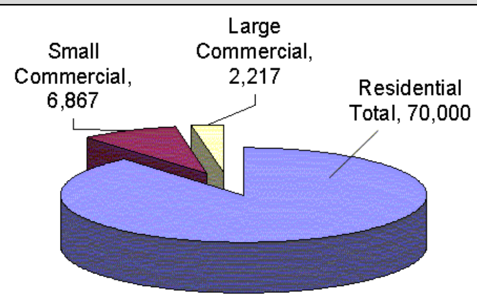
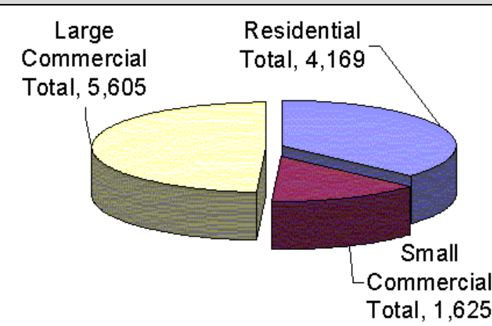
Strategic conservation includes energy efficiency and conservation measures that reduces the demand on the delivery system throughout the year. It can be employed to address opportunities to defer capital upgrades where the potential savings impact is meaningful. Strategic conservation can support overall cost reductions for a given consumer energy end-use despite, potential small increases in rates.

4.4 Market Analysis

A specific market's DSM portfolio provides a collection of targeted "load shaping" programs. It therefore needs to be developed in the context of the existing market considering the customer classes, their stage of maturity, the existing technologies, and the projected growth. The following provides a DSM specific overview of considerations for Vancouver Island:

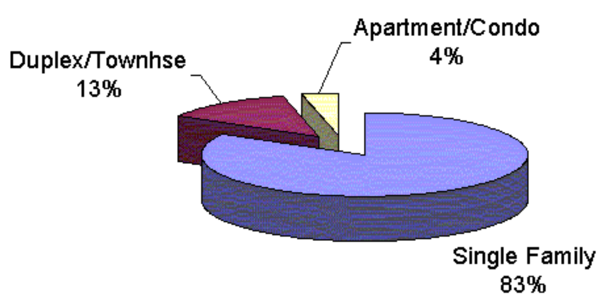
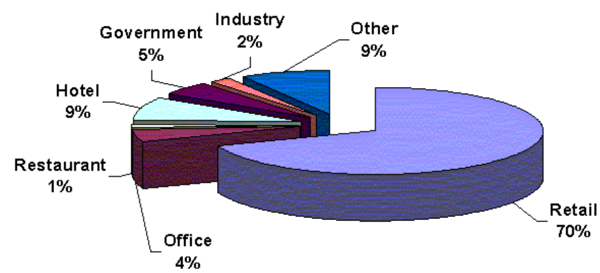
4.4.1 Customer Segments

Figure 4-2. Customer Profile

Number of Customers	Load in Terajoules
	

Although the majority of the 80,000 Vancouver Island natural gas customers are residential, they represent only 35% of the market applicable to DSM. (Industrial customers are excluded from this DSM analysis[11]) Natural gas did not start flowing on Vancouver Island until 1991, thus the markets are relatively new—particularly when considering furnaces and boilers, which last 25 years on average, constitute a significant portion of the market.

Figure 4-3. Residential and Commercial Customer Segmentation

Residential Segments – by consumption	Commercial Segments – by consumption
	

The above segmentation of the residential and commercial sectors represents the entire market for these customer classes. Slightly more than half the residential market uses gas while less then half of the commercial market currently uses gas. When examining the segments shown above, it is evident that the clear majority of the existing residential market housing is single family dwellings while the majority of the commercial market is retail.

If evaluating the market in the context of the maturity curve (from Implementation, to Transition, to Maturity) the market generally falls in the Transition portion of the curve with significant conversion market still available—only 60% of the residential homes "on the main" (with natural gas nearby) have gas accounts. The conversion potential is 55,000 non-gas users who are currently on the main indicating a significant opportunity for customers currently relying on heating oil and electricity for their space and water heating requirements to convert to natural gas.

The "off-main" potential for residential and commercial accounts is also significant with over 100,000 non-gas users as potential candidates where a main extension proves feasible. Programs centred on maximizing gas end uses with efficient technologies for new accounts, such as the existing pre-piping program, are ideal in that they lower the cost of service for all

11 Terasen Gas Inc. experience has shown that gas is utilized efficiently in the industrial sector, with many firms retaining qualified personnel to oversee their energy operations

customers and leverage the benefits of natural gas for a greater share of the energy requirements in the home.

Another consideration is market growth through new construction. DSM programs are centred on this growth—attracting customers, providing incentives for efficiency, and encouraging economic load such as the program that pre-pipes for natural gas appliances during construction.

4.5 DSM Opportunities

When considering the DSM load management strategies outlined in section 4.3, the strategic load building approach is the most suitable in TGVI's service territory. Although opportunities for valley filling will continue to be explored through TGVI's high load factor commercial customer rate options and peak shaving opportunities will also be included in the list of DSM activities, it is anticipated that they will be limited due to the young age of existing heating equipment. Strategic conservation will be employed where cost effective.

4.5.1 Energy Efficiency Opportunities

Compared to the Terasen Gas mainland service territory, the Vancouver Island and Sunshine Coast service territories are relatively immature markets for natural gas. For this reason, activities to date have focused on adding economic gas load to ensure a viable and sustainable gas delivery system.

There appears to be limited opportunity for residential or small commercial efficiency programs, and a low likelihood of them deferring the growing need for capital system improvements. Residential customers contribute only 12% of the total TGVI load with an average annual use per customer of 58 GJs. Similarly, small commercial customers contribute only 4% of the load and with limited potential to impact the peak demand requirements through conservation. There may be some potential for audit-based programs with savings typically in the 5 to 15% range (although they will most likely be in the lower end of this range due to the relatively young age of end use equipment in the market).

The majority of consumption is by the electricity generation and industrial sectors representing roughly two thirds of total load in 2003. Except for the interruptible transportation agreements established with its large industrial customers, TGVI has not considered efficiency opportunities in the industrial sector, as these customers have the required economic incentives and engineering expertise to drive the efficient end use of natural gas.

In summary, while the opportunities to increase energy efficiency through equipment upgrades are limited as compared to more mature gas markets, opportunities to increase energy efficiency do exist. Energy audits may be a worthwhile investment. Overall though, opportunities lie primarily in new construction and conversions from other fuels.

4.6 Existing DSM Programs

TGVI has employed marketing programs since its inception to attract new customers to improve the utilization of the gas delivery system. TGVI plans to continue these activities under the present regulatory funding mechanisms (Marketing Operating and Maintenance (O&M) funding and Incentive Deferral accounts). The existing programs shown in the table below are discussed in more detail in Appendix J.

Program	Description
Home Builder's Grand	Incentive for builders & developers to install high efficiency gas appliances in new home construction
Build Smart Program	Incentive for builders & developers to pre-pipe for gas in new construction
Conversion Program	Incentive for existing customers to convert to their space and water heating from another heating source to gas

4.7 Potential New DSM Programs and Research Initiatives

Looking to the future, TGVI is proposing several new initiatives to be delivered in conjunction with its present customer programs. Overall, the future direction can be summarized as follows:

- Continue to add customers and encourage those customers to use gas efficiently.
- Identify, characterize and prioritize DSM opportunities through completion of a Conservation Potential Review.
- Collaborate with BC Hydro to identify and deliver economic fuel substitution opportunities including a review of system extension tests, connection policies and new customer efficiency programs. The Conservation Potential Review will determine the net efficiency potential gains of fuel substitution opportunities.
- Extend current and planned Terasen Gas mainland DSM initiatives to TGVI customers.
- Work with provincial and federal energy efficiency initiatives to advance market transformation efforts to more efficient technologies.

A description of potential new programs for TGVI is provided in Appendix J.

4.7.1 Market and Technology Research

TGVI's last analysis of energy saving opportunities was completed in 1996. At that time, the analysis indicated that efficiency measures were not economically viable. Since that time, markets, construction techniques and end-use technologies have matured. Terasen Gas acknowledges this, and believes that it is worthwhile to consider completion of a Conservation Potential Review (CPR) to capture DSM opportunities for all of its service territories - TGVI in particular. A CPR would identify opportunities for energy savings across gas and electrical energy delivery infrastructures and improvements to overall energy utilization efficiency[12]. TGVI recommends that a CPR should consider all DSM opportunities including cost-effective electric-to-gas fuel substitution. Anecdotal evidence suggests that the energy savings impacts from fuel substitution activities could be significant.

A CPR would examine a wide range of DSM measures, for example opportunities such as new construction building envelope improvements, heat recovery ventilation, improving heating system operation and maintenance, electric range and dryer conversions, high efficiency heating and domestic hot water system for new construction applications and high efficiency building retrofits to name a few. Overall costs for the study could be minimized by conducting the CPR in conjunction with Terasen Gas on the mainland and through partnerships with other parties interested in collaborating and sharing the costs of the study.

In combination with a Conservation Potential Review, TGVI also intends to pursue non-program related approaches to optimizing the overall energy efficiency of the TGVI region. Potential opportunities to consider include revisions to system extension tests and jointly-delivered customer programs. Work in the program area has already been initiated and some of the program concepts outlined in the following section reflect this.

4.8 DSM Portfolio Relationship to Provincial Strategic Plan for Energy Efficiency in Buildings[13]

Terasen Gas is an engaged stakeholder in the Province's Review of Energy Performance Measures for Buildings in B.C. This Review has culminated in a series of recommended actions that will be presented to the Minister responsible this summer for consideration. A number of the initiatives within this DSM portfolio directly support these recommended actions. Table 4.2 outlines how each of the proposed DSM programs supports the Province's Strategic Plan.

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12 Substantial energy efficiency improvements can result when gas, burned at 80 to 90+% efficiency in end-use applications such as space and water heating, displaces thermally generated electricity used for similar end-use applications.

13 Strategic Plan for Energy Efficiency in Buildings (Draft), Andrew Pape-Salmon, Ministry of Energy and Mines; Innes Hood, the Sheltair Group, March 26, 2004.

Table 4-2. DSM Portfolio Relationship to Provincial Strategic Plan for Energy Efficiency in Buildings

Provincial Strategic Plan Recommendation	Action	Program/initiative	Measure
Update and expand Energy Efficiency Act, including building components	Support market transformation efforts to High Efficiency equipment	Home Builders' Grand	Energy Star residential furnaces and boilers – new buildings
		Fireplace Upgrade Program	High efficiency fireplaces – existing buildings
		Commercial Boiler Upgrade Program	Mid and high efficiency commercial boilers – new and existing buildings
Harmonized delivery pilot programs for new and existing buildings and equipment	Implement pilot efficiency program with multiple partners	Consumer and Small Business Partnership	EnerGuide "Plus" home audit program for existing residential and small commercial applications
B.C. government wide leadership for new and existing buildings and equipment	Improve energy utilization efficiency	Commercial Boiler Upgrade Program	Mid and high efficiency commercial boilers – new and existing buildings
		Commercial Utilization Advisory	Energy assessments for existing commercial customers

A number of additional measures have been identified in the Province's Strategic Plan, such as:

- Community action on Energy Efficiency Pilot Program
- Residential/developer/trades training and capacity building programs
- Multi-unit residential building market transformation strategy
- Building energy system operator training and certification program

These measures will be considered in subsequent Resource Plans.

4.9 DSM Portfolio Impact

To place this in perspective of the TGVI customer demand, the potential energy savings impact of the new programs being considered by TGVI is less than 0.1% of annual customer demand. This relatively low figure is a result of the limited magnitude of energy efficiency opportunities in a new gas market and the small size of the residential and commercial markets as compared to the industrial and electrical generation sectors.

In the short term, Terasen Gas would like to proceed with launching its 2004 energy efficiency programs across all of its service territories where appropriate. This approach provides cost effective delivery of programs and ensures all Terasen Gas customers have access to its energy efficiency programs. It also serves to support the market transformation nature of these programs.

Looking ahead, if DSM is to impact the market, a more robust DSM strategy is required. This can be best accomplished through a CPR; it would be a useful tool in identifying and characterizing energy efficiency opportunities in the residential and commercial markets - particularly if it included fuel substitution in the analysis. TGVI supports participation in a CPR, and intends to prepare a proposal to conduct a CPR in 2004 as an important component in the Resource Planning process.

4.10 Incremental Funding Requirements for 2004 - 2005

TGVI will apply current DSM specific Marketing O&M funding and incentive deferral budgets to the following programs: Home Builders' Grand, Build Smart and the fall Conversion Incentive Programs. These initiatives are sufficiently funded through these existing accounts. It is also expected that the costs related to the Furnace Upgrade Program Pilot to be implemented in June of 2004 will be covered by these budgets.

All new programs are under development. TGVI expects to apply for the required incremental funding once the program design and cost benefit analysis is complete. TGVI will also submit a request for incremental funding to cover the cost of the CPR.

5 RESOURCE PORTFOLIO DEVELOPMENT

5.1 Introduction

Natural gas is moved from producer to end user through a pipeline system. To allow gas to flow through the pipeline, a pressure differential between the inlet and the downstream delivery points is required. Compressors driven by natural gas fuelled turbine (jet) engines are used to create the pressure differential. A compressor unit is an external engine that drives an impeller within the pipeline to push the gas downstream. A compressor station may house one or more compressor units.

Generally, there are three types of "supply side resources" that can be used to increase the physical capacity of a pipeline system; pipeline looping, compression or on-system storage. In addition, "demand side resources" such as industrial curtailment can be used to limit demand during peak periods. Each of these resources is described below.

Pipeline Looping

In this case, a second pipeline is added, usually in parallel and usually adjacent to the existing one. This increases the cross-sectional area of the pipeline and allows a greater flow rate for a given pressure differential.

Compression

Compressors can be added to increase capacity in one of two ways; additional or larger compression units can be added to increase the pressure differential across an existing station, or additional stations can be added along the pipeline to maintain a higher average pressure.

Storage

Storage allows natural gas to be put away in times of low demand when pipeline capacity is available, such as the summer months, to be used later during period of high demand to augment the capacity of the pipeline system. To augment the capacity of the pipeline system, the storage facility must be located in the service area close to the load the pipeline is meant to serve. There are generally two types of storage facilities. Underground faculties use salt caverns or depleted gas wells to store large amounts of natural gas in the earth. LNG facilities cool gas until it condenses into a liquid and stores it in an insulated tank. During peak demand periods in the winter, the liquid is vaporized and pushed back into the pipeline. Suitable geological conditions for an underground storage facility have not been confirmed in southern British Columbia, therefore only LNG storage is considered in this analysis.

Curtailment

Industrial curtailment is where the utility has the right to recall firm transportation service from its large industrial customers under specific conditions. The utility then uses this recalled capacity to ensure service to its Core residential and commercial customers during periods of peak demand. Curtailment arrangements are usually based on the transport customer's ability to switch to an alternate fuel and may or may not include rights to the customer's gas supply during the curtailment period. The value of the curtailment service is recognized through direct fixed/variable charges paid by the utility or through reduced transportation costs relative to the transport customer's firm or interruptible alternatives. Utility customers realize value for curtailment through avoided expansion or gas supply costs.

5.2 Description of the TGVI System

Natural gas for TGVI customers is delivered from upstream sources on the Duke Energy (Westcoast) pipeline system to the Huntingdon trading point near Abbotsford. From there TGVI contracts transport capacity across the Terasen Gas Inc. Coastal Transmission System to the inlet of TGVI transmission system in Coquitlam.

Figure 5-1. Existing TGVI Transmission Pipeline System

The pressure of gas received at Coquitlam is increased and maintained near the 2,160 psig maximum operating pressure (MOP) of the TGVI pipeline system. This is accomplished using three parallel gas turbine-compressor units at the V1 Coquitlam Compressor Station, one gas turbine-compressor unit at the V3 Port Mellon Compressor Station on the Sunshine Coast and one gas turbine-compressor unit at the V4 Kiddie Point Compressor Station on Texada Island. Natural gas is transported through TGVI's 615 km of pipeline, including dual marine crossings of the Georgia and Malaspina Straits, to various metering and pressure regulating stations located near the customers and communities served by the TGVI distribution network. Operating pressure is reduced at these stations from 2,160 psig to 500 psig or less, depending on load and customer requirements.

Currently, TGVI also has curtailment contracts with its major industrial customers (the 7 large pulp and paper mills represented by the Joint Venture) and with BC Hydro.

Figure 5.2 illustrates how the TGVI system has been expanded to meet growing demand since 1991 when it came into service. Although not originally required as a capacity resource, the chart also shows how reliance on industrial curtailment grew requiring the addition of a third compressor unit at V1 (Coquitlam) in 1998, and the addition of the V3 (Port Melon) compressor station in 1999. In 2001, the V4 (Texada) compressor station was added to offset the 28 TJ/day step change in demand that resulted when service to ICP began. In 2002, service to ICP was increased to 38 TJ/day, further increasing the shortfall of capacity currently met with curtailment. Looking forward, beyond 2004, the figure shows that continuous growth of the Core Market along with step-changes in demand for the Joint Venture in 2006 and BC Hydro in 2007 will increase this shortfall.

By 2007, expansion of the pipeline system will be required to resolve this shortfall. This is illustrated in Figure 5.3. In this example, forecast load duration for 2004 and 2007 Base +20 TJ/day forecasts are compared to the capacity of the existing pipeline system. While the 2004 shortfall can be resolved with extensive use of curtailment, the example shows that without pipeline expansion the 2007 shortfall would extend for more than one third of the year – almost the entire winter season.

Figure 5-2. History of TGVI Expansion and Forecast Demand Requirements.

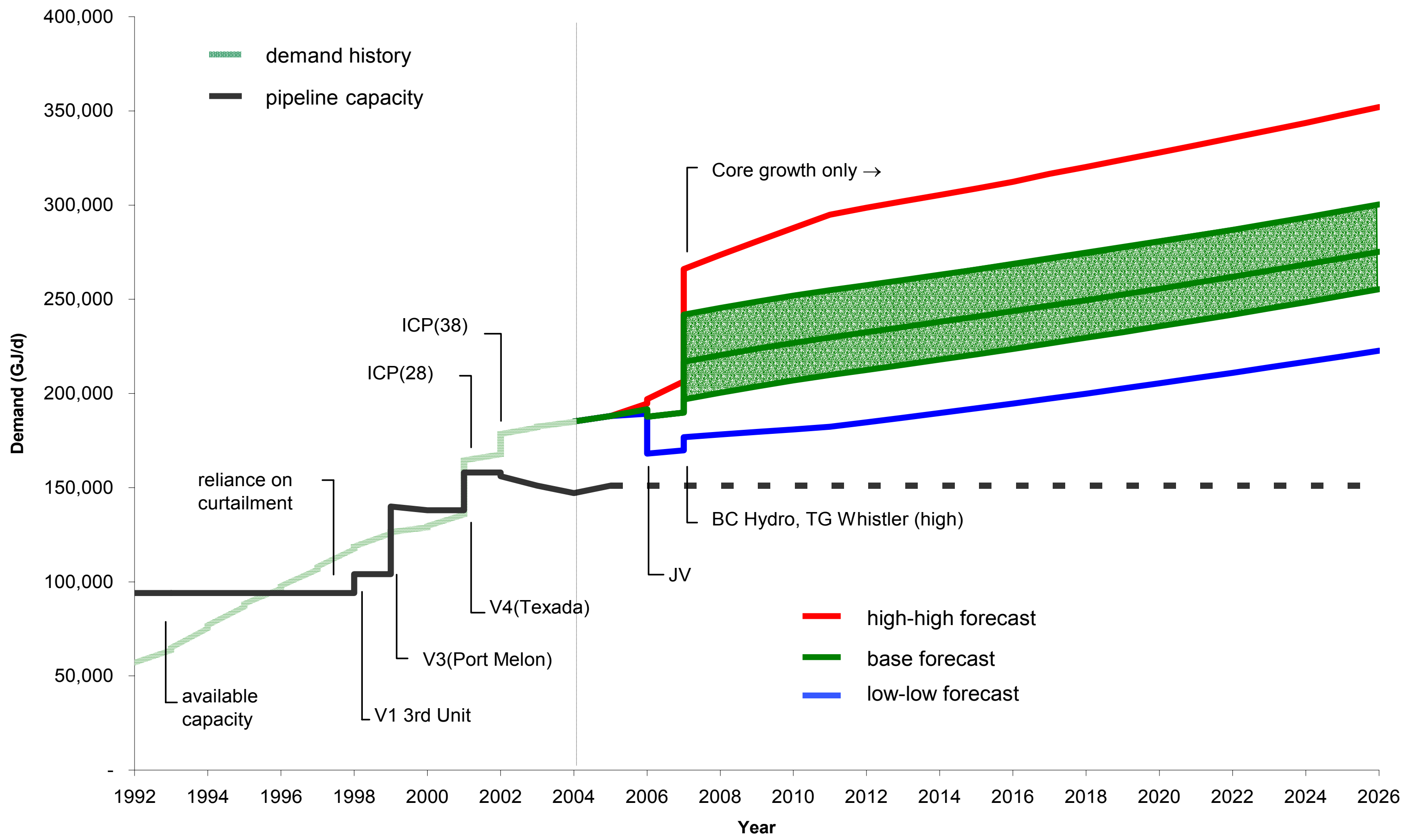
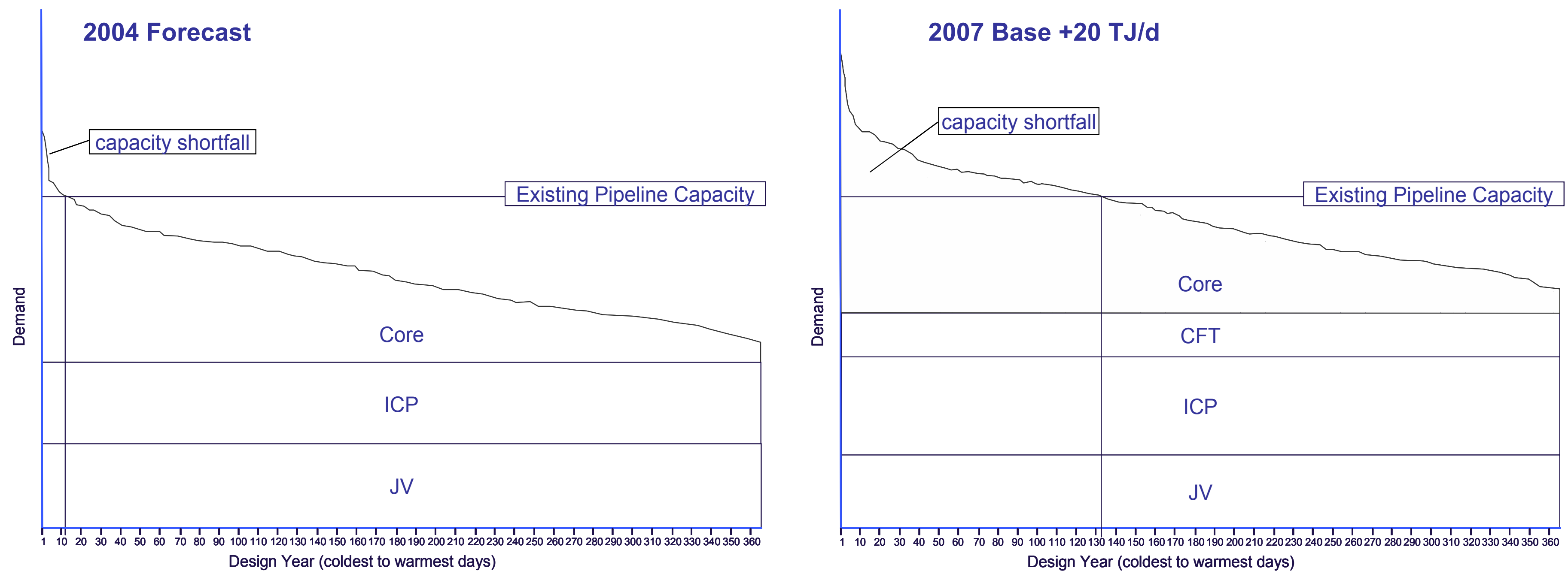


Figure 5-3. Comparison of Capacity Shortfall for 2004 and 2007 Base + 20 Forecasts.



5.3 Portfolio Development

One of the primary roles of Resource Planning is to assess capacity alternatives over a range of expected demand scenarios to determine the preferred resources required to meet demand over the long term. To this end, multiple long-term system plans have been assembled to address the requirements of each of the gross demand forecasts discussed in Section 3. Each plan identifies a "portfolio" of investments in capacity resources, differentiated by both type and timing, used to meet the demand requirements of each forecast.

The supply side components of these portfolios are identified using a computer model that simulates the hydraulic characteristics of the TGVI transmission system and TGVI planning criteria that address the design limitations and operating requirements of the system. Considerations addressed by the planning criteria include:

- Optimization of resource additions to meet the requirements over a 20-year planning period, beginning in 2007 when the first new facility addition is required.

- Life cycle costs over the planning period of any new facilities as measured by the associated cost of service that must be recovered through customer rates.

- Capacity requirements under both design-day (coldest weather in 25 years) and normal day (coldest day in an average year). In portfolios where it is assumed to be available, industrial curtailment is used to meet the design-day condition. The normal day condition is met without curtailment.

- Construction and operating logistics are considered when assessing the feasibility of proposed projects. For example, in some cases minimum looping lengths identified by the hydraulic modeling are increased to reflect the practicalities of construction and other operating constraints.

5.4 Supply Side Resource Components

The distinct supply side components identified in the modeling process and used in the various portfolios include; six looping projects on the Mainland and Texada portions of the system, a second marine pipeline crossing of Georgia Straight between Sechelt and Harmac, five compressor station projects, and a LNG storage facility located on Southern Vancouver Island. The location of these potential projects on the TGVI system is shown in Figures 5.4 through 5.6 and each of these projects are discussed in detail in the following appendices:

Appendix G: Compressor Additions

Appendix H: Primary Pipeline Looping

Appendix I: LNG Storage

Figure 5-4. Pipeline Alternatives

Figure 5-5. Compression Alternatives

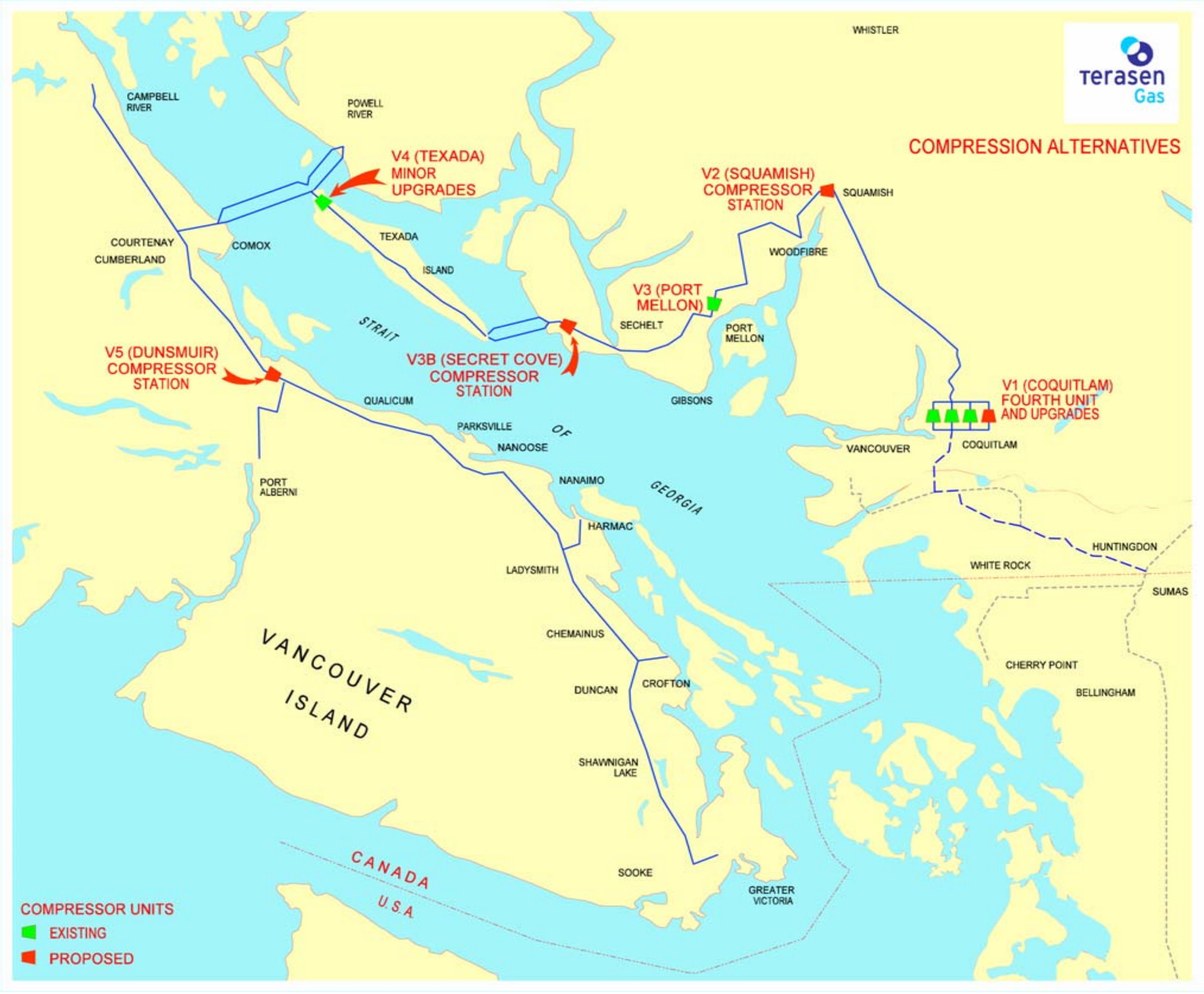


Figure 5-6. Storage Alternatives

5.4.1 Schedule and Cost Risk of Supply Side Components

The conventional schedule for implementing the mainland looping projects is two years, which includes time for consultation, design, permitting, and construction. Similarly, the time required to implement the compressor projects is also two years. The conventional schedule for LNG is longer. However, some work has already been completed to meet a 2007 in-service date. The process of selecting a suitable site for the LNG Storage was initiated in early 2003. This program of consultation, field reconnaissance, and technical analysis led to the selection of a site near Mt. Hayes northeast of Ladysmith as the preferred location. TGVI subsequently applied to and received approval from the Cowichan Valley Regional District for a zoning amendment that would allow use of the site for LNG Storage. With these activities complete, sufficient time remains to construct the LNG facility in time to meet the demand increase forecast for 2007.

Each type of resource has different cost risks. Linear projects like the pipeline loops can be affected by weather (forest fire closures, rain) and unanticipated geologic conditions (rock, soil instability). In comparison, for site specific projects like the Compressor Stations or the LNG Storage Facility, the risks that could lead to cost overruns are lower and more easily mitigated. The components of these facilities lend themselves to standard designs, off-site prefabrication, and turn-key construction contracts. Site conditions can be investigated extensively prior to design. For these reasons, the risk of cost and schedule overruns for the Compression and Storage projects is expected to be lower than that of the looping projects.

5.4.2 Consideration of Second Marine Crossing

The Sechelt Marine Crossing project (See Figure 5.4) was considered in the hydraulic modeling process. However, subsequent assessment of the scheduling requirements indicated that it was unlikely that the project could be implemented in time to meet the demand increase forecast for 2007. In addition, for the range of demands considered, the costs of portfolios with the Sechelt Crossing were not competitive with portfolios that did not include a new marine crossing. For these reasons, the marine crossing was not considered in the final comparison of portfolios.

Use of a marine crossing would be re-considered, if another large step-change in demand occurs. An example of this situation would be the addition of a third large on-Island generation facility in addition to requirements that may result from BC Hydro’s current CFT process. This type of event is not anticipated in the current forecast. While current cost comparisons favour the Sechelt Crossing, a final decision would depend on the requirements and feasibility of the projects at the time. The options that would be evaluated could include the Sechelt Crossing, Tilbury Crossing (Point Roberts to Harmac), or a route similar to the proposed Georgia Strait Crossing.

5.4.3 LNG Storage Considerations

The addition of the LNG facility to the TGVI system affects both the cost of the facilities required to expand the capacity of the system and also can reduce the natural gas commodity costs for Core customers.

From a gas supply perspective, with LNG on-system, TGVI customers would avoid the cost of downstream storage, seasonal pipeline capacity or base-load pipeline capacity that would otherwise be required. And, since the minimum practical size of the LNG facility would be greater than TGVI's immediate needs, TGVI could offer storage services to Terasen Gas mainland and others in the region at the market price of storage to defray some of the costs of the LNG facility. The LNG Storage benefit is discussed in more detail in Appendix C and considered in the evaluation of resource portfolios discussed in Section 6.

Other than the physical capabilities of the storage facility, there are essentially no limitations on the number of hours or days in the year that the supply can be used. Two hours notice is required to initiate winter sendout and the sendout rate can be varied continuously. This allows the utility to manage the resource in an efficient manner, responding quickly and accurately to variations in demand as they occur. These characteristics give LNG Storage superior load following capability both in terms of capacity and energy. This capability enables its use as an intermediate or seasonal supply, not just as a peaking resource.

5.4.4 Whistler Lateral

Terasen Gas (Whistler) Inc. is currently developing the long term Resource Plan for the Whistler service area. One alternative being considered is the conversion of the existing propane system to natural gas. Under this scenario, Whistler would contract with TGVI for transportation capacity to move gas from Huntingdon to Whistler. In order to provide this service, it is anticipated that TGVI would build a pipeline lateral approximately 50 kilometers to connect Whistler with the transmission system at Squamish. Costs associated with the new facilities and any upstream system improvements would be recovered through transportation rates, and may require a capital contribution from Terasen Gas (Whistler) Inc.

5.5 Demand Side Resource Components

As previously noted, Demand Side Management (DSM) is defined as "any utility activity that modifies or influences the way in which customers utilize energy services". The demand side resources available to TGVI can be categorized in two types; as capacity resulting from Core DSM programs, or as capacity resulting from industrial curtailment.

5.5.1 Core Market Demand Side Management

As described in Section 4, TGVI has been working with the provincial government and with BC Hydro to ensure that builders and developers, and end-use customers understand the benefits of natural gas over alternative energy choices for space and water heating, cooking, and clothes drying. However, the potential energy savings impact of the new programs being considered by TGVI is less than 0.1% of annual customer demand. This relatively low figure is a result of the limited magnitude of energy efficiency opportunities in a new gas market and the small size of the residential and commercial markets compared to the industrial and electrical generation sectors. For this reason, Core DSM programs are assumed to have no effect on TGVI's need for additional resources to meet forecast demand requirements.

5.5.2 Industrial Curtailment

TGVI currently holds peaking agreements with BC Hydro and the seven large industrial customers represented by the Joint Venture whereby TGVI can recall or curtail a portion of their firm transport capacity and use this to meet Core demands. These agreements will expire concurrently with the current transport agreements. BC Hydro's agreements expire in October 2004, while the Joint Venture agreements could expire as early as December 2005 but otherwise will expire in 2011.

During the Resource Plan stakeholder consultation, both BC Hydro and the Joint Venture have indicated that they are prepared to continue to offer curtailment rights associated with their long term capacity requirements based on agreement of commercial terms. In BC Hydro's case, it is expected ICP and/or any new generation projects would have the ability to switch to oil during periods of curtailment to ensure dependable generation capacity criteria is met. The industrial mills can also switch a large part of their load to oil and/or other fuels or reduce their production levels if their natural gas supply is curtailed.

On this basis, the supply side portfolios were modeled assuming that curtailment from BC Hydro and the Joint Venture would be available over the planning period, potentially allowing deferment of other supply side alternatives. In developing these long term portfolios, it is assumed that curtailment will not be relied on to meet expected demands in a normal or average winter, but that it will be available to meet peak load requirements in a colder than normal winter. This results in more curtailment potentially being available than is practical for TGVI to consider as part of its resource stack to meet its firm transportation requirements.

For long-term Resource Planning, curtailment is not used as a capacity resource to meet normal demand due in-part to dispatch restrictions that are typical of this resource. These restrictions arise from environmental permits, commercial considerations, as well as the physical requirements of process loads or fuel switching procedures. On the other hand, curtailment can be valuable as a short term resource to meet temporary loads or as a bridging option to meet requirements until long term facilities can be constructed.

In the portfolio development carried out for this Resource Plan, the results of the modeling does show that curtailment can be used to defer expenditure on pipe and compression resources that would otherwise be installed to meet the requirements associated with colder than normal weather. However, as discussed below, in portfolios that include a LNG storage facility the value of curtailment to defer expenditure on other resources is not significant.

The delivery capacity of the proposed LNG facility is large enough that subsequent system capacity expansion needs are generally driven by storage capacity limits. Since the LNG facility and fuel-switching based curtailment both provide energy storage as a substitute for pipeline capacity, the effect of adding curtailment to the LNG Storage portfolio is essentially to increase on-Island energy storage extending the duration of LNG use. While the use of LNG storage is optimized in each year, the proposed storage capacity allows sendout duration to reach 70 days or more in the years before the next pipeline expansion is required. Due to the weather sensitive characteristics of the TGVI Core Market, the amount of storage required to extend this duration and delay pipeline expansion increases significantly with sendout duration. Adding curtailment to the LNG Storage portfolio, therefore, has little effect on the timing and extent of subsequent expansion.

Although the availability of LNG Storage reduces TGVI's need for curtailment as a capacity resource, the customer's ability to switch to alternate fuels means that curtailment could be valued as a peaking gas resource serving Terasen Gas or other regional market players. As well, in the case of generation, the fuel switching capability could be reserved to mitigate a Force Majeure event.

5.6 Identification of Resource Portfolios

From this evaluation process, three types of resource portfolios emerge based on the components employed to meet initial demand growth:

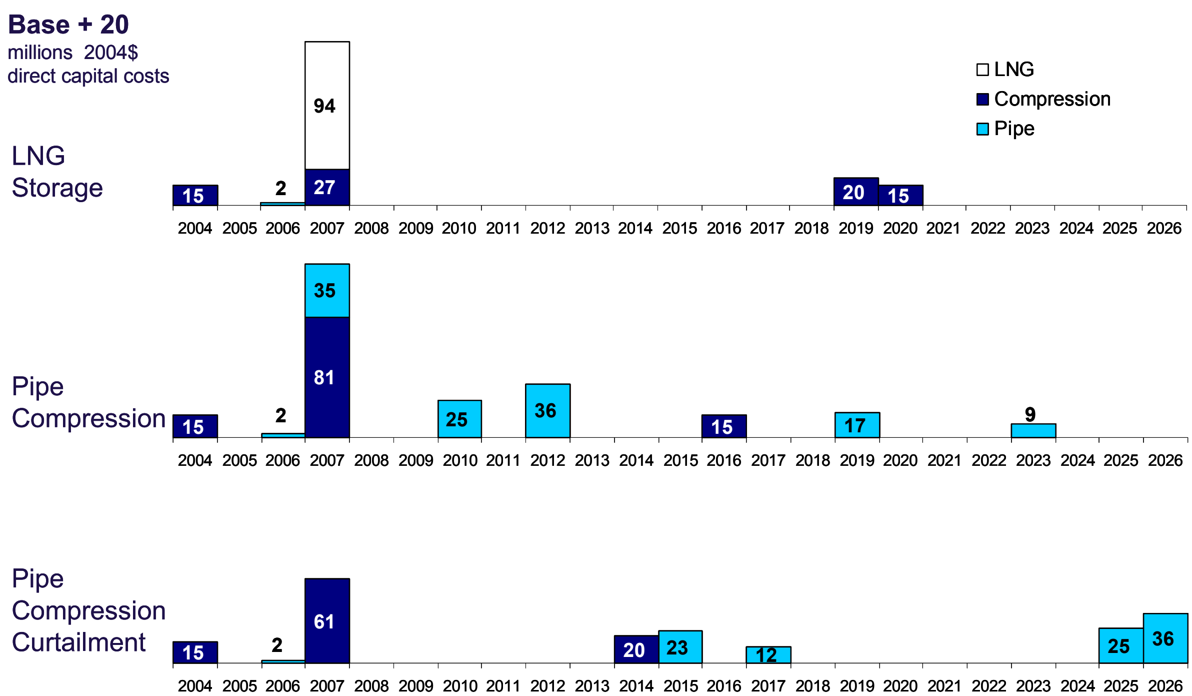
1. LNG Storage – an LNG Storage facility followed by phased pipe and compression additions
2. Pipe & Compression – phased pipe and compression additions
3. Pipe & Compression & Curtailment – phased pipe and compression additions with industrial curtailment

Each of these three portfolio types is evaluated for the Base, Low-Low, and High-High gross demand forecasts described in Section 3 Demand Forecasts. The Base case reflects the most likely demand scenario for the Core, industrial markets, and the requirements of the existing ICP generation facility. Additional demand that might be required as a result of BC Hydro's CFT process, however, is uncertain. To address this uncertainty, the Base forecast has been evaluated over a range of possible CFT outcomes:

- Base + 20 TJ: Base forecast plus 20 TJ/day from new generation arising from the BC Hydro CFT process (100 to 150 MW of new gas-fired generation)
- Base + 45 TJ: Base forecast plus 45 TJ/day from new generation (250 – 300 MW of new gas-fired generation)
- Base + 0 TJ: Base forecast with no new gas-fired generation load (0 MW of new gas-fired generation)

Figure 5-7 illustrates the impact of the different portfolio approaches on the capital spending profile indicating the type of supply side investment for each year of the planning period for the Base + 20 TJ / day demand scenario. Tables showing the timing and type of expenditure for each demand forecast and portfolio are included as Appendix E.

Figure 5-7. Base +20 TJ/day Capital Spending Profile for Three Portfolios



The difference between the Pipe & Compression portfolios with and without curtailment shows how curtailment can be used to defer the timing and extent of supply side expenditures. In the Pipe & Compression & Curtailment portfolio, capital expenditures over the full planning period are equivalent to those made in the Pipe & Compression (without curtailment) portfolio by 2012.

Common to all portfolios is the significant expenditure required to meet the 2007 step change in demand. In these early years, the choice of the LNG Storage or the Pipe and Compression alternatives is critical. A decision to invest in pipe, compression, or curtailment for 2007 diminishes the opportunity to add storage at a future date. Since subsequent expansion requirements are small, driven only by Core Market growth, they are unlikely to support the level of investment required to add market area storage to the TGVI system after 2007.

In each portfolio, the expenditure in 2004 represents the costs associated with retaining and upgrading the Texada Compressor Station. Under the current transport arrangements with BC Hydro to serve ICP, this payment is triggered when the current short term transportation agreement is replaced by a long-term arrangement. The existing arrangements are set to expire in October 2004 therefore it is expected that a payment may be required in 2004. This expenditure is common to all portfolios, so a deferral of this cost will have the same impact in all scenarios.

6 RESOURCE PORTFOLIO EVALUATION

Evaluation of the alternative resource portfolios is based on a comparison of the portfolios relative to the Resource Planning objectives. These objectives, discussed in Section 1, are to:

- Ensure reliable and secure supply
- Provide service to customers at the least delivered cost.
- Reduce rate volatility
- Balance socio-economic and environmental impacts

6.1 Provide Service to Customers at the Least Delivered Cost

6.1.1 Financial Performance Measures

The performance of each portfolio relative to this objective is measured based on following costs and benefits:

Incremental Facilities Cost

The incremental cost of service associated with new facility additions. Cost of service includes cost of capital, depreciation, taxes, and operating costs.

Fuel Differential

The difference between portfolios in annual system-wide fuel costs. System-wide fuel includes compressor fuel, meter station fuel, unaccounted for gas, and where applicable, fuel consumed by the LNG facility. The LNG Storage portfolio is used as the basis for comparison in the tables that follow.

Storage Benefit

The storage benefit described in Appendix C reflects TGVI's avoided costs associated with leasing storage capacity from other gas utilities in the Pacific Northwest as well as mitigation revenue created by leasing its available storage space to Terasen Gas in the lower mainland and others in the same region.

Curtailment Costs

TGVI's existing curtailment contracts are set to expire shortly (BC Hydro in 2004, the Joint Venture at the end of 2005 or 2010). Since terms of curtailment contracts are determined through commercial negotiations, the long-term cost of holding curtailment rights is unknown.

6.1.2 Financial Comparison of Portfolios

The present value of the net cost over the planning period was calculated in order to compare the portfolios for each gross demand forecast. The results expressed in millions of 2004 dollars using after tax nominal discount rates are as follows:

- 6% reflecting TGVI's expected Weighted Average Cost of Capital over the period; and,
- 10% as a sensitivity case to reflect uncertainty of future demands and costs.

Table 6-1 summarizes the results for the Base Case demand scenario where no new gas-fired generation facilities are built on Vancouver Island (Base Case + 0 TJ / day). This reflects the forecasted demand over the planning period for the existing customers on TGVI's system including the expected Core Market growth.

Table 6-1. Incremental Costs and Storage Benefits for Base Case +0 TJ/day

Base Case +0 TJ/d (PV 2004-2026 @ 6%, $M)	**LNG Storage**	**Pipe Compression**	**Pipe Compression Curtailment**
Incremental Facility Cost	178	167	88
Fuel Differential	-	(5)	2
Storage Benefit	(89)	-	-
Curtailment Cost	-	-	?
Effective Cost	**89**	**163**	**90 + ?**

Base Case +0 TJ/d (PV 2004-2026 @ 10%, $M)	**LNG Storage**	**Pipe Compression**	**Pipe Compression Curtailment**
Incremental Facility Cost	120	104	55
Fuel Differential	-	(2)	1
Storage Benefit	(59)	-	-
Curtailment Cost	-	-	?
Effective Cost	**61**	**101**	**57 + ?**

These results indicate that the LNG Storage portfolio offers a competitive alternative to pipe and compression portfolios, regardless of the outcome of BC Hydro's CFT process on Vancouver Island. For this demand forecast, the results show that:

- The LNG Storage portfolio is significantly less expensive than the Pipe & Compression portfolio where no industrial curtailment is considered.
- When curtailment is considered the cost of the Pipe & Compression portfolio can be reduced. For this demand forecast, the costs could be reduced to a point of indifference

with the LNG Storage portfolio but this is only possible if the curtailment service is provided at no cost to TGVI.

- Costs for curtailment will be based on a negotiation between TGVI and the transport customer. While these costs would not exceed TGVI's avoided costs to put in facilities; the end result could be a much higher costs than what is offered by the LNG Storage Portfolio.

- Common to all portfolios is the significant expenditure required to meet the 2007 step change in demand. In these early years, the choice of the LNG Storage or the Compression alternatives is critical. A decision to invest in pipe, compression, or curtailment for 2007 diminishes the opportunity to add storage at a future date. If LNG is not used to resolve the 2007 step-change in demand, the opportunity to ensure the lower net cost of the LNG Storage portfolio would be lost.

The results for the other demand scenarios are provided in Appendix L and are summarized in Table 6-2. As can be seen from these results, the advantage the LNG Storage portfolio has relative to the other resource portfolios improves with incremental demand associated with new generation requirements, regardless of the cost or availability of curtailment. A similar result would be expected if and when other loads were added to the system, for instance if natural gas service were extended to Whistler. In other words, the selection of the LNG facility to meet the 2007 demand requirement positions TGVI to add future loads to the system at the least cost.

Table 6-2. Summary of Incremental Costs and Storage Benefits for All Demand Forecasts

Effective Cost (PV 2004-2026 @ 6%, $M)	**LNG Storage**	**Pipe Compression**	**Pipe Compression Curtailment**
High-High Case	223		243 + ?
Base Case +45 TJ/d	174	246	194 + ?
Base Case +20 TJ/d	123	218	136 + ?
Base Case +0 TJ/d	89	163	90 + ?
Low-Low Case	82	100	46 + ?

Effective Cost (PV 2004-2026 @ 10%, $M)	**LNG Storage**	**Pipe Compression**	**Pipe Compression Curtailment**
High-High Case	146		164 + ?
Base Case +45 TJ/d	115	164	125 + ?
Base Case +20 TJ/d	82	142	87 + ?
Base Case +0 TJ/d	61	101	57 + ?
Low-Low Case	57	64	29 + ?

6.1.3 Sensitivity Analysis

As discussed in Section 3, the High-High and Low-Low forecasts referred to in Table 6-2 bracket the expected range of forecast combinations. Both these scenarios have low probability of occurring; however they can be used to assess sensitivity at the extreme high and low ends of expected demand:

- In the High-High Case, the hydraulic modeling concluded that either the LNG storage facility or the Sechelt Crossing would be required to meet the firm demand requirements without relying on curtailment. It is not expected that the Sechelt Crossing could be built to meet the 2007 requirement therefore this result was not considered in this analysis. Regardless, when taking into account curtailment, the LNG Storage portfolio continues to offer a lower cost alternative to the pipe and compression portfolio. Choice of the LNG Storage portfolio allows demand, in addition to that forecast for the Base +45 forecast, to be added economically.

- The Low-Low Case reflects a scenario where poor economic conditions prevail resulting in low customer growth and a depressed pulp and paper sector over the entire 20 year planning period. The LNG Storage portfolio continues to offer a lower cost alternative to the Pipe and Compression portfolio, however the effect of using curtailment to defer facility additions is greater than in other scenarios.

- Potential lower cost of the Pipe Compression and Curtailment portfolio assumes sufficient foreknowledge of demand requirements that capital investment for 2007 is avoided (see the capital schedule in Appendix E) and is also dependent on the cost of curtailment. For these reasons, and because the cost of the LNG Storage is less than that of Pipe and Compression, the alternative that curtailment cost would not be expected to exceed, the LNG storage portfolio could offer comparable performance to Pipe Compression and Curtailment under the Low-Low forecast

- Overall, the potential for lower cost in the Low-Low case is offset by the expected benefits of the LNG storage portfolio in all other cases.

Table 6-2 presents the present value results using 6% and 10% after tax nominal discount rates. As discussed previously, the former reflects TGVI's expected weighted average cost of capital, while the higher discount rate reflects uncertainty on future costs and timing of facility additions. Although the difference between the different portfolios narrow when using the higher discount rate, the LNG Storage portfolio continues to offer the best alternative.

6.1.4 Preferred Portfolio

In summary, financial evaluation of the different resource portfolios to meet the demand requirements supports the LNG Storage portfolio as the preferred alternative to meet the objective of *providing service to customers at the least delivered cost*:

- For the most likely demand forecast scenarios, the LNG Storage portfolio results in the lowest incremental cost and is not dependent on the outcome of BC Hydro's CFT process on Vancouver Island.

- The benefit of the LNG Storage portfolio increases with higher loads and therefore helps to position TGVI to add new loads at the lowest cost. For example, it improves TGVI's ability to offer natural gas transportation service to Whistler.

- Choice of an alternative portfolio that does not include the LNG Storage facility results in a lost opportunity cost.

- The potential for opportunity cost in the Low-Low demand scenario is dependent on the long term costs to hold the right to curtail industrial or generation customers and is offset by the expected benefits in all other cases.

6.2 Balanced Impacts

The Resource Planning objective *Balance Socio-Economic and Environmental Impacts* involves measurement and evaluation of emissions factors, land use impacts, and employment impacts for each of the portfolios. Results appear in Table 6.3 below.

Table 6-3. Socio-Economic and Environmental Evaluation of Resource Portfolios

Forecast	Impact	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Base +0	CO_2 (average tonnes/TJ delivered)	1.90	1.97	2.08
	NO_x (average kg/TJ delivered)	1.03	1.11	1.20
	SO_2 (average kg/TJ delivered)	0.038	0.040	0.042
	Land Use (hectares)	31	238	66
	Employment - construction (person years)	266	244	114
	Employment - permanent	9.5	1.5	1.5
Base +20	CO_2 (average tonnes/TJ delivered)	2.20	2.03	2.21
	NO_x (average kg/TJ delivered)	1.29	1.16	1.30
	SO_2 (average kg/TJ delivered)	0.044	0.041	0.044
	Land Use (hectares)	37	255	204
	Employment - construction (person years)	293	256	218
	Employment - permanent	10.0	1.5	1.5
Base +45	CO_2 (average tonnes/TJ delivered)	2.43	2.07	2.20
	NO_x (average kg/TJ delivered)	1.48	1.19	1.29
	SO_2 (average kg/TJ delivered)	0.049	0.041	0.044
	Land Use (hectares)	85	320	251
	Employment - construction (person years)	369	304	253
	Employment - permanent	10.5	1.5	1.5

The emissions measures for carbon dioxide (CO_2), nitrogen oxide (NOx) and sulphur dioxide (SO_2) are quite similar for all three portfolios across all forecast scenarios. The land use and employment impacts quite clearly favour the *LNG Storage* portfolio across all forecasts.

6.3 Security of Supply

The Resource Planning objective *Ensure Reliable and Secure Supply* was evaluated qualitatively for each of the three resource portfolios. While TGVI is confident that any of the portfolios would deliver an adequate level of reliable service to customers, a storage facility on Vancouver Island provides additional security should an upstream failure occur on the Duke, Terasen Gas mainland or TGVI system. Storage in close proximity to the Utility's major market area adds diversity to the resources available to TGVI.

6.4 Rate Volatility

The Resource Planning objective *Reduce Rate Volatility* measures the relative rate impact of each portfolio and was measured qualitatively. A large storage facility close to the major market helps to mitigate commodity price increases during peak demand periods. LNG storage facility would also increase regional supply capacity and decrease the risk of a regional price disconnect. Storage can provide a dampening effect on summer versus winter price differentials.

6.5 Selection of Preferred Portfolio

When evaluated against the four Resource Planning objectives (see Table 6.4), the LNG Storage resource portfolio is clearly the preferred portfolio. LNG Storage ranks first in reliability and security of supply, cost, and rate impact. LNG is also preferred in terms of employment and land use impacts, and ranks favourably with the other portfolio options in air emissions impacts across the range of demand forecasts.

Table 6-4. Evaluation Summary

TGVI Planning Objective	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Ensure reliable secure supply	✓		
Lowest delivered cost	✓		
Reduce long-term volatility	✓		
Balanced impacts	✓	✓	

7 STAKEHOLDER CONSULTATION

7.1 Stakeholder Consultation to Date

Stakeholder needs and concerns are critical to Resource Planning. More than simply facilitating open communication, effective stakeholder consultation provides the Utility with insights that can impact the entire planning process, from trends that influence demand forecasting and DSM analysis through to the development of an action plan for implementing preferred planning solutions. TGVI has established a record of conducting thorough and effective stakeholder consultation programs, and continues to do so in preparing this plan. In keeping with the overall purpose of stakeholder consultation, TGVI began consulting stakeholders early, allowing time for meaningful input, and included a broad range of interest groups.

In its 2003 Resource Planning Guidelines, the BCUC encourages utilities to tailor their consultation efforts to areas of the planning process that will prove the most effective and to use methodologies that best fit their needs. Because the issues to consider in planning for the future needs of Vancouver Island customers are quite specific, the Utility undertook a focused stakeholder consultation process. These efforts included stakeholder workshops in spring 2004 seeking input on a range of system expansion needs and DSM alternatives, as well as an earlier background study on the costs and benefits of a possible LNG storage facility on the Island to help meet growing demand. Table 7.1 presents a summary of stakeholder consultation events associated with the TGVI Resource Planning.

Table 7-1. Summary of Stakeholder Consultation Events

Event & Date	Issues Presented / Discussed	Audience	Attendees / Respondents
Stakeholder workshop – Sunshine Coast May 19th, 2004	- Background to Resource Planning - Planning considerations (supply and demand side) - Supply needs and market characteristics - Potential new DSM initiatives - Resource portfolio considerations & preliminary evaluation - LNG storage as a portfolio option	- Municipal Staff and local government representatives	7
Terasen Gas Customer Advisory Council meeting May 7th, 2004	- Background and overview of the proposed LNG storage project	- Customers	
Stakeholder workshop / presentation – Vancouver Island May 4th, 2004	Same as May 19th Sunshine Coast workshop	Direct mail invitations to approx. 200 separate stakeholders: - customers & business - municipal & provincial government & BCUC - First Nations - Environmental non government organizations (NGO) - Others	16

Event & Date	Issues Presented / Discussed	Audience	Attendees / Respondents
BC Hydro Consultation – Ongoing TGVI RP Meeting – April 27th, 2004	Same as above	BC Hydro technical staff and management	Not applicable
BCUC Consultation Ongoing	Same as above	Commission staff	Not applicable
Chemainus First Nation Open House (Ladysmith) April 30, 2004	Proposed LNG Facility	First Nations / Public	30
Ladysmith Open House January 14, 2004	Proposed LNG Facility	- General Public (via Public Notice) - municipal & provincial government & BCUC - First Nations - Environmental NGOs - Intervenors on the Vancouver Island Gas Pipeline Project	122
Duncan Open House December 4, 2003	Proposed LNG Facility	Same as above	Approx. 25
Nanaimo Open House December 3, 2003	Proposed LNG Facility	Same as above	Approx. 50
Information letter May 22nd, 2003	Proposed LNG Facility	- municipal & provincial government & BCUC - First Nations - Environmental NGOs - Intervenors on the Vancouver Island Gas Pipeline Project	No written responses
Information letter November 21st, 2003	Proposed LNG Facility	Same as above	No written responses
Information letter December 30th, 2003	Proposed LNG Facility	Same as above	No written responses

7.2 Comments from Stakeholder Consultation

7.2.1 Stakeholder Workshops - Nanaimo and Sunshine Coast

Invitations were sent out to a broad group of stakeholders representing different interests. Stakeholders invited included representatives from customers, businesses, municipal and provincial government, First Nations, environmental organizations, BCUC and other interested stakeholders such as BC Hydro and energy industry organizations.

Issues raised by stakeholders during the Nanaimo workshop generally followed the pattern of topics presented by Terasen Gas staff. These issues included:

- How various resources in the portfolios, including the proposed LNG facility, would affect the price of gas to customer segments and who would / would not benefit. More questions were asked in regard to this issue than any other single issue raised during the workshop.
- A few participants questioned the certainty of gas supply reserve forecasts.
- Questions were raised about recent trends in system capacity and the potential for curtailment of industrial customers during peak use.
- Similarly, several questions were aimed at better understanding recent trends in demand for natural gas.
- Several questions were technical in nature, seeking additional details on the development of the design and peak day gas consumption forecasts.
- Additional details on the impact of DSM programs on costs, facility decisions and timing were sought by a few workshop participants.
- A participant questioned why TGVI was not considering DSM programs for industrial customers.
- The remaining questions and comments focused on clarification of resource portfolio details and future steps in the Resource Planning and acquisition processes.

Municipal officials from the Sunshine Coast region requested that an additional presentation / workshop be held in their area due to the difficulty in scheduling a trip to Nanaimo. This request resulted in a second, smaller workshop being held in Sechelt on May 19th, attended by seven staff from nearby municipal areas. Questions and comments from stakeholders followed a similar pattern to those from the May 4th, Nanaimo workshop:

- Questions were raised regarding the impact of various options on the cost of gas.
- Discussion arose about the certainty of future gas supply reserve forecasts.

- Several questions sought clarification of the details and benefits of various resource alternatives.

- One participant asked if system expansion would improve the availability to current consumers who use energy sources other than natural gas.

- Clarification of technical details regarding demand issues was sought.

- Some questions focused on the Resource Planning process.

In general, participants from both the Nanaimo and Sechelt workshops appeared to be satisfied with the information presented and answers to the questions they posed. Formal, written responses were received from two separate stakeholders and are contained in Appendix K.

7.2.2 BC Hydro Consultation

TGVI and BC Hydro are the two largest suppliers of energy and related services on Vancouver Island. As such, the actions of one utility, very much impact the other. To ensure that both utilities are acting in the best interests of their customers while remaining fiscally responsible, a high degree of open and cooperative consultation is required during planning stages. TGVI has sought input from BC Hydro throughout the Resource Planning process.

Consultation efforts with BC Hydro led to a presentation of Resource Plan details to date with BC Hydro staff, coinciding with the general date of the stakeholder workshop held in Nanaimo. While Hydro staff generally supported the work presented, they had numerous technical and editorial comments and raised the following items for consideration.

- Reiterated the uncertainty in the outcome of the Call for Tenders process for alternatives to meet Vancouver Island's future Hydro electricity demands, including a potential gas-fired electric generating plant on the Island. Hydro cannot provide any indication of a preferred portfolio of electrical supply resources until completion of the CFT process in November, 2004.

- Inquired about the costs for potential DSM initiatives being reviewed by TGVI and inquired whether the potential for the Vancouver Island Pulp Mill Joint Venture participants to substitute fuel from electricity to natural gas had been included in the TGVI analysis.

- Asked a number of technical questions regarding LNG proposal details.

- Discussed the potential benefits of developing DSM programs for industrial customers.

In addition to the above comments, BC Hydro provided further feedback in response to a draft of the Resource Plan. The comments reiterated some of the points mentioned previously noting the uncertainty of the outcome of BC Hydro's Vancouver Island Call for Tenders process. BC Hydro also sought clarification on some of the assumptions in the analysis provided including quantification of the LNG storage benefits and the assumed levels of curtailment for ICP and the Joint Venture in the Pipe + Compression + Curtailment alternative. Sensitivity analysis to test the impact of the timing of the LNG facility in-service date was also suggested. BC Hydro noted allocation issues and stranded cost risk as concerns.

TGVI will be providing further information and analysis to address the comments received in its upcoming CPCN application for the proposed LNG facility and also during the consultative process with stakeholders leading up to the filing of the application.

7.2.3 Stakeholder Consultation on LNG Storage

In anticipation of the need for increased natural gas storage on Vancouver Island and as a next step in locating a potential LNG storage facility, TGVI undertook a rigorous and systematic site selection process and commissioned an Environmental and Social Review (ESR), on the preferred site. The ESR was completed in April 2004.[14]

This extensive stakeholder consultation program included correspondence with local, regional and provincial agencies throughout 2003 and eight presentations to municipal agencies and First Nations groups between September 2003 and January 2004. In addition, focus group sessions were conducted in October 2003 and public open houses were held in December 2003 and January 2004. The details of these sessions and excerpts from local media that resulted are also included in the ESR.

The concerns raised about the LNG proposals during the open houses focused on social and safety issues and are being addressed through site selection, design, equipment selection and related mitigation measures. Local governments including the Cowichan Valley Regional District (CVRD), City of Nanaimo and the Nanaimo Regional District were supportive of the project.

On May 26th, the CVRD Board of Directors approved a zoning amendment that will allow construction of an LNG facility on the Mt. Hayes site. The new ‘Utility 1 Zone (Terasen LNG)’ allows construction and operation of an LNG facility. Storage capacity is limited to two 1.5 billion cubic feet (bcf) tanks.

With local zoning approval in hand, the only significant approval remaining for the LNG storage facility proposal is to obtain Certificate of Public Convenience and Necessity (CPCN) approval from the BCUC.

7.3 Future Consultation Opportunities for Stakeholders

The process of consulting stakeholders about TGVI’s future Resource Planning issues continues after submitting the Resource Plan. Once the BCUC has received and reviewed the TGVI Resource Plan, CPCN application(s) to support the selection of individual resources within the preferred resource portfolio may be required. These application(s), also submitted to the BCUC, include a public hearing process and will be subject to further consultation with the Joint Venture participants prior to the submission of the applications. For certain types of projects, design approvals, permits and land development applications under various Federal and

[14] A copy of the ESR report can be found on the Terasen Gas website at www.terasengas.com

Provincial Acts and under municipal planning bylaws may also be required. Effective stakeholder consultation is a key component of most of these approval processes.

In the case of the proposed LNG facility on the Island, these provincial and municipal approval procedures are already underway and have been well documented.

8 ACTION PLAN

As described in the BCUC 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 Action Plan describes the actions that TGVI intends to pursue over the next 4 years based on the information and evaluation provided in this Resource Plan.

1. *Obtain approvals and construct a Liquefied Natural Gas Storage Facility on Vancouver Island*

   The proposed LNG storage facility is a common component of the preferred portfolios identified for the most likely demand forecast regardless of the outcome of BC Hydro's call for generation capacity on Vancouver Island. TGVI will be filing a Certificate of Public Convenience and Necessity (CPCN) in 2004 to support a 2007 in-service date for the LNG storage facility.

2. *Monitor the BC Hydro Vancouver Island Call for Tenders Process and develop additional facilities as required to support any new generation requirements.*

   If new gas-fired generation is developed on Vancouver Island, new compression and pipeline facilities may be required in addition to the LNG storage facility. TGVI will identify and develop project plans for these facilities once the outcome of the CFT is known. In some scenarios, CPCN applications for new compressor stations or pipeline loops may be required as early as second quarter 2005.

3. *Evaluate potential options to contract for curtailment and/or peaking gas with BC Hydro and the Joint Venture.*

   Both BC Hydro and the Joint Venture have the ability to switch to alternate fuels (e.g. distillate, oil, hog fuel, or coal) and are prepared to offer curtailment and/or peaking gas rights. Evaluation of the different resource portfolios concludes that a LNG facility is a better option as a capacity resource, however the fuel switching capability can offer value as a peaking gas resource to TGVI's Core customers or to other market participants in the region that require peaking gas.

4. *Examine funding opportunities for the preparation and implementation of marketing plans that will help Terasen Gas reach customer targets and build energy efficient gas load for both new and existing customers.*

   Adding new customers and encouraging existing customers to make high efficiency gas appliance choices will be critical in maintaining competitive energy choices in the region. Marketing programs and materials will be essential for encouraging new customers to choose natural gas, increasing gas usage per account and reducing the individual's share of fixed costs. Each of these conditions will in turn help to maintain a very competitive position for natural gas, benefiting the entire regional energy outlook in keeping with the provincial Energy Policy.

5. *Conduct a Conservation Potential Review*

   To fully understand the future potential market for DSM programs, TGVI will be applying to the BCUC for funding to conduct a Conservation Potential Review (CPR). The CPR will provide the necessary market information essential for effectively targeting demand side opportunities for strategic load building, conservation and efficiency initiatives. TGVI is of the view that the market is best served if the scope of the CPR includes other energy options, including electricity. To this end, TGVI will be requesting participation of BC Hydro in the CPR and will be seeking partners interested in jointly funding this initiative.

6. *Continue with Existing and Implement New Demand Side Management Initiatives*

   TGVI believes there is significant potential for strategic load building DSM programs in the residential and commercial markets. The Utility is recommending continuing three successful strategic load building programs: the *Home Builders' Grand*, the *Build Smart*, and the *Conversion Program* and, where applicable, to introduce four new conservation and efficiency programs currently offered or planned for the Terasen Gas mainland service area. The Energy Efficiency and Conservation Alternative Energy Policy Branch of the Ministry of Energy and Mines has expressed support for the plan outlined in the DSM section.

7. *Retain and Upgrade the Texada Compressor*

   The current arrangements with BC Hydro contemplate retention of the Texada compressor once a long term transportation arrangement is in place to serve the ICP generation facility. This may require a payment to BC Hydro to refund their capital contribution as early as November 2004, when the current short term agreements expire.

8. *Monitor the Resource Planning process for Terasen Gas (Whistler) Inc. and assess feasibility of providing natural gas service to Whistler.*

   If natural gas service to Whistler is supported by the Whistler Resource Plan, it is anticipated that TGVI would build a pipeline lateral to connect Whistler to the TGVI transmission system at Squamish in 2007. This may require the filing of a CPCN for approval as early as third quarter 2004.

9 GLOSSARY

Annual demand – the cumulative daily demand for natural gas over an entire year.

Avoided cost – the incremental cost that a utility would incur to purchase gas supplies and capacity equivalent to that saved under a demand side management program. Components of avoided cost could include energy, capacity, storage, transmission and distribution.

BCUC – British Columbia Utilities Commission. The provincial body regulating utilities in British Columbia.

Call for Tenders (CFT) – in this document, CFT refers to a specific Call for Tenders that BC Hydro has initiated as part of a review of electricity supply options for Vancouver Island.

Cogeneration – in this document, cogeneration refers to the generation of both electrical and thermal power simultaneously by utilizing the waste heat from a gas turbine to generate steam.

Commission – see BCUC

Compression, compressor station – the application of increased pressure to a natural gas pipe system to create gas flow. Higher levels of compression can be applied to increase the carrying and storage capacity of the pipe. Increased pressure is applied through a compressor station constructed along the pipeline.

Conservation Potential Review (CPR) – a study completed to identify opportunities for energy savings across gas and electrical energy delivery infrastructures and improvements to overall energy utilization efficiency.

Core, core customers, core market – residential, commercial and small industrial customers that have gas delivered to their home or business. TGVI purchases natural gas and delivers it to the customer in a bundled sales rate. Core customers typically use a significant portion of their gas requirements for heating applications, resulting in weather sensitive demand.

Certificate of Public Convenience and Necessity – A Certificate of Public Convenience and Necessity (a "CPCN") is 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.

Curtailment – the planned interruption of gas supply to specific customers during periods of high demand for natural gas – usually during extreme cold weather events.

Daily demand – the amount of natural gas consumed by Terasen Gas' 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.

Demand side, Demand Side Management (DSM) – defined as “any utility activity that modifies or influences the way in which customers utilize energy services”. From Terasen Gas’ perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources.

Design-day, design-day demand (see also: peak day) – the maximum demand for natural gas a utility expects it must provide over a single day. As Core demand is weather dependent, design-day is forecast based upon the coldest weather observed in the last 25 years. For transportation customers, the design-day is equivalent to the firm contract demand.

DHW – domestic hot water

EnerGuide – an energy rating program managed by the Office of Energy Efficiency at Natural Resources Canada, that uses interactive tools to help energy-wise consumers and industries make the right choice when purchasing "off the shelf" equipment such as motors, dry-type transformers, HVAC, lighting products, refrigeration products, boilers, compressors, and pumps.

FE rated – an official rating that verifies that the efficiency of vented gas fireplaces have been tested by the Canadian Standards Association.

GJ – Gigajoule – A measure of energy of natural gas - 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).

GWH – Giga-watt Hours

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 Celcius.

HVDC – High Voltage Direct Current cable – in this document, HVDC refers to the BC Hydro’s high voltage cable currently serving Vancouver Island and scheduled for retirement.

Huntingdon/Sumas – gas flow regulating stations on either side of the British Columbia / US 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 US. The I – 5 Corridor includes B.C.’s Lower Mainland and Vancouver Island, Western Washington and Western Oregon.

Industrial curtailment – see curtailment

Integrated Resource Plan – see Section 1 for a detailed description of Resource Planning. An integrated resource plan is a document that details the resource planning process and outcomes that guide a utility in planning to serve its customers over the long term.

Integrated Electricity Plan – BC Hydro's 2004 Integrated Resource Plan

Interruption – see curtailment

Island Cogeneration Plant (ICP) – A cogeneration plant located at Elk Falls, Campbell River supplying electricity and thermal energy on Vancouver Island.

Joint Venture – see Vancouver Island Gas Joint Venture

Least delivered cost – the lowest cost for which natural gas can be supplied to a customer's home or facility where the gas is consumed.

Liquefied natural gas (LNG), LNG storage – natural gas contained under high pressure 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.

Load duration, load duration curve – the load duration is the daily load over each day of the year, represented from the highest load to the lowest load.

Load shaping – demand side management strategies that affect the shape of the annual demand curve for a given year or years (see Section 4.3 for further details).

Looping – the twinning of sections of gas supply transportation pipe to improve storage and flow characteristics within the service area.

Market saturation – the degree to which all the potential customers in a market or service area who could be natural gas customers, have been captured as actual customers.

Mist – the name and location of an underground, natural gas storage facility situated in Oregon, northwestern US.

National Energy Board (NEB) – an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. Visit www.neb-one.gc.ca

Normal demand (also called annual demand) – the expected demand during a year of 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.

Off-main potential – the market potential for customers that are currently not located near a gas supply main.

On-main saturation – similar to market saturation – the degree to which all of the potential natural gas customers who are near a gas supply main have been captured as actual customers.

O&M – operations and maintenance

Peak day, peak demand, peak day demand (see also: design-day) – the maximum demand for natural gas a utility expects it must provide over a single day. As Core demand is weather dependent, design-day is forecast based upon the coldest weather observed in the last 25 years. For transportation customers, the design-day is equivalent to the firm contract demand.

PJ – Petajoule – equal to 1000 Terajoules or 10^6 Gigajoules.

Portfolio, resource portfolio, supply portfolio – selected supply and / or demand resources that, when grouped, together can meet the future demand and supply needs of a service area.

Ratepayer Impact Measure (RIM) test – a measure of the distribution of equity impacts of DSM programs on non-participating rate-payers. From this perspective, a program is cost effective if it reduces a utility's rates. This can be expressed as a ratio or in dollars of net benefits.

Rate volatility – the amount to which natural gas rates fluctuate and the frequency of those fluctuations.

Resources – demand side and supply side means available to meet forecasted energy needs. Examples of supply side resources within the context of the Resource Planning process are Pipeline Looping, Compression and Storage. Examples of demand side resources are industrial customer curtailment and load management programs for residential and commercial customers.

Tcf – Trillion cubic feet.

Terasen Inc. – the parent company of Terasen Gas Inc. and all other subsidiaries

Terasen Gas Inc. – a subsidiary and utility owned by parent Terasen Inc., and a separate corporate entity from Terasen Gas (Whistler) Inc., Terasen Gas (Squamish) Inc., Terasen Gas (Vancouver Island) Inc. and all other Terasen Inc. subsidiaries.

Terasen Gas (Whistler) Inc. – a subsidiary and utility owned by parent Terasen Inc., and a separate corporate entity from Terasen Gas Inc., Terasen Gas (Squamish) Inc., Terasen Gas (Vancouver Island) Inc. and all other Terasen Inc. subsidiaries.

Terasen Gas (Squamish) Inc. – a subsidiary and utility owned by parent Terasen Inc., and a separate corporate entity from Terasen Gas Inc., Terasen Gas (Whistler) Inc., Terasen Gas (Vancouver Island) Inc. and all other Terasen Inc. subsidiaries.

Terasen Gas (Vancouver Island) Inc. – a subsidiary and utility owned by parent Terasen Inc., and a separate corporate entity from Terasen Gas Inc., Terasen Gas (Squamish) Inc., Terasen Gas (Whistler) Inc. and all other Terasen Inc. subsidiaries.

TJ – Terajoule – equal to 1000 Gigajoules

Total Resource Cost (TRC) Test – a test used to evaluate the economic benefits and costs of utility DSM program from the perspective of all utility customers. Test can be expressed as a ratio or dollars of net benefits.

Transportation customers – customers who purchase natural gas directly from producers or brokers and pay the utility a fee to deliver the gas to their facilities.

Vancouver Island Gas Joint Venture – a joint venture of industrial customers (primarily large mills) on Vancouver Island who purchase energy as a single bargaining unit.

APPENDIX A

BC Utilities Commission
Resource Planning Guidelines

BRITISH COLUMBIA UTILITIES COMMISSION

Resource Planning Guidelines

Issued: December 2003

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PURPOSE AND SCOPE OF THE RESOURCE PLANNING GUIDELINES

The Commission's mandate to direct and evaluate the resource plans of energy utilities is intended to facilitate the cost-effective delivery of secure and reliable energy services. The Resource Planning Guidelines (the "Guidelines") outline a comprehensive process to assist the development of such plans.

The Utilities Commission Act ("UCA") was amended in 2003 to provide the Commission with a mandate to implement the policy actions of the Provincial Government's November 2002 energy policy, "Energy For Our Future: A Plan For BC" ("Energy Plan"). Amendments to Section 45 of the UCA expand upon and clarify the planning requirements of utilities and the Commission's role to review filed plans to determine whether expenditures are in the public interest and whether associated rate changes are necessary and appropriate. The additions to Section 45 of the UCA are as follows:

45 (6.1) A public utility must file the following plans with the commission in the form and at the times required by the commission;

- (a) a plan of the capital expenditures the public utility anticipates making over the period specified by the commission;
- (b) a plan of how the public utility intends to meet the demand for energy by acquiring energy from other persons, and the expenditures required for that purpose;
- (c) a plan of how the public utility intends to reduce the demand for energy and the expenditures required for that purpose.

(6.2) After receipt of a plan filed under subsection (6.1), the commission may:

- (a) establish a process to review all or part of the plan and to consider the proposed expenditures referred to in the plan;
- (a) determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who receive, or who may receive, service from the public utility, and
- (b) determine the manner in which expenditures referred to in the plan can be recovered in rates.

On the basis of subsection 6.1, the Commission will require that any resource plans filed under paragraph 6.1, (a), (b) and (c) be prepared in accordance with the Guidelines.

The Commission requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional and alternative supply sources (including "BC Clean Electricity" as referred to in the Energy Plan), and those which focus on conservation of energy and Demand Side Management ("DSM").[1] 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 process aids in defining and

[1] *Demand Side Management* may be defined as a deliberate effort to decrease, shift or increase energy demand. Utilities develop DSM programs to encourage customers to enact DSM measures. Because of measurement difficulties and uncertainty about consumer behavior, DSM programs should be evaluated before and after implementation to determine their full impacts.

assessing market-based costs and benefits, while also entailing the assessment of tradeoffs between other expected impacts that may vary across alternative resource portfolios. Such impacts may be associated with objectives such as reliability, security of supply, rate stability and risk mitigation, or specific social or environmental impacts. In sum, a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service.

In most circumstances, Certificates of Public Convenience and Necessity ("CPCN") applications should be supported by resource plans filed pursuant to Section 45 of the UCA. The Commission expects that resource plans will help facilitate the review of utility revenue requirements and rate applications.

The Guidelines do not alter the fundamental regulatory relationship between the utilities and the Commission. The Guidelines do not mandate a specific outcome to the planning process, nor do they mandate specific investment decisions. The Guidelines provide general guidance regarding Commission expectations of the process and methods for utilities to follow in developing plans that reflect their specific circumstances. More specific directions regarding resource plans will be provided to utilities on a utility to utility basis. Further directions may address issues regarding the elements of the resource plan or the underlying methodology. The Commission will review resource plans in the context of the unique circumstances of the utility in question. For this reason, the Guidelines do not distinguish between the circumstances of small and large utilities or between transmission and distribution utilities, nor do they prescribe specific planning horizons or approaches to resource acquisition. Although the Guidelines are not prescriptive in that sense, after review of a resource plan the Commission expects to be prescriptive on a utility by utility basis, as necessary, to facilitate cost-effective delivery of a reliable and secure supply that meets demand for a utility's service.

RESOURCE PLANNING GUIDELINES

1. Identification of the planning context and the objectives of a resource plan

Key underlying issues and assumptions that inform the planning context should be identified and discussed (e.g., reliability and security issues, risk factors, major uncertainties). Objectives include, but are not limited to: adequate and reliable service; economic efficiency; preservation of the financial integrity of the utility; equal consideration of DSM and supply resources; minimization of risks; compliance with government regulations and stated policies; and consideration of social and environmental impacts.[2]

2. Development of a range of gross (pre-DSM) demand forecasts

In making a demand forecast, it is necessary to distinguish between demographic, social, economic and technological factors unaffected by utility actions, and those actions the utility can take to influence demand (e.g. rates, DSM programs). The latter actions should not be reflected in the utility's gross demand forecasts.[3] More than one forecast would generally be required in order to reflect uncertainty about the future: probabilities or qualitative statements may be used to indicate that one forecast is considered more likely than others. The energy end-use categories[4] used to analyze DSM programs should be compatible with those used in demand forecasting, so that at any point a consistent distinction can be made between demand with and without DSM on an end-use category-specific basis. Thus, the gross demand forecast should be structured in such a way that the savings, load shifting or load building due to each DSM resource can be allocated to specific end-uses in the demand forecast.

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[2] Bonbright, Danielsen and Kamerschen, (Principles of Public Utility Rates, 1988, Ch.8, p.165) suggest that the rates set by utility commissions invariably involve some discretionary judgment about the extent to which broader social principles should influence ratemaking. Because of social and environmental impacts, the rates charged by utilities may be allowed to deviate from those that would result from a rate determination based exclusively on financial least cost. The objectives to be addressed may be identified by the utility, intervenors, or government. The BC Utilities Commission interprets its jurisdiction as extending only to consideration of environmental and social impacts that are likely to become financial costs in the foreseeable future.

[3] In other words, gross forecasts represent an attempt to simulate markets in which the utility did nothing to influence demand. Of course, this is not entirely possible. Utilities will continue to require rate increases and existing DSM programs will affect demand as will already ordered rate design changes. However, the assumptions made with respect to these factors in estimating future gross demand should be clearly specified so that the effects of these assumptions may be distinguished from the effects of future utility actions designed to influence demand.

[4] The term *End-use categories* is intended to mean energy consumption by categories of end-user, such as industrial, commercial, or residential. Guideline No. 2 does not prescribe *end-use forecasting* or *end-use modeling*, but rather requests that forecast outputs and DSM results be organized and checked according to end-use categories.

3. Identification of supply and demand resources

Feasible[5] individual supply and demand resources, both committed and potential, should be listed. Individual resources are defined as indivisible investments or actions by the utility to modify energy and/or capacity supply, or modify (decrease, shift, increase) energy and/or capacity demand.

4. Measurement of supply and demand resources

Each supply-side and demand-side resource must be measured against the objectives established under Guideline No. 1. This includes identifying utility and customer costs (life cycle costs, impact on rates, etc.), associated risks, and lost opportunities.[6] Characterizing the feasible supply and demand resources could also include reporting how these resources perform[7] relative to specific social and environmental objectives. This can facilitate a more comprehensive understanding of the tradeoffs between objectives as they may be associated with various supply and demand resources. Supply and demand resource cost estimates should represent the full costs of achieving a given magnitude of the resource. These cost estimates may be represented as supply curves; i.e. graphs showing the unit costs associated with different magnitudes of the resource.

5. Development of multiple resource portfolios

For each of the gross demand forecasts, several plausible resource portfolios should be developed, each consisting of a combination of supply and demand resources needed to meet the gross demand forecast. The gross demand forecasts and the resource portfolios should cover the same period, generally 15 to 20 years into the future.

6. Evaluation and selection of resource portfolios

For each of the gross demand forecasts, the set of alternative resource portfolios that match the forecast are assessed against the objectives. Analysis of the tradeoffs between portfolios and how they perform under uncertainty will facilitate determining which portfolio performs best relative to the stated objectives. This process will lead to the selection of a set of preferred resource portfolios, each portfolio matching one of the gross demand forecasts.[8]

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[5] Feasible resource options are defined as those options consistent with the objectives of the resource planning process, as established under Guideline No. 1. For example, government policy may rule out a particular technology or form of energy.

[6] *Lost opportunities* are opportunities that, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. Examples can include cogeneration opportunities that are available but not taken when renovating a pulp and paper mill, or additional insulation that is not installed in a new house.

[7] Performance measures may be quantitative or qualitative.

[8] Guidelines No. 4 through No. 6 may require an iterative process to account for any interdependencies.

7. Development of an action plan

The selection process in Guideline No. 6 provides the components for the action plan. The action plan consists of the detailed acquisition steps for those resources (from the selected resource portfolio) which need to be initiated over the next four years in order to meet the most likely gross demand forecast. The action plan should include a contingency plan that specifies how the utility would respond to changed circumstances, such as changes in loads, market conditions or technology and resource options. For resources with considerable uncertainty, the action plan should incorporate an experimental design and monitoring plan to allow for hindsight evaluation of associated market impacts and full resource costs.

8. Stakeholder input

Although utility management is responsible for its resource planning and resource selection process, utilities should normally solicit stakeholder input during the resource planning process. Methods could include stakeholder collaboratives, information meetings, workshops, and issue papers seeking stakeholder response. Utilities are encouraged 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.

9. Regulatory input

To streamline the regulatory process, utilities are encouraged to seek review and comment from Commission staff during the various phases of resource plan preparation.

10. Consideration of government policy

A resource plan filed in accordance with the UCA and these Guidelines should be consistent with government policy, as it is expressed in legislation (e.g. efficiency standards) or in specific policy statements and directives. Emerging policy issues, such as increased control of emissions, may be addressed as risk factors.

11. Regulatory review

Upon receipt of a resource plan filed pursuant to Section 45, paragraph 6.1, the Commission will establish a review process, as necessary, pursuant to Section 45, paragraph 6.2. A review may provide, as the Commission considers appropriate, opportunities for written and/or oral public comment.

APPENDIX B

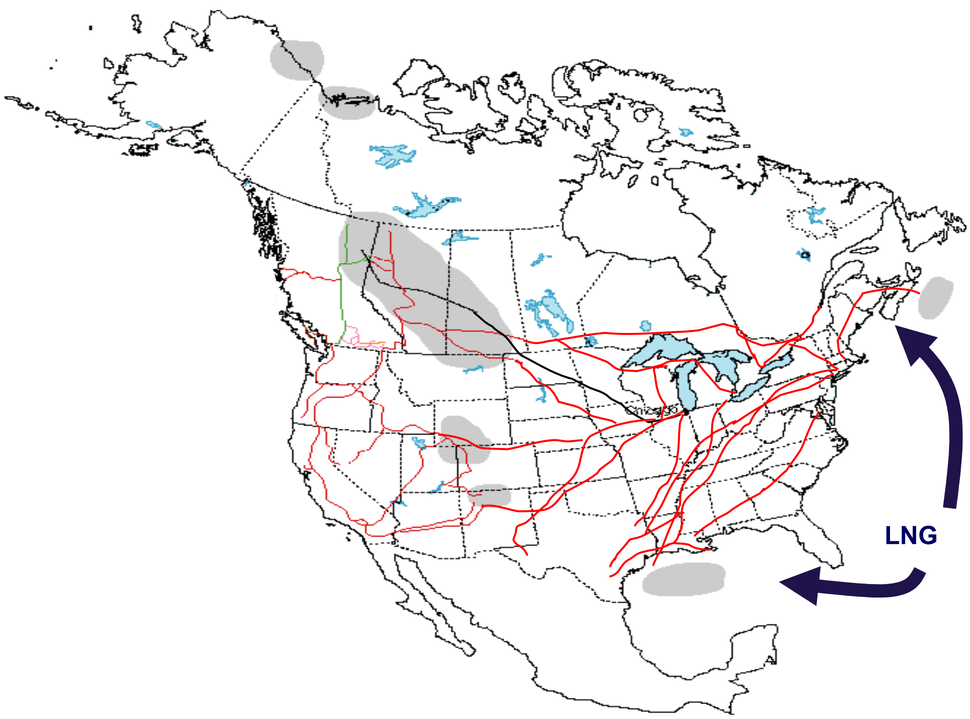
Gas Supply Market Overview

North American Gas Market

The continental gas supply perspective is important when evaluating the requirement for new facilities which are to be used over their lifetime of thirty or more years. TGVI has reviewed the latest forecasts for gas reserves from a variety of sources.

In its 2003 study, the North American Petroleum Council (NAPC)[1] found 272 trillion cubic feet (Tcf) of proven reserves or roughly 10 years of supply at current demand levels. Further, the study estimated 1,970 Tcf of total technical resource or 73 years of supply at current production levels. The NAPC's estimate of total technical resource included unconventional resources such as coal-bed methane, tight sands and fractured shale deposits. The National Energy Board (NEB), in its April 2004 review of conventional resources, concluded that Canada has an ultimate potential of over 500 Tcf of conventional marketable gas. Conventional marketable gas is defined as gas that using current or expected technology could be produced and brought to market. This estimate excludes unconventional resources. In the NEB study of the B.C. Market[2] published in April 2004 (refer to Appendix D for a full copy of the report), the Board also concluded that there remains ample supply for the needs of the British Columbia consumers.

Figure B-1. North American Natural Gas Supply Regions



1 North American Petroleum Council, 2003

2 The British Columbia Natural Gas Market: An Overview and Assessment, National Energy Board, April 2004.

In North America, a migration to newer supply areas is taking place as supply is exhausted in heavily exploited areas such as the U.S. inshore Gulf coast and mid-continent. Areas where gas supply is continuing to build include the U.S. Rocky Mountain region and Northeastern B.C. Frontier or new areas include the McKenzie Delta, Alaska North Slope and Sable Island. North American gas supply estimates do not include liquefied natural gas (LNG) imported to North American via tanker, another sizable resource.

Proven gas reserves worldwide are vast. The U.S. Department of Energy's World Energy Outlook published in April 2004 estimates world proven (discovered) reserves at approximately 6,000 Tcf or more than 60 years at current production levels. About half of this is in areas that require LNG facilities to exploit the resource because of their distance from a market.

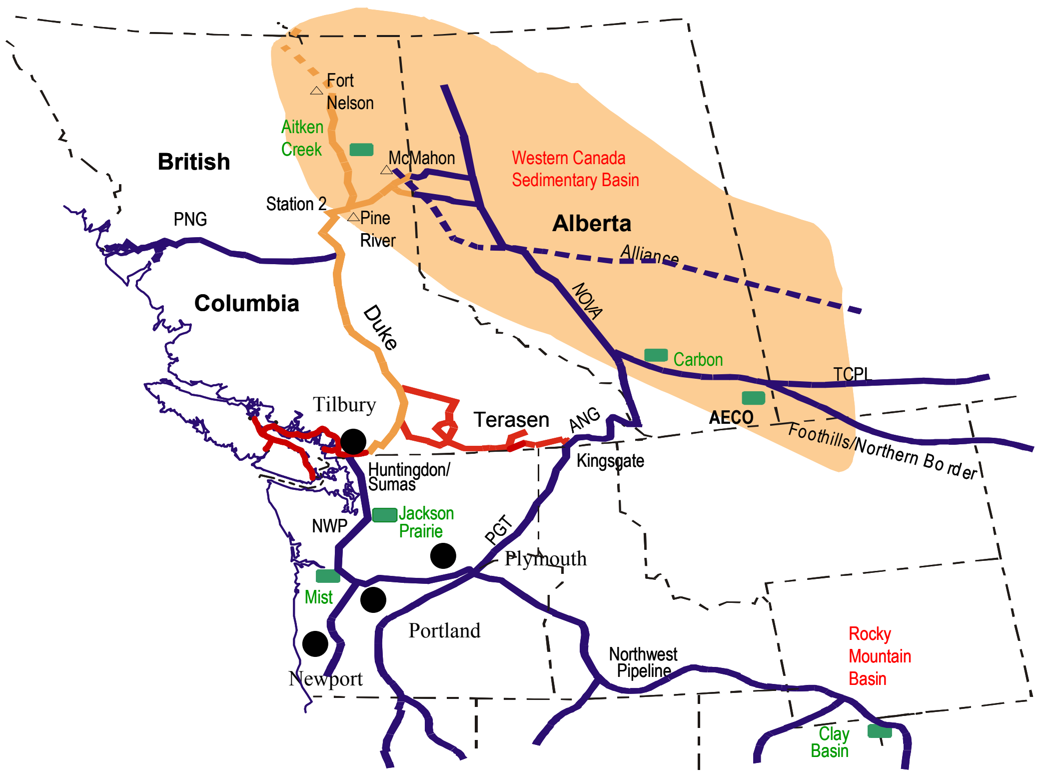
Regional Market

The regional market is centered around the regional gas trading point at the Huntingdon/Sumas border crossing. The major demand centers in the region run along the I-5 corridor, from Southwestern B.C. to Portland Oregon. As shown in Figure B-2, three major gas supply pipeline routes bring gas from Northeastern B.C. (Duke), Alberta (Terasen Gas Southern Crossing) and the US Rocky Mountain Region (Williams Northwest Pipeline). The majority of the gas delivered to the region comes from Northeastern B.C. The Terasen and Williams pipelines provide smaller quantities of supply to the region but play an important role in providing some supply diversity to the region. This network of pipelines is important in establishing security of supply to the region. In addition to gas pipelines, gas storage is used to meet the variances or peaks in demand characteristic of the residential/commercial heating market.

Storage is most efficient when it is located in proximity to the load it serves as this reduces the required facilities that must be put in place to bring gas to the market. There are two forms of storage commonly in use, underground and LNG storage. Underground storage typically makes use of existing gas or oil reservoirs to store gas. Examples of underground storage facilities in the region include Jackson Prairie, south of Seattle and Mist near Portland. Suitable geological conditions for an underground storage facility have not been confirmed in southern British Columbia, therefore options for storage within the Terasen Gas' service area are currently limited to LNG facilities where pipeline gas is transported to the site, liquefied and stored for use in high demand periods.

LNG storage is very flexible in terms of where it can be located. LNG facilities in the Pacific Northwest include Tilbury Island (Delta) on the Terasen Gas Inc. system, the Williams facility at Plymouth Washington, and the Northwest Natural facilities at Portland Oregon and Newport Oregon.

Figure B-2. Regional Natural Gas Supply



By North American standards, the regional market known as the I-5 corridor is relatively small with design-day demand estimated at between 4 and 5 petajoules per day (PJ/day). In comparison, the Alberta market is approximately 15 PJ/day. Total demand across North America averages approximately 70 PJ/day. The region is also characterized by a tight supply / demand balance that has contributed to price volatility during periods of high demand. A situation of tight supply / demand is typically mitigated by development of storage resources that provide supply during periods of high demand. Storage allows a balancing of supply and demand between low summer demand months where supply is put into storage and high winter demand months where it is withdrawn. However, there is no expectation of any new large underground storage reservoirs being developed in the region.

In the National Energy Board's 2004 study[3], the Board concluded that the B.C. market has experienced rising gas prices that have occurred elsewhere in North America. Producers have responded by increasing exploration for gas to serve the region. Consumers, particularly industrial consumers, have responded to higher prices by changing their fuel use and adopting energy conservation measures. Overall, the NEB study found the market is functioning well but that the lack of storage resources in the region could contribute to price volatility during periods of high demand. Gas market participants are active in managing this risk.

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3 The British Columbia Natural Gas Market: An Overview and Assessment, National Energy Board, April 2004.

APPENDIX C

Liquid Natural Gas Storage Benefits

LNG Gas Supply Benefits Overview

The addition of the LNG facility to the TGVI system impacts both the cost of the facilities required to move natural gas to TGVI customers and natural gas commodity costs for Core customers. This section discusses the facility's value from a gas supply perspective. These benefits must be considered in conjunction with the work done optimizing the transmission facility requirements because the combination of avoided gas supply cost and revenue expected from third parties partially offset the cost of the LNG facility and therefore lower the overall cost of the facilities.

From a gas supply perspective, TGVI customers could benefit from this facility in two ways. First, by holding LNG capacity, TGVI customers would avoid the cost of downstream storage, seasonal pipeline capacity or baseload pipeline capacity that would otherwise be required. Second, since the minimum practical size of the LNG facility would be greater than TGVI's immediate needs, TGVI could offer storage services to Terasen Gas Inc. (TG) and others in the region at the market price of storage to defray some of the costs of the LNG facility. Over time, TGVI's use of the capacity would increase and it would receive less from third party storage holders.

The regional gas market would benefit from the LNG facility through increased deliverability and supply security within the region. Additional supply sources help to provide protection should there be disruption on either of the pipelines that provide gas to Huntingdon. Other local storage such as at Mist or Jackson Prairie still relies partially on pipeline capacity to redeliver the gas to TGVI. LNG would also reduce the need to provide supply through displacement. Currently gas is delivered by displacement to TGVI and TG from storage facilities south of Huntingdon such as Mist. Delivering by displacement means that gas destined for markets south of Huntingdon is diverted to TGVI and TG and replaced further south by the gas from the storage facility. This means that on a peak day, there is actually less gas available to flow south because it is being diverted for TGVI and TG. For this reason, local LNG would contribute to both higher liquidity and reduced price volatility at Huntingdon/Sumas on high demand days. The sendout from the LNG facility represents roughly 5% of the gas available at Huntingdon / Sumas on a peak day.

The analysis done for the Resource Plan assumes that for each of the demand cases, TGVI avoids the cost of equivalent upstream facilities for the LNG service it holds. For any remaining capacity in the LNG facility it was assumed that TG would pay TGVI market value for use of the service. Other third parties might also be willing to pay for LNG service but what they would be willing to pay likely does not exceed what TG would value the service at.

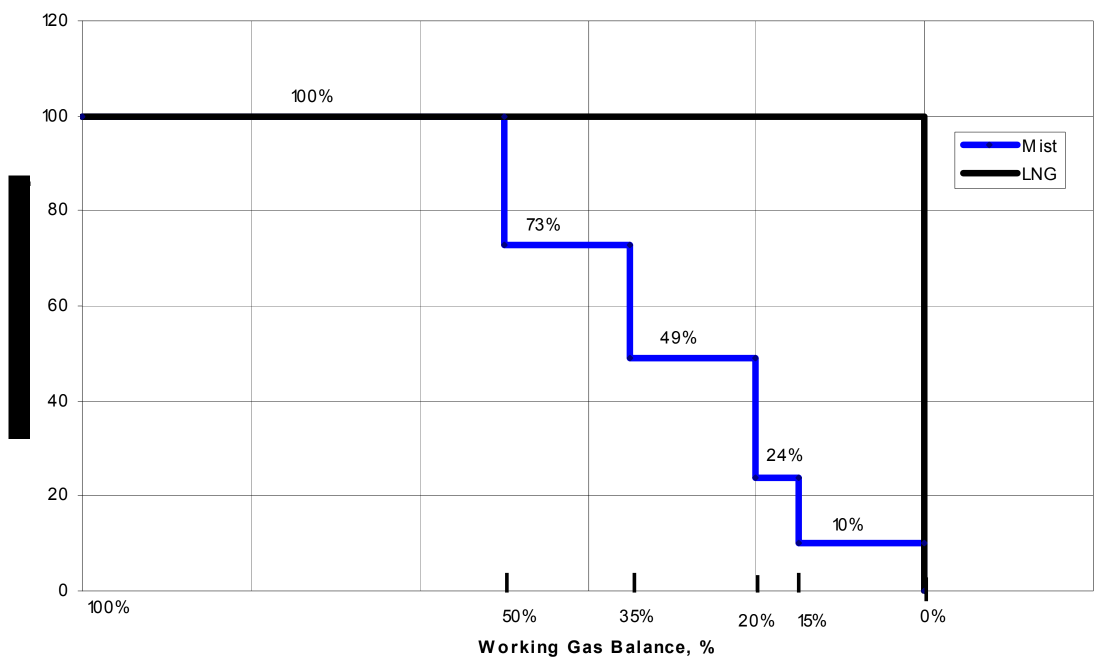
There are other storage facilities in the region. LNG facilities exist at Tilbury in Delta BC, Plymouth Washington, Newport Oregon and Portland Oregon. Underground storage facilities are located at Jackson Prairie in Washington and Mist in Oregon. Mist is the only facility where capacity for new storage contract holders is being added. New service is only available at other facilities through purchasing capacity from existing storage holders. In most cases, those holding the storage contracts are fully utilizing their service and so the market price is difficult to establish. At Mist, both TGVI and TG have recently completed long term arrangements with the developer, NW Natural, so the pricing is well understood. NW Natural leases out space in the facility that is surplus to its requirements to serve its own core market.

Comparison of Service

The characteristics of storage service and the value of storage are somewhat unique to each storage facility. Generally speaking, the closer the storage facility is to the market being served, the greater the value of the service. This is because infrastructure is not required to be dedicated to bringing the storage gas to the market on cold days. In the case of TGVI's LNG, this is partially accounted for in the transmission portfolios outlined in this plan. There is no extra pipeline capacity required on the TGVI system to bring the LNG storage gas to market as there would be in the case of using a storage facility outside the TGVI service territory. In other words, the LNG facility means that less compression and pipeline looping are required on the TGVI system to serve the expected load than otherwise would be the case without LNG. There are also similar cost savings upstream of the TGVI system. Currently, for Mist service, TGVI must hold agreements with third parties to redeliver gas from Oregon to the Huntingdon/Sumas market centre.

The other major difference between storage services, particularly underground storage, is the way in which the natural gas is delivered to and from the facility. With LNG, the amount that can be delivered to and from the facility is based on the design of the liquefaction and vapourization equipment and the size of the tank. In the case of underground storage, the gas must be pushed in and out of the storage reservoir. Because this involves pressurization of the reservoir, the ability to withdraw gas is tied to the volume of gas in the reservoir and as the volume of gas declines, pressure and deliverability generally decline as well. The following graph illustrates the difference between LNG and a typical underground storage facility for deliverability.

Underground Storage Deliverability vs. LNG



The differences outlined above mean that differences in deliverability must to be accounted for in comparing the value to the services. In order to account for the decline rates of underground storage deliverability, a slightly longer duration of underground storage capacity would be required to get a service similar to LNG storage. For this study, 26 days of underground storage capacity was compared to a 20 day LNG service, 15 days to 10 days of LNG and 9 days to 6 days of LNG.

Assessment of Benefits

For TGVI, the underground alternative assumes that LNG storage capacity is used to meet all core load growth that was not met by pipeline additions on the TGVI transmission system. While some underground storage capacity may still remain in the TGVI portfolio, most would be replaced by LNG storage capacity. For TG, it is not anticipated that there would be any reduction in its underground storage capacity but that, as a result of core market growth and the loss of other resources, there is more than sufficient peak day demand growth to justify acquiring available LNG capacity. Because there is a limited amount of pipeline redelivery from other local storage sources available, TG may also benefit by taking up any capacity at underground storage not required by TGVI. It is expected that TGVI will have acquired 20 TJ of Mist capacity by 2007 which could then be released to TG. In the analysis, it was assumed that the LNG would be slotted in with capacity provided through short-term peaking arrangements in its portfolio. TG requirements are for short term capacity of 6 to 10 days to meet this need.

Underground storage costs include storage facility costs, fuel for storage injection, transportation to storage from Huntingdon, transportation from storage to Huntingdon and fuel for transportation both ways. If firm pipeline capacity was used for transportation, the cost would be approximately $0.40 per GJ of deliverability paid each day throughout the year. Because the storage is only used occasionally, TGVI typically pays a third party to deliver the gas via displacement. The third party delivers gas it has moving south on Northwest Pipeline to TGVI at Huntingdon and takes delivery of TGVI's gas at Mist in exchange. This is less expensive than holding firm pipeline capacity. For delivery to the storage field, TGVI will then purchase unused pipeline capacity at discounted rates during the summer. For redelivery, there is typically a standby charge based on the number of days in which the third party must be available to provide the service and a transportation charge for the days it is actually used.

Storage Assumptions:

- Demand charge for withdrawal capability
- Demand charge for storage capacity
- 2% injection fuel

Transportation Assumptions:

- $0.04 US/mmBtu per day standby charge (for 120 winter days)
- $0.30 US/mmBtu for volume withdrawn
- $0.10 US/mmBtu for volume injected (assuming discounted summer capacity)
- 1.6% pipeline fuel each way

In both the TGVI and TG cases, the underground storage alternative is a conservative comparison as it ignores the limitations on the level of Northwest Pipeline displacement pipeline capacity that may be available in the long term to TGVI and TG to Huntingdon. If displacement capacity is not available, the next option is to contract for firm pipeline capacity for redelivery which is expensive if only used on a few days per year. It also does not take into account the expectation that storage fees may increase over time. Finally for TGVI and TG, the LNG service is more flexible. The LNG facility does not have to follow pipeline re-nomination schedules so the service can be provided on much shorter notice and flow can be altered to best match TGVI requirements for capacity on an hour-by-hour basis. Similar service could be provided to TG as well.

TGVI Mist Alternative

For TGVI, the cost of LNG was compared to the cost of a 26 day underground storage service as the forecast requirements for the storage service are over a similar sendout period. TGVI currently contracts for similar capacity at NW Natural's Mist facility. The major difference with underground storage is that TGVI would only need LNG tank capacity equal to the forecast design requirements. With underground storage, because of the decline in withdrawal capability as the reservoir is used, a larger capacity is required to maintain required deliverability. This extra volume provides an additional risk in that it must be resold into the market to cycle the storage each year. For this analysis, it was assumed that this extra gas in storage could be sold at no additional cost to TGVI. The value of the service is approximately $100 per GJ of sendout or approximately $3.85 per GJ of 26 day capacity. LNG tank capacity would be optimized to release as much as possible to maximize third party revenue.

The following example shows TGVI requirements for LNG capacity versus what would be available to TG or third parties in the base demand case which include ICP plus and incremental 20 TJ of new demand on the TGVI system.

LNG Capacity Split – Base Case ICP + 20 TJ

Year	TGVI Capacity (TJ)	Capacity Available to Others (TJ)
2007	169	907
2008	225	851
2009	291	785
2010	358	718
2011	424	652
2012	491	585
2013	557	519
2014	623	453
2015	690	386
2016	756	320
2017	822	254
2018	1030	46
2019	976	100
2020	239	837
2021	303	773
2022	366	710
2023	429	647
2024	493	583
2025	556	520

Terasen Gas Inc. Mist Alternative

It was assumed that TG would lease any capacity that was not immediately needed for TGVI or its customers. This was split between 6 day and 10 day capacity to optimize the amount of capacity left in the tank after TGVI had taken its allocation. The value of this service is approximately $70 per GJ of sendout for 6 day service and $80 per GJ of sendout for 10 day service. This equates to a cost of $12 (6 day) and $8.25 (10 day) per GJ of capacity. The value was calculated based on displaced equivalent underground storage service of 9 and 15 days which has an average cost per GJ of $8 (9 day) and $5.50 (15 day).

Summary

The LNG benefit in terms of avoided gas costs and third party revenue can be summarized as follows:

Case	TGVI Avoided Storage Cost ($mm)		Third Party LNG Revenue ($mm)	
	NPV @ 6%	**NPV @ 10%**	**NPV @ 6%**	**NPV @ 10%**
Low Case	29	18	58	39
Base Case - ICP	55	36	34	23
Base Case – ICP + 20 TJ	53	34	36	25
Base Case – ICP + 45 TJ	55	36	32	23
High Case	69	45	20	14

The table shows that in cases where there is lower demand on the TGVI system there is little impact on the overall LNG benefit because the lower demand means that there is more space that can be leased to third parties. The increase leased storage revenue offsets the lower avoided storage cost of TGVI.

In summary, TGVI is expected to benefit not only from reduced cost in transmission facilities due to the LNG facility, but also from savings in the gas supply portfolio associated with the cost of short term storage when compared to underground storage and other alternatives. TGVI can also expect to receive revenue from leased LNG storage that it does not require in the short term to other parties such as TG.

As a participant in the regional market, TGVI will also benefit indirectly from the beneficial effect of additional storage in the region. In the NEB Market Assessment referenced in Section 2 the Gas Supply Overview, the NEB found that "B.C.'s small market size and lack of storage in the Lower Mainland limit market liquidity in comparison with other major market centres such as AECO-C in Alberta". The regional gas market will benefit from the addition of LNG storage through increased deliverability, supply security within the region, and a reduced requirement to displace gas flowing south. Local LNG contributes to both higher liquidity and reduced price volatility at Huntingdon/Sumas on high demand days. The sendout from the LNG facility represents roughly 5% of the gas available at Huntingdon/Sumas on a peak day.

APPENDIX D

National Energy Board
The British Columbia Natural Gas Market
An Overview and Assessment

National Energy Board
Office national de l'énergie

The British Columbia **Natural Gas** Market

An **O**verview *and* **A**ssessment

An **ENERGY MARKET ASSESSMENT** • April 2004

National Energy Board
Office national de l'énergie

The British Columbia **Natural Gas** Market

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FIGURES

Acronyms

B.C.	British Columbia
BCUC	British Columbia Utilities Commission
CBM	coal bed methane
EMA	Energy Market Assessment
EnCana	EnCana Corporation
Enron	Enron Corporation
FERC	Federal Energy Regulatory Commission (U.S.)
GSX	Georgia Strait Crossing Pipeline Project
GTN	Gas Transmission Northwest Corporation
ICE	Intercontinental Exchange
I-5 Corridor	U.S. Interstate Highway 5 Corridor
LDC	local distribution company
LNG	liquified natural gas
M-KMA	Muskwa-Kechika Management Area
NEB or Board	National Energy Board
NGX	Natural Gas Exchange
NYMEX	New York Mercantile Exchange
PNG	Pacific Northern Gas Ltd.
PNW	United States Pacific Northwest (Washington, Oregon and Idaho)
SCP	Southern Crossing Pipeline
TCPL Alberta	TransCanada PipeLines Alberta system
Terasen	Terasen Gas Inc.
The Province	Province of British Columbia

U.S.	United States
VIGP	Vancouver Island Generation Project
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc., which carries on business as Duke Energy Gas Transmission Canada

UNITS

Bcf	=	billion cubic feet
Bcf/d	=	billion cubic feet per day
GJ	=	gigajoule
m^3	=	cubic metres
m^3/d	=	cubic metres per day
mcf	=	thousand cubic feet
MMcf	=	million cubic feet
MMcf/d	=	million cubic feet per day
MW	=	megawatt
Tcf	=	trillion cubic feet

CONVERSION FACTORS

cubic metre	=	35.3 cubic feet
gigajoule	=	0.95 thousand cubic feet of natural gas at 1 000 Btu per cubic foot
hectare	=	2.47 acres
kilometre	=	0.62 mile

FOREWORD

As part of its mandate, under the *National Energy Board Act*, the National Energy Board (NEB or the Board) continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas and natural gas liquids) and the demand for Canadian energy commodities in both domestic and export markets. The Board publishes reports on energy, known as Energy Market Assessments (EMA), which examine various facets of the Canadian energy market. These reports include both long-term assessments of Canada's supply and demand and specific reports on current and near-term energy market issues.

In addition to its mandate to monitor energy markets in Canada, the Board has a specific monitoring role pursuant to its regulatory responsibilities. The Board is required to monitor Canadian energy markets to ensure that markets are operating such that Canadian energy requirements are being met at fair market prices.

This EMA, *The British Columbia Natural Gas Market: An Overview and Assessment*, examines the current functioning of the British Columbia (B.C.) natural gas market and provides an overview of the issues in this market. The objective of this report is to advance the understanding of the B.C. natural gas market and to heighten awareness of regional natural gas markets in Canada.

During the preparation of this report, a series of meetings and discussions was held with a cross-section of the natural gas industry, including producers, gas marketers, pipeline transmission companies, local distribution companies, end-users, industry associations and government agencies. The Board appreciates the information and comments it received.

EXECUTIVE SUMMARY

The B.C. natural gas market has faced a number of challenges in the last few years, including rising prices, price spikes and increased price volatility. New exploration and development projects have been announced for northeast B.C. New pipeline projects have been developed that move gas from northeast B.C. to eastern markets, away from the traditional B.C. domestic and U.S. Pacific Northwest (PNW) export markets along the West Coast. Consumers, especially industrial consumers, are taking measures to reduce natural gas consumption and are exploring fuel alternatives. Is the market functioning as it should? This is the question that some market participants and consumers are asking.

Findings

The Board is of the view that, although there are some challenges, the B.C. natural gas market is working well. The Board finds that:

- natural gas prices in B.C. are now integrated with the North American gas market;
- there has been a significant upward step in natural gas prices throughout North America, including B.C.;
- B.C. consumers have responded to higher prices by reducing demand;
- producers in B.C. have responded to higher prices by increasing exploration and production;
- transportation developments have facilitated the movement of B.C. produced gas to markets east of B.C.;
- price discovery is being improved due to better price reporting standards and access to electronic gas trading at pricing points for B.C. gas;
- price volatility is being managed by market participants;
- B.C.'s small market size and lack of storage in the Lower Mainland limit market liquidity in comparison with other major market centres such as AECO-C in Alberta; and
- overall the market is working well and consumers and producers are making the appropriate changes to the higher natural gas price environment.

Discussion

Prior to 1998, the B.C. natural gas market was not fully connected with the North American gas market. After 1998 a series of pipeline expansions, including the construction of the Alliance pipeline from northeast B.C. to Chicago, increased the potential for B.C. and Alberta gas from the Western Canada Sedimentary Basin (WCSB) to reach North American gas markets. Gas prices in Alberta and B.C. rose and prices at AECO-C, Station 2 and Sumas/Huntingdon became more closely aligned with other North American markets.

Since 2000, natural gas price dynamics in North America have changed fundamentally. The growth in natural gas production that occurred throughout the 1990s slowed and in the face of increasing demand, prices rose throughout North America. As the balance between supply and demand became tighter, gas prices became more volatile than in the 1990s.

B.C. and PNW consumers have reacted to higher prices by reducing demand. After the California gas price spike in the winter of 2000/2001, consumers became concerned about natural gas price levels and price volatility. Industries changed their gas purchasing practices, switched fuels and improved energy efficiency. Residential consumers reduced their household consumption by improving energy conservation and turning down thermostats.

The gas exploration and development industry responded to higher prices and to regulatory incentives from the Province of British Columbia (the Province) with increased bidding at provincial land sales and with increased drilling activity. By 2003, production had risen from 54 $10^6m^3/d$ (1.9 Bcf/d) in 1998 to 71 $10^6m^3/d$ (2.5 Bcf/d), while oil and gas revenues to the Province rose from $0.4 billion in 1998 to in excess of $2 billion.

Transportation developments in B.C. have improved market access for B.C. gas production. New pipeline developments such as construction of the Alliance pipeline and numerous cross-border pipelines connecting with the TransCanada PipeLines Alberta system (TCPL Alberta) have facilitated the movement of gas to eastern markets. These transportation developments have provided B.C. gas producers with more market options and have provided additional impetus to increased exploration efforts in northeast B.C.

U.S. regulatory initiatives with respect to price discovery have improved price transparency at U.S. pricing points like Sumas/Huntingdon. The commencement of electronic gas trading at Station 2 on the Natural Gas Exchange (NGX) is improving price discovery there. However, prices at Sumas/Huntingdon remain susceptible to short-term price spikes, especially during peak winter demand. Without a major gas storage facility near the Lower Mainland, the Sumas/Huntingdon market does not have the same flexibility to respond to rapidly changing demand conditions as some other gas markets in North America. Market participants have become accustomed to managing gas price volatility through improved market monitoring and revised gas purchasing strategies, short-term fuel switching and demand management techniques. Nonetheless, liquidity and, hence, flexibility in B.C. is limited by the small size of the regional gas market.

Two features of the B.C. gas market stand out from other regional markets. The first is the lack of market-based storage for the Lower Mainland. With the expected growth in gas-fired power generation demand and a decrease in industrial demand, the overall demand profile has become more weather sensitive. Additional storage facilities in the Lower Mainland would assist in managing peak demand loads and would also improve the functioning of the gas market at Sumas/Huntingdon.

The second feature, in contrast with many other parts of North America, is that opportunities exist to increase gas supply from B.C. Current NEB resource estimates indicate that potential exists to increase production from northeast B.C. and that there is potential to find natural gas in other B.C. supply basins. The pace of any gas resource development will depend on many factors, including the management of various environmental, land-use, socio-economic and First Nations issues.

INTRODUCTION

The last ten years have witnessed many profound changes in the B.C. natural gas market. Numerous exploration developments have been announced for northeast B.C. Discussion of offshore oil and gas development has been initiated by the Province. New pipelines, including the Alliance pipeline and cross-border pipelines that connect with the TCPL Alberta system, have been built to take gas production from northeast B.C. to market. The Southern Crossing Pipeline (SCP) was completed and enables Alberta gas to access the Lower Mainland market.

Led by the industrial and power generation sectors, demand for natural gas in B.C. rose by one-third during the 1990s. Natural gas exports to the U.S. Pacific Northwest (PNW) more than doubled during this period. Producers responded to the increased demand by tripling the annual number of gas wells drilled, thereby increasing production by 67 percent over the last ten years. In recent years, however, B.C. consumers have cut back on their use of natural gas and exports to the PNW through Huntingdon have waned. B.C. gas producers have looked at other markets in which to sell growing production.

For many British Columbians, however, the most significant change has been in the price of natural gas. In the last five years, natural gas prices have risen about three times above the historic levels experienced in the 1990s. In addition, gas prices have become more volatile and sharp price spikes have occurred at the Sumas/Huntingdon market.

What has brought about these changes in the marketplace? Are markets working well? B.C. consumers have become concerned about the impact higher and unpredictable natural gas prices are having on heating and energy costs for their homes and businesses and on the provincial economy. Concerns have also been raised by some market participants about price transparency and liquidity in the B.C. market, especially at Sumas/Huntingdon.

This report presents an overview and assessment of the gas market in B.C. Examinations of natural gas demand in B.C. and the PNW markets are provided in Chapter 2. Recent transportation developments and issues are reviewed in Chapter 3. Chapter 4 presents an overview of regional gas pricing and looks at the evolution of natural gas prices in B.C. Chapter 5 concludes with a discussion of recent developments in supply with a focus on northeast B.C. By comprehensively reviewing various aspects of the B.C. gas market, this EMA intends to familiarize readers with the current state and functioning of this regional Canadian market.

Markets for British Columbia Natural Gas

Highlights

- Higher natural gas prices have impacted demand
- B.C. natural gas demand has been flat since 2000 and declined in 2003
- Lower Mainland consumers have reduced household natural gas consumption
- B.C. industrial natural gas use has declined in the last two years
- Natural gas exports to the PNW through Huntingdon peaked in 1998
- Power generation is a growing market for natural gas in the PNW

This chapter focuses on trends and developments in B.C. and the PNW markets for northeast B.C. gas. Gas from northeast B.C. can also reach markets accessible through Alberta including Alberta, Eastern Canada and the continental U.S. as well as California. The B.C. domestic gas market and the PNW market, concentrated along the U.S. Interstate Highway 5 corridor (I-5 Corridor), are the major traditional markets for B.C. gas transported by Westcoast Energy Inc., which carries on business as Duke Energy Gas Transmission Canada (Westcoast). In order to provide a context for the discussion of gas use trends in these traditional markets, especially consumer reaction to higher gas prices, an overview of the B.C. gas distribution system is provided.

2.1 British Columbia Natural Gas Distribution System

A single major transmission pipeline connects northeast B.C., the only producing area in the province, with the Lower Mainland market around Vancouver (Figure 2.1). Owned by Westcoast, this long distance pipeline transports gas to the B.C. Interior and Lower Mainland markets and to Huntingdon, B.C. for export to U.S. markets in the PNW. Gas exports through Huntingdon physically serve coastal markets along the I-5 Corridor.

Gas is delivered to B.C. consumers, mainly by the two major local distribution companies (LDCs) that operate in B.C.: Terasen Gas Inc. (Terasen) and Pacific Northern Gas Ltd. (PNG). Terasen provides gas distribution services to customers in the most highly populated regions of B.C., including the Lower Mainland, the B.C. Interior (Prince George, Kamloops and the Okanagan Valley) and eastern Vancouver Island, Campbell River to Victoria. West central B.C., around Prince Rupert and Kitimat, is served by PNG. Northeast B.C., which includes Fort St. John and Dawson Creek, is served by PNG's subsidiary, Pacific Northern Gas (N.E.) Ltd.

2.2 British Columbia Domestic Natural Gas Markets

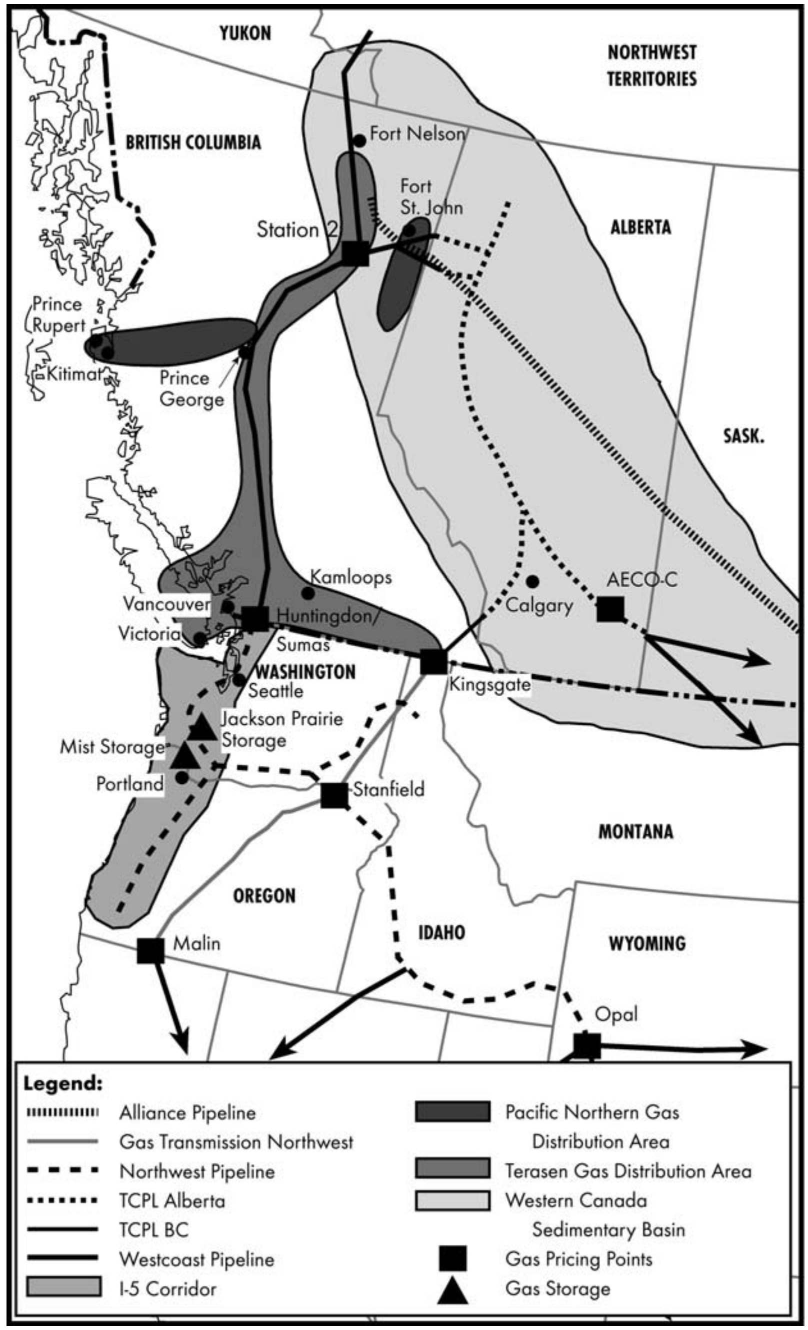
B.C. is the third largest natural gas consuming province in Canada. Provincial consumption grew steadily throughout the 1990s to 23 10^6m^3/d (820 MMcf/d) in 2000. Since 2000, when natural gas prices began to increase sharply, B.C. demand has generally been flat, followed by a decline in 2003 (Figure 2.2).

Gas consumption in B.C. is dominated by industrial demand. In 1990, one half of the natural gas consumed in the province was used by core (residential and commercial) customers and the other half by industrials and power generators. By 2003, industry and power generation use had grown to 58 percent of total gas consumption and core customer use was at 42 percent.

Industry uses natural gas for heat and power in manufacturing processes and also as a raw material for manufacturing industrial products. Fertilizer (e.g. ammonia) and chemical manufacturers (e.g. methanol) are examples of industries that use natural gas as a raw material feedstock. Residential and commercial consumers predominantly use natural gas for space heating and appliances.

FIGURE 2.1

B.C. and Pacific Northwest Regional Natural Gas Markets



Peaks in demand can occur either with the arrival of an Arctic cold front, or when the west coast experiences low water level conditions, with the accompanying reduced ability to generate hydro electricity. When electricity from hydro generation is limited, gas-fired electrical generation is a common back-up.

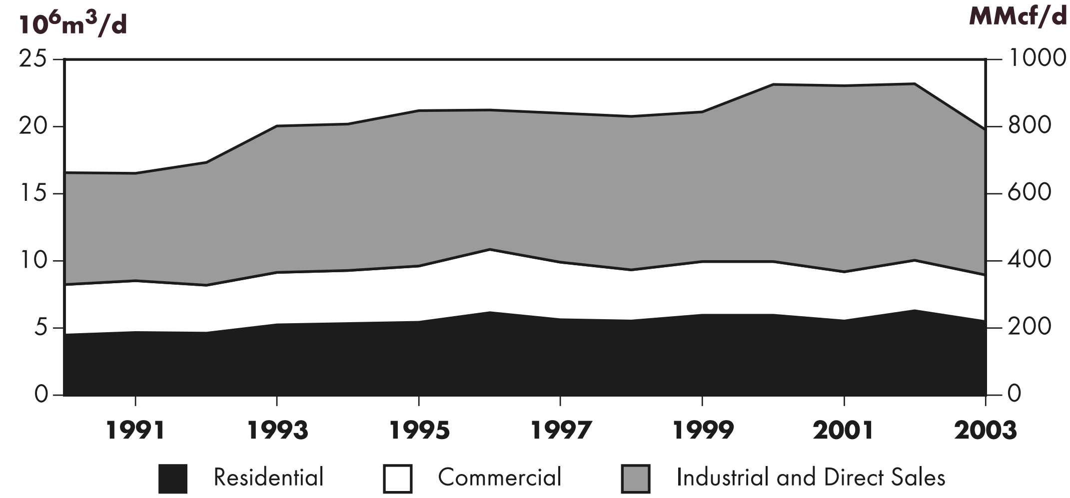
Residential and Commercial Markets

From 1990 to 2003, residential consumption retained its share of B.C.'s gas market, but commercial consumption lost market share.

The largest core market in B.C. for natural gas is the Lower Mainland, where weather is a major determinant of demand. The heating season in the Vancouver area lasts from November to February. By Canadian standards, B.C.'s Lower Mainland heating season is comparatively short and mild, but it can experience fairly severe winter peaks. Figure 2.3 compares weather severity between Vancouver, B.C. and the average for Canada.

F I G U R E 2 . 2

B.C. Annual Natural Gas End-Use

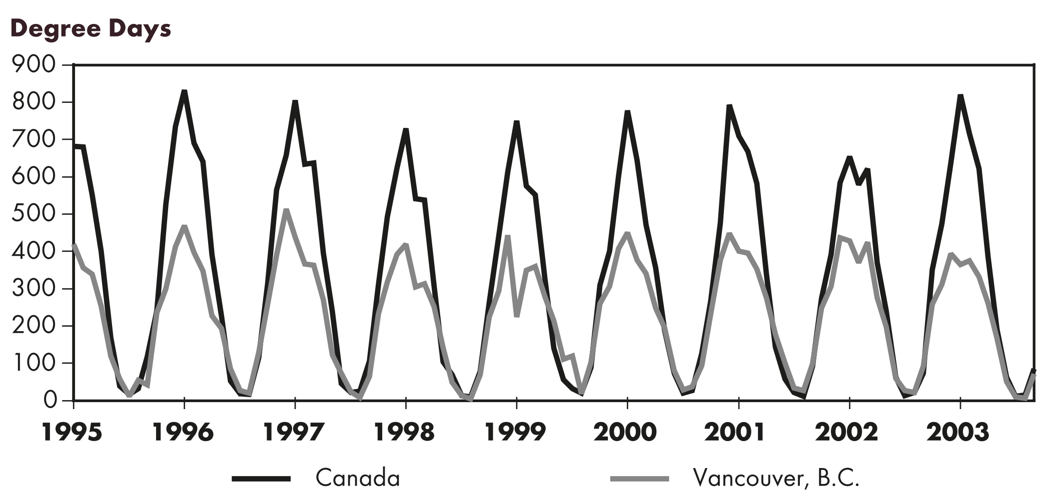


Source: Statistics Canada

Note: Direct sales are combined with the industrial category, because most direct sales are made to industrial and power generation users. Direct sales may also include some large commercial users (e.g. hospitals, schools and post-secondary institutions).

F I G U R E 2 . 3

Degree Days Comparison between Canada and Vancouver, B.C.



Source: Statistics Canada

In response to higher prices, residential and commercial consumers have taken measures to reduce gas consumption. During periods of high natural gas prices many consumers have turned down thermostats or used portable baseboard electrical heaters instead of natural gas. Some consumers have also installed more efficient furnaces and water heaters and improved home insulation. These measures are reducing demand per household. According to Terasen, average gas use per Lower Mainland customer has fallen from over 120 GJs in the late 1990s to about 104 GJs in 2003, after adjusting for weather variablility.

Growth in natural gas consumption also faces competition from electricity for space heating. In contrast to rising natural gas prices, BC Hydro electricity rates have been frozen since 1993. Electricity rates may be set to rise in 2004 as BC Hydro has applied to the British Columbia Utilities Commission (BCUC) for a rate increase. In order to reduce land development costs, some real estate developers are installing only electricity services to new homes, thereby limiting gas penetration into the new home market. At the same time, many consumers perceive gas prices as high and volatile in comparison with electricity prices, thereby influencing home buyers' decisions on space heating installations. Despite these competitive factors, population growth is a major driver for residential gas demand. B.C.'s population continues to grow, which is expanding the overall housing market and should help maintain residential gas demand.

Industrial Market

The industrial sector is the largest user of natural gas in the province. Nevertheless, natural gas meets only about one-quarter of the province's total industrial energy demand. Hog fuel and pulping liquor, used by B.C.'s forestry industries, are the largest industrial energy sources in the province, followed by natural gas and electricity. Fuel oil is an important industrial back-up fuel.

Large natural gas users in B.C. are the pulp and paper, wood product, petroleum refinery and petrochemical industries. These commodity-based industries use large amounts of energy to convert raw materials into semi-finished and finished products. For forest products industries, natural gas costs can represent between 5 to15 percent of overall production costs. Another industry that uses natural gas is the Lower Mainland greenhouse industry. Natural gas can account for up to 25 percent of a greenhouse operator's overall costs.

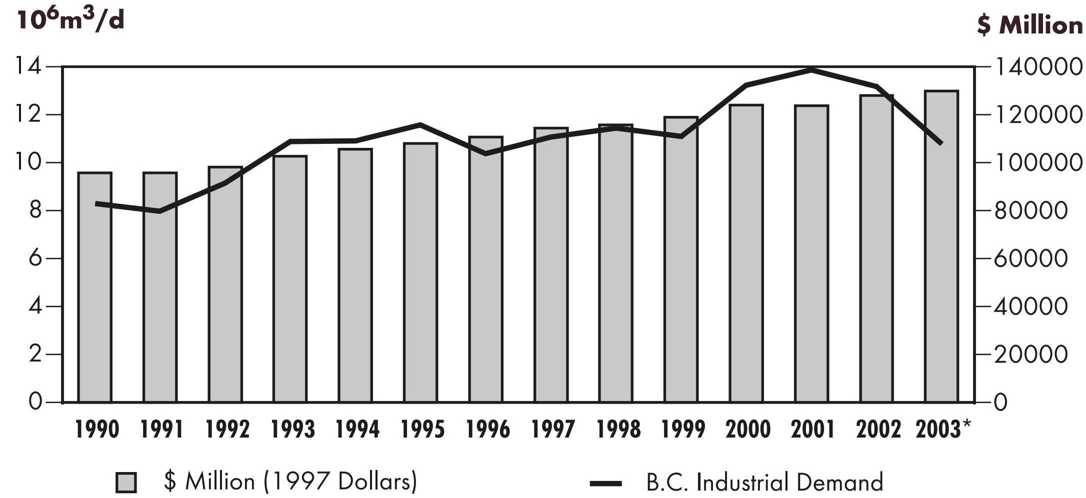
Natural gas demand in the industrial sector, including gas-fired generation, grew at about six percent per year between 1990 and 2001 (Figure 2.4). Combined industrial and gas-fired generation demand grew faster than the 2.7 percent average annual provincial rate of economic growth for the same period. Despite a growing B.C. economy over the last two years industrial demand has declined, partially in response to higher gas prices.

During the 1990s, stable prices, convenience and environmental concerns promoted natural gas use in the industrial sector at a rate faster than the province's rate of economic growth. However, convenience of use and environmental concerns about using alternative fuels may not overcome the cost pressures that many gas-intensive B.C. industries presently face. The softwood lumber dispute with the U.S., appreciation of the Canadian dollar and international competition are competitive business factors that are having an impact on B.C. industries. A higher natural gas price is only one of many cost pressures facing B.C.'s large industrial gas users.

Industries in B.C. have taken a number of steps to manage costs. These include greater use of financial risk management tools, improved energy efficiency measures, alternative fuel use and temporary plant closures. Gas price volatility has created a business environment in which industries continually monitor natural gas costs and plan their gas purchasing strategies. When compared with

FIGURE 2.4

A Comparison of B.C. Gross Domestic Product and B.C. Industrial Natural Gas Demand



Source: Statistics Canada, B.C. Government

* Preliminary estimate for B.C. Gross Domestic Product

the stable price environment of the 1990s, gas has become a larger and more unpredictable component of total production costs.

Every large industrial user of natural gas is evaluating its natural gas usage with an eye to reducing consumption. Industrial users are making incremental energy efficiency improvements to their manufacturing plants based on rising gas price thresholds. Gas price volatility hampers making efficiency investments, because of the risk that gas prices may fall below the breakeven point for the efficiency investment. Steady prices, even if higher, make it easier for companies to plan their efficiency investments. Another uncertainty surrounding making an investment in energy efficiency revolves around the issue of individual plant viability. In a competitive business climate, it is difficult to justify energy efficiency investments in plants that may be closed.

Industries are also looking at increasing their use of fuel alternatives such as wood waste, hog fuel, coal and petroleum products. For example, NorskeCanada has applied to the B.C. government for an environmental permit to use tire-derived fuel, coal and old railway ties as supplemental fuels at its Crofton B.C. pulp and paper mill on Vancouver Island. Currently, the plant uses natural gas and fuel oil as supplemental fuels in conjunction with hog fuel. Uncertainties related to fuel switching include air quality and CO_2 emissions standards relating to the use of wood waste, fuel oil and coal. Many large industries have also expressed concern with respect to the availability of long-term wood waste supplies and the cost of fuel oil.

One area where the forest industry is making major investments is in electricity generation from biomass. Major projects by Canadian Forest Products Ltd., Weyerhaeuser Company, Riverside Forest Products Limited and West Fraser Mills Ltd. will make manufacturing facilities owned by these companies more electricity self-sufficient or will deliver excess power into the BC Hydro grid. Some of these investments will have the additional benefit of reducing natural gas consumption.

In recent years, announcements of new major industrial plants in B.C. have been rare, limiting prospects for growth in industrial gas usage. Industry consultations also indicate that adjustments to higher prices will be an ongoing effort for the near term. Natural gas represents the highest

CanAgro Produce Ltd. – The Energy Challenges Faced by a Greenhouse Grower

South coastal British Columbia is among the best sites in Canada for greenhouse growers because the temperate climate and favourable solar and wind conditions of the region minimize the amount of energy required to operate greenhouse facilities. This region is home to CanAgro Produce Ltd. (CanAgro), a major greenhouse grower whose operation has expanded since 1996 to cover 33 hectares. CanAgro primarily grows tomatoes and peppers with about 70 percent of production destined for the U.S. export market.

Energy accounts for 20 to 25 percent of CanAgro's total costs and is third after marketing and distribution costs and the cost of labour. With an average annual energy requirement of 680 000 GJ, the combination of price increases in the order of $2.00 to $3.00/GJ over the past year, compounded by price spikes of even higher magnitude, can translate into millions of dollars of additional cost to CanAgro. However, these costs cannot easily be passed on when competing in a global market. Further, once a crop is planted in December, the grower is committed for eleven months with harvesting occurring from February to November. In other words, unlike some other commercial businesses, greenhouse growers like CanAgro cannot simply reduce or cease operations for a short period during energy price spikes because it would lose millions of dollars of crop inventory.

Many greenhouse growers such as CanAgro rely primarily on natural gas for their energy needs. Gas service is provided through a contract for interruptible service from the local distributor. When service interruptions occur, perhaps to meet residential demand during extremely cold weather, CanAgro must rely on # 2 fuel oil stored on site.

CanAgro has seen higher and increasingly volatile natural gas costs since the winter of 2000/2001. Moreover, within the context of an increasingly connected North American market, increases in local gas costs for CanAgro often seem to be triggered by weather patterns experienced in other parts of the continent. The ability to estimate future energy costs within an overwhelming North American gas market is a serious challenge faced by many end-users. Some end-users manage price volatility through hedging practices. However, such practices require a letter of credit that is often unobtainable for smaller businesses. Credit requirements for an operation the size of CanAgro can be as high as 30 percent of the total gas cost committed in advance.

CanAgro has taken a number of steps to manage energy costs. For example, it has imported state-of-the-art boilers from Europe that are rated 93 to 95 percent energy efficient. Flue gas economizers are also employed. At this level, there is little room left to improve energy efficiency and any such improvements would be very costly to achieve.

Alternatives to natural gas are widely sought by the greenhouse industry. However, restrictions on combustion emissions limit the ability to switch from gas to alternative fuels in some areas. For example, while some operations in the Fraser Valley air-shed have installed wood waste boilers, others have been unable to obtain emission permits. CanAgro will be offsetting a portion of its energy requirements by securing waste heat from a nearby landfill cogeneration facility. The future, though, may rest with the use of coal in a cleaner way. In addition to perhaps more stable costs than natural gas, the combustion of coal instead of gas would provide almost twice as much carbon dioxide, a necessary component for plant growth, and would alleviate the cost of buying carbon dioxide to pipe into greenhouses.

The greenhouse industry in B.C. accounts for about half a billion dollars to the provincial economy. Many greenhouse operations are challenged to operate in an environment of gas prices at $6.00/GJ. CanAgro is of the view that the natural gas industry must recognize that gas prices have been too high. Without relief from high gas prices, the industry fears that a number of greenhouses may be forced to move south to a warmer climate.

In December 2003, CanAgro Produce Ltd. merged with Century Pacific Greenhouses to form Hot House Growers Incorporated (HHGI). This merger created a larger scale greenhouse operation with greenhouses located in the Lower Mainland at Delta, Pitt Meadows and Abbotsford. The Lagoons Division in Delta uses waste heat from the co-generation facility.

HHGI's total annual energy requirement is presently over one million gigajoules. With the merger, HHGI has since been able to establish a five year natural gas hedge that included delivery charges. The co-generation facility and the purchase of a long-term gas hedge have reduced energy costs to 13 to 15 percent of total costs from 20 to 25 percent.

proportion of overall operating costs in industries that use gas as a feedstock. Methanex, a methanol manufacturer, closed its Kitimat methanol plant in 2000 because of high feedstock prices and reopened the plant in 2001. The plant continues to operate, but Methanex is building or acquiring new plants in Chile and Trinidad where gas costs are lower.

The industrial sector is the most price sensitive market for gas. Many industries relied on low energy cost inputs as one of the competitive factors for locating in B.C. With higher natural gas prices and greater competition for natural gas supplies from gas-fired power generators, especially in the PNW, large industrial users have had to take remedial actions to manage gas costs. The industrial sector has also had to compete with the core market, especially during price peaks, which is not as sensitive to price changes as the industrial sector.

Power Generation Market

Most of the electricity in B.C. is generated from hydro sources. Annual natural gas demand for power generation fluctuates, but can account for up to 15 percent of provincial natural gas demand in any year depending on water levels and weather conditions. Vancouver Island is the only area presently under consideration by BC Hydro for new gas-fired power generation. However, BC Hydro is considering alternative power generation proposals for Vancouver Island from independent power producers, not all of which would be gas-fired.

On the Lower Mainland, the future of BC Hydro's large Burrard Power Plant is under review by Members of the Legislative Assembly. This is an older, less efficient, gas-fired power generation facility. Replacing Burrard with a new generating facility may not necessarily increase gas usage because of the increased efficiency of new equipment. During an early 2004 cold spell, BC Hydro used Burrard to meet high provincial electricity demand. Gas-fired generation will continue to fulfill a back-up generation role in B.C. as well as competing for additional electricity loads.

2.3 Pacific Northwest Natural Gas Market

The PNW market covers the states of Washington, Oregon and Idaho. The PNW market is divided by the Cascade Mountain range. Coastal areas along the I-5 Corridor, largely within 160 kilometres (100 miles), receive gas exports from Sumas/Huntingdon (Figure 2.1). Gas exports from Huntingdon peaked in 1998 at 32.8 $10^6m^3/d$ (1 167 MMcf/d) and declined to 2003 (Figure 2.5). Exports from Huntingdon satisfied about 55 percent of the total PNW demand for gas in 2001.

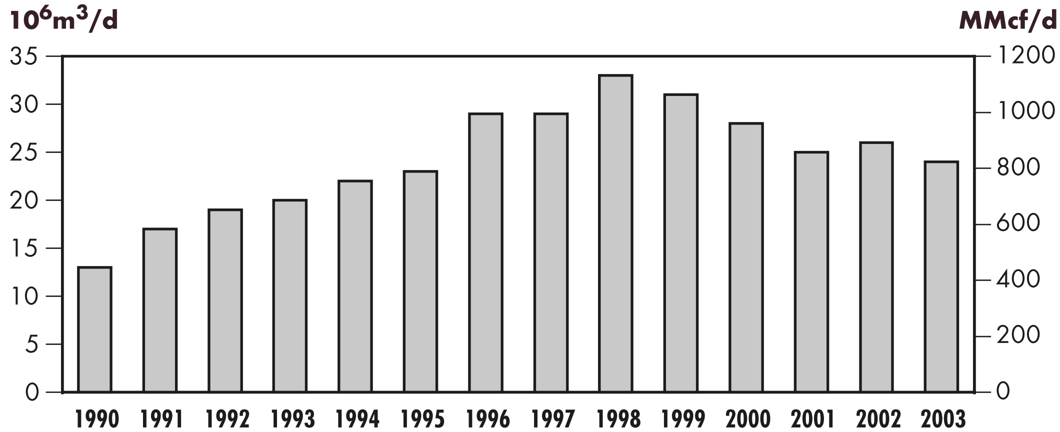
Eastern Washington, eastern Oregon and Idaho receive Canadian gas, mostly from Alberta, via the Gas Transmission Northwest Corporation (GTN) pipeline that crosses the international border at Kingsgate, B.C. Only a small amount of B.C. gas enters this market via GTN. Gas from the U.S. Rockies Basin also reaches the PNW through Opal, Wyoming. In Feburary 2004, TransCanada Corporation announced it was purchasing GTN from National Energy & Gas Transmission, Inc.

The PNW is typically a winter peaking market that responds to core and power market peaks simultaneously. The core load represented about 41 percent of the PNW market in 2001. Industrial use and power generation made up the balance of 59 percent. At about 30 percent of total demand, the gas market for power generation is larger in the PNW than in B.C.

In the past few years, weak economic conditions and higher gas prices have eroded industrial demand; its proportion of the total market shrank from 51 percent in 1990 to 29 percent in 2001. Further, it is widely expected that coastal manufacturing and other facilities, which were once attracted to the

FIGURE 2.5

Natural Gas Export Volumes at Huntingdon, B.C.



Source: NEB

region by cheap and abundant hydro power, such as those that produce aluminum or steel, will not return. Forest products companies, like Weyerhauser Company, are using as much wood waste as possible. Other consumers have turned to small hydro facilities or #2 fuel oil. Reduced industrial demand has implications for the market. Industrial load is normally not peaking in nature and greater industrial demand would lower transportation costs for residential and commercial consumers.

Growth in gas demand for power generation has been rapid over the past decade, reaching over 13.7 $10^6m^3/d$ (482 MMcf/d) in 2001 from 0.6 $10^6m^3/d$ (21 MMcf/d) in 1990. As with industrial demand, the power generation load has been reduced as of late due to weak economic conditions, higher gas prices and improved water levels for hydro power. Several gas-fired generation projects have been delayed and not all of the plants that have been built in the PNW are fully utilized. In 2003, the Northwest Gas Association reduced its estimate of growth in the power generation sector from 4.5 to 2.3 percent per year to 2025. However, while power generation growth may have slowed, development continues. Calpine Corporation expects to place a 248 MW plant at Goldendale, Washington into service in July 2004.

Despite eroding demand in the industrial sector and slowdown in the growth of the power generation sector, the outlook for the residential and commercial sectors remains constant. Core demand grew from 10.8 $10^6m^3/d$ (383 MMcf/d) in 1990 to 18.7 $10^6m^3/d$ (659 MMcf/d) in 2001. Puget Sound Energy, a major LDC in the I-5 corridor, expects its total load to grow 2.5 percent per year, but its peaking requirement to grow by 3.8 percent. Within the next four years, Puget Sound Energy anticipates that a second, summer demand peak will be experienced with growth in power generation to meet air-conditioning requirements.

NATURAL GAS TRANSPORTATION AND STORAGE

Highlights

- Pipeline developments to markets east of B.C. have provided northeast B.C. gas production with greater access to eastern markets
- Planned Westcoast pipeline expansion to B.C. and PNW markets scaled back
- Some PNW LDCs are holding more capacity on Westcoast to Station 2
- B.C. Lower Mainland market lacks gas storage, but storage capacity expanded in PNW

The transportation infrastructure to move natural gas out of northeast B.C. has undergone considerable development in the past five years. The most notable development has been the growth in pipeline capacity from northeast B.C. to connections in Alberta which allow producers to access a large number of markets. Northeast B.C. gas can now be transported to markets via the Westcoast system, the Alliance pipeline and through various producer pipelines which interconnect with the TCPL Alberta system. Before discussing transportation trends, a brief discussion of each of these transportation systems is provided.

3.1 Westcoast System

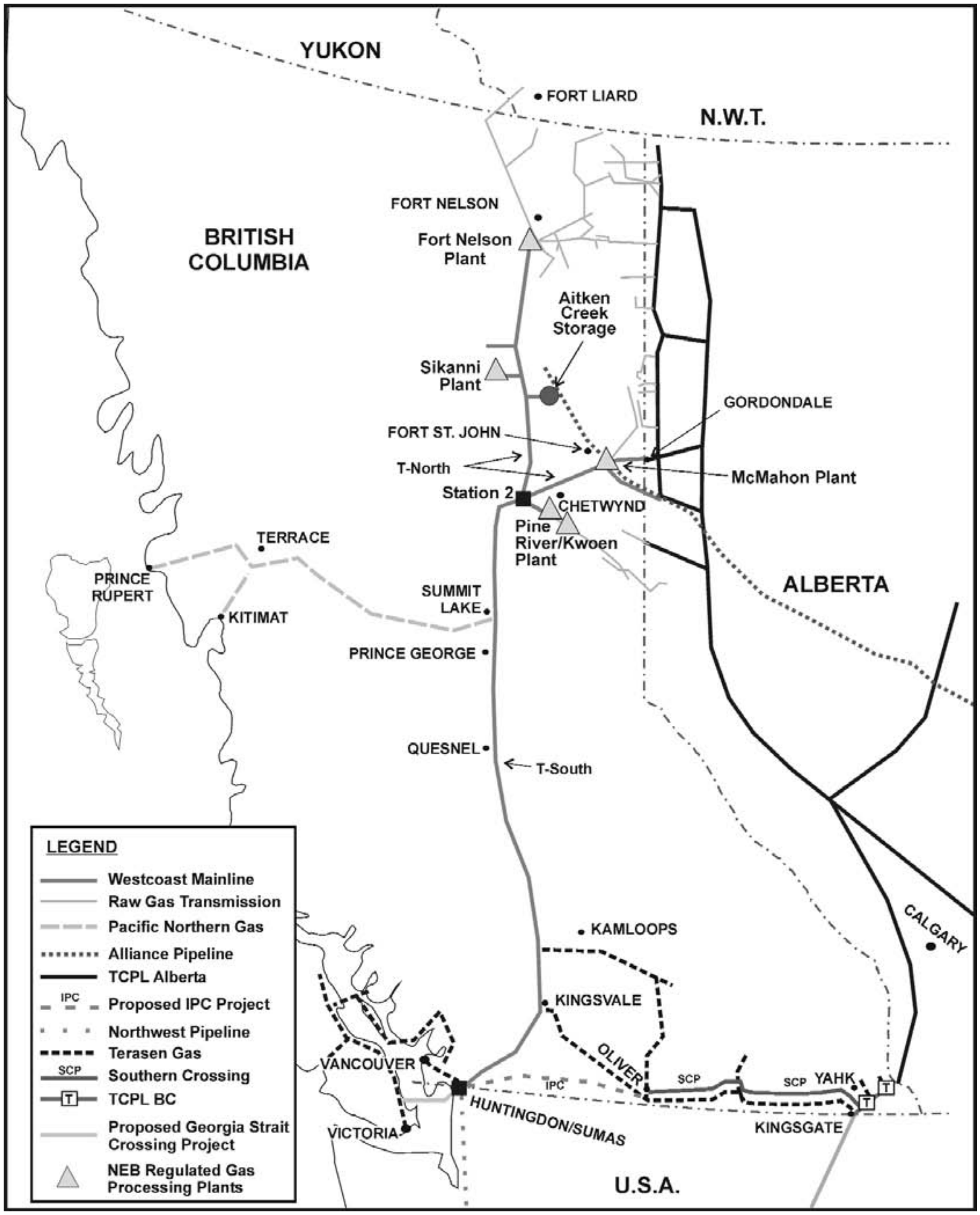
The Westcoast system has been delivering natural gas, primarily from northeast B.C., since 1957 when it was the first major gas export pipeline built in Canada (Figure 3.1). Unlike other major natural gas transporters in Canada, its system includes gathering and processing facilities in addition to transmission. The gathering system brings raw gas from fields in B.C., the Yukon, the Northwest Territories and, to a limited extent Alberta to Westcoast's processing plants. In B.C., there are significant quantities of gas, called acid gas, that have a high sulphur and carbon dioxide content. Acid gas requires more processing to make it suitable for pipeline transportation than natural gas with fewer impurities.

Westcoast owns and operates four gas plants (Fort Nelson, McMahon, Sikanni, PineRiver/Kwoen) in northeast B.C. which are under the NEB's jurisdiction (Figure 3.1). By international standards, three of the four are considered to be very large facilities and their existence has allowed fewer plants to be built in the province. As a result, there are 35 gas plants in B.C. compared with over 700 plants in Alberta. B.C. has less than five percent of the processing plants in the WCSB despite having 15 percent of production. This large plant model is changing as producers are building more gas plants in the province in competition with Westcoast's gas gathering and processing services.

Westcoast's transmission system includes the Fort Nelson and Fort St. John Mainlines (also known as T-North or Zone 3) and the Southern Mainline (T-South or Zone 4). T-North connects to the Southern Mainline at Station 2, an important gas trading point. T-North's capacity is approximately 34.0 $10^6m^3/d$ (1.2 Bcf/d) from Fort Nelson and 21.5 $10^6m^3/d$ (760 MMcf/d) from Fort St. John.

FIGURE 3.1

Natural Gas Transportation Systems in British Columbia



The Southern Mainline, with a capacity of approximately 56.7 $10^6m^3/d$ (2.0 Bcf/d), extends from Station 2 southward to a point on the international boundary near Huntingdon, B.C. and Sumas, Washington. There it connects to multiple pipelines including: (1) Terasen, which takes gas from the interconnect to serve the Lower Mainland and Vancouver Island markets; (2) Northwest Pipeline, which serves the PNW; and (3) a number of smaller pipelines that cross the border and supply gas to various industrial facilities in Washington State.

In January 2003, Westcoast received the Board's approval to expand its Southern Mainline system by 5.7 $10^6m^3/d$ (200 MMcf/d), effective November 1, 2003. However, Westcoast has only proceeded with a reduced expansion of 2.4 $10^6m^3/d$ (85 MMcf/d), as some shippers chose not to renew expiring transportation contracts. Subsequently, additional pipeline transportation capacity of 5.6 $10^6m^3/d$ (198 MMcf/d) was not renewed by shippers effective November 2004. The capacity coming available in November will have to be absorbed before Westcoast can proceed with the remaining facilities for which it has received regulatory approval. As a result, the Westcoast system is not currently capacity constrained.

Shippers do not fully utilize their annual contracted capacity on Westcoast given the seasonal nature of the markets served. However, the system is full during peak winter periods. The average utilization rate on T-South was 78 percent in 2003, which is little changed from the previous year.

Contracting Trends on Westcoast

There has been a shift in the type of organizations holding long-haul capacity on T-South. A trend across North America in recent years has seen producers and consumers gradually allowing their long-haul capacity to expire and contracting for transportation capacity only as far as the nearest market hub at which point they can buy or sell gas from the many market players there. B.C. producers have also indicated that they would prefer to contract mainline capacity on Westcoast only as far as Station 2, rather than all the way to Sumas/Huntingdon. By doing so, their capital is freed up for other uses and they do not have to assume the risk of holding long-term pipeline capacity.

Marketers held a significant amount of capacity on T-South between Station 2 and Sumas, but since the collapse of Enron Corporation (Enron) in late 2001, fewer companies are actively engaged in the gas marketing business. However, the contracts held by these marketers continue to be in effect until their termination dates, so the freeing up of capacity on Westcoast by marketing companies has been a gradual process.

With marketers retrenching, and some producers preferring to go only to Station 2, some PNW LDCs have stepped in to take the capacity on T-South and purchase gas at Station 2 rather than at Sumas/Huntingdon. Their stated reasons for taking T-South capacity include the desire to purchase gas closer to the producing area, to better partner with financially sound B.C. gas producers, to better ensure security of supply and to obtain access to the best possible gas prices.

An additional reason that PNW LDCs gave for going to Station 2 was a desire to reduce the risk of price volatility by bypassing the Sumas/Huntingdon market. PNW LDCs calculated that in just two months, December 2000 and January 2001, when prices spiked at Sumas/Huntingdon well above Station 2 prices, they could have paid for four or five years of pipeline capacity on T-South if they could have bought gas at Station 2 instead.

LDCs are taking additional T-South capacity despite the issue noted by a number of parties consulted for this EMA, that prices at Station 2 are not sufficiently below Sumas prices to fully cover the cost of transportation on that segment. The fact that producers' netbacks are higher if they sell at Station 2 rather than Sumas provides additional motivation for them to give up T-South capacity and sell at Station 2. For LDCs, the security and access to supply benefits appear to outweigh the risk that the differential will not fully cover the transportation costs.

Westcoast Transportation Rate Regulation

Since June 1998, Westcoast's tolls for gathering and processing services (not transmission) have been freely negotiated in the marketplace. Westcoast, which is regulated by the NEB, and its stakeholders agreed to a framework for light handed regulation that defined the principles under which Westcoast would negotiate contracts with individual shippers, including appropriate tolls. This method was established to accommodate producers' desire for faster response to service requests and more flexible tolling arrangements.

Since 1997, Westcoast's transmission tolls have been determined through settlements negotiated between all the major stakeholders. Over that period, the T-North toll has increased by 25 percent and the T-South toll to Huntingdon has increased by 16 percent. The current long-haul T-North toll is \$110.50/10^3m^3/month (\$.103/mcf), while the T-South toll is \$294.37/10^3m^3/month (\$.274/mcf). In December 2003, Westcoast applied to the Board for 2004 tolls seeking a 7.9 percent increase in the T-South toll.

3.2 Alliance Pipeline

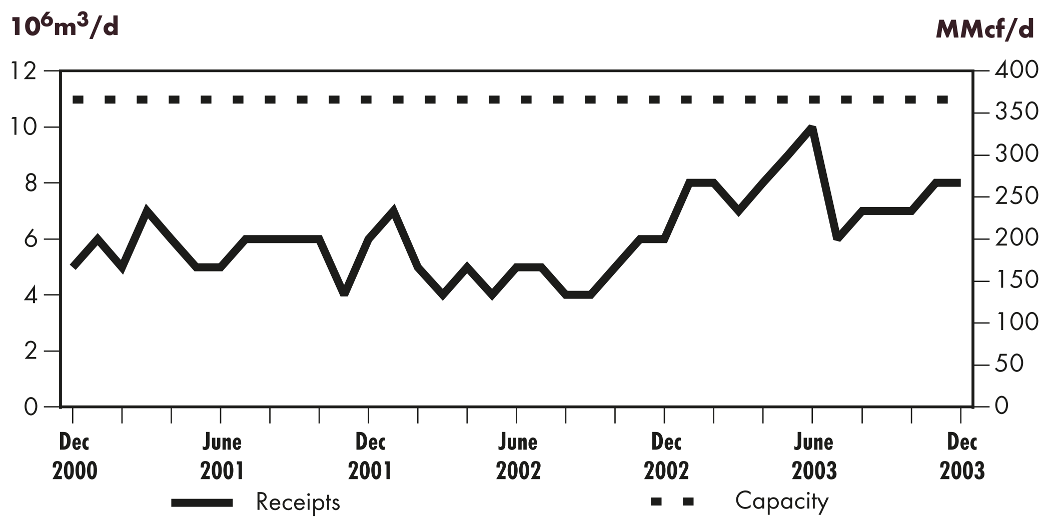
The Alliance pipeline transports approximately 44 10^6m^3/d (1.55 Bcf/d) of liquids-rich Canadian gas mainly from Alberta and, to a lesser extent from B.C., to Chicago and the U.S. Midwest market. It began shipping gas to markets in December of 2000. Although the Alliance mainline starts in Alberta at Gordondale, a lateral extends into B.C. as far west as the Aitken Creek storage facility (Figure 3.1). Alliance's total capacity to take gas out of B.C. is 10.4 10^6m^3/d (366 MMcf/d).

Alliance's B.C. flows to date have been less than capacity would allow. However, shipments showed an increase in 2003, with flows averaging 7.6 10^6m^3/d (270 MMcf/d), up from 5.0 10^6m^3/d (178 MMcf/d) the previous year (Figure 3.2).

In response to enquiries by producers seeking additional capacity out of B.C., either because of increasing production or due to a desire to find alternative transportation arrangements, Alliance sought non-binding, confidential expressions of interest for incremental capacity in June 2003 and received some expressions of interest from producers. Alliance has said that an expansion, if it proceeds, would not involve any expansion of mainline capacity. Therefore, given that the mainline is essentially full in Canada, any additional flows from B.C. would have to be accommodated by reduced Alberta gas volumes.

FIGURE 3.2

Alliance Pipeline B.C. Receipts



Source: Alliance Pipeline Ltd.

3.3 Cross-border Pipelines into Alberta

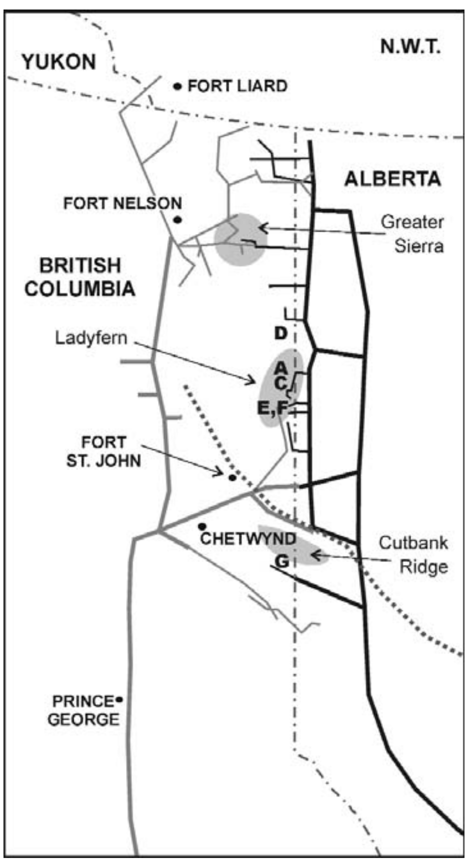
The Westcoast system also interconnects with the TCPL Alberta system at Gordondale, Alberta enabling the eastward flow of gas to Alberta and downstream domestic and export markets. (Figure 3.1) The interconnection with TCPL Alberta is bidirectional and permits Westcoast to either deliver or receive gas there. While the net flows of B.C. gas at Gordondale are quite small (averaging less than 0.9 $10^6m^3/d$ (30 MMcf/d) in the 2002/2003 contract year), the capacity of the line is approximately 5.7 $10^6m^3/d$ (200 MMcf/d) and there is firm capacity available to move gas eastward.

Since the mid-1980s, at least 20 pipelines have been built to move gas from northeast B.C. into Alberta. These have ranged in size from gathering systems with a capacity of a few million cubic feet per day to large diameter pipelines capable of flowing several hundred million cubic feet daily. Most extend for a very short distance to a pipeline built by TCPL Alberta in 1995 along the B.C./Alberta border. Many of these pipelines are no longer flowing at full capacity.

Most of these pipelines have been segments of less than 35 kilometres, designed to bring gas from B.C. production areas located near the inter-provincial border, such as Ladyfern, to the nearby TCPL Alberta system (Figure 3.3). In fact, approximately 90 percent of the capacity built in this time frame was built to access the Ladyfern play. In 2003, an average of 15.6 $10^6m^3/d$ (550 MMcf/d) of marketable gas flowed into Alberta on these producer-owned lines, down from 24 $10^6m^3/d$ (845 MMcf/d) in 2002, largely reflecting the decline in production from the Ladyfern field.

F I G U R E 3 . 3

Northeast B.C. Cross-border Pipelines Built to Alberta since 1999



Legend

Location on Map	Pipeline	Capacity $10^6m^3/d$	Capacity MMcf/d
A	Pioneer Chinchaga	1.1	40
B	PennWest Wildboy	2.4	85
C.1	Murphy Chinchaga	1.7	60
C.2	Murphy Chinchaga Loop (Ladyfern)	6.5	230
D	Canadian Hunter	1.0	35
E	EnCana Ladyfern	4.8	170
F	CNRL Ladyfern	19.2	680
G	EnCana Tupper	1.2	45
H	EnCana Ekwan	11.8	418

In April 2004, EnCana will bring the 83 kilometre Ekwan pipeline into service. Ekwan will transport gas from the Greater Sierra region, an area currently served by the Westcoast system. Although EnCana was already moving significant volumes from the region into Westcoast, additional capacity was required to accommodate future production growth from the area and to diversify its market and transportation options.

3.4 Transportation Trends for Northeast British Columbia Production

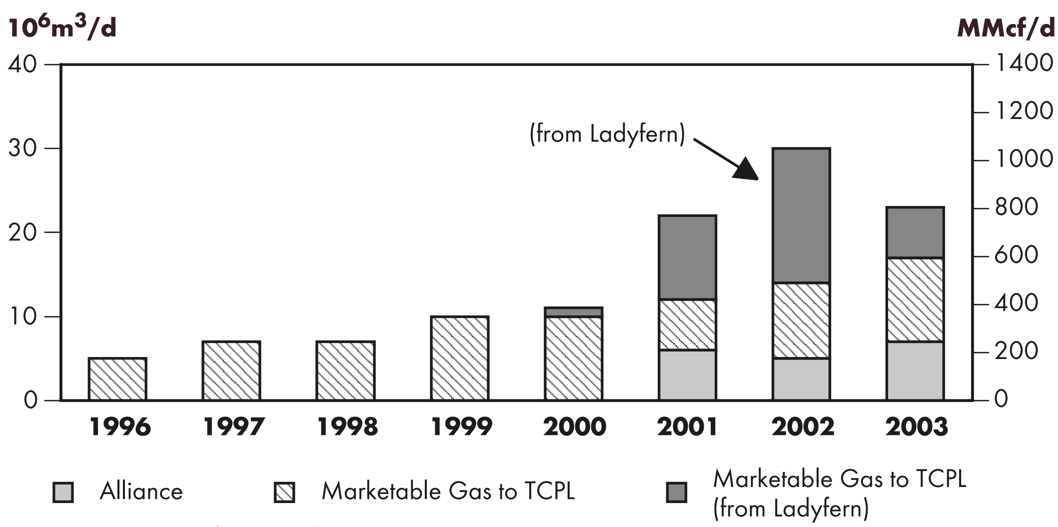
Gas flows into Alberta started to increase substantially in 2000 and 2001, with the start of production from the Ladyfern field and the beginning of flows on the Alliance system (Figure 3.4). LadyFern had a particularly significant impact since deliverability from the Ladyfern field rose to over 19.8 $10^6m^3/d$ (700 MMcf/d) by mid-2002. However, production has since fallen rapidly to 4.4 $10^6m^3/d$ (155 MMcf/d) in November 2003, accounting for the lower gas flows into Alberta in 2003.

Approximately one third of marketable B.C. production is now moved into Alberta. While traditional export and provincial markets have been declining since 2000, according to pipeline disposition data, gas production has grown (Figure 3.5). These incremental supplies have been absorbed by Alberta and markets further east, as the B.C. and PNW markets could not absorb the increased production. In addition, access to Alberta provides producers with a greater choice of options for markets, transportation systems and storage facilities than flowing gas west to B.C. or the PNW.

B.C. market participants expressed two views concerning the impact that increasing transportation capacity into Alberta is having on the market. Consuming groups were concerned that B.C. gas moving east into non-traditional markets would no longer be available to B.C. or PNW buyers. On the other hand, producers stated that having the ability to flow into Alberta, as well as B.C., increased security of supply for B.C. by encouraging increased exploration and development of supply. Further, weak markets, particularly in the summer months, limited producer ability to sell incremental supplies in B.C. and the PNW. Access to multiple markets has provided producers with an additional impetus to increase natural gas supply because gas would not be trapped in the Province.

F I G U R E 3 . 4

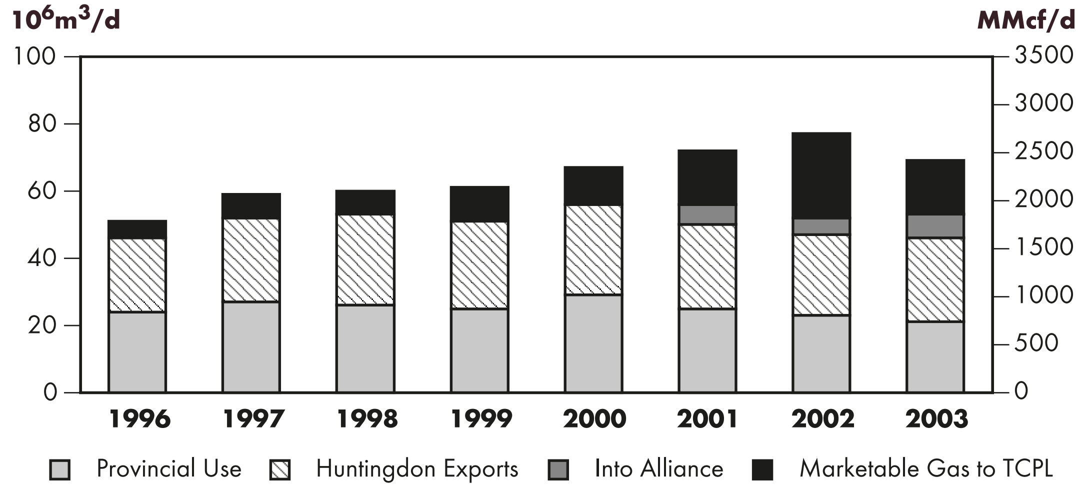
Marketable Natural Gas Flows from Northeast B.C. to Alberta



Source: B.C. Ministry of Energy and Mines

FIGURE 3.5

***Disposition of Marketable Northeast B.C. Natural Gas Supplies*[1]**



1. Includes Yukon and NWT production

Source: B.C. Ministry of Energy and Mines

Future cross-border pipeline developments will continue to be influenced by the location of discoveries, producer desire to diversify markets and market conditions in B.C. and the PNW. In April 2004, the Ekwan pipeline will commence deliveries into the TCPL Alberta system and later gas from EnCana's Cutbank Ridge play is expected to flow east as well.

3.5 Storage and Peaking Capacity in British Columbia

Natural gas storage is extremely limited in B.C. and consists of one underground storage production area facility, Aitken Creek Storage (Aitken Creek), in northeast B.C. and a small liquefied natural gas (LNG) facility on Tilbury Island in the Lower Mainland used by Terasen to meet the peaking needs of its own system.

There is no large underground market area gas storage facility in the Lower Mainland. Upstream storage facilities, while beneficial for producers and shippers, have limited usefulness for downstream consumers during times of pipeline constraint which typically occur during peak demand periods when storage is most critical. Two important facilities for the Lower Mainland and PNW end-use markets are Jackson Prairie in Washington and Northwest Natural's Mist facility in Oregon. Both facilities have undergone expansions in recent years. During winter demand peaks, Terasen can exchange gas it has stored in U.S. storage facilities, like Jackson Prairie, for access to gas that may be flowing at Sumas/Huntingdon.

While most parties consulted for this EMA in B.C. do not expect additional storage will be built in the Lower Mainland in the near future, it continues to be an issue because more storage capability could improve utilization of the pipeline system and help mitigate seasonal price spikes. Some producers have pointed out that expanded upstream storage would also be desirable. Without expanded upstream storage, producers must flow gas to markets even if market conditions are unfavourable. Further, producers indicated that they would be more willing to lock in prices if there were additional storage available in either the production or market areas.

Southern Crossing Pipeline

Southern Crossing Pipeline (SCP) was built by Terasen primarily to meet its peak and seasonal load. In addition, it provides transportation service to third party shippers. It is a 312 kilometre bidirectional line extending from the TCPL B.C. system at Yahk, just north of Kingsgate, B.C. on the U.S. border to Terasen's smaller Interior Transmission System near Oliver, B.C. (Figure 3.1). With this facility, Terasen can receive 7.8 $10^6 m^3/d$ (275 MMcf/d) at Yahk and deliver up to 3.0 $10^6 m^3/d$ (105 MMcf/d) to the Westcoast system at Kingsvale for ultimate delivery to the Lower Mainland. This provides an alternative supply source for both the B.C. Inland and Lower Mainland markets.

Approximately two thirds of the capacity is dedicated to manage peaks in demand in Terasen's service territory, the other third to third party shippers. Pipeline utilization has been low, as would be expected from a facility built to manage peaks in demand. If Alberta gas prices were sufficiently lower than Station 2 prices, it would be economic to use SCP to bring Alberta gas to the Lower Mainland and utilization of the system would increase. Terasen is still contemplating construction of the Inland Pacific Connector pipeline, which would extend SCP from Oliver, B.C. directly to Sumas/Huntingdon.

3.6 Georgia Strait Crossing Pipeline Project

The proposed Georgia Strait Crossing Pipeline Project (GSX) would carry gas from Sumas/Huntingdon across western Washington State and the Strait of Georgia to Vancouver Island. The pipeline would be capable of supplying 2.71 $10^6 m^3/d$ (96 MMcf/d) to two power generation facilities on the island, one of which is already operating, and other users. The pipeline has received regulatory approval from the Federal Energy Regulatory Commission (FERC) in the U.S.

In Canada, a Joint Review Panel established under the *Canadian Environmental Assessment Act* and the *National Energy Board Act* approved the pipeline subject to a number of conditions, one of which is that GSX must provide evidence that the proposed Vancouver Island Generation Project (VIGP) has received the required regulatory approvals before construction commences on the pipeline. BC Hydro has undertaken a call for a tender process inviting private sector developers to either submit proposals for new generating capacity to be located on Vancouver Island or to tender bids to acquire VIGP assets. If VIGP is found to be part of a cost-effective solution to provide power to Vancouver Island, then BC Hydro would submit the proposal for BCUC review.

NATURAL GAS PRICING

4.1 Natural Gas Market Price Formation

Station 2 and Sumas/Huntingdon are the two main pricing points for B.C. gas (Figure 2.1). Station 2 is a pricing point for gas on the Westcoast system that originates primarily from northeast B.C., but can also include gas from the Yukon, the Northwest Territories and Alberta. Sumas/Huntingdon is a U.S. border pricing point for Canadian natural gas on the Westcoast system. The Sumas/Huntingdon price point largely reflects market conditions for natural gas from the B.C. Lower Mainland to Portland, Oregon.

Highlights

- Average natural gas prices in B.C. have tripled since the 1990s
- Gas prices in B.C. are integrated with North American prices
- Sumas/Huntingdon and Station 2 are not as liquid as some other markets
- The B.C. natural gas market remains susceptible to short-term price spikes
- Price discovery has improved at Sumas/Huntingdon and Station 2
- Market participants have become accustomed to managing price volatility

Sumas/Huntingdon and Station 2 are small regional pricing points. In contrast, Henry Hub, in Louisiana, the pricing point for gas traded on the New York Merchantile Exchange (NYMEX), and AECO-C, the pricing point for gas traded in Alberta on the Natural Gas Exchange (NGX), are considered by the natural gas industry to be highly liquid trading points. Smaller regional pricing points have neither the liquidity nor all of the gas transportation services offered by the larger pricing points, such as storage. Small regional pricing points have lower traded volumes, fewer transactions and fewer buyers and sellers. Access to pipeline systems, creditworthy counterparties and financial credit may also be diminished because of small market size. The lack of Lower Mainland storage hampers market development at Sumas/Huntingdon because market participants cannot store gas for sale at a later date at Sumas/Huntingdon.

Parties consulted for this EMA were of the view that the markets at both Sumas/Huntingdon and Station 2 were not functioning under ideal conditions, although some parties consulted for this EMA reported that liquidity at Sumas/Huntingdon was improving. These parties also indicated that new market participants had entered the Sumas/Huntingdon market since the decline in liquidity following the departure of Enron and other marketers in 2001. Most parties consulted for this EMA held the view that Station 2 was less liquid than Sumas/Huntingdon, because fewer market participants trade gas at Station 2.

The California price spike of 2000/2001 shook market confidence in the validity of gas price indices. In the U.S., FERC and the Commodity Futures Trading Commission began to investigate these allegations. In the course of these investigations, specific instances of gas and electricity market manipulation came to light, such as the reporting of false gas trades to industry trade publications. To improve price transparency and confidence in U.S. price reporting, FERC, gas price publishers, and companies reporting gas transactions to publishers have worked toward establishing gas price reporting standards. As a consequence, price reporting at Sumas/Huntingdon has improved. After the departure of the Enron gas trading system in 2001, Intercontinental Exchange (ICE), an electronic energy trading system, started providing gas trading services at Sumas/Huntingdon and Station 2.

In December 2003, NGX, an electronic energy trading system with operations in Canada's major gas markets including Alberta and Dawn, Ontario began offering service at Station 2. Market information for Station 2 (gas volumes traded, number of transactions, bid price range and daily weighted average price) is now available on-line for gas traded on NGX. Information on the NGX system is based on all trades conducted through NGX, in contrast with U.S. pricing points that rely on market price surveys which sample a limited number of buyers and sellers. NGX was purchased in January 2004 by the TSX Group Inc. whose core operations include the Toronto Stock Exchange.

Better price reporting standards and the emergence of new electronic trading platforms are helping to improve price discovery at Sumas/Huntingdon and Station 2. Small market size, however, continues to limit liquidity in the B.C. market.

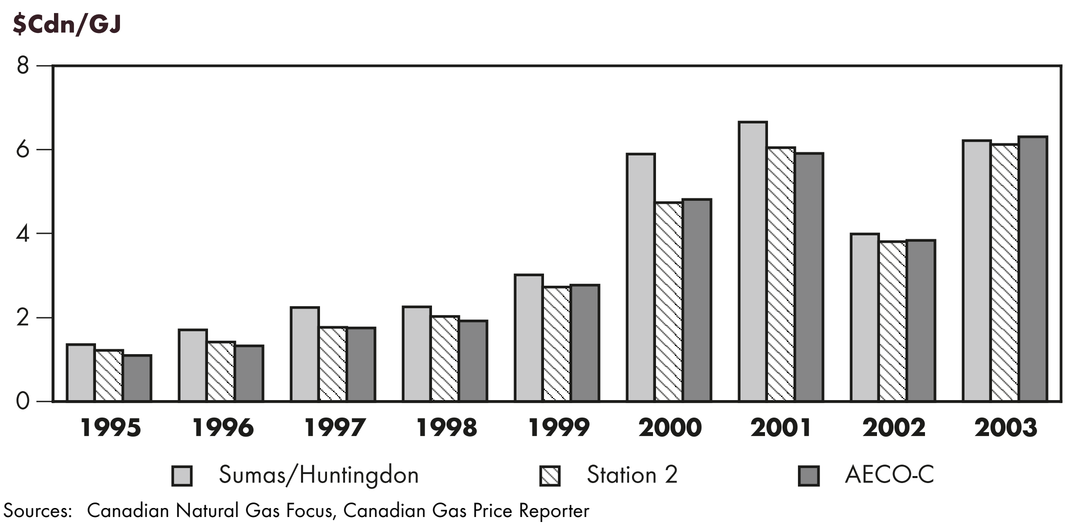
4.2 A History of Natural Gas Prices in British Columbia

In 1995, the average annual price of natural gas at Sumas/Huntingdon and Station 2 was under $2.00/GJ; by 2003 the price was over $6.00/GJ, a threefold increase. During this period, gas prices rose across North America including AECO-C in Alberta (Figure 4.1).

Prior to 1998, gas prices at Station 2 and AECO-C were lower than in other parts of the continent and not fully connected with the North American gas market. Pipeline expansions on Foothills Pipe Lines/Northern Border Pipeline and TransCanada PipeLines alleviated the pipeline transportation capacity constraint that had existed out of the WCSB. As a consequence, gas prices rose in the fall of 1998 at AECO-C and Station 2 in relation to the Henry Hub price for natural gas as traded on

FIGURE 4.1

Annual Average Natural Gas Price Comparison: Sumas/Huntingdon, Station 2 and AECO-C



Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

NYMEX (Figure 4.2). The price of gas at Huntingdon/Sumas also rose in conjunction with prices at Station 2 and AECO-C. By 1999, prices for gas in the WCSB and at Sumas/Huntingdon were more closely aligned with other North American pricing points.

Like most markets, there is a history of seasonal natural gas price spikes in B.C. These occurrences can be seen in the history of natural gas prices at Sumas/Huntingdon prior to 2000, especially in the winters of 1997 to 1999 (Figure 4.2). Markets in the Lower Mainland and the PNW typically experience peak demand during the winter heating season, from November to February. Consequently, prices tend to be highest during January, usually the coldest month.

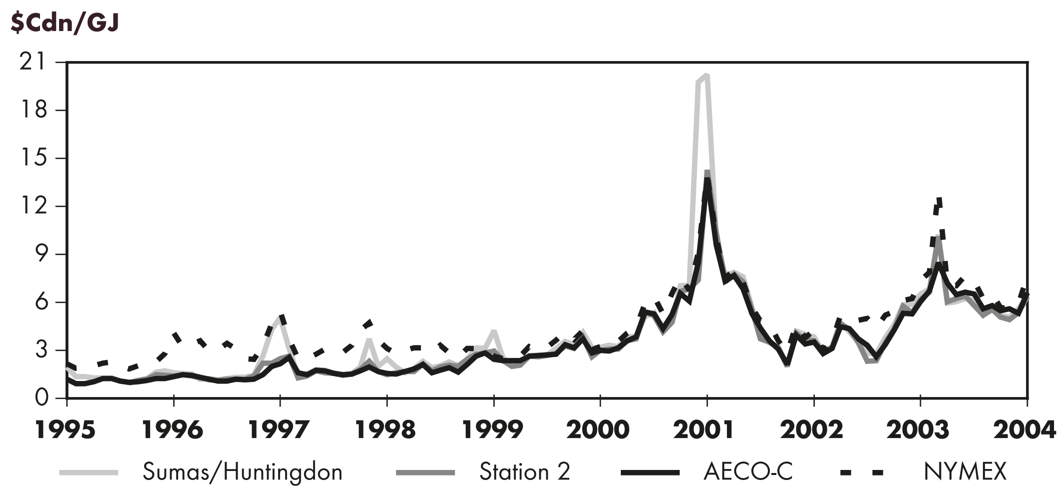
The impact of this cold weather can be exacerbated by the limited amount of storage facilities within the Lower Mainland market area. Unlike some regions where many buyers can draw on gas storage to meet peaking demand, buyers at Sumas/Huntingdon, who do not have storage elsewhere, must compete for gas volumes available off the Westcoast system. While transportation capacity on Westcoast is available through most of the year, system utilization can be very high during the winter peaks. The lack of market storage leaves Sumas/Huntingdon more susceptible to winter price spikes.

Prices at Sumas/Huntingdon can also be influenced by developments in California. Similar weather conditions along the west coast can influence demand in B.C., the PNW and California at the same time. Another major influence on Sumas/Huntingdon gas prices is California electricity demand, especially in low hydro years such as 2000/2001. Electricity generators located in B.C. and the PNW can increase electricity exports to California by bringing spare gas-fired generation on-line. The additional electric power load can increase the demand for natural gas at Sumas/Huntingdon in a very short period of time which can cause price volatility. For example, in the winter of 2000/2001, spot prices at Sumas/Huntingdon peaked at $20.23/GJ and followed the price spike at Malin, a pricing point on the California/Oregon border (Figure 4.3). Prices at AECO-C were lower than at Sumas/Huntingdon during the 2000/2001 price spike showing that the Sumas/Huntingdon market followed developments in California.

Prices at Station 2 in B.C. are related to AECO-C prices in Alberta (Figure 4.4). Both of these pricing points reflect market conditions for WCSB sourced gas. In 2003, the average annual price of

F I G U R E 4 . 2

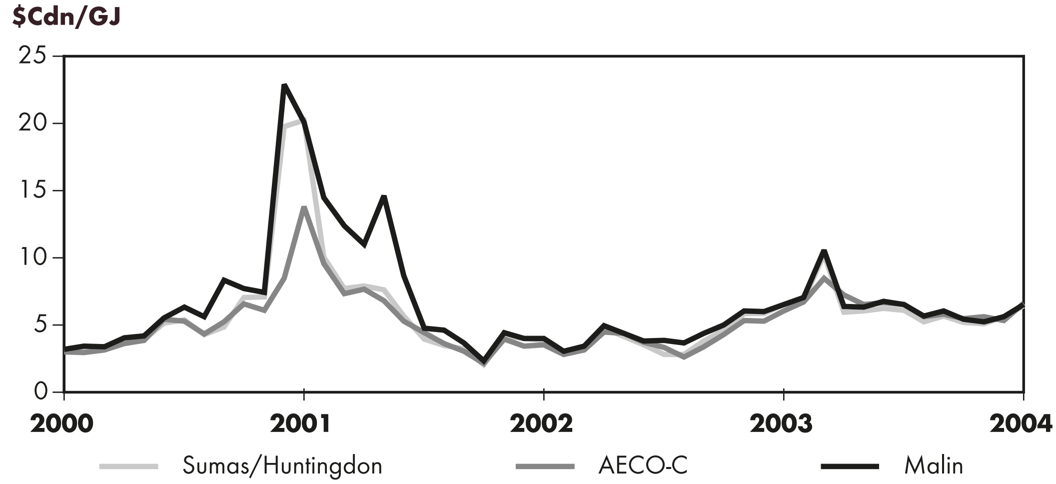
Spot Natural Gas Price Comparison: Sumas/Huntingdon, Station 2, AECO-C and NYMEX



Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

FIGURE 4.3

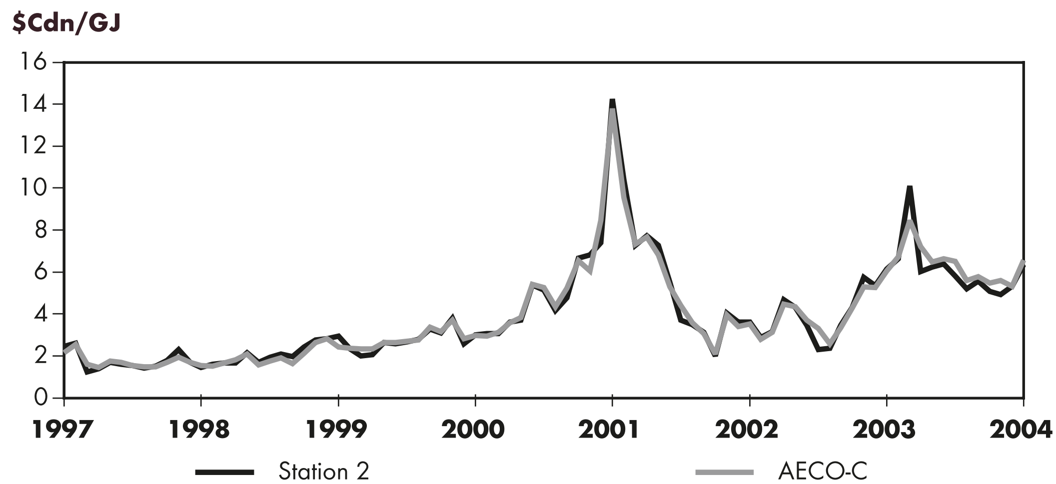
Spot Natural Gas Price Comparison: Sumas/Huntingdon, Malin and AECO-C



Source: Canadian Natural Gas Focus

FIGURE 4.4

Spot Natural Gas Price Comparison: Sumas/Huntingdon, Station 2 and AECO-C



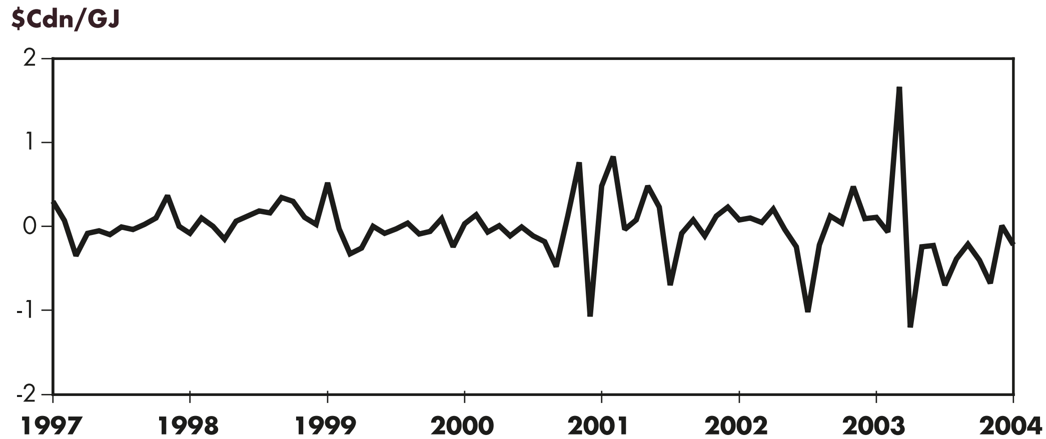
Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

gas at AECO-C slightly exceeded the average annual price at Huntingdon/Sumas as well as Station 2 (Figure 4.1). This reflected the relative change in the market price for gas from eastern markets served by AECO-C and western markets served by Station 2. Price signals indicated a somewhat stronger demand for gas in eastern markets.

Since the 1990s, the overall impact on B.C. consumers of changing market dynamics has been exposure to higher and more volatile North American gas prices and increased competition for gas supply in northeast B.C. from eastern markets. Price variability between Station 2 and AECO-C rose in late 2000. At this time, the Alliance pipeline began operations in northeast B.C. providing an additional market outlet for northeast B.C. gas supply and North American demand for gas increased prices in all supply regions including the WCSB (Figure 4.5).

FIGURE 4.5

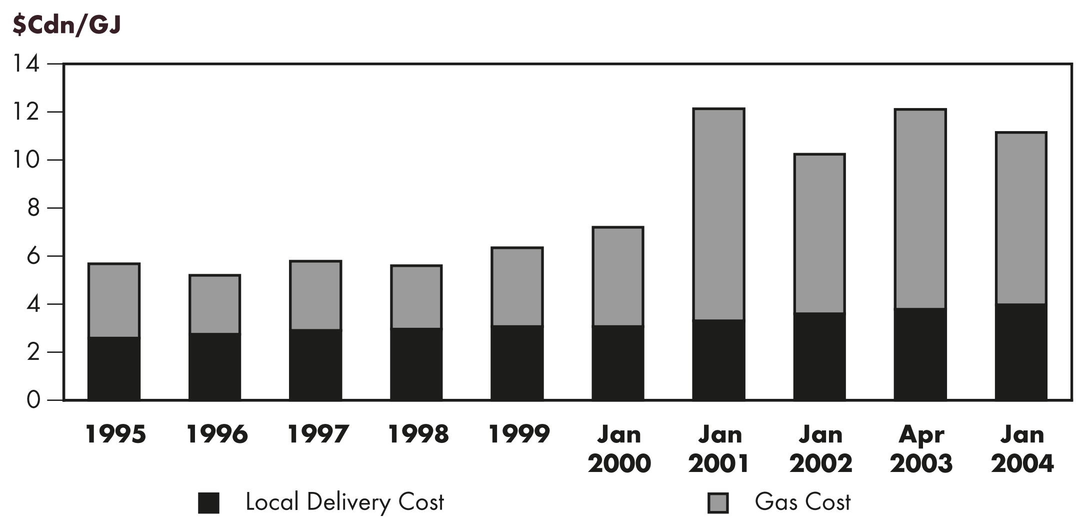
Price Differential: Station 2 less AECO-C



Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

FIGURE 4.6

Residential Natural Gas Price Components (Lower Mainland) - Terasen Gas Inc.



Source: Terasen Gas Inc.

Note: Average customer use has been kept constant at 120 GJ per year in order to demonstrate gas cost at the same level of use over time, however, as noted earlier Lower Mainland customers have reduced average use over this period.

4.3 Retail Natural Gas Prices

Retail gas prices paid by B.C. consumers include gas costs and local delivery costs. During the 1990s, there was an almost even split between the cost of gas and local delivery costs for a typical Lower Mainland residential consumer (Figure 4.6). Since 2000, when continental gas prices moved into a new trading range, the cost of gas has assumed a much larger proportion of a Lower Mainland residential customer's natural gas utility bill.

The British Columbia Utilities Commission (BCUC) sets the local delivery rates for Terasen and PNG and reviews gas costs. Terasen uses financial risk management tools, including a portfolio of fixed price contracts from various supply sources, contract hedges and spot purchases to manage gas price risk, but the cost of gas largely flows through to consumers based on market prices.

4.4 Managing Natural Gas Price Volatility

Market participants in B.C. have developed various strategies for dealing with price volatility. These include both physical and financial solutions.

The main physical tool for dealing with gas price volatility, which reflects short-term changes in gas demand, is storage. Injecting gas into a physical underground storage facility during low price periods and then drawing down storage during high price periods is the usual manner in which markets deal with peaks in gas demand, especially winter gas demand. The B.C. Lower Mainland is one of the few large urban centres in North America without access to a nearby storage facility. Without adequate market-based storage, it is more difficult for large Lower Mainland gas users to manage short-term gas price spikes.

Short-term demand can also be managed with simple strategies such as altering industrial production schedules or lowering residential room temperatures during a price spike. Burning alternative fuels, such as wood in home fireplaces or fuel oil in greenhouses, are other options that B.C. consumers have used to manage short-term price volatility. Air emissions standards, regulated by the Greater Vancouver Regional District in the Lower Mainland, can limit the use of alternative fuels for some large users. Alternative fuel use may also be restricted by limited supply, and may not necessarily be cheaper than gas because of increased short-term demand for alternatives such as fuel oil.

Market participants consulted for this EMA revealed a variety of gas buying strategies to help manage price volatility. Each strategy was tailored to meet a particular market outlook and specific business need. Some participants were not prepared to lock-in their gas purchases and bought gas on a daily basis at Sumas/Huntingdon on the spot market. Other market participants purchased yearly gas contracts for future delivery at Sumas/Huntingdon on a quarterly basis, thereby averaging their annual acquisition costs for the year. Some purchasers, with access to pipeline transportation on Westcoast, locked in fixed price deals directly with producers at Station 2. Other market participants, such as Terasen, had a mixed portfolio of fixed price contracts from various supply sources, contract hedges and spot purchases.

Hedging, purchasing a long term contract and protecting the value of that contract with an offsetting short position, is a sophisticated and costly endeavour. Many market participants pointed out that they do not have the expertise, independent financial resources or access to credit to enter into a long-term gas market hedge. After the departure of Enron and other marketers from Sumas/Huntingdon, it has become difficult to find counterparties with whom to conduct a hedge. Financial institutions such as banks and insurance companies, who might play an intermediary financing role, are exploring entering these markets.

Unstable and unpredictable prices reduce end-users' perception of natural gas as a reliable low-cost energy source. Natural gas price volatility and the cost of managing that volatility have become factors when considering future long-term investments, especially by industrial consumers.

Natural Gas Supply

5.1 British Columbia Natural Gas Resources

B.C. is the second largest provincial producer of natural gas in Canada. All of the gas is produced in northeast B.C., which is part of the WCSB. In addition, geological and geophysical exploration, and some exploratory drilling have identified nine other basins within the province and the west coast offshore area that are believed to have hydrocarbon potential (Figure 5.1).

Highlights

- A large resource potential exists for future development
- Natural gas production has increased by 62 percent in the past ten years.
- Higher natural gas prices have been a key factor encouraging rising drilling activity
- Technological advancements have opened areas for drilling
- Provincial oil and gas strategy has encouraged exploration and development
- Provincial oil and gas revenues from royalties and land sales have risen

The total marketable gas resource potential for conventional gas in B.C., including the west coast offshore, is estimated at 1 921 10^9m^3 (68 Tcf), of which 1 243 10^9m^3 (44 Tcf) remains undiscovered. Prospects appear numerous in northeast B.C.; the NEB currently estimates the ultimate potential for conventional marketable natural gas in northeast B.C. at 1 436 10^9m^3 (51 Tcf). Of this, about 773 10^9m^3 (27 Tcf) of conventional marketable gas remains undiscovered.

The Plains area of northeast B.C., while one of the most developed areas in B.C., is not as mature in development as Alberta. The recent discovery in the Slave Point formation at Ladyfern indicates that additional resources may be found in the deeper horizons. The Foothills region, forming the western edge of the WCSB, is also estimated to have good potential for additional resources. Overall, the potential volume of undiscovered gas resources has spurred higher drilling activity, especially exploratory wildcat wells, which have increased by 30 percent over the past decade.

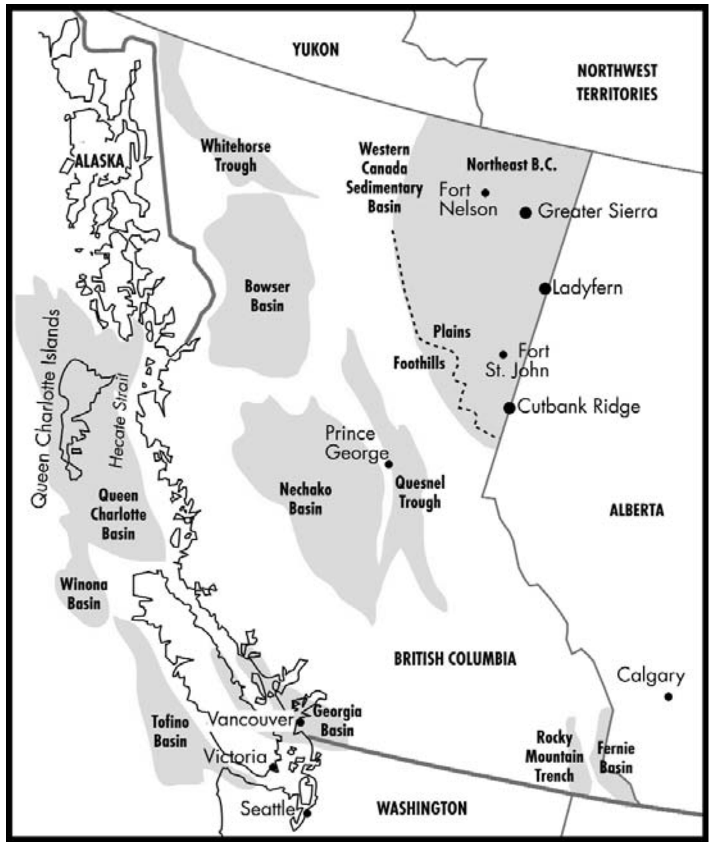
Throughout the central part of the province, several sedimentary basins, such as the Bowser, Whitehorse and Nechako Basins, have been identified as having significant petroleum and natural gas resource potential. However, it has been difficult to estimate the ultimate potential of natural gas resources due to the limited geological and geophysical information that is available. The Province, though, is commencing a program to evaluate the resource potential of the basins in conjunction with industry partners.

There are also basins located offshore from the west coast that are expected to contain natural resources, based on limited exploration drilling that occurred in the 1960s. The NEB estimates the ultimate potential of the west coast offshore at 255 10^9m^3 (9 Tcf). The majority of the offshore natural gas resources are expected to be found in the Queen Charlotte Basin, which is the largest offshore basin and is situated around the Queen Charlotte Islands. In 1972, the Canadian government declared an indefinite moratorium on offshore oil and gas activities due to environmental concerns. This was extended after the Exxon Valdez oil spill in 1989. In 2003 the Minister of Natural Resources Canada announced that Canada will proceed with a review of the federal moratorium for the Queen Charlotte Area.

In addition to the sizeable potential for conventional gas resources, the province is known to have unconventional natural gas resources such as coalbed methane (CBM). Estimates of the volume of this resource range as high as 2 510 $10^9 m^3$ (89 Tcf) but, it is unclear as to how much CBM may eventually be produced. Nine experimental projects are currently underway in the province but, at this point, there has not been any commercial production.

FIGURE 5.1

B.C. Natural Gas Supply Basins



Sources: B.C. Ministry of Energy and Mines; Geological Survey of Canada

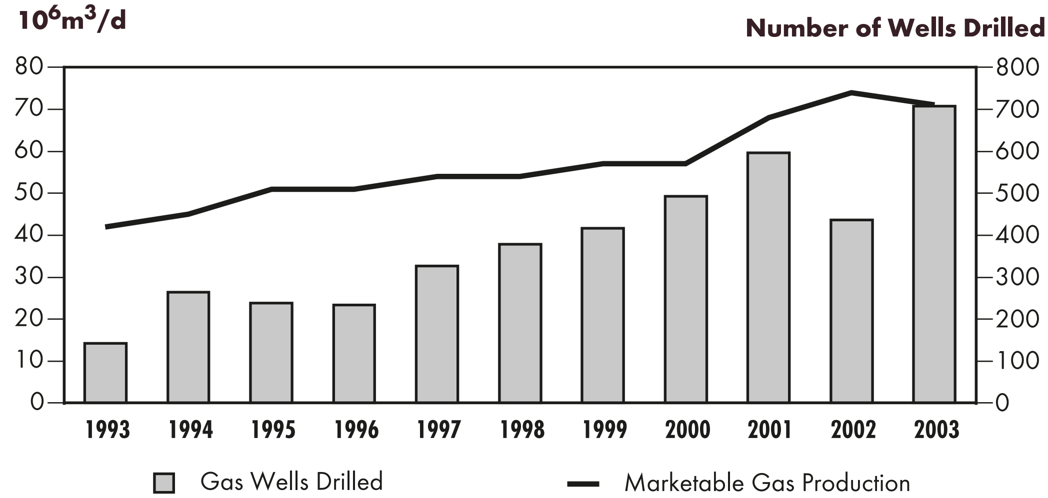
5.2 Exploration and Development Activity in Northeast British Columbia

Considering the relative volume of the conventional natural gas resources that remain undiscovered, many producers are focusing on northeast B.C. as an area with excellent prospects for exploration and development. Encouraged by higher natural gas prices, producers have been pursuing these opportunities. In fact, over the past 10 years, drilling activity has increased over 300 percent, with 708 gas wells drilled in 2003 (Figure 5.2).

Almost all drilling in 2003 occurred in the Plains area with some 698 wells located there and only 10 wells were drilled in the Foothills. Wells drilled in the Foothills tend to be deeper and more expensive than those drilled on the Plains. Much of the natural gas activity was development drilling focused on the Fort St. John and Fort Nelson areas. These areas have experienced more development over the years than other regions and therefore, the average recoverable reserves per new well has been decreasing.

In terms of drilling, northeast B.C. is less developed than Alberta. Consequently, individual gas wells are generally more productive than those in most areas of Alberta. The average well in B.C. has an initial productivity of about 25 $10^3 m^3$/d (0.9 MMcf/d), whereas the average well in Alberta has an initial productivity of one-third that volume. In some regions of B.C., such as the Foothills, wells can exhibit initial productivity of 226 $10^3 m^3$/d (8 MMcf/d) or more. Based on average well production,

B.C. Marketable Natural Gas Production and Wells Drilled



Source: B.C. Ministry of Energy and Mines

production from wells in B.C. tends not to decline as quickly as production from wells in Alberta, although there can be variability between different producing areas in each province.

Gas Production

Marketable gas production in B.C. has increased by 62 percent in the past ten years, from about 42 $10^6m^3/d$ (1.5 Bcf/d) to 71 $10^6m^3/d$ (2.5 Bcf/d) in 2003 (Figure 5.2). The Plains region, which includes the highly productive Ladyfern field, accounted for about 88 percent of production with the remainder from the Foothills. Exploration and development drilling by producers replaced 115 percent of production in 2002. This level of reserves replacement further reinforces the optimistic outlook for gas supply in B.C. The Energy Market Assessment published by the NEB in December 2003 titled *Short-term Natural Gas Deliverability from the Western Canada Sedimentary Basin 2003-2005* projects an increase in B.C. gas production of 11 percent from year-end 2002 to 2005.

Exploration Plays

An exploration and development play that has received much attention is the 1999 Ladyfern gas field near the Alberta border. This is the first deep Devonian gas play in B.C. Production commenced in early 2000 and grew quickly to 20.5 $10^6m^3/d$ (725 MMcf/d) by March 2002; at this date Ladyfern accounted for more than one-quarter of provincial production. However, the wells have experienced high decline rates and production has since fallen off sharply. Drilling in the Devonian continues, but producers are now also drilling shallower wells at Ladyfern. These less prolific, shallow targets are now considered to be economic by producers because of access to existing pipeline facilities that were installed to produce the Devonian zone.

The Greater Sierra area, east of Fort Nelson, is another play under development. The field is currently producing about 6.2 $10^6m^3/d$ (220 MMcf/d) and the planned drilling of 150 horizontal wells per year is expected to increase production to 11.3 $10^6m^3/d$ (400 MMcf/d) by 2005. It is anticipated that an extensive drilling program will reduce drilling costs from $4 million to about $1.5 million per well.

The Cutbank Ridge area, south of Dawson Creek on the Alberta border, has been the focus of large investments in land sales over the past year. EnCana Corporation (EnCana) purchased $369 million of lease rights totaling 142 000 hectares at a single land sale in the fall of 2003. As well, EnCana had purchased additional rights in the area prior to that sale. This new play is estimated to contain more than 113 10^9m^3 (4 Tcf) of recoverable gas based on seismic surveys, geological analysis and exploratory drilling. EnCana estimates about 100 to 200 horizontal wells will be drilled each year. Drilling costs, initially about $4 million per well, are expected to decline over time. EnCana forecasts significant production by 2005.

B.C. can be a costly region for gas exploration and development. Drilling gas wells in northeast B.C. can be very challenging, since it is a remote, rugged and geologically complex region with limited road and pipeline infrastructure. Often producers need to construct roads across muskeg in order to access drilling sites, which limits drilling to the winter season when the surface is frozen. Some producers have acted to extend the drilling season by using wooden and plastic drilling mats to transport rigs and drilling equipment into muskeg areas (Figure 5.3).

The application of technology such as drilling mats, horizontal drilling, under-balanced drilling and 3-D seismic has improved drilling economics in the region. Northeast B.C. has also seen the implementation of some large scale drilling programs that improve economies of scale by lowering costs per well.

The remoteness of northeast B.C. and the limited development to date can present environmental, socio-economic and land management issues many of which involve First Nations communities. Pristine environments can have many potential uses including wildlife areas, forestry and tourism. First Nations issues largely arise over the potential impacts of oil and gas development on traditional land-use such as trapping, fishing and hunting. Also of importance is the impact any development can have on archeological, cultural and heritage sites. With respect to oil and gas activity, First Nations have raised concerns over both the effects and the cumulative effects of these activities. In

FIGURE 5.3

Wooden Mats for Drilling Site and Road Access in Northeast B.C.

Photo courtesy of EnCana Corporation

most cases, producers have been able to resolve land access issues with First Nations successfully, although delays may occur that can increase project costs.

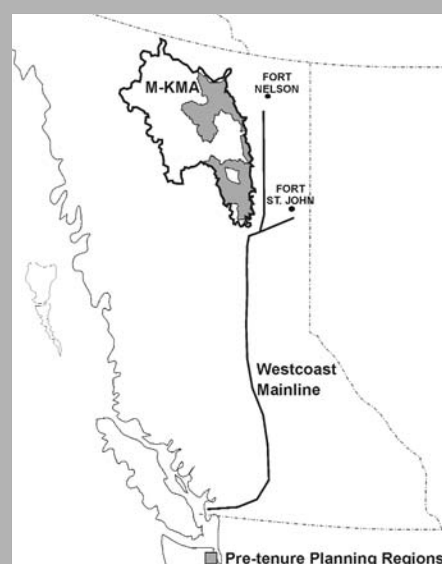
5.3 British Columbia Oil and Gas Strategy

The Province has launched initiatives to improve the industry's competitiveness in B.C. compared with Alberta and other producing regions. The Province began by creating the Oil and Gas Commission in 1998 to provide a single window for regulatory approvals for oil and gas activities. Other initiatives included increased spending on road infrastructure and working with First Nations to develop consultation protocols for dealing with oil and gas exploration and development applications. The Province also established a planning framework to facilitate the development of natural resources, for example, in the Muskwa-Kechika Management Area (M-KMA).

Other initiatives introduced over the past few years include the elimination of the provincial sales tax on production machinery and equipment, a reduction in the corporate income tax rate to match Alberta, elimination of the corporate capital tax and various fees, and modification to the royalty regime for natural gas production. Of note, production grew substantially over this period, increasing 32 percent between 1998 and 2003.

Pre-tenure Planning: the Muskwa-Kechika Management Area

The Muskwa-Kechika Management Area (M-KMA) is a 63 000 square kilometre area in northeast B.C. that straddles the western edge of the WCSB. It was created by the Province in 1997 to protect a unique and relatively undeveloped ecological region. It encompasses one of the continent's largest wilderness expanses south of the 60th parallel and supports extensive wildlife populations in terms of both numbers and species diversity. An innovative approach to managing development given its ecological, cultural, archaeological and economic importance has been taken. The M-KMA is divided into (1) Parks and Protected Areas (16 400 square kilometres), (2) Special Management Areas (36 300 square kilometres) where environmentally sensitive industrial activities including oil and gas operations are allowed and (3) Special Wildland Zones (9 200 square kilometres), which allow some mining and oil and gas development, but no timber harvesting.



The Province has a legal requirement for an oil and gas pre-tenure development plan to be in place in an area before petroleum and natural gas rights can be sold there. However, it is not required before geophysical activities can take place. The intent of the pre-tenure planning is to encourage and guide responsible socio-economic and environmental planning ahead of most development activities.

One area in the M-KMA, the Sikanni, has experienced oil and gas activity for many years. Some of the other areas within the M-KMA now have pre-tenure plans in place and plan development is actively underway in the other pre-tenure plan areas. Plans completed to date have focused on the eastern edge of the M-KMA, where resource potential is thought to be the highest. The Province estimates that there is gas resource potential of 90 to 181 $10^9 m^3$ (3.2 to 6.4 Tcf) in the pre-tenure plan areas of the M-KMA. Oil and gas land sales commenced in some parts of the M-KMA in early 2004. The Province estimates the value of the natural gas in the area at about $16 billion.

In recent years, energy policy in the province has been under review. The provincial government commissioned a task force that released a report, titled *Strategic Considerations for a New British Columbia Energy Policy*, in March 2002. Using the task force's recommendations as a foundation, the provincial government formulated an energy plan released in November 2002, *Energy for Our Future: A Plan for B.C.* The plan recognizes that B.C. is increasingly integrated into the North American energy market and that the energy sector is well positioned to generate economic growth for the province. Several provincial government initiatives emerged from the energy plan, which are relevant to the development of B.C.'s natural gas industry.

In May 2003, the Province announced further measures to attract energy investment. The Province identified four pillars for its Oil and Gas Development Strategy: (1) a road infrastructure program; (2) targeted royalty reductions for marginal, deep wells and summer drilling; (3) further regulatory streamlining; and (4) oil and gas service sector development.

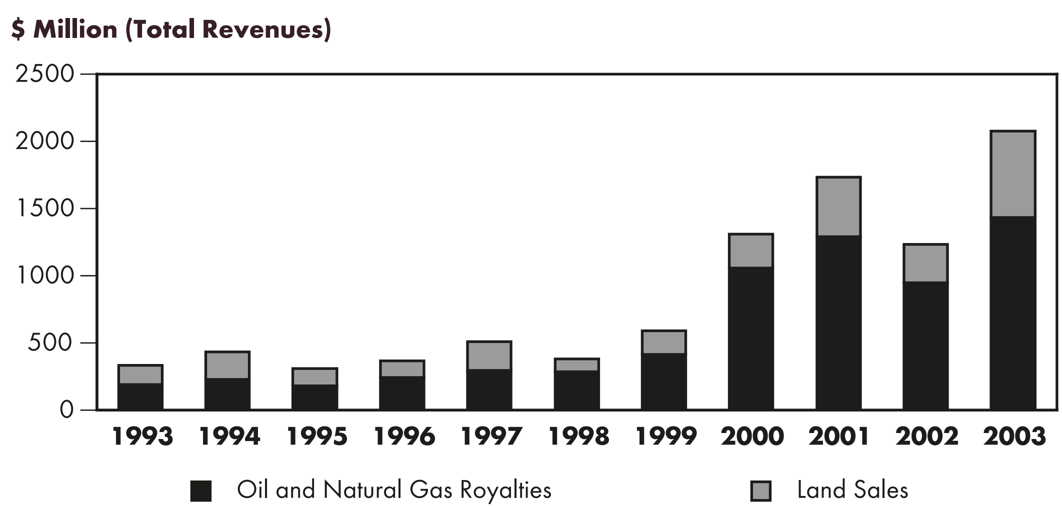
Six months later, in November 2003, additional steps were announced toward the stated goal of making B.C. the most competitive oil and gas jurisdiction in North America. These initiatives included: (1) further changes to deep drilling royalty credits; (2) royalty credits to encourage environmentally friendly horizontal and directional drilling technologies; (3) additional funding for road infrastructure; (4) creation of a single piece of legislation to govern the Oil and Gas Commission; and (5) a training fund to equip workers with the skills for employment in the oil and gas sector.

Land sales have also risen in recent years as industry interest in B.C. has grown. Over the past ten years, the Province has received $2.58 billion from land sales for oil and gas activity. Last year, alone, an unprecedented $647 million was raised from land sales, further demonstrating producer interest in B.C.

The Province estimates that in 2003, oil and gas revenue from royalties and land sales will exceed $2 billion (Figure 5.4). The oil and gas industry now provides more direct revenue to the Province than any other natural resource sector. In contrast, the revenue generated by the oil and gas industry in 1998, prior to the rise in continental natural gas prices, was only about $0.4 billion.

F I G U R E 5 . 4

B.C. Provincial Oil and Natural Gas Revenues



Source: B.C. Ministry of Energy and Mines

LIST OF PARTIES CONSULTED

Alliance Pipeline Ltd.
Apache Canada Ltd.
Avista Energy Canada, Ltd.
BC Greenhouse Growers' Association
British Columbia Utilities Commission
Calpine Energy Services, LP.
Canadian Association of Petroleum Producers
Canadian Forest Products Ltd.
Canadian Natural Resources Limited
CanAgro Produce Ltd. (merged with Century Pacific Greenhouses to form Hot House Growers Incorporated, December 2003)
Cascade Natural Gas Corporation
Central Heat Distribution Ltd.
Chevron Canada Resources
EnCana Corporation
Export Users Group
IGI Resources, Inc.
Ministry of Energy and Mines, Province of British Columbia
Murphy Oil Company Ltd.
National Energy & Gas Transmission, Inc.
Natural Gas Steering Committee
Norske Skog Canada Limited
Oil and Gas Commission (British Columbia)
Puget Sound Energy, Inc.
Samson Canada, Ltd.
Talisman Energy Inc.
Terasen Gas Inc.
Unocal Canada Limited
West Fraser Mills Ltd.
Westcoast Energy Inc. (carrying on business as Duke Energy Gas Transmission Canada)
Western Pulp Inc.
Weyerhaeuser Company
Willis Energy Services Ltd.

Glossary

3-D Seismic	A geophysical survey using equipment which sends a seismic signal into the earth which can be recorded and analyzed to obtain information on subsurface formations and features. A three dimensional survey provides a more dense cluster of data than conventional two dimensional seismic.
Acid Gas	Natural gas containing some percentage of hydrogen sulphide or carbon dioxide.
Capacity	The amount of natural gas that can be produced, transported, stored, distributed or utilized in a given period of time.
Coal Bed Methane	Natural gas, primarily methane, found in coal deposits.
Cogeneration	A facility which produces process heat as well as electricity.
Conventional Gas	Natural gas occurring in a normal porous and permeable reservoir which, at a particular point in time, can be technically and economically produced using normal production practices.
Core Market	Consists of the residential and commercial customers of a local natural gas distribution company.
Decline Rate	A term used to describe the decrease in production rate over time as a resource is depleted.
Degree Day	Data are calculated by Environment Canada and measure the extent to which the outdoor mean temperature (the average of the maximum and the minimum) falls below 18 degrees for each calendar day. One-degree day is counted for each degree of deficiency below 18° Celsius for each calendar day.
Deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
Direct Sales	Gas purchase arrangements transacted directly between producers, brokers or marketers and end-users
Directional Drilling	Drilling whereby the drill bit can be turned in any direction to reach the desired location.

Drilling mats	Wooden or plastic mats or pallets which are placed on a soft ground surface to stabilize it and allow placement and movement of heavy drilling equipment.
Electronic Trading	Refers to gas purchases and sales which take place via an electronic trading system. These systems allow gas to be bought and sold on an anonymous basis and provide for price discovery.
Exchange	Natural gas that is received from, or delivered to, another party in exchange for natural gas delivered to, or received from that other party.
End-Use Markets	Refers to the total consumer market for natural gas which includes the industrial, gas-fired power generation, commercial and residential markets.
Feedstock	Natural gas used as an essential component of a process for the production of a product (e.g. fertilizer).
Flue Gas Economizer	Captures waste heat from the flue gas of a boiler and transfers it to the boiler feedwater, thereby reusing energy and improving energy efficiency.
Formation	A geological zone or sedimentary layer which may be of interest in exploration for hydrocarbons.
Fuel-switching	The ability to substitute one fuel for another. It is generally based on price and availability.
Gas Well	A well bore with one or more geological horizons capable of producing natural gas
Geophysical	The analysis of sedimentary zone formations by the use of seismic equipment which records subsurface data.
Hedging	A financial risk management tool used for protecting the value of an investment from the risk of loss in case the price fluctuates. Hedging is accomplished by protecting one market transaction with another. A long position in an underlying market instrument can be hedged or protected with an offsetting short position in a related underlying market instrument.
Hog Fuel	Wood waste fuel consisting of pulverized bark, wood shavings, sawdust, low grade lumber and lumber rejects from sawmills, plywood mills and pulp mills.
Horizon	A term often used to describe a subsurface formation or zone.
Horizontal Drilling	A well which deviates from the vertical and is drilled horizontally along the pay zone.

Hub	A geographical location where large numbers of buyers and sellers trade natural gas and where gas can be physically delivered.
Land Sales	The sale of leases and licenses by the Crown of subsurface formations for hydrocarbon exploration.
Liquidity	A measure of the ease with which potential buyers and sellers may transact business.
Liquids Rich	Gas that contains significant quantities of natural gas liquids.
Liquefied Natural Gas	Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260° F at atmospheric pressure.
Local Distribution Company	An entity that owns a distribution system for the delivery of natural gas to end-use customers.
Marketable Gas	Natural gas that has been processed to remove impurities and natural gas liquids and is ready for consumer use. Its heating value may vary depending upon its chemical composition.
Natural Gas Liquids	Hydrocarbon components recovered from raw natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes, and pentanes plus.
NYMEX	The largest physical commodity futures exchange traded on the New York Mercantile Exchange for delivery of natural gas at the Sabine Pipe Line Co.'s Henry Hub in Louisiana.
Pre-tenure Planning	In some regions, prior to the British Columbia government making oil and gas tenures available in the region, pre-tenure plans must first be developed which identify sensitive resource values and develop appropriate objectives and strategies to support environmentally responsible development.
Price Differential	The difference in gas prices between two pricing points.
Price Transparency	The degree to which prices and other aspects of trades (volumes, duration, etc.) can be determined or verified at pricing points.
Price Volatility	The range of movement in commodity market prices.
Pulping Liquor	A by-product of the manufacture of chemical pulp which can be used as a fuel.
Reservoir	A porous and permeable underground rock formation containing a natural accumulation of crude oil or raw natural gas that is confined by impermeable rock or water barriers.
Royalty Credits	The British Columbia government is paid a royalty on natural gas produced from crown leases. Royalty credits are an elimination of certain royalties based on types of development work performed.

Spot Market	Transactions for gas that are generally for 30 days or less.
Storage	A facility or reservoir used to accumulate natural gas during periods of low demand and used to deliver natural gas during periods of high demand.
T-North	The Westcoast Fort Nelson and Fort St. John Mainlines which both terminate at Station 2, also known as Zone 3.
T-South	The Westcoast Mainline between Station 2 and Huntingdon, B.C., also known as Zone 4.
Undiscovered Resources	Resources that are estimated to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence but which have not yet been shown to exist by drilling, testing or production.
Ultimate Gas Potential	An estimate of all the resources that may become recoverable or marketable, having regard for the geological prospects and anticipated technology. It consists of cumulative production, remaining established reserves, discovered resources and undiscovered resources.
Under-balanced Drilling	Drilling when using a light drilling fluid which lowers bottomhole pressure to avoid damaging the formation with drilling fluid.
Wildcat Wells	A well drilled in an unproven area. Also known as an "exploration well".

APPENDIX E

Capital Spending Schedules for all Portfolios

Incremental TGVI Facility Requirements for the Base + 0 TJ/day Forecast

Year	LNG Storage			Pipe + Compression			Pipe + Compression + Curtailment		
	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)
2004	V4	15		V4	15		V4	15	
2005									
2006									
2007	LNG, spares	99	2.0%	V1U4, V2, V3b, spares	61	2.4%	V2, spares	27	2.5%
2008			2.0%			2.4%			2.6%
2009			2.0%			2.4%			2.6%
2010			2.0%			2.4%			2.6%
2011			2.1%	loop 25km d/s WS	23	2.4%			2.6%
2012			2.1%			2.4%	V3b	20	2.6%
2013			2.1%	loop 12km d/s V2	12	2.4%			2.6%
2014			2.1%			2.4%	V1	15	2.6%
2015			2.2%	V5	20	2.4%			2.6%
2016			2.2%	loop 27km d/s V3b	25	2.4%			2.6%
2017			2.2%			2.4%			2.6%
2018			2.2%			2.4%			2.7%
2019	V2	22	2.3%			2.4%			2.7%
2020			2.3%	loop 40km d/s WF	36	2.4%			2.7%
2021			2.3%			2.4%	V5	20	2.7%
2022			2.3%			2.4%			2.7%
2023			2.4%	V1U5	15	2.4%			2.7%
2024			2.4%			2.4%			2.8%
2025			2.4%	loop 19km d/s PM	17	2.4%	loop 25km d/s WS	23	2.8%
2026			2.5%			2.4%	loop 12km d/s V2	12	2.8%

Legend

CFT MS	CFT Meter Station	V1U5	5th unit to VI - Coquitlam Compressor Station
d/s	'downstream of'	V2	V2 - Squamish Compressor Station
km	'kilometre'	V3b	V3b - Secret Cove Compressor Station
LNG	Mt Hayes LNG Storage Facility	V4	V4 - Texada Compressor Station (retention and upgrades)
PM	'Port Mellon'	V5	V5 - Dunsmuir Compressor Station
spares	Spare Engines	WF	'Woodfibre'
V1U4	4th unit to VI - Coquitlam Compressor Station	WS	'Watershed'
V1U4 (Mars)	4th unit (Mars) to VI - Coquitlam Compressor Station		

Incremental TGVI Facility Requirements for the Base + 20 TJ/day Forecast

Year	LNG Storage			Pipe + Compression			Pipe + Compression + Curtailment		
	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)
2004	V4	15		V4	15		V4	15	
2005									
2006	CFT MS	2		CFT MS	2		CFT MS	2	
2007	LNG, V2, spares	121	2.7%	V1U4, V2, V3b, V5, spares, loop 12km d/s V2, loop 25 km d/s WS	117	2.5%	V1U4, V2, V3(b), spares	61	2.7%
2008			2.7%			2.5%			2.8%
2009			2.7%			2.5%			2.8%
2010			2.7%	loop 27km d/s V3b	25	2.6%			2.8%
2011			2.8%			2.6%			2.9%
2012			2.8%	loop 40km d/s WF	36	2.6%			2.9%
2013			2.8%			2.6%			3.0%
2014			2.8%			2.6%	V5	20	3.0%
2015			2.9%			2.6%	loop 25km d/s WS	23	3.0%
2016			2.9%	V1U5	15	2.6%			3.1%
2017			2.9%			2.6%	loop 12km d/s V2	12	3.1%
2018			2.9%			2.6%			3.1%
2019	V3(b)	20	3.0%	loop 19km d/s PM	17	2.6%			3.1%
2020	V1U4	15	3.0%			2.5%			3.0%
2021			3.0%			2.5%			3.0%
2022			3.0%			2.5%			3.0%
2023			3.1%	loop 10km d/s WS	9	2.5%			2.9%
2024			3.1%			2.5%			2.9%
2025			3.1%			2.5%	loop 27km d/s V3b	25	2.9%
2026			3.1%			2.5%	loop 40km d/s WF	36	2.9%

Legend

CFT MS	CFT Meter Station	V1U5	5th unit to VI - Coquitlam Compressor Station
d/s	'downstream of'	V2	V2 - Squamish Compressor Station
km	'kilometre'	V3b	V3b - Secret Cove Compressor Station
LNG	Mt Hayes LNG Storage Facility	V4	V4 - Texada Compressor Station (retention and upgrades)
PM	'Port Mellon'	V5	V5 - Dunsmuir Compressor Station
spares	Spare Engines	WF	'Woodfibre'
V1U4	4th unit to VI - Coquitlam Compressor Station	WS	'Watershed'
V1U4 (Mars)	4th unit (Mars) to VI - Coquitlam Compressor Station		

Incremental TGVI Facility Requirements for the Base + 45 TJ/day Forecast

Year	LNG Storage			Pipe + Compression			Pipe + Compression + Curtailment		
	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)
2004	V4	15		V4	15		V4	15	
2005									
2006	CFT MS	2		CFT MS	2		CFT MS	2	
2007	LNG, V1U4, V2, V3(b), V5, spares	156	3.1%	V1U4, V2, V3(b), V5, spares, loop 12km d/s V2, loop 25 km d/s WS, loop 40km d/s WF, loop 27km d/s V3b	179	2.6%	V1U4, V2, V3(b), V5, spares, loop 12km d/s V2, loop 25 km d/s WS	117	3.0%
2008			3.2%	V1U5	15	2.6%			3.0%
2009			3.2%			2.6%			2.9%
2010			3.2%			2.6%			2.9%
2011			3.3%	loop 19km d/s PM	17	2.6%			2.9%
2012			3.3%			2.6%			2.9%
2013			3.4%			2.6%	loop 27km d/s V3b	25	2.9%
2014			3.4%			2.6%	loop 40km d/s WF	36	2.9%
2015			3.4%			2.6%			2.9%
2016			3.5%	loop 13km d/s WS	12	2.6%			2.9%
2017			3.5%			2.6%			2.9%
2018			3.6%	loop 10km d/s V4	12	2.6%			2.9%
2019	loop 25km d/s WS	23	3.6%			2.6%			2.9%
2020	V5	20	3.6%			2.6%	loop 19km d/s PM	17	2.9%
2021	loop 12km d/s V2	12	3.6%			2.6%	V1U5	15	2.9%
2022			3.5%	loop 4km d/s V4, loop 7km d/s V5	12	2.6%			2.9%
2023			3.5%	loop 5km d/s V3b	5	2.6%			2.9%
2024			3.5%			2.6%			2.9%
2025			3.5%	loop 5km d/s V5	5	2.7%	loop 7km d/s V5	7	3.0%
2026			3.5%			2.7%			3.0%

Legend

CFT MS	CFT Meter Station	V1U5	5th unit to VI - Coquitlam Compressor Station
d/s	'downstream of'	V2	V2 - Squamish Compressor Station
km	'kilometre'	V3b	V3b - Secret Cove Compressor Station
LNG	Mt Hayes LNG Storage Facility	V4	V4 - Texada Compressor Station (retention and upgrades)
PM	'Port Mellon'	V5	V5 - Dunsmuir Compressor Station
spares	Spare Engines	WF	'Woodfibre'
V1U4	4th unit to VI - Coquitlam Compressor Station	WS	'Watershed'
V1U4 (Mars)	4th unit (Mars) to VI - Coquitlam Compressor Station		

Incremental TGVI Facility Requirements for the Low-Low Forecast

Year	LNG Storage			Pipe + Compression			Pipe + Compression + Curtailment		
	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct Cost (millions 2004$)	System Fuel (%)
2004	V4	15		V4	15		V4	15	
2005									
2006									
2007	LNG, Spares	99	2.3%	V2, Spares	27	2.3%	Spares	5	2.3%
2008			2.3%	V3b	20	2.3%			2.3%
2009			2.3%			2.3%			2.3%
2010			2.3%			2.3%			2.3%
2011			2.3%	V1	15	2.3%			2.3%
2012			2.2%			2.3%			2.3%
2013			2.2%			2.3%	V2	22	2.3%
2014			2.2%			2.3%			2.3%
2015			2.2%			2.4%			2.3%
2016			2.2%			2.4%			2.4%
2017			2.3%			2.4%			2.4%
2018			2.3%			2.4%			2.4%
2019			2.3%			2.4%			2.4%
2020			2.3%			2.4%			2.4%
2021			2.3%	loop 25km d/s WS	23	2.4%			2.4%
2022			2.3%			2.4%			2.5%
2023			2.3%	loop 12km d/s V2, V5	32	2.4%	V3b	20	2.5%
2024			2.3%			2.4%			2.5%
2025			2.4%			2.4%	V5	20	2.5%
2026			2.5%			2.4%			2.5%

Legend

CFT MS	CFT Meter Station	V1U5	5th unit to VI - Coquitlam Compressor Station
d/s	'downstream of'	V2	V2 - Squamish Compressor Station
km	'kilometre'	V3b	V3b - Secret Cove Compressor Station
LNG	Mt Hayes LNG Storage Facility	V4	V4 - Texada Compressor Station (retention and upgrades)
PM	'Port Mellon'	V5	V5 - Dunsmuir Compressor Station
Spares	Spare Engines	WF	'Woodfibre'
V1U4	4th unit to VI - Coquitlam Compressor Station	WS	'Watershed'
V1U4 (Mars)	4th unit (Mars) to VI - Coquitlam Compressor Station		

Incremental TGVI Facility Requirements for the High-High Forecast

Year	LNG Storage: Required TGVI Facilities	LNG Storage: Forecast Direct Cost (millions 2004$)	LNG Storage: System Fuel (%)	Pipe + Compression + Curtailment: Required TGVI Facilities	Pipe + Compression + Curtailment: Forecast Direct Cost (millions 2004$)	Pipe + Compression + Curtailment: System Fuel (%)
2004	V4	15	4.1%	V4	15	4.1%
2005			4.0%			4.0%
2006	CFT MS	2	4.6%	CFT MS	2	4.6%
2007	V1U4 (Mars), V2, V3b, spares, LNG	161	3.8%	V1U4, V2, V3(b), V5, spares, loop 12km d/s V2, loop 25 km d/s WS	117	3.1%
2008			3.7%	loop 27km d/s V3(b), loop 40km d/s WF	61	3.1%
2009	loop 25km d/s WS	23	3.7%			3.1%
2010			3.7%	loop 13km WS	17	3.0%
2011	loop 12km d/s V2	12	3.7%	V1U5	15	3.0%
2012			3.7%			3.0%
2013			3.7%	loop 19km d/s PM	17	3.0%
2014			3.7%			2.9%
2015	V5	20	3.7%	loop 7km d/s V5	7	2.9%
2016			3.6%			2.9%
2017			3.6%			2.9%
2018			3.6%			2.9%
2019			3.6%	loop 12km d/s V5	12	2.9%
2020	loop 40km d/s V2	36	3.6%	loop 10km d/s V4	10	2.9%
2021			3.6%			2.9%
2022			3.5%			2.9%
2023	loop 27km d/s V3(b)	25	3.5%	loop 5km d/s V3(b), loop 10km d/s Qualicum	16	2.9%
2024			3.5%			2.9%
2025			3.5%	loop 6km d/s V4	7	2.9%
2026			3.5%			2.9%

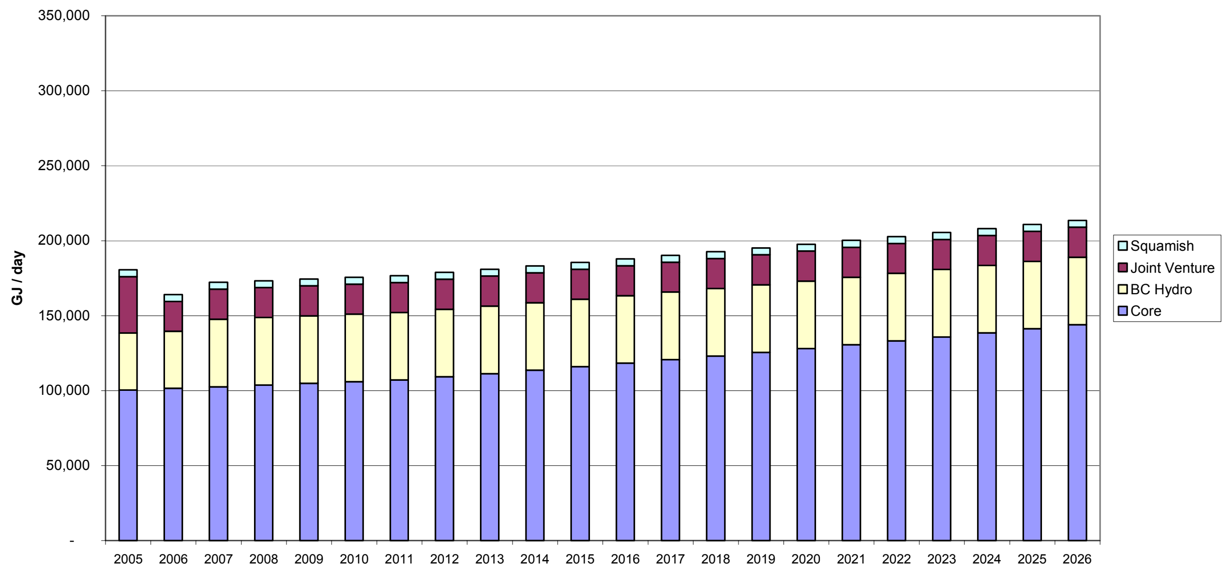
Legend

CFT MS	CFT Meter Station
d/s	'downstream of'
km	'kilometre'
LNG	Mt Hayes LNG Storage Facility
PM	'Port Mellon'
spares	Spare Engines
V1U4	4th unit to VI - Coquitlam Compressor Station
V1U4 (Mars)	4th unit (Mars) to VI - Coquitlam Compressor Station
V1U5	5th unit to VI - Coquitlam Compressor Station
V2	V2 - Squamish Compressor Station
V3b	V3b - Secret Cove Compressor Station
V4	V4 - Texada Compressor Station (retention and upgrades)
V5	V5 - Dunsmuir Compressor Station
WF	'Woodfibre'
WS	'Watershed'

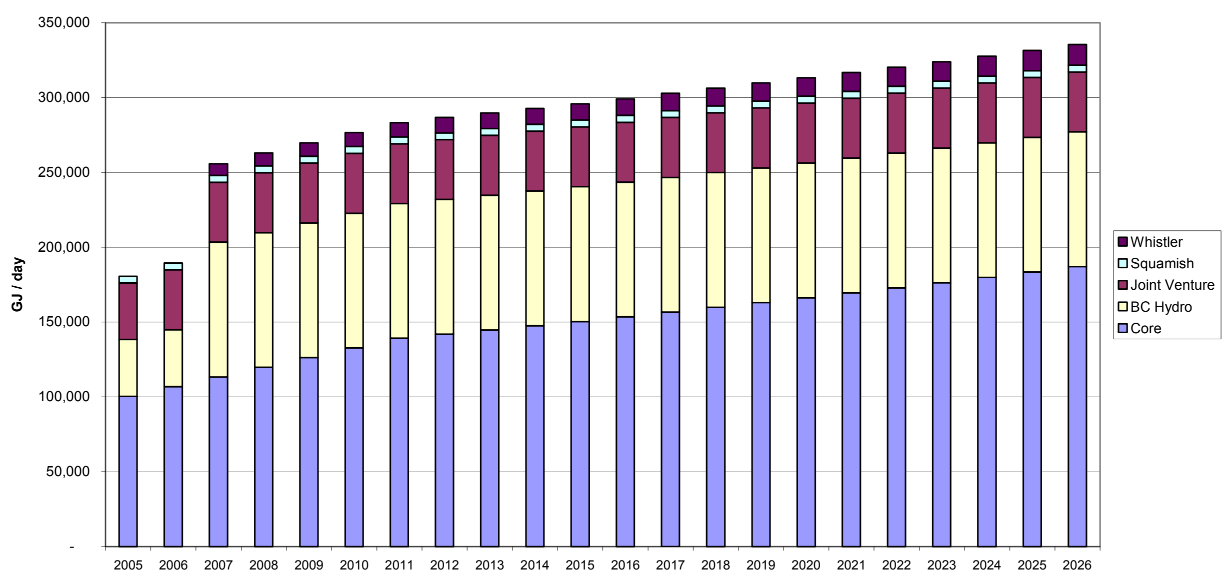
APPENDIX F

Design-Day Demand Scenarios

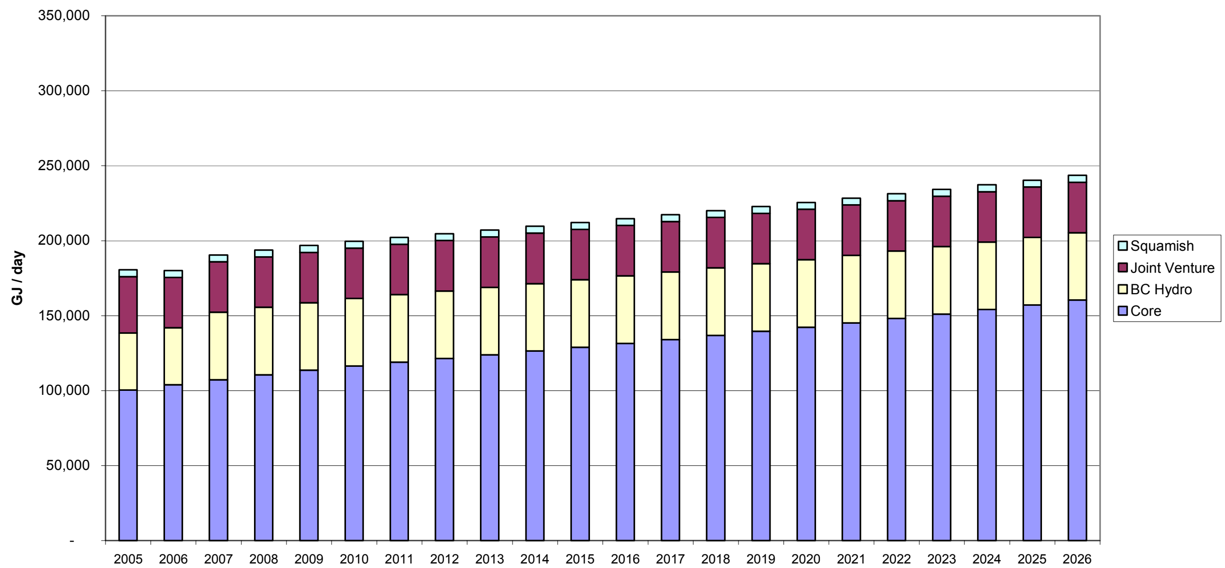
Low-Low Design-Day Demand Forecast Scenario



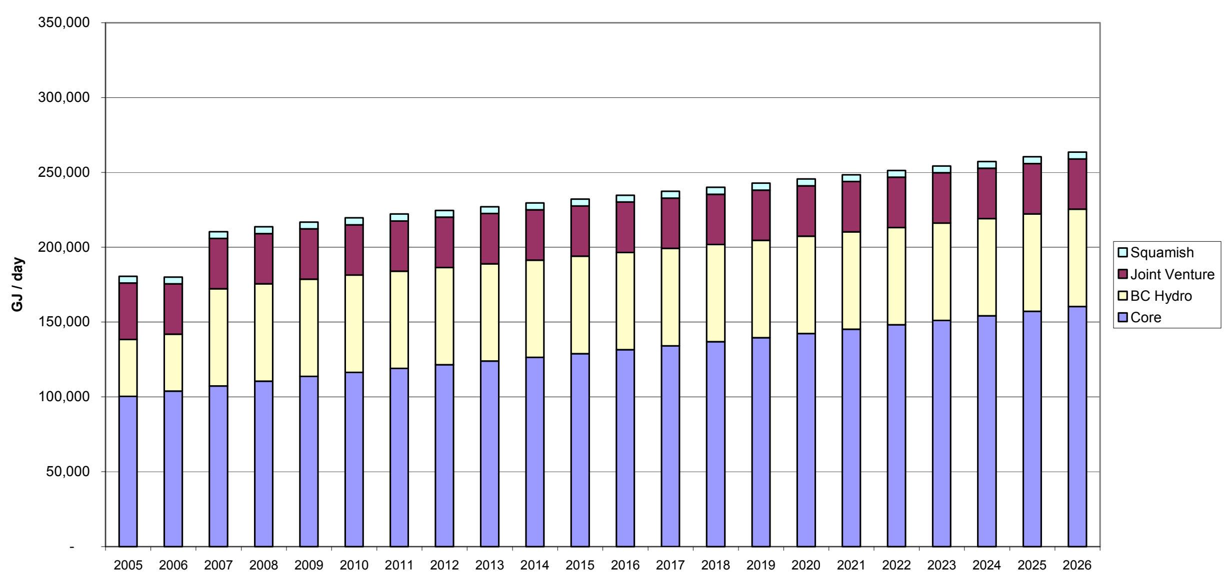
High-High Design-Day Demand Forecast Scenario



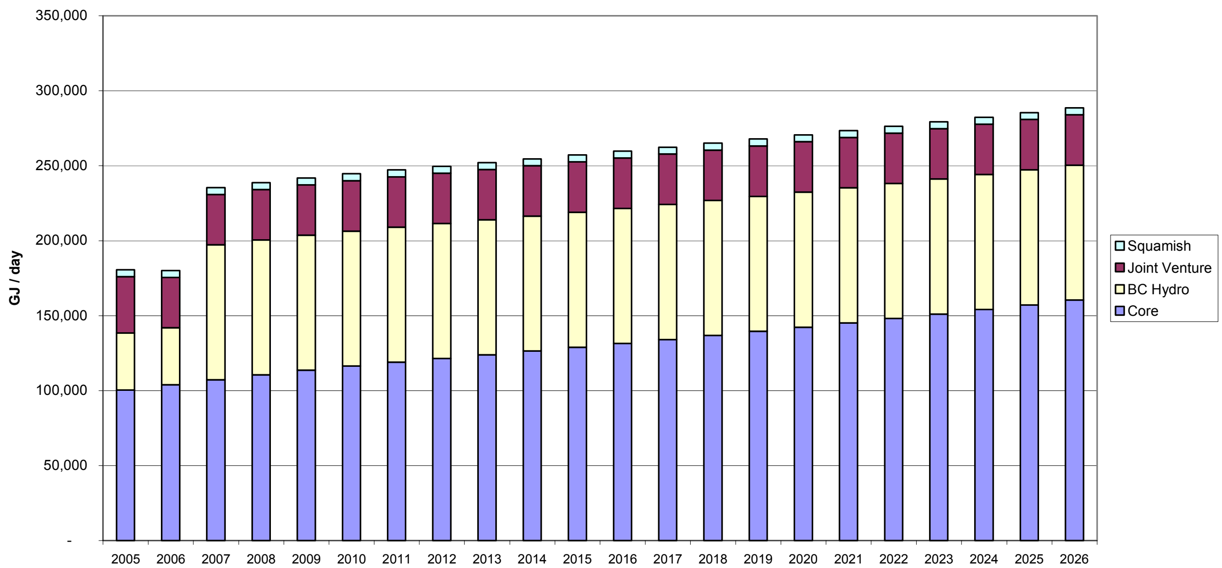
Base + 0 TJ / day Design-Day Demand Forecast Scenario



Base + 20 TJ / day Design-Day Demand Forecast Scenario



Base + 45 TJ / day Design-Day Demand Forecast Scenario



APPENDIX G

Compressor Additions

1.0 COMPRESSOR ADDITIONS

Over the next 20 years, TGVI will require compression upgrades to its transmission system to meet forecast load requirements. Where and when new compression is required are subject to the forecast load growth.

Given the alternative load growth scenarios faced by the system, the individual compression needs, associated costs and typical work scopes are presented as discrete projects. Individual projects can then be bundled to support of any particular load growth scenario.

Development of this information is based upon TGVI's considerable experience in constructing such compression facilities including the 3rd unit addition at our V1 Station in Coquitlam in 1998, the new V3 Port Mellon Compressor station in 1999 and the new V4 compressor station on Texada Island in 2001.

2.0 EXISTING PIPELINE SYSTEM

Natural gas is received by TGVI at its V1 Compressor Station in Coquitlam from Terasen Gas Inc. The delivery pressure for transmission to customers is increased to 2,160 psig maximum operating pressure (MOP) through three gas turbine-compressor units at the V1 Compressor Station, one gas turbine-compressor unit at the V3 Port Mellon Compressor Station on the Sunshine Coast and one gas turbine-compressor unit at the V4 Kiddie Point Compressor Station on Texada Island. Natural gas is transported through 615 km of pipeline, including dual marine crossings of the Georgia and Malaspina Straits, to various metering and pressure regulating stations located near customers and communities being served. Operating pressure is reduced at these stations from 2,160 psig to 500 psig or less, depending on load and customer requirements.

3.0 DESIGN CONSIDERATIONS AND RESULTS

The size, in terms of horsepower, and physical location of the facility upgrades on the transmission system affects the incremental system capacity derived from the facility. Extensive computer-aided hydraulic modeling of the transmission system based on the spectrum of possible long term load forecasts has identified the best size and locations for the compression upgrades. As well as satisfying the hydraulic criteria, the location must also satisfy various biophysical and human environmental factors.

The results of the hydraulic analysis indicate that up to three new compressor stations: one located at the town of Squamish (V2), one in Secret Cove on the Sunshine Coast (V3B), another at Dunsmuir on Vancouver Island (V5), assisted by compression upgrade at our existing Coquitlam facility (V1), could be required (alone or in conjunction with other facility additions) to meet anticipated system capacity requirements of the next 20 years in the most cost effective and efficient manner.

Because the existing TGVI compressor stations use Solar gas fired turbines, the planning estimates assume that Solar gas fired turbine units will also be used at the new stations.

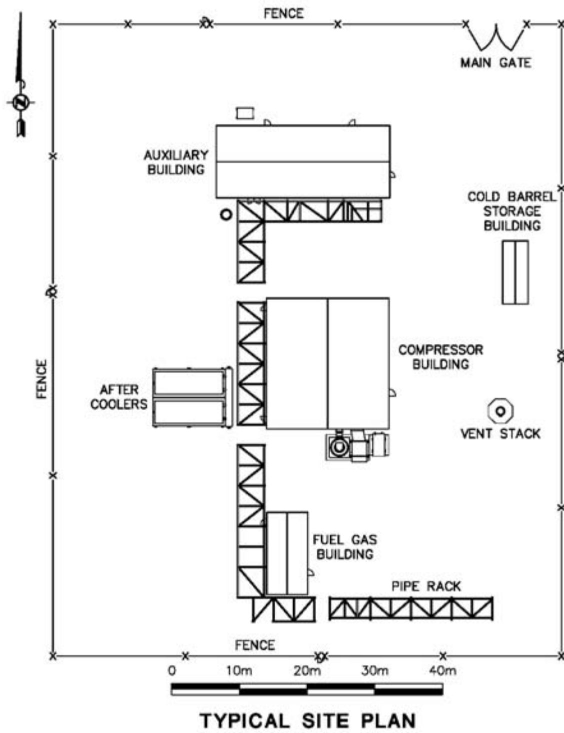
Table 3.1 summarizes the various compression horsepower addition and location options considered.

Table 3.1: Compression Requirements		
Location	**Equipment**	**Horsepower Added**
Existing V1 Station, Coquitlam	Additional T70 Compressor Unit	10,300
New V2 Station, Squamish	New T60 Compressor	7,800
New V3(b) Station, Secret Cove	New T60 Compressor	7,800
Existing "Temporary" V4 Station, Texada Island	Retention & Infrastructure Upgrades	0
New V5 Station, Dunsmuir, Vancouver Island	New T60 Compressor	7,800

The following **Map 3.1** graphically represents TGVI's transmission system and the proposed locations of each of these compressor additions.

Map 3.1

4.0 TYPICAL COMPRESSOR STATION CONSIDERATIONS



The V2, V3B and V5 Compressor Stations will be constructed using the same general equipment assemblies and will require similar commissioning activities. For instance, the stations will all be designed to a maximum operating pressure of 2,160 psig (14,893 Kpa) and use single Solar Taurus 60 gas turbine engines and associated equipment.

All design and construction will be in accordance with TGVI's specifications and comply with the standards of the Pipeline Act of British Columbia and all applicable standards and codes. Typically, the acquired site size is a minimum of 10 acres, with approximately 7 acres requiring clearing. The stations will all be designed for semi-attended operation with unit self-protecting and fail-safe control systems. The stations will be equipped with a gas and fire detection system, as well as an emergency shutdown system both automatic and manual, pressure relief valves, and a common station venting system.

The V1 and V4 upgrades to existing compressor stations will be discussed separately in the Site-Specific section.

5.0 DESCRIPTION OF TYPICAL BUILDINGS AND MAJOR EQUIPMENT

5.1 A compressor station will consist of the following:

a) The Compressor Building sized to accommodate the gas turbine and compressor unit.

b) The Auxiliary Building will consist of a control room, auxiliary equipment room, storage facilities, washroom and work area. The auxiliary equipment room will house the generator set, the heating boilers and the air compressors.

c) The Fuel Gas Building will house the fuel gas filter, heater and regulator modules.

d) The Cold Barrel Building will provide dry cold storage of operating fluid barrels. Insurance requirements recommend that fluids such as lube oil be stored in a designated building away from the compressor or auxiliary buildings.

5.2 A description of the typical compressor station's major equipment is as follows:

a) One gas turbine driven centrifugal compressor unit to compress natural gas taken from the upstream portion of the 10" Vancouver Island Pipeline and discharge the gas into the downstream portion of the pipeline. The power of the driver will be in the 7800 HP range.

b) One station scrubber will remove any liquid or solid particles from the gas stream prior to the gas entering the inlet to the compressor unit. Liquids and solids removed by the scrubber will be collected into an atmospheric storage tank and will be trucked off site routinely for recycling by a licensed operator.

c) One gas aftercooler to cool hot gas from the discharge of the compressor unit prior to the gas entering the pipeline. The cooler will be a forced air cooled unit.

d) One fuel gas filter to remove liquid or solid particles from the fuel gas stream (natural gas is taken off the pipeline and used as fuel by the compressor unit, generators and heating boilers).

e) One fuel gas heater to heat the fuel gas to prevent hydrates in the gas from freezing off pressure reduction valves (the pressure valves are required for regulating the pressure from pipeline pressure to fuel gas supply pressure).

f) Other equipment including air compressors, air dryers and air receivers to supply and store the compressor station's compressed air requirements; a.standby generator to supply the compressor station's emergency back-up electrical power requirements; heating boilers to supply the compressor station's process and space heating requirements and other appurtenances.

6.0 REGULATORY REVIEW AND APPROVALS OVERVIEW

Two key provincial agencies regulate the construction and upgrade of compressor stations: the British Columbia Utilities Commission (BCUC) and the Oil and Gas Commission (OGC). At this time, these facilities do not trigger either a federal or provincial statutory environmental assessment.

An application for a Certificate of Public Convenience and Necessity (CPCN) will be made to the BCUC for the proposed works. The timing and content of such application(s) depends upon the actual loads realized. Permit applications for site acquisition, facility design, construction and operation will be made to the OGC.

Local governments may have approval requirements through the application of their rezoning, development and other local permit requirements. To date, after completing similar construction projects, TGVI has successfully addressed any issues and received all required approvals from local governments for such facilities.

6.1 Land and Construction Permits

Typically, the acquisition process for Crown Land takes approximately one year to complete. Private land acquisition takes approximately 6 months. TGVI will need to make applications to secure all the permits required for the proposed land use as well as ensuring all local bylaws are met. Building, Development and/or Development Variance permits will be acquired from the local municipalities or regional districts as required.

TGVI will also apply directly to the Oil and Gas Commission (OGC) for a PL103 permit covering engineering design and for a Leave to Construct pursuant to the Pipeline Act prior to commencing construction and after all public notices and consultations have been made.

6.2 Environmental Permits Requirements

The most significant environmental impacts from compressor stations are generally perceived to be viewscape disruption, and noise and air emissions. However, in reality compressor stations typically have limited impact on air, land or water, or on local residents. Several provincial statutes govern the environmental requirements for transmission system upgrades, these are:

- the Environmental Assessment Act (EA)
- the Water Act and
- the Waste Management Act

However, not all Acts apply generically to compressor projects. Requirements under each Act are triggered by specific aspects of each project.

The compressor stations and compression upgrades as proposed are exempt from the requirements of the EA Act. However, TGVI will address many of the EA requirements, such as broad stakeholder consultation, to ensure overall approval of the project is obtained quickly and the possibility of delays due to environmental concerns are minimized.

The proposed compressor stations will require air emission permits under section 10 of the provincial Waste Management Act. Legislative authority to issue air emission permits for such facilities rests with the Oil and Gas Commission. TGVI plans to use ‘dry’ low NOx (DLN) technology. The DLN technology easily achieves these permit requirements. Typically, such permits and/or permit modifications take approximately four months to process, and can be done coincidently with other planning and construction activities.

Under the provincial Contaminated Site Regulation, there is a property disclosure requirement known as a site profile. Development of these sites may require that a site profile be provided to the local government, and if there is evidence of contamination, clean up may be required. Preliminary site investigations will be completed for each of the sites prior to completing the acquisition process to determine if there are any unmanageable environmental liabilities.

Noise and visual impacts are generally controlled through the installation of acoustical insulation in the compressor enclosure and siting and landscaping facilities to limit viewscape impacts. TGVI's V1 station in Coquitlam operates in close proximity to an urban area. The station meets all noise requirements and has attracted little to no attention from its neighbors.

6.3 Socio-Economic Assessment

Typically, the construction of each compressor facility will require approximately 6,000 person days of work and employ approximately 30 contract personnel during peak construction. Local construction companies will benefit through subcontracts for some of the general construction work. The projects will also create secondary employment by generating the need for construction support and supply services.

Safety to the public will be ensured through full enclosure by fence. In addition, construction of the facility will be in compliance with all building codes and will have the benefit of current safety practices. Each station will be remotely controlled with state of the art emergency reporting and shut down equipment and will be monitored 24 hrs per day from the Terasen Gas' control centre in Surrey. TGVI has emergency response procedures to effectively deal with emergencies related to compressor facilities and the pipeline.

6.4 Public Consultation

Adequate public consultation is a specific requirement of air emission permit process, a general OGC requirement and is necessary to support the BCUC application for such facilities. Typically, to meet these requirements TGVI completes a public consultation process that includes public notices in local newspapers, open houses, mail outs and door knocking campaigns as necessary to ensure that the public is aware of our activities and are provided adequate opportunity to comment. Typically, this process takes two to four months to complete and can be run as part of the air emission process and coincident with other application processes.

Additionally, development or variance permit processes may also trigger public involvement at the municipal level. To date, TGVI has successfully completed all such processes for siting similar stations.

6.5 First Nations Consultation

First Nation consultation is required as part of the Crown Land acquisition process and is considered a component of meeting the air emissions permit consultation requirements. As part of its ongoing operational strategy, TGVI has developed Memorandum of Understandings (MOU) with most First Nations in our operational area. While these MOUs do not contain specific commitments, they do embody TGVI's general commitment to working with local First Nations to the betterment of both. TGVI has been proactive in pursuit of this commitment, and will undertake all First Nation consultation necessary to ensure successful completion of these facilities.

7.0 SCHEDULE

Below is a typical schedule for the construction of a new compressor station or the addition of compression at an existing station. In both cases, the timeline to construct these upgrades is two years or less from initial approvals. If required, compressing the timeline may be possible, particularly if the compressor package vendor is able to reduce delivery times.

Project activities include land acquisition, public consultation, external approvals, detailed engineering design, drawings, equipment purchasing, off-site module fabrication, site preparation, installation, testing and commissioning.

Timeline	Activity
Project Start	Receive Engineering Bid Packages
Start + 1 Month	Award Engineering Contract
Start + 7 Months	Order Compressor Components
Start + 12 Months	Issue Construction Drawings for Tender
Start + 13 Months	Award Construction Contract
Start + 16 Months	Begin Construction
Start + 21 Months	Complete Building Construction
	Commissioning
Start + 24 Months	Compressor Start Up

8.0 SITE-SPECIFIC CONSIDERATIONS

In 1997, TGVI commissioned Westcoast Energy Inc and Enkon Environmental to complete two separate compressor site selection studies in anticipation of meeting future load requirements. These studies considered ground condition, aquatic resources, local air quality impact, terrestrial resources, prominence in landscape, archeological and historical assessment, and aboriginal considerations. The results of these studies were used to site our Port Mellon (V3) station. Additionally, these studies identified sites at Secret Cove (V3B) and Squamish (V2) as being suitable for compression facilities. More recent work completed by TGVI identified the Dunsmuir (V5) as a suitable site.

In 1997, during the initial site selection study activities, TGVI completed a public consultation process related to potential compressor sites in the vicinity of Squamish (Woodfibre) and on the Sunshine Coast (Port Mellon). The Squamish open house attracted 17 people including representatives from the District of Squamish and several individuals looking for employment opportunities. Open houses were also held in Gibsons and, more recently, in Van Anda on Texada Island related to our V4 facility with similar results. Summaries of the above open houses were submitted in support of the V3 and V4 CPCN applications.

8.1 V1 Coquitlam Compressor Station Upgrade (Km 0, 12" Mainland)

At this existing station, a Solar T70 turbine compressor unit is proposed to add to the existing three units. The existing units are two Solar Centaur 50s units and one Solar Taurus 70 unit.

To re-permit this station with the new compressor, an application for an air emission permit modification to the Greater Vancouver Regional District (GVRD) rather than the OGC will be required. The GVRD is responsible for administering air emissions in this area.

No additional property is required to accommodate this addition and relatively minor improvements are needed as a fourth unit was anticipated in the design of the existing third unit compressor building and related works.

While the typical project schedule as described allows 2 years for project completion, given the existing level of preparation, this project could be accelerated to target completion within one year if necessary. However, the feasibility of an accelerated schedule would depend upon the delivery of the compressor package.

8.2 V2 Squamish Compressor Station (~Km 34, 10" Mainland)

In 1997, TGVI had identified but not acquired a site for V2 on Crown land within the service area of the District of Squamish. TGVI believes that this site is no longer suitable for V2 since a new subdivision has been constructed in close proximity.

Current investigations have focused on privately held land with suitable zoning in the Squamish area and a suitable 15 acre site zoned Heavy Industrial has been identified approximately 400 meters north of existing Squamish meter station. The zoning suitability has been confirmed with the District of Squamish.

Preliminary engineering work has been completed to establish site specific costs and confirm that there are no significant issues with the site and the First Nations consultation process has been initiated. Negotiations for potential purchase of this site are underway.

In all other aspects this station will follow the typical compressor project process described previously.

8.3 V3B Secret Cove Compressor Station (Km 129, 10" Mainland)

The V3B site is on Crown Land and TGVI has held a License of Occupation for this site for a number of years. Through consultation with the Crown, TGVI has initiated the process to convert the License of Occupation into a Crown Grant in order to be able to continue to hold interest in the site. As part of the process, TGVI has confirmed the zoning suitability with the Regional District and has initiated First Nations consultation.

In all other aspects, this station will follow the typical compressor project process described previously.

8.4 V4 Kiddie Point Station Upgrade (Km 50, Texada Island Pipeline)

No additional compression is required at this site as part of the proposed upgrade. Upgrades relate to creating more permanent facilities to house the skid mounted facilities that currently exist. The cost associated with the V4 station upgrade generally relates to TGVI's retention of the compressor station through repayment to BC Hydro of the BC Hydro capital funding and relocation of equipment if required as outlined in the Compressor Facility Agreement as noted BCUC Order C-6-01, Item H.

Negotiations with the area landowner are underway to establish whether or not equipment relocation will be required in order to secure long term land tenure without any relocation caveats.

8.5 V5 Dunsmuir Compressor Station (~Km 53, Vancouver Island Mainline)

The V5 site is on private land. No attempt has yet been made to acquire this site, although we have positive negotiation experience with the landowner, and we anticipate no issues in acquiring this site when required. In all other aspects this station will follow the typical compressor project process described previously.

9.0 COST

9.1 Capital Costs

TGVI's forecast of capital costs (in $2004 Direct) for the upgrades is outlined in **Table 9.1.** These forecasts include materials, labour, the gas turbine packages, site acquisition where necessary and preparation, engineering design consultants, project management, testing and commissioning and spare parts.

Table 9.1: Cost Summary ($2004 Direct)		
Location	**Equipment**	**Cost ($000,000)**
Existing V1 Station, Coquitlam	Additional T70 Compressor Unit	$15
New V2 Station, Squamish	New T60 Compressor	$22
New V3(b) Station, Secret Cove	New T60 Compressor	$20
Existing V4 Station, Texada Island	Infrastructure Upgrade & Retention*	$15
New V5 Station, Dunsmuir, Vancouver Island	New T60 Compressor	$20
	Spare T70 & T60 Compressors (one each)	$5

Costs are based on recent TGVI experience in the construction of two new compressor stations in 1999 and 2001, and the addition of compression at our existing V1 station in 1998 combined with a 2004 review of land costs. TGVI completed all projects on time and on or under budget. The compression upgrades proposed are similar in scope and TGVI is confident it can efficiently and effectively construct the proposed upgrades as outlined.

Costs associated with the V4 station (* - above table) relate largely to TGVI's retention of the compressor station through repayment of estimated capital costs to BC Hydro and relocation of equipment if required as outlined in the Compressor Facility Agreement as noted BCUC Order C-6-01, Item H.

APPENDIX H

Pipeline Looping

1.0 PIPELINE LOOPING

Over the next 20 years, TGVI may require twinning (or looping) of pipeline sections of its existing transmission system to meet forecast load requirements. Where and when this looping is required are subject to the forecast load growth.

Given the alternative load growth scenarios faced by the system, the individual looping needs, associated costs and typical work scopes are presented as discrete projects. Individual projects can then be bundled to support of any particular load growth scenario.

Development of this information is based upon information provided by reports by Colt Engineering, Golder and Associates Ltd., Enkon Environmental Limited, the Cornerstone Planning Group, and Intec Engineering commissioned by TGVI in 1997 to investigate looping options.

1.1 Existing Pipeline System

Natural gas is received by TGVI at its V1 Compressor Station in Coquitlam from TG. The delivery pressure for transmission to customers is increased to 2,160 psig maximum operating pressure (MOP) through three gas turbines-compressor units at the V1 Compressor Station, one gas turbine-compressor unit at the V3 Port Mellon Compressor Station on the Sunshine Coast and one gas turbine-compressor unit at the V4 Kiddie Point Compressor Station on Texada Island. Natural gas is transported through 615 km of pipeline, including dual marine crossings of the Georgia and Malaspina Straits, to various metering and pressure regulating stations located near customers and communities being served. Operating pressure is reduced at these stations from 2,160 psig to 500 psig or less, depending on load and customer requirements.

1.2 Design Considerations and Results

The size, in terms of pipeline length and diameter, and physical location of the looping on the transmission system affects the incremental system capacity derived from the loop. Extensive computer-aided hydraulic modeling of the transmission system based on the spectrum of possible long-term load forecasts has identified the best size and locations for system looping. As well as satisfying the hydraulic criteria, the individual loops must also satisfy various biophysical and human environmental factors.

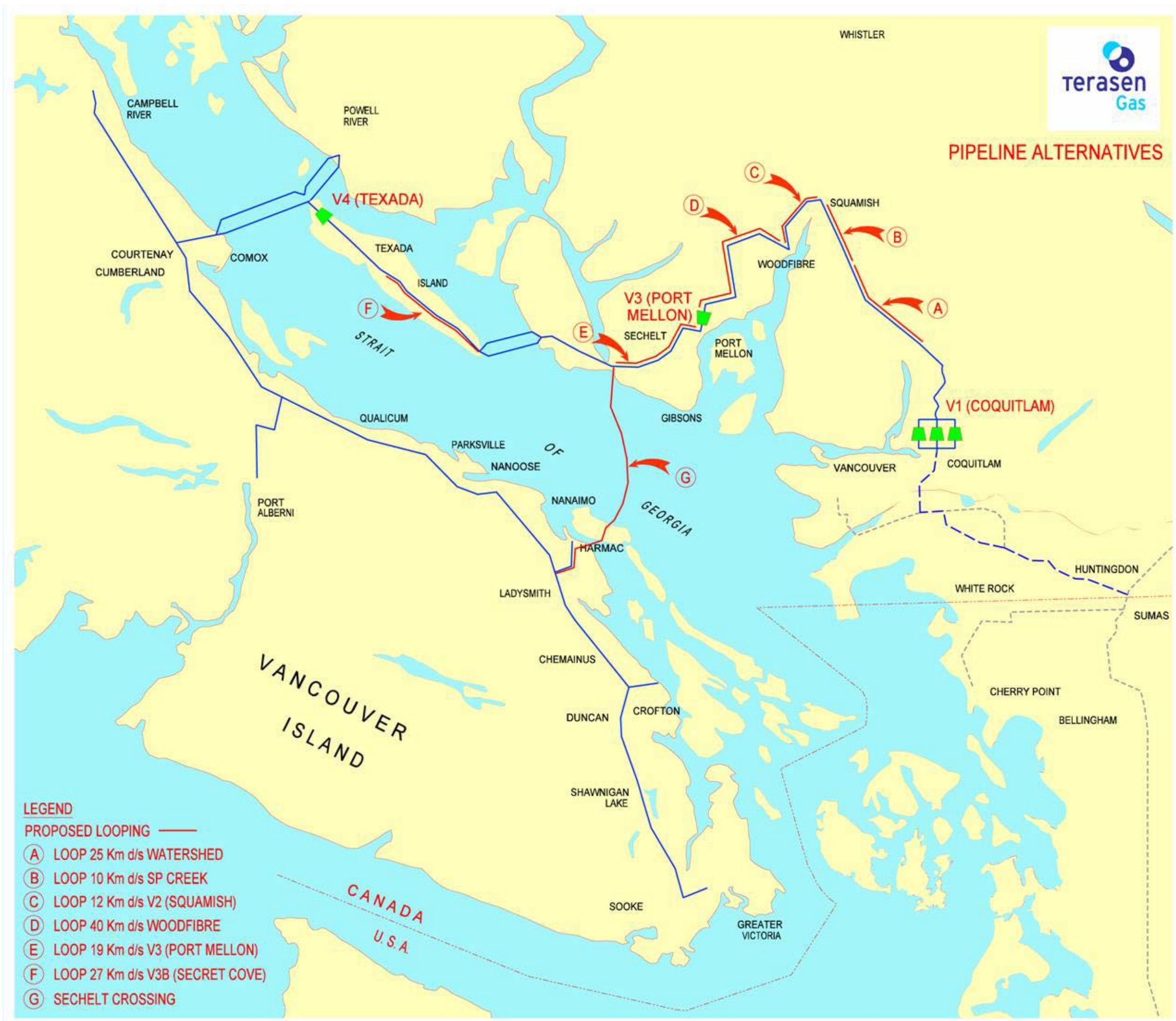
In order to meet the forecast load growth associated with the various scenarios, the results of the hydraulic analysis indicate that up to four looped sections could be required (alone or in conjunction with other looped sections) to meet anticipated system capacity requirements of the next 20 years in the most cost effective and efficient manner. **Table 1.2** summarizes the system looping requirements associated with the various scenarios considered.

The pipeline loops will be designed and constructed to meet the Canadian Standards Association (CSA) Z662 Oil and Gas Pipeline Systems criteria for high-pressure natural gas transmission pipelines. The loops will be NPS 12 and will have a design and maximum operating pressure of 2160-psig. All piping will be installed with factory applied yellow jacket protective coating or equivalent, as well as concrete rock jacket coating as required.

Table 1.2: Looping Summary		
Location	**Pipeline Size**	**Pipeline Length (kms)**
Loop 25km d/s Watershed	NPS 12"	25.3
Loop 13km d/s SP Creek	NPS 12"	13.1
Loop 12km d/sV2	NPS 12"	11.6
Loop 40km d/s Woodfibre	NPS 12"	39.8
Loop 19km d/s V3	NPS 12"	18.6
Loop 27km d/s V3(b)	NPS 12"	26.7

The following **Map 1.2** graphically represents TGVI's transmission system and the proposed locations of each of the looped sections.

Map 1.2



1.3 Typical Looping Considerations

Typical loop construction involves a routine sequence of pipeline activities similar to those used for other pipeline projects throughout B.C. These techniques will include:

- clearing the right-of way of trees and stumps (the existing right-of-way is already cleared so only minimal additional clearing will be required);
- grading and leveling the right-of-way;
- stripping and stockpiling topsoil;
- excavating the pipeline trench;
- preparing and installing the pipe;
- backfilling the trench;
- pressure testing of pipe sections;
- re-establishing topsoil and ground cover;
- revegetation;
- cleaning up and grooming the right-of-way; and
- connecting the pipeline loop into the existing pipeline system.

The bedrock portions of the route would require some rock blasting and rock removal to prepare the right-of-ways and excavate a trench. In addition, some upgrading of existing forestry or powerline roads may be necessary to provide access to the right-of-way for heavy equipment. Conventional pipeline looping in rugged terrain requires a minimum offset of about six meters to help protect and maintain safe operating conditions for the existing pipeline during loop construction activities. Smaller offset can be tolerated using special construction procedures.

A number of stream crossings will be required. The method of crossing the stream with the pipeline will be determined by a number of factors such as the environmental resources of the stream and geotechnical considerations. Each stream crossing will be subject to receiving a Section 9 approval under the Water Act from the Oil and Gas Commission and done in consultation with the Department of Fisheries and Oceans.

The existing pipeline sections will remain in service during construction of the loops with the exception of short outages required for final tie-ins to the existing system. These outages will be conducted with minimal, if any, impact on existing customers.

1.4 Regulatory Review and Approvals Overview

At the initial permitting stage, six key agencies may provide regulatory oversight of the construction of pipelines in British Columbia. These are the British Columbia Utilities Commission (BCUC), the Canadian Environmental Assessment Office, the Provincial Environmental Assessment Office, the Oil and Gas Commission (OGC), the Department of Fisheries and Oceans and the Ministry of Water Land and Air Protection. Other agencies may play important approval roles as the looping project proceeds, such as managing archeological issues, but these are subsequent to the above.

Individual loops are not large enough to trigger either a federal or provincial statutory environmental assessment (EA). However, the individual circumstances of each loop will need to be assessed in detail to determine if there are specific EA triggers, such as a HADD (Habitat Alternation, Disruption or Destruction) trigger associated with a difficult stream crossing that may trigger a federal Canadian Environmental Assessment Act (CEAA) review. TGVI's experience indicates that with appropriate planning and design most HADD triggers can be avoided. Regardless, TGVI will address many of the EA requirements, such as comprehensive environmental assessment and broad stakeholder consultation, to ensure overall approval of the project is obtained quickly and the possibility of delays due to environmental concerns are minimized.

An application for a Certificate of Public Convenience and Necessity (CPCN) will be made to the BCUC for each of the proposed loops. The timing and content of such application(s) depends upon the actual loads realized. Permit applications for site acquisition, facility design, construction and operation will be made to the OGC.

1.4.1 Environmental

Environmental impacts from loop construction and operation are generally limited to site impacts including potential impacts to animals, fish and natural habitats and can be generally be mitigated through appropriate route selection, design, and the use of best construction practices. TGVI has extensive experience and an excellent reputation in successfully completing such construction projects in environmentally challenging circumstances and particularly in doing work 'in and about' streams.

1.4.2 Land Acquisition

To ensure that the existing pipeline right-of-way (ROW) is wide enough to construct each pipeline loop, TGVI will typically need to acquire additional right-of-way, in most cases to add additional width to the current right-of-way but in some locations new right-of-way will be required. The precise amount of land required and that land's disposition will not be known until a more detailed assessment has taken place.

Sections of land along and adjacent to the pipeline corridor are subject to ALR, mineral, forestry and trapping tenure designations as well as being Crown and Private Land holdings. Typically, the acquisition process for Crown Land takes approximately one year to complete. Private land acquisition takes approximately 6 months. TGVI will make applications to secure all the permits required for the proposed land use as well as ensuring all local bylaws are met.

1.4.3 Public and First Nation Consultation

While it is expected that the land loops will not be subject to a statutory environmental assessment and the associated consultation process, adequate public and First Nation consultation for such looping projects is an OGC requirement and also is necessary to support a BCUC application for such works.

Typically, the consultation process undertaken by TGVI for such pipeline looping projects is comprised of three key components:

- Stakeholder and First Nations identification
- Project notification
- Communications activities

Typically, to meet these requirements TGVI completes a public consultation process that includes public notices in local newspapers, open houses, mail outs and door knocking campaigns as necessary to ensure that the public is aware of our activities and has adequate opportunity to comment. Typically, this process takes two to six months to complete sufficiently to meet approval requirements.

First Nation consultation will be triggered by the referral process associated with the acquisition of Crown Land acquisition process and is also a component of meeting the OGC's expectations for project approval. In 1997, TGVI commissioned the Cornerstone Planning Group to evaluate the First Nations Consultation process that would be required by such looping projects. As part of its ongoing operational strategy, TGVI is developing Memorandum of Understandings (MOU) with most First Nations in our operational area. While these MOUs do not contain specific commitments, they do embody TGVI's general commitment to working with local First Nations to the betterment of both. TGVI has been proactive in pursuit of this commitment, and will undertake all First Nation consultation necessary to ensure successful completion of these facilities.

1.4.4 Socioeconomic Assessment

Typically, pipeline looping projects have a positive economic impact on local economies. A typical 20km loop provides approximately 27 person years of employment. However, once operational, these loops will provide limited maintenance employment. It is anticipated that at least some of construction skills required for each loop should be available in the local labour market. In turn, the hiring of local workers should contribute to a modest, short-term improvement in the number of EI claimants registered with Human Resources Development Canada, plus generate several indirect and induced jobs in local economies.

1.5 Schedule

Below is a typical schedule for the construction of a pipeline loop. The schedule is less controlled by the length of the proposed loop than by the regulatory and land acquisition processes. Typically, the timeline to construct such loops is two years or less from initial approvals. If required, compressing the timeline may be possible, particularly if regulatory approval and land acquisition can be expedited.

Typical timeline to construct a pipeline loop

Timeline	Activity
Project Start	Initial Engineering & Design
Start + 8 Months	Consultation, Regulatory Approvals & Land Acquisition
Start + 10 Months	Detailed Engineering & Design
Start + 11 Months	Work Order Approvals
Start + 14 Months	Materials Procurement
Start + 22 Months	Construction of Pipeline
Start + 23 Months	Testing & Commissioning
Start + 24 Months	In Service

2.0 SPECIFIC CONSIDERATIONS

In 1997, TGVI commissioned Colt Engineering and Golder and Associates Ltd. to conduct a looping study from kp 0.0 on the 10" Mainland pipeline to kp 131.95 at Secret Cove. Colt concluded that it is feasible to loop the entire 10" mainland pipeline in close proximity to the existing pipe within a two year construction timeframe. With the exception of the Texada pipeline loop which was not part of this study, all proposed loops fall within the study area. A Texada Island pipeline loop was not part of the Colt report's scope; however, in TGVI's own assessment, this Loop is feasible as well.

The existing pipeline corridor was chosen in 1989 on the basis of geotechnical, environmental, land use and property ownership considerations consistent with current route selection techniques. From a safety, integrity and cost perspective, geotechnical considerations were particularly important in the selection of the original route. These considerations included topography, surficial geology, surface and subdrainage, and slope stability. The selection of the most geotechnically sound route was also important from an environmental perspective to minimize erosion and sedimentation problems. This information remains available and the proposed pipeline loop projects will benefit from this previous work and experience.

In conjunction with the Colt Engineering report, overview flights were taken to examine the routes and to determine how they could be adjusted to avoid areas of concern. Selection of the route for expanding the pipeline was dictated by the alignment of the existing pipeline. Aligning each loop adjacent to the existing pipeline has the following advantages over selecting a new corridor:

- the general route is often utilized by both the pipeline and BC Hydro transmission lines right-of-way;

- there is a significant amount of environmental and geotechnical information available for this route from the previous work undertaken;
- potential problems for construction of the pipeline are well understood as they have been previously encountered and mitigation measures have been used and tested; and
- a parallel route minimizes the number of potential environmental issues.
- more economical, fewer unknowns, and previously accepted by regulatory agencies.

2.1 Loop 25km d/s watershed (Watershed to Sky Pilot Creek)

Loop 25km d/s watershed starts at kp 0.0 on the 10" Mainland pipeline, where the pipeline emerges from the Greater Vancouver Water District (GVWD) watershed, and continues to Sky Pilot Creek at kp 25.7. In general, this loop parallels the existing pipeline through the Hixon Creek, Brandt Creek, Indian River and Stawamus River Valleys. These valleys are narrow to moderately wide, having steep slopes comprised of loose to compact granular soils and talus overlying steeply sloping intact bedrock.

While numerous small, steep gradient, low fish value stream crossings are required, the main river crossing in this section is of the Indian River. The Indian River has considerable environmental value and will require a carefully designed crossing to avoid HADD triggers and other concerns.

Reasonable construction access exists by existing forestry roads, although the Hixon Creek Valley presents some construction access challenges. The shoefly roads installed during the original construction would need to be temporarily re-commissioned.

2.2 Loop 13km d/s SP Creek (Sky Pilot Creek to Squamish)

Loop 13km d/s SP Creek starts downstream of Sky Pilot Creek at kp 25.7 on the 10" Mainline and continues to the proposed Squamish compressor station at kp 38.5. Initially, this section enters the steep and narrow Stawamus Valley where thin granular soil overlying bedrock is anticipated. Construction challenges in this area include unstable rock fall areas and limited access. At about kp 34, this section exits the narrow Stawamus Valley, and enters the wider Squamish Valley slope. Over the first half of the Squamish Valley ground conditions are generally good as soil is of variable thickness over bedrock. The last two kilometers of the loop will be installed in flood plain sediments, and the pipeline loop design will need to consider the liquefaction potential of such sediments given the relatively high seismic rating of the Squamish area (seismic zone 3). While several minor drainages and creeks are crossed by the loop, no major river crossings are required. Reasonable construction access exists by existing forestry roads, although several shoefly roads installed during the original construction will need to be temporarily re-commissioned.

2.3 Loop 12km d/s V2 (Squamish to Woodfibre)

Loop 12km d/s V2 begins downstream of the proposed Squamish compressor station at kp 38.5 on the 10" Mainline and continues to the Woodfibre Block Valve at kp 50.1. In general, this loop exits the Squamish River Valley by crossing the Squamish River and climbing over the western valley wall to Woodfibre. As with Loop 13km d/s SP Creek, consideration to seismic design appropriate for the conditions and seismic zone rating will be necessary. While several creek and minor river crossings with environmental value are crossed and will require design and approval consideration, one of the main challenges of this loop will be the crossing of the Squamish River. However, the original pipeline was installed by directional drill without issue. It is proposed that the loop crossing be installed in a similar fashion. Construction of the loop will also be constrained by Squamish's urban development.

The loop section between kp 43 and kp 50 is confined by very steep to near vertical exposed bedrock and/or unstable soil slopes over bedrock. Loop construction in this section is considered difficult, but feasible. As with the original construction, specialized construction procedures for steep slopes and difficult ground conditions will need to be employed.

2.4 Loop 40km d/s Woodfibre (Woodfibre to Port Mellon)

Loop 40km d/s Woodfibre begins downstream of the Woodfibre Block Valve at kp 50.1 on the 10" Mainline and continues to the Port Mellon Mill Block Valve at kp 89.9. In general, this area comprises rugged bedrock with access only from Woodfibre. The original pipeline route scales a steep slope out of the creek valley at about kp 55.5 using a switchback.

From about kp 60, the loop follows a series of wide water course valleys in granular soil overlying bedrock. Leaving the Sechelt Watershed into McNab Creek (kp 64.5), the route crosses a series of known slope instabilities and washouts and ascends steep slopes to a maximum elevation of about 3,800 ft in Box Canyon at about kp 78.5.

2.5 Loop 19km d/s V3 (Port Mellon to Sechelt)

Loop 19km d/s V3 begins downstream of the Port Mellon Compressor Block Valve at kp 91.4 on the 10" Mainline and continues to the Sechelt Airport Block Valve at kp 110.0. From Port Mellon, the route follows the south side of the Dakota Creek valley which is steeply sloped with a series of gullies and tributary creek crossings. Looping in this area should encounter thin granular soil and rock fall debris overlying bedrock. From Dakota Creek, the route crosses overland and through Wilson Creek at kp 105.0 towards Sechelt. The expected soil conditions comprise varying thicknesses of course granular soils, cobbles and boulders over hummocky bedrock. Near Sechelt, looping will be restricted by existing land uses and an existing narrow utility corridor crossing native lands.

2.6 Loop 27km d/s V3(b) (Texada Island)

Loop 27km d/s V3(b) begins at the Anderson Bay block valve at kp 0 of the 10" Texada Island pipeline and continues to the Texada Block Valve at kp 26.7. In general, this loop commences from the Texada Island block valve at the landing of the Secret Cove Marine pipelines, gradually climbs northwest along the center of Texada Island to the Texada Island block valve approximately half way up the island. The anticipated soil conditions comprise generally thin, variable granular soils over hummocky intact bedrock. While numerous small creeks and marshes with environmental value are crossed and will require design and approval consideration, no major rivers are encountered. Reasonable construction access exists by existing forestry roads, although several shoefly roads installed during the original construction will need to be temporarily re-commissioned.

2.7 Capital Costs for Land Loops

TGVI's forecast of capital costs (in 2004$) for the individual loops are outlined in **Table 2.7**. These forecasts include obtaining all approvals, materials, labour, land acquisition where necessary and right-of-way preparation, engineering design consultants, project management, testing and commissioning.

Table 2.7: Cost Summary ($ 2004 Direct)

Location	Cost ($000,000)
Loop 25km d/s watershed	$23
Loop 13km d/s SP Creek	$15
Loop 12km d/sV2	$12
Loop 40km d/s Woodfibre	$36
Loop 19km d/s V3	$17
Loop 27km d/s V3(b)	$25

Costs outlined in Table 2.7 are based on TGVI's experience, historic information from the original pipeline construction and information provided by Colt Engineering et al.

3.0 SECHELT CROSSING

In 1997, TGVI commissioned INTEC Engineering, Inc. of Houston to conduct a feasibility study to evaluate the engineering, construction, cost and schedule for a planned natural gas pipeline crossing of the Strait of Georgia to Vancouver Island, Canada.

The study area ranged from the Sechelt airport on the Sunshine Coast, to Harmac, Vancouver Island, on the south. It included the marine portions of the pipeline crossing the Strait of Georgia and the Northumberland Channel, as well as the landlines from Sechelt to Wilson Creek landfall, across Gabriola Island, and from landfall near Joan Point to the Harmac and then to the Main Line.

3.1 Routing

3.1.1 Sechelt Airport Block Valve to Wilson Creek Landfall

The corridor from the Sechelt Airport Block Valve runs in a straight line to the Wilson Creek Landfall, crossing relatively flat terrain and passing to the east of the airport proper. The corridor crosses a BC Hydro corridor north of the airport. The route also crosses Highway 101 and several smaller roads as well as Wilson Creek. It does not cross any park or Indian Reserve lands. The corridor is generally lightly populated with some density near the Wilson Creek Landfall. The length is approximately 5.5 kilometers.

3.1.2 Wilson Creek Landfall to Gabriola Island Landfall (Strait of Georgia Crossing)

The corridor passes from the Wilson Creek Landfall through three intersection points and on to the Gabriola Island East Landfall while crossing Strait of Georgia. The length of the crossing is 34 kilometers. The maximum depth of the crossing of Strait of Georgia is 395 m.

3.1.3 Gabriola Island

Several routes across Gabriola Island have been reviewed. The final route selection is dependent on the selected landfall site south of Hoggan Lake. The length is approximately 6.3 kilometers. The routes cross a number of minor local roads. No streams are crossed by any of the corridors on the Island.

3.1.4 Gabriola Island to Vancouver Island (Northumberland Channel Crossing)

The crossing traverses a narrow shipping channel, used by small craft and coastal traffic avoiding open water on the outside of the Gulf Islands. The orientation and location of the crossing may be altered based on geotechnical information or crossing methodology, which in this review is considered to be by directional drill. Geotechnical investigations and preliminary design work would be required to confirm the suitability of this location for a directionally drilled installation. The maximum water depth in this channel is approximately 5 m. The scaled distance across the channel is 1,000 m. A drill trajectory under Northumberland Channel would be approximately 1,500 m long. A local distribution BC Hydro aerial powerline crosses the channel to the east and another to the west.

3.1.5 Vancouver Island Landfall to Harmac Main Line

The corridor from Joan Point to the Harmac Main Line was selected as a direct route through undeveloped property. The area falls within the City of Nanaimo boundary. The termination is at the Harmac Main Line Pigging station. The length is approximately 13.4 kilometers.

3.2 Pipeline Construction Methods

The pipeline construction methods differentiate between the onshore, shore approach, and the marine pipeline. The following candidate methods have been reviewed:

3.2.1 Onshore Pipeline

- Weld and bury

3.2.2 Shore Approaches

- Pull from shore (pipe string welded on barge)
- Pull from tug barge (pipe string welded on shore)
- Directional drilling

3.2.3 Marine Pipeline

- Bottom pull
- Tow methods (various)
- Conventional pipelay (S-lay)
- Modular J-lay
- Reel method

Each marine crossing method has pros and cons that require additional site specific analysis. Confirmation of the final construction methods would be confirmed in the next stage of project development.

3.3 Environmental and Permitting Considerations

A comprehensive investigation into the Environmental Considerations impacting the proposed pipeline crossing will be required including land use and permitting. Other considerations likely to impact the design of the pipeline as well as influence the selection of shore crossing locations are listed below:

- Oceanography (with hindcasting of weather conditions)
- Geology
- Seismicity
- Biological resources
- Cultural resources (historical and archaeological)

A detailed site investigation would be undertaken to determine design constraints unknown at this time. An environmental impact assessment will also be required and it is anticipated that this investigation will be part of the permitting process.

3.4 Conclusions

The following were the principal conclusion of the Intec study:

1. The identified route, selected crossing locations, and associated construction methods are feasible.
2. Environmental requirements appear likely to be a strong driving factor. On this basis, a directionally drilled crossing at Northumberland Channel appears to be most attractive, with conventional shore crossings at Wilson Creek and the east landfall to Gabriola Island.
3. The principal unknown factor is whether the soils below the Northumberland channel crossing will be suitable for directional drilling at acceptable risk. Present knowledge of the soils is limited. New soil borings at the proposed location would allow this risk to be better defined. In the absence of this information, the shore-to-shore drilling is assigned the highest risk level.

3.5 Capital Cost for Crossing

Costs based on the various construction methods were derived in order to carryout a feasibility level, cost analysis. These costs were based on Intec in-house data and preliminary discussions held with potential construction equipment suppliers.

The estimated costs are based on the route survey data provided along the centerline of the pipeline corridor. The data provided in adjacent areas show that there is potential to reduce the number of spans, and thus the costs for the span supports, by re-routing the pipeline away from the high spanning areas. This would be investigated in the detailed engineering phase.

The total cost estimate for the crossing including onshore pipeline, shore approaches and the marine pipeline is $83 million based on inflating Intec's 1997 estimate to $2004.

APPENDIX I

LNG Storage

1.0 NATURAL GAS STORAGE

The following is a description of Terasen Gas (Vancouver Island) Inc. (TGVI)'s, natural gas storage proposal for a 1 Bcf liquid natural gas storage facility to be located in the Cowichan Valley Regional District (CVRD) adjacent to TGVI's Vancouver Island transmission pipeline network.

A site has been selected at a location known as Mt. Hayes, approximately 6km NW of Ladysmith. Rezoning for LNG use was approved for the site by the Cowichan Valley Regional District on May 26, 2004. The property, owned by Weyerhaeuser Forest Products, is in the process of being purchased (through an option agreement).

2.0 PROJECT DESCRIPTION

Terasen Gas Inc mainland (TG) owns and operates a 0.6 billion standard cubic feet ("Bcf") liquefied natural gas (LNG) storage and peak shaving facility, located on Tilbury Island in the municipality of Delta. The TGVI liquid natural gas storage proposal is based on the experience and expertise of TG in constructing and operating the Tilbury LNG facility which has been in service since December 1970 combined with current cost information provided by major LNG facility construction contractors and consultants.

2.1. Facility Design Basis

The TGVI proposal is for a 1 Bcf LNG facility to be located on Vancouver Island at a site located within the CVRD, approximately 6km NW of Ladysmith. The LNG facility will be connected directly to TGVI's existing transmission pipeline system and have the capacity to liquefy and vaporize as noted in Figure 2.1.

FIGURE 2.1: FACILITY CAPACITY TABLE		
Design Capacity	**Units**	**Capacity**
Storage	Bcf	1.0
Liquefaction Rate	mmscfd	5
Sendout Rate	mmscfd	100

2.2. Facility Components

A LNG storage facility consists of six major elements including:

- feed gas purification
- liquefaction
- LNG storage
- sendout
- facility ancillary equipment and facilities
- connecting pipeline and power line

2.2.1. Feed Gas Purification

Liquefaction of natural gas requires process temperatures to -1620C (-2600F). Any impurities such as water, carbon dioxide, heavy hydrocarbons and odorant in the feed gas must be removed to prevent fouling or plugging by the freezing of these impurities. A variety of purification systems are available with selection dependent upon the feed gas composition. The impurities removed are returned back to the gas transmission system to be mingled with the natural gas stream.

2.2.2. Liquefaction

Following the purification process, the clean gas stream is sent to a refrigeration unit where the gas is condensed to its liquid state for storage.

TGVI anticipates using a mixed refrigerant cycle liquefier (similar to the process used at Tilbury) as it generally has a lower capital and operating cost.

2.2.3. LNG Storage

After liquefaction, the LNG is stored in a double shell, insulated tank. The internal tank pressure is limited to near atmospheric pressure (a maximum of 2 psig) while keeping the LNG at -162 0C. The LNG storage system consists of a tank with an inner shell and an outer shell, and secondary containment. A thermal insulation system, consisting of expanded perlite and foam glass, separates the inner and outer shells.

The inner shell, which is in direct contact with the LNG, is made of 9% nickel alloy steel. The outer shell, designed as a vapour holding vessel, is made of carbon steel.

Secondary containment (in the form of an earthen dike surrounding the tank) capable of holding more than the total volume of the LNG tank, will be constructed according to code as a safety feature.

Figure 2.2 provides a conceptual image of a LNG facility with a low earthen dike.

FIGURE 2.2

LNG tank with a 9% nickel alloy steel inner shell, a carbon steel outer shell and a low earthen dike.

2.2.4. Sendout

A sendout system performs the following functions:

- Pumping LNG from storage to transmission line pressure
- Vaporizing liquid to form a gas
- Controlling process flow and temperature
- Odorizing and metering the sendout stream

The total sendout capacity is divided into several independent sendout systems (trains) with interconnections.

2.2.5. Ancillary Equipment and Facilities

In addition to the basic functions of liquefying, storing and sendout of natural gas, other ancillary equipment systems are required. These systems include:

- Boil-off compressors
- Security
- Backup electrical power generation
- Fire protection and control systems
- Independent monitoring and safety shutdown controls

2.2.6. Connecting Facilities

2.2.6.1. Pipelines

An LNG storage facility must be connected to the natural gas transmission system for the supply of feed gas during liquefaction and for the return of natural gas during sendout. The impurities from the purification process during liquefaction are returned to the transmission system (tail gas). As a result, an LNG facility is connected to the transmission system by two pipelines.

2.2.6.2. Powerline

Electrical power is required for general plant utilities and to supply the liquefaction compressor and sendout pumps. A minimum of 69 kV powerline connection to the electric transmission grid is required.

2.3. Facility Operations

Operation of an LNG facility involves liquefaction of natural gas during periods of low demand, typically in warmer weather periods (up to 200 days of the year), followed by sendout during periods of high demand, typically during colder winter weather. Additionally, should upstream transmission system problems occur, the plant could sendout at any time to supplement or maintain gas supply. The plant can be turned around on short notice and therefore can be filling one day and sending out the next.

The facility will be staffed 24 hours per day, every day of the year, 9 trained operators and one manager are anticipated.

Operating and maintenance standards and practices will be developed for the new facility based on the proven standards and practices utilized by TG at its Tilbury Facility.

2.4. Environmental and Safety Considerations

2.4.1. Environmental & Social Review

The operation of the proposed LNG facility at the Mt. Hayes site will not have any significant impact on the environment following planned mitigation. Details of the Environmental and Social Review (ESR) completed for the proposed site can be found on Terasen Gas' web site at www.terasengas.com. (Note: The ESR was completed based on the potential of a 1.5 Bcf storage facility being constructed, however it has now been determined that the facility will be 1.0 Bcf in size). An Environmental Management System (EMS) will be developed for the design and operation of the facility.

2.4.2. Safety

LNG facilities have a proven public safety record. There have been no LNG accidents affecting the general public in North America in the last 55 years. Hundreds of such facilities, constructed to rigorous design codes, are safely operating in North America and elsewhere in the world. TG's existing Tilbury LNG Facility has operated safely without incident since being placed into operation in 1970.

3.0 FACILITY SITING

3.1. Background

The primary purpose of the proposed LNG Facility is to meet the gas load demands of TGVI's customers on Vancouver Island. Consequently, siting of the LNG facility must allow for sendout into the TGVI gas transmission system. In addition, the location of the facility must also consider operational flexibility and capacity benefits to the transmission system.

Given this purpose, studies were initiated to determine whether suitable areas within the TGVI region, and eventually a site, could be identified to locate the facility. The area chosen for the study included a ten km wide band centred on the TGVI main transmission pipeline on Vancouver Island.

The ESR provides details of the site selection and public consultation process that was undertaken to locate the final site at Mt. Hayes, in the Cowichan Valley Regional District, approximately 6 kms NW of Ladysmith.

The following map illustrates the approximate location of the proposed LNG facility.

4.0 REGULATORY / APPROVALS PROCESS

There are a number of Regional, Provincial and Federal Agencies that could be involved in the review and approval of the storage proposal.

4.1. Utilities Commission Act

As a public utility, TGVI must apply to the British Columbia Utilities Commission ("BCUC") for a Certificate of Public Convenience and Necessity ("CPCN") to build and operate an LNG facility.

4.2. Regional: Municipal or Regional District Zoning

TGVI has successfully received rezoning approval from the CVRD for utilization of the selected site at Mt. Hayes for LNG Storage.

4.3. B.C. Oil and Gas Commission

The BC Oil and Gas Commission ("OGC") regulates the design, construction and operation of LNG storage facilities that feed into the gas transmission system. In addition, the OGC is responsible for specified permits under the Oil and Gas Commission Act. TGVI has applied to the OGC for easements for the segments of connecting pipelines, powerline and access road improvements that fall within crown land as well as for a lease for a portion of crown land required to extend TGVI control to limit potential future development that falls within the LNG facility safety buffer zone.

4.4. Environmental Review

The BC Environmental Assessment Act ("BCEAA") is not triggered as the proposed 1 Bcf LNG facility falls well beneath the 3 Pj limits for reviewable energy storage projects. Similarly, a comprehensive review under the Canadian Environmental Assessment Act ("CEAA") is not required based on the characteristics of the Mt. Hayes site.

Regardless, TGVI has completed the ESR which was filed with the CVRD rezoning application and which was intended to be similar in nature to the environmental considerations, mitigation requirements and public process that would normally be reviewed under the provincial and federal EA Act(s).

4.5. Permits and approvals

Once the LNG project receives regulatory approvals, it will be necessary to seek specific permits and authorizations from a number of provincial bodies including the OGC, the BC Boiler and Pressure Vessel Branch and various provincial ministries.

5.0 COST ESTIMATES

Capital costs include such items as: land, storage tank (including secondary containment), process facilities for liquefaction and vaporization and connecting facilities as well as other items. Operating costs are further designated as fixed and variable (based on sendout) costs. Operating costs include routine maintenance, as well as plant operating costs (O&M) and exclude fuel.

5.1. Cost Assumptions

5.1.1. Capital Cost

A cost of $94.3 million ($2004 Direct) is estimated for the facilities described in Section 2. The Equipment and construction costs are based on information provided by major LNG facility EPC contractors and consultants. Costs for project services, land, connections, etc. are based on the experience of TG and TGVI.

5.1.2. Operating Costs

Fixed costs of $930,000/year include regular staff required to operate and maintain the facility, utility costs, materials and contractors for routine preventative maintenance, annual licensing and inspection fees, right of way maintenance for interconnecting pipelines, and staff training costs.

Variable costs of $450,000/year include electricity consumed during liquefaction and sendout operations, extra staff costs during sendout operations, refrigerant consumption, and maintenance costs incurred due to equipment usage. Variable costs exclude natural gas fuel costs. The primary component of the variable cost is the electrical power for the liquefaction compressor.

6.0 SCHEDULE

The key factors affecting the critical path of the LNG Project include:

- The regulatory/approvals processes
- Public consultation, site evaluation (including environmental assessment) and acquisition
- Site preparation and foundations construction
- Storage tank, secondary containment and equipment installation

Based on completion of the purchase of the Mt. Hayes site and receipt of an EPC price from a contractor and CPCN approval by the end of 2004 and a construction period of up to 27 months (including commissioning and start-up), an in service date of November 01, 2007 can be achieved with more than 25% tank fill, which is sufficient storage for the first operating season.

APPENDIX J

Demand Side Management Programs

Current Customer Programs

1. Home Builders Grand

Program Description: $1000 incentive for builders and developers to install an Energy Star qualified natural gas high efficiency furnace or boiler in combination with natural gas domestic hot water in residential new construction applications. It is being delivered in partnership with Natural Resources Canada, BC Hydro and industry suppliers. The program supports provincial and federal market transformation strategy for home heating systems.

Objective: To increase the penetration of high efficiency natural gas space heating and water heating systems in the new construction market.

Market Barriers: The primary barriers are the long lead times required for builders, the upfront capital cost of natural gas systems as compared to electric, the higher price and greater installation complexity associated with high efficiency gas systems, contractor and builder familiarity with high efficiency natural gas heating systems, and product availability.

Customer Benefits: This program has two levels of customers who benefit: the builders and developers who receive the incentives to offset the higher capital cost and yet receive an attractive heating system to assist in the sale of the home, and the eventual homeowners who benefit from efficient and economic gas space and water heating systems.

Expected program impact: There are 500 participants projected in 2004. Although there is a significant benefit from fuel substitution in this service territory, limiting the scope to the savings derived from upgrading from conventional mid-efficiency to high efficiency space heating results in 110,000 gigajoules (GJ) savings and 6,000 tonnes of CO_2e over the life of installed equipment.[1]

2. Build Smart Program

Program Description: $75 incentive for builders and developers for each pre-piped appliance outlet in homes where natural gas heat and domestic hot water is installed during residential new construction.

Objective: To increase the penetration of natural gas end uses in the existing residential market.

Market Barriers: The primary barriers are the lack of primary demand driven by end users, and the additional upfront costs to the builder associated with pre-piping.

Customer Benefits: This program has two levels of customers who benefit: the builders and developers who receive the incentives to offset or eliminate the cost of pre-piping and yet receive an additional selling feature of the home, and the eventual homeowners who have more options around energy choices when selecting appliances for their home now or in the future.

Expected program impact: There are 550 participants projected in 2004.

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[1] Assumed life of a furnace is 25 years.

3. Conversion Program

Program Description: Possible program planned for fall 2004 to provide $600 incentive to homeowners who convert their space and water heating from another energy source to natural gas. This offer is complementary to the Province's current Clean Choice Grant that provides conversion incentives from oil or electric heat. These two programs provide combined incentives of up to $1200. There is potential for expansion in both scope (other end uses, such as ranges and dryers) and scale in 2005 as a result of expected BC Hydro interest in pursuing fuel substitution opportunities.

Objective: To improve distribution system utilization by adding economic customers to increase penetration of natural gas space and water heat by converting customers from other energy sources.

Market Barriers: The primary barriers are the up-front capital costs associated with converting energy sources, and the market's acceptance and familiarity with other energy sources for the home. The popularity of baseboard electric heat limits the market potential of this program – a conversion from baseboard to gas typically requires a very expensive and involved conversion in most cases and therefore the application of this program is limited primarily to customers who use non-baseboard means to heat their homes. Lack of awareness of the benefits of natural gas is another barrier.

Customer Benefits: The customer receives significant incentives to convert their heating system which may operate at lower costs, and, in the case of oil, a much cleaner burning fuel. Interest in the program has increased since many insurance companies will not insure homes with older or in-ground oil tanks.

Expected program impact: 150 participants are anticipated in 2004 for the furnace conversion and 90 participants for the domestic hot water incentive.

Proposed New Programs

1. Residential Fireplace Upgrade Program

Program Description: Program providing $100 incentive to upgrade decorative log set to an EnerGuide 55% minimum FE-rated heater style fireplace. The program, available to all Terasen Gas customers (except Whistler), provides matching incentives from Natural Resources Canada, Fireplace Suppliers and—if the homes are electrically heated—BC Hydro. The Pilot program will launch in June of 2004 with a full program launch expected in 2005.

Objective: To replace existing residential decorative fireplaces with higher efficiency fireplaces in order to reduce overall fuel costs, measure the impact of fireplace program, and promote the new EnerGuide rating among gas contractors and consumers.

Market Barriers: The primary barriers are the upfront capital cost of a new fireplace, the accessibility of eligible fireplaces in all communities, and the consumer misperception that existing decorative fireplaces are already efficient.

Customer Benefits: The customers will be able to offset their space heat requirements, have a backup heat source in case of electrical outages, and have the benefits of heating fireplace in high use rooms.

Expected Program Impacts: For the 200 expected participants in 2004, the cost will be $30,000 but is expected to result in forecast reductions of 70,000 GJs and 3,700 tonnes of CO_2e over the life of the installed equipment.[2]

2. Consumer and Small Business Partnership

Program Description: Proposed multiple partner energy efficiency program pilot.

Objective: To provide a harmonized delivery program to increase installation of high efficient equipment in the market.

Market Barriers: to be identified

Customer Benefits: to be identified

Expected Program Impacts: To be determined; program is currently at the conceptual stage of development.

3. Commercial Boiler Upgrade

Program Description: Proposed program to provide incentives to improve overall hydronic system efficiency for commercial and multi-family customers.

Objective: To improve efficiency of commercial boilers.

Market Barriers: The primary barriers are the upfront capital cost of the upgrade, the misperception that existing systems are already efficient and limited awareness of the program.

Customer Benefits: Participants are able to lower gas usage and overall operating costs.

Expected Program Impacts: Five customers are expected to participate in 2004, with a forecast reduction of 175,000 GJs and 9000 tonnes of CO_2e of the life of the installed equipment.[3]

4. Commercial Utilization Advisory

Program Description: On site assessments of commercial and multi-family energy systems identifying efficiencies and potential savings to the customer.

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2 Assumed average life of a fireplace is 25 years.

3 Assumed average life of a commercial boiler is 25 years.

Objective: To provide commercial and multi-family customers an impartial no-cost evaluation of their energy systems in order to use potential savings as the incentive to make system improvements.

Market Barriers: The primary barriers are limited awareness of the program and the limited knowledge of consumers regarding the potential savings that could be achieved.

Customer Benefits: Participants receive a detailed assessment of their energy systems and the potential savings that are available to offset the capital costs.

Expected Program Impacts: Ten customers are expected to participate in 2004, with a forecast reduction of 100,000 GJs and 5000 tonnes of CO_2e of the life of the installed equipment.

5. Natural Gas Conservation Potential Review

Project Description: A market and technology analysis of the Vancouver Island service area to quantify attainable energy savings—inclusive of fuel substitution potential.

Objective: To provide a strategy that uncovers conservation potential for the unique resource-bound Vancouver Island territory.

Market Barriers: The primary barriers to providing a conservation potential is identifying the true avoided cost of electricity and the complex interrelationship between natural gas and electrical supply on Vancouver Island.

Customer Benefits: Increased energy efficiency and economic load addition programs may result from the study and new programs may be uncovered.

Expected Program Impacts: It is estimated that the CPR for the entire Terasen Gas service territory will be approximately $320,000. Terasen Gas is seeking partner(s) interested in collaborating and sharing the costs to fund this initiative.

APPENDIX K

Stakeholder Consultation Written Submissions

bp

IGI Resources, Inc.

Doug Stout
VP, Gas Supply
Terasen Gas Utility Ltd.
16705 Fraser Highway
Surrey, BC V3S 2X7

May 17, 2004

Re: TGVI Customer Advisory Council Meeting May 2004

Dear Doug:

On behalf of the Joint Venture I would like to thank Terasen Gas Utility - Vancouver Island (TGVI) for the opportunity to attend the above meeting and further understand Terasen's plans for the long term strategies for reliable cost effective delivery of natural gas to Vancouver Island.

In response to TGVI's suggestion that LNG is the optimal solution for long term capacity the Vancouver Island Gas Joint Venture (JV) would like to ensure that both TGVI and the BCUC see the JV's members mills as a realistic alternative to the need to match capacity and demand over the long term.

We would expect that in order to properly evaluate alternatives TGVI would be able to present the JV with accurate costs for the proposed LNG solution and present a concrete financial offer that would reflect a DSM solution that would match or better the TGVI's proposed LNG solution.

Finally the JV would encourage TGVI to explore options with the BCUC to ensure there is a level playing field for TGVI's shareholders between Rate of Return Capital additions and Demand Side Management initiatives located at customer sites. Without such equity we would see it difficult for TGVI to be able to present an un-biased solution to the future capacity problem.

We look forward to TGVI's filing of the Resource Plan in June.

Sincerely,

Jim Langley for
Dave Hargreaves
Chair, Vancouver Island Gas Joint Venture

c. Rob Pellatt, Secretary, BCUC
Mgmt Committee, VIGJV

Fax Cover Sheet

IGI Resources, Inc.

Date :	**May 17, 2004**
Pages:	**2**
To :	**Doug Stout** **Rob Pellatt;**
Company :	**TGU** **BCUC**
Fax Number :	**~~604-592-7891~~** **604 660 1102**
From :	**Jim Langley Ph 604 982 0204 Fx 604 982 0206**
Subject :	TGVI CAC Response

Comments from the Ministry of Energy and Mines:

-----Original Message-----
From: Pape-Salmon, Andrew EM:EX [mailto:Andrew.PapeSalmon@gems8.gov.bc.ca]
Sent: Monday, May 17, 2004 1:35 PM
To: Pape-Salmon, Andrew EM:EX; James Wong
Cc: Bates, Stirling EM:EX; Green, Dan L EM:EX; Wieringa, Paul EM:EX; 'Stephen Connelly (E-mail)'

Subject: RE: Written Stakeholder Comments for Terasen Gas Vancouver Island's (TGVI) Resource Plan

Please note that we are supportive of the overall plan outlined in the DSM section of the TGVI Resource Plan. Following the completion of a Gas Conservation Potential Review, we would be pleased to work with you to identify other potential initiatives and programs in 2005 and beyond.

Sincerely,
Andrew Pape-Salmon

Andrew Pape-Salmon, P.Eng., MRM
Senior Policy Advisor - Energy Efficiency and Conservation Alternative Energy Policy Branch
Ministry of Energy and Mines
Government of British Columbia
Email: Andrew.PapeSalmon@gems8.gov.bc.ca
Tel: 250-952-0819 http://www.em.gov.bc.ca/AlternativeEnergy/default.htm

APPENDIX L

Least Delivered Cost
Portfolio Measurement Results

Table L-1. Incremental Costs and Storage Benefits for all demand forecasts discounted at 6%

Base Case +0 TJ/d (PV 2004-2026 @ 6%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	178	167	88
Fuel Differential	-	(5)	2
Storage Benefit	(89)	-	-
Curtailment Cost	-	-	?
Effective Cost	**89**	**163**	**90 + ?**

Base Case +20 TJ/d (PV 2004-2026 @ 6%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	212	230	136
Fuel Differential	-	(12)	0
Storage Benefit	(89)	-	-
Curtailment Cost	-	-	?
Effective Cost	**123**	**218**	**136 + ?**

Base Case +45 TJ/d (PV 2004-2026 @ 6%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	261	279	216
Fuel Differential	-	(33)	(22)
Storage Benefit	(87)	-	-
Curtailment Cost	-	-	?
Effective Cost	**174**	**246**	**194 + ?**

High-High Case (PV 2004-2026 @ 6%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	312		283
Fuel Differential	-		(40)
Storage Benefit	(89)		-
Curtailment Cost	-		
Effective Cost	**223**	**-**	**243 + ?**

Low-Low Case (PV 2004-2026 @ 6%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	169	101	47
Fuel Differential	-	(1)	(1)
Storage Benefit	(88)	-	-
Curtailment Cost	-	-	?
Effective Cost	**82**	**100**	**46 + ?**

Table L-2. Incremental Costs and Storage Benefits for all demand forecasts discounted at 6%

Base Case +0 TJ/d (PV 2004-2026 @ 10%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	120	104	55
Fuel Differential	-	(2)	1
Storage Benefit	(59)	-	-
Curtailment Cost	-	-	?
Effective Cost	**61**	**101**	**57 + ?**

Base Case +20 TJ/d (PV 2004-2026 @ 10%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	142	149	86
Fuel Differential	-	(7)	1
Storage Benefit	(59)	-	-
Curtailment Cost	-	-	?
Effective Cost	**82**	**142**	**87 + ?**

Base Case +45 TJ/d (PV 2004-2026 @ 10%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	174	185	139
Fuel Differential	-	(21)	(14)
Storage Benefit	(59)	-	-
Curtailment Cost	-	-	?
Effective Cost	**115**	**164**	**125 + ?**

High-High Case (PV 2004-2026 @ 10%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	205		182
Fuel Differential	-		(18)
Storage Benefit	(59)		-
Curtailment Cost	-		
Effective Cost	**146**	**-**	**164 + ?**

Low-Low Case (PV 2004-2026 @ 10%, $M)	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Incremental Facility Cost	116	65	30
Fuel Differential	-	(1)	(1)
Storage Benefit	(58)	-	-
Curtailment Cost	-	-	?
Effective Cost	**57**	**64**	**29 + ?**