Terasen Gas

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

16705 Fraser Highway
Surrey, B.C. V3S 2X7
Tel: 604-592-7784
Fax: 604-592-7890
Email: scott.thomson@tersengas.com
www.terasengas.com

August 4, 2004

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Mr. R.J. Pellatt
Commission Secretary

Dear Sirs:

Re: Terasen Gas (Vancouver Island) Inc. ("TGVI")
Application for a Certificate of Public Convenience and Necessity (CPCN")
LNG Storage Project

Pursuant to Section 45 of the Utilities Commission Act, TGVI hereby files with the British Columbia Utilities Commission ("Commission") twenty (20) copies of an Application for a CPCN to construct and subsequently operate a new LNG Storage Facility. This LNG facility is to be constructed at a location referred to as Mount Hayes, in the Cowichan Valley Regional District near Ladysmith. TGVI will post the Application on the TGVI website at www.terasengas.com under Publications, Vancouver Island, and then BCUC.

TGVI filed its 2004 Resource Plan with the Commission on June 18, 2004 in accordance with the Resource Planning Guidelines released by the Commission in December 2003.

TGVI requests that the Commission's review of its 2004 Resource Plan and this CPCN Application take place concurrently. Many of the issues to be reviewed by the Commission and interested parties are common to both documents and a merging of the two processes will eliminate any duplication or overlap of activities associated with each review. Streamlining the process in this manner will also more specifically focus the review on the economic justification of the LNG Storage Project.

If there are any questions on the attached reports prior to our meeting, please contact Mike Davies, P.Eng. at 604-592-7836.

Yours very truly,

TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed by Tom Loski

For: Scott A. Thomson

Enclosures

Terasen Gas

LNG STORAGE PROJECT

IN THE MATTER OF the Utilities Commission Act, R.S.B.C. 1966, Chapter 473 (the "Act")

AND IN THE MATTER OF an Application by Terasen Gas (Vancouver Island) Inc. for a Certificate of Public Convenience and Necessity Pursuant to Section 45 of the Act

Submitted to the British Columbia Utilities Commission

August 2004

TABLE OF CONTENTS

IN THE MATTER OF the Utilities Commission Act, R.S.B.C. 1996, Chapter 473 (the "Act")

AND IN THE MATTER OF an Application by Terasen Gas (Vancouver Island) Inc. ("TGVI" or the "Company") for a Certificate of Public Convenience and Necessity ("CPCN") pursuant to Section 45 of the Act.

To: The Secretary
British Columbia Utilities Commission
6th floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

1. APPLICATION

1.1 APPLICANT

1.1.1 NAME, ADDRESS AND NATURE OF BUSINESS

TGVI is a company incorporated under the laws of the Province of British Columbia and is a wholly owned subsidiary of Terasen Inc. ("TI"). TGVI maintains an office and place of business at 1111 West Georgia Street in the City of Vancouver in the Province of British Columbia, V6E 4M4.

TGVI operates a high-strength steel transmission pipeline beginning in Coquitlam and crossing the Strait of Georgia from Powell River to the Courtenay-Comox area. TGVI delivers natural gas to approximately 80,000 homes and businesses and seven pulp mills.

1.1.2 FINANCIAL CAPABILITY OF APPLICANT

TGVI is regulated by the British Columbia Utilities Commission ("BCUC" or "Commission"). TGVI is capable of financing this Liquefied Natural Gas ("LNG") storage facility either directly or through its parent, TI. TI has credit ratings for unsecured debentures from Dominion Bond Rating Service, Moody's Investors Service and Standard and Poor's of A (low), A3 and BBB-, respectively. TI has, through its subsidiary companies, completed large-scale system implementation projects and has the financial capacity to undertake them by means of borrowing and from funds internally generated from business operations.

1.1.3 TECHNICAL CAPABILITY OF APPLICANT

TGVI delivers natural gas to approximately 80,000 homes and businesses and seven pulp mills on the Sunshine Coast and Vancouver Island. TGVI has designed, constructed, and operated its system of integrated high-pressure and low-pressure pipelines since 1991 when the Vancouver Island Natural Gas Pipeline was completed. TGVI and its affiliate Terasen Gas Inc. ("TGI") operate more than 30,000 kilometres of gas transmission and gas distribution mains and service lines in British Columbia.

1.1.4 NAME, TITLE AND ADDRESS OF CONTACT

Communications with respect to this Application should be addressed to:

S.A. Thomson, C.A.
Vice President, Finance and Regulatory Affairs
Terasen Gas (Vancouver Island) Inc.
16705 Fraser Highway
Surrey, B.C. V3S 2X7

Phone: (604) 592-7784
Facsimile: (604) 572-7620
E-mail: scott.thomson@terasengas.com

1.1.5 NAME, TITLE AND ADDRESS OF LEGAL COUNSEL

Legal counsel for this Application is:

S.M. Richards
General Counsel, Chief Risk Officer & Corporate Secretary
Terasen Gas (Vancouver Island) Inc.
1111 West Georgia Street
Vancouver, B.C. V6E 4M4

Phone: (604) 443-6631
Facsimile: (604) 443-6630

1.2 PROJECT DESCRIPTION

TGVI proposes to construct and operate a new LNG storage facility to be constructed at a location referred to as Mount Hayes, in the Cowichan Valley Regional District ("CVRD") near Ladysmith (the “Project”). The LNG facility will provide storage capacity and peaking resources for TGVI.

The Mount Hayes location in the CVRD is approximately 6 km northwest of Ladysmith. Rezoning of the site for LNG facility use was approved by the CVRD on May 26, 2004 after a comprehensive consultation process. The property, owned by Weyerhaeuser Company Limited ("Weyerhaeuser"), has been optioned by TGVI through a two-year option agreement.

The addition of the Project to the TGVI system will increase the overall capacity to serve existing and new firm demands on the system and will also provide opportunity to reduce the costs of the natural gas supply portfolio for TGVI’s sales customers. By holding LNG capacity, TGVI customers will avoid the cost of downstream storage, seasonal pipeline capacity or baseload pipeline capacity that will otherwise be required. As well, since the size of the LNG facility will be greater than TGVI’s immediate needs, TGVI can offer storage services to TGI and others in the region at the market price of storage. This will serve to mitigate the revenue requirement associated with the Project until such time as the capacity is required to serve growing demand in TGVI's service territory.

TGVI is confident that if the major LNG facility contract (for Engineering, Procurement and Construction of the storage facility) is awarded by January 1, 2005, the LNG facility can be constructed in approximately thirty months, leaving approximately four months to sufficiently fill the tank for the first heating season's requirements beginning on November 1, 2007. Other components of the project including connecting facilities are not on the critical path and can be readily completed within the overall schedule.

TGVI has completed a cost estimate for the Project based on information supplied by consultants and contractors, and utilizing TGVI and TGI experience in project management of other major capital projects. The estimated direct capital cost is $94.4 million ($2004).

Operating costs for the Project have been determined from TGI experience operating the Tilbury LNG facility in Delta, B.C. and from TGVI and TGI experience operating transmission pipelines throughout B.C. The estimated annual operating costs are approximately $1.5 million ($2004).

1.3 PROJECT JUSTIFICATION

Demand for natural gas on Vancouver Island and the Sunshine Coast has seen considerable growth since construction of the TGVI system, with growth expected to continue in the future. TGVI's system currently relies on peaking gas arrangements with the Vancouver Island Gas Joint Venture ("VIGJV") and BC Hydro to meet the gas requirements of the Core[1] market during periods of peak demand. With the growth in demand expected by 2007, TGVI has concluded that the addition of new facilities will be required.

TGVI submitted its 2004 Resource Plan to the BCUC in June 2004. The Resource Planning process reviewed options for addressing this requirement for new facilities and showed that an on-system LNG facility is a common component of the preferred portfolios for the most likely demand scenarios. While the benefits of portfolios with LNG increase with the addition of demand that might result from BC Hydro's Vancouver Island Call For Tenders ("VI CFT") process or the extension of natural gas service to Whistler, LNG is the preferred resource to increase capacity to the Island Cogeneration Project ("ICP") and meet forecast growth of the core market.

TGVI has determined that the Project is technically feasible. TGI has operated gas storage in the Lower Mainland for over thirty-three years. TGVI and TGI have a highly skilled and trained workforce which has the requisite experience in natural gas facility design, construction, project management and operations to construct and operate the proposed facilities. TGVI has installed and operated the Vancouver Island transmission and distribution system reliably since start-up in 1991. External engineering and environmental consultants will supplement TGVI and TGI staff where required.

1 Core sales customers are high priority customers who have no alternate fuel standby, primarily residential and commercial customers.

1.4 COST OF SERVICE

Net Present Value analyses show that the LNG Storage Portfolio is the preferred alternative for meeting TGVI's requirements in the future, primarily because it supports the Company's ability to provide natural gas service to its customers at the least delivered cost.

One of TGVI's principle objectives for rate design is to maintain competitive rates for customers, which in turn supports long-term financial sustainability of the utility. Use of the Project in conjunction with other TGVI transmission assets is planned to make the most efficient use of the combined system and thereby minimize costs that need to be recovered from sales and transport customers.

An evaluation of the impact to the customer's costs concludes that over the long term, TGVI's costs to provide natural gas services to the Core market customers are competitive with the costs of alternate fuels. This allows the Company to continue to offer competitive rates to these customers and supports TGVI's long-term financial sustainability.

The results of analyses also show that the LNG Storage Portfolio will allow TGVI to offer firm transportation services at comparable or lower rates than is currently available. As is the case for the Core customer, this benefit is expected to increase if new generation or other loads are added to the system.

1.5 REGULATORY REVIEW OF CPCN APPLICATION

TGVI requests that the Commission's review of its 2004 Resource Plan and this CPCN Application take place concurrently. Many of the issues to be reviewed by the BCUC and interested parties are common to both documents and a merging of the two processes will eliminate any duplication or overlap of activities associated with each review. Streamlining the process in this manner will also more specifically focus the review on the economic justification of the Project.

ALL OF WHICH is respectfully submitted.

August 4, 2004.

TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed by Tom Loski

For: Scott A. Thomson
Vice President, Finance and Regulatory Affairs

2. INTRODUCTION

TGVI proposes to construct and operate a one Bcf LNG storage facility to be constructed at a location near Mount Hayes in the CVRD and to be in-service in 2007. Natural gas will be delivered to the facility using available transmission pipeline capacity during the off peak season, stored as a liquid and then liquefied to meet requirements during periods of high demand. The direct cost of the Project is estimated at $94.4 million.

TGVI's 2004 Resource Plan was filed with the BCUC on June 18 2004. The Resource Plan provides an assessment of the capability of TGVI's committed resources to meet current and future demands on the system, including the potential for new generation loads, and concludes that new facilities will be required as early as the winter of 2007. A number of alternative resource portfolios were evaluated against TGVI's planning objectives:

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

In this context, the addition of an LNG facility on Vancouver Island was identified as a key component of the preferred resource portfolio to meet future requirements under a range of demand scenarios. From a cost-impact perspective alone, the LNG Storage Portfolio is a competitive alternative to other resource options if no new generation loads are developed on Vancouver Island, and is the least-cost alternative if new generation loads are developed. In addition the Project will deliver additional benefits through enhanced security of supply and operational flexibility and reduced rate volatility. This CPCN Application seeks approval of the LNG Storage Project.

The Project is expected to deliver both system capacity and natural gas commodity benefits to TGVI's customers. These benefits will allow the utility to continue to offer competitive transport and sales rates to its customers and will support the long-term financial viability of the utility. In addition, the Project will enable TGVI to provide storage services and other benefits to TGI, thereby mitigating the impact of the cost of the facility to TGVI's customers and reducing the risk of unforeseen demand reductions.

3. BACKGROUND

TGVI first identified a Vancouver Island LNG facility in 2003 as a viable and more cost-effective solution to meeting future demands on Vancouver Island than the proposed Georgia Strait Crossing (“GSX”), a joint BC Hydro/Williams pipeline project. BC Hydro had applied for approval of the Vancouver Island Generation Project (“VIGP”) at Duke Point and proposed to use GSX to provide firm transportation service to both the existing ICP and VIGP. TGVI currently provides natural gas transportation service to ICP.

BC Hydro requires new generation capacity on Vancouver Island to meet dependable capacity requirements in 2007 when the existing HVDC submarine cable system is to be retired. In September 2003, the BCUC denied BC Hydro’s VIGP CPCN Application on the basis that insufficient evidence had been provided to conclude VIGP was the most cost-effective solution to meeting Vancouver Island's electric capacity and reliability. The BCUC decision also encouraged BC Hydro to solicit proposals from the independent power market to meet the generation capacity requirement and to consider natural gas transportation options offered by TGVI as well as GSX. As a result of that decision, BC Hydro has issued a VI CFT for proposals to provide 150 to 300 MW of generation capacity located on Vancouver Island which must achieve commercial operation by 2007. The VI CFT process is expected to conclude in October 2004.

Since the BCUC decision on VIGP, TGVI has continued preliminary development activities to confirm the technical and economic feasibility of the Project, and to ensure that the Project can be put in service to meet BC Hydro’s 2007 requirement for service to meet the firm requirements of ICP and any new generation loads. Following a comprehensive community consultation process, the Mount Hayes site was identified as the preferred location for the Project. TGVI received the necessary approvals from the CVRD to develop the Project on the site in May 2004.

The need and justification for the Project is supported by TGVI's Resource Planning process. 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 impacts and risks for ratepayers over the long run"*. The Resource Plan filed in June 2004 examines various resource portfolios to meet future demands on TGVI's system over the planning period ending in 2026, including the availability and cost effectiveness of committed and potential new resources such as storage, compression or pipeline looping, and industrial curtailment.

Since the planning period extends beyond the term of the current BC Hydro Peaking Agreement and the VIGJV Peaking Gas Management Agreement ("PGMA"), the Resource Plan considers industrial curtailment as a potential resource option to replace existing commitments when they expire. Industrial curtailment, as it is discussed in the Resource Plan, is where an industrial customer curtails its use of gas in order to make its gas supply or transmission capacity available to the utility. The utility then uses the gas supply or transmission capacity to provide service to its residential and commercial sales customers during periods of peak demand. Curtailment as discussed in this Application is intended to reflect such arrangements and could include new peaking gas agreements such as those TGVI currently has in place with the VIGJV and BC Hydro.

4. DEMAND FORECAST

Section 3 of the Resource Plan describes the forecasts of gross demand used to determine the preferred resource portfolio. In addition to long-term core customer growth, these forecasts are characterized by a step change in demand as early as 2007 due to firm requirements of ICP, potential impact of BC Hydro's VI CFT process, potential contract changes for the VIGJV, and potential conversion of the Whistler region to natural gas service.

The Base forecasts for TGVI, Terasen Gas (Squamish) Inc. ("TGS"), and VIGJV represent the most likely demand requirements for these customers; for BC Hydro, demand in addition to that required for ICP is uncertain and depends on the outcome of the CFT process. To address this uncertainty, the Base + 0 and the Base + 45 gross demand forecasts are both used in this Application to bracket the most likely range of demand expected.

- Base + 0 TJ/d: Base forecast components with no new gas-fired generation (0 MW of new gas-fired generation)
- Base + 45 TJ/d: Base forecast plus 45 TJ/d from new gas-fired generation (250 to 300 MW of new gas-fired generation)

Component forecasts for the Base gross demand forecast are contained in Appendix 3.

It is expected that TGVI will continue to serve the ICP load over the long term with ICP's firm contract demand increasing from 38 TJ/day to 45 TJ/day which is representative of the full operating requirement of the facility. This requirement is common to both the Base + 0 and the Base + 45 forecasts.

In its 2004 Integrated Electricity Plan[2], BC Hydro has assumed a contract demand of 45 TJ/day in estimating the costs for obtaining firm gas supply for ICP. In addition to the requirement for ICP, BC Hydro has also identified a future gap between electricity supply and demand on Vancouver Island from 150 megawatts ("MW") to 300 MW. In order to fill this supply gap, BC Hydro has recently initiated the VI CFT process. The outcome of the process and its impact on gas demand will not be known until near the end of 2004. To date, eleven bidders have been pre-qualified to submit tenders under the VI CFT process. Of the eleven pre-qualified bidders, nine rely on gas fired generation as the means to produce electricity. In its 2004 Integrated Electricity Plan[3], BC Hydro considers three possible outcomes of the VI CFT process; a low of less than 150 MW, a medium of 150 MW, and a high of up to 300 MW. The Base + 0 and Base + 45 forecasts bracket the range considered by BC Hydro.

In addition to consultation for the Resource Plan, TGVI continues to work with BC Hydro to provide information. This information will enable BC Hydro to estimate the cost of gas transportation solutions for current and potential facilities. BC Hydro may become responsible for providing gas transportation as a result of the VI CFT.

[2] BC Hydro 2004 Integrated Electricity Plan, Part 6 Portfolio Evaluation Results, page 12
[3] BC Hydro 2004 Integrated Electricity Plan, Part 6 Portfolio Evaluation Results, page 24

5. PROJECT DESCRIPTION

5.1 PROJECT SCOPE

The Project consists of a new 1.0 Bcf LNG facility to be constructed at a location referred to as Mount Hayes, in the CVRD near Ladysmith.

5.2 TRANSMISSION SYSTEM

Natural gas is received at the V1 compressor station in Coquitlam from the Terasen Gas Coastal Transmission System ("CTS") at a contracted minimum suction pressure of 260 psig. The delivery pressure for transmission to customers is increased to 2,160 psig Maximum Operating Pressure ("MOP") via three gas turbine driven compressors at the V1 Compressor Station, one gas turbine driven compressor at the V3 Port Mellon Compressor Station and one gas turbine driven compressor at the V4 Texada Compressor Station. Natural gas is thereby 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 on the Sunshine Coast and Vancouver Island. The delivery pressure is reduced at these stations to 500 psig or less, depending on load and customer requirements.

The V4 Compressor Station was installed as a short-term facility under a Compressor Funding Agreement ("CFA") with BC Hydro and is subject to decommissioning if system demand is insufficient for TGVI to reimburse BC Hydro in order to retain the station. For the purposes of system assessment, it is assumed that the V4 compressor station will be retained on the basis that the BC Hydro demand at the ICP generating facility is supported by a long-term transportation agreement with TGVI. The following Figure 5.2 outlines the route and basic components of the existing TGVI transmission system.

Figure 5.2

Existing TGVI Transmission System

5.2.1 System Design Criteria – Operating Pressures

Through many years of operations, TGVI has determined that under normal conditions, transmission pressures are most stable at 1000 psig or higher and that the lowest pressure to ensure system recovery is 700 psig. 700 psig allows for a reserve relative to the maximum customer delivery pressure of 500 psig on transmission laterals and also provides a short duration reserve in the event of system upsets or system flow exceeding forecasts and/or nominations. On this basis, forecast design day events are modelled with the 700 psig minimum and forecast normal year pressure events are modelled with the 1000 psig minimum. The discharge pressures at the compressor stations are limited to 2160 psig since this is the licensed MOP.

5.2.2 Current System Capacity

TGVI continues to experience strong demand for natural gas in its service area. To ensure that demand growth can be met, TGVI continually evaluates the ability of its transmission system to deliver the required loads. The evaluation provided in Section 5 of the Resource Plan concludes that present installed system design capacity (including V4) of approximately 155 TJ/day will not be sufficient to satisfy the 2007 Forecast Peak Day demand.

5.2.3 Resource Options

TGVI considered several alternatives to address the above forecast system capacity shortfall including:

- LNG Storage – an LNG storage facility followed by phased pipe and compression additions.
- Pipe & Compression ("P&C") – phased pipe and compression additions.
- Pipe Compression & Curtailment ("PC&C") – phased pipe and compression additions with industrial curtailment

The alternatives and key components are identified and described in detail in the TGVI 2004 Resource Plan. The Resource Plan concluded that an LNG facility commissioned in 2007, combined with compression and pipe looping as required by 2007 or later to meet future incremental demand, represents the best alternative for TGVI and its customers.

5.2.4 LNG Storage Utilization

The Project, which will interconnect with the transmission system just north of Ladysmith on Vancouver Island, has been designed to inject gas into the system at flow rates of up to approximately 100 TJ/day and at the system MOP of 2160 psig as required throughout the heating season. The only limitation on the LNG use is the LNG storage capacity. The maximum storage capacity for one heating season is 1075 TJ, assuming that the tank is not partially refilled during the heating season.

TGVI intends to sell available storage capacity above that which is needed to meet the expected forecast demand in any given year.

In order to ensure that the existing system is fully utilized and that maximum value is obtained for the sale of available storage, the system was modeled to make the most efficient use of the combined system thereby minimizing the costs that need to be recovered form TGVI's sales and transport customers. Subsequent additions (compression and looping) are triggered only when TGVI's forecast demand requires the full LNG storage volume.

This is illustrated by load duration curves included in Appendix 9 for the Base + 0 and Base + 45 forecasts which outline the initial year, the year before the next capital addition and the year after the next capital addition as follows:

- Base + 0 Forecast

  Figures 1, 2 and 3 illustrate load duration curves for 2007 (initial year), 2018 (before next addition), and 2019 (after next addition).

- Base + 45 Forecast

  Figures 8, 9 and 10 illustrate load duration curves for 2007 (initial year), 2018 (before next addition), and 2021 (after next additions).

Pressure profiles for the transmission system demonstrate how the system operates with and without the LNG facility injecting gas. This is illustrated by the pressure profiles for the Base + 0 and Base + 45 forecasts in 2018 which show the pressure profile for the design peak day, the last day LNG is sent out and the day after LNG has stopped being sent out. The three profiles are also shown overlaid for each forecast.

- Base + 0 Forecast in 2018

  Figures 4, 5 and 6 show the pressure profile during the design peak day, during day 74 of the design year (the last day that the LNG is sent out), and during day 75 (after the LNG has stopped being sent out). Figure 7 overlays all three pressure profiles to show the relative differences.

- Base + 45 Forecast in 2018

  Figures 11, 12 and 13 show the pressure profile during the design peak day, during day 74 of the design year (the last day that the LNG is sent out), and during day 75 (after the LNG has stopped being sent out). Figure 14 overlays all three pressure profiles to show the relative differences.

5.3 DESIGN BASIS – LNG FACILITY

A site has been selected at a location referred to as Mount Hayes, approximately 6 km NW of Ladysmith. Rezoning of the site for LNG facility use was approved by the CVRD on May 26, 2004. The property, owned by Weyerhaeuser Company Limited (Weyerhaeuser), has been optioned by TGVI (through a two-year option agreement).

TGI owns and operates a 0.6 Bcf LNG facility, located on Tilbury Island in the municipality of Delta. The TGVI LNG Project is based on the experience and expertise of TGI in upgrading, maintaining and operating the Tilbury LNG facility which has been in service since December 1970 combined with current information provided by major LNG facility construction contractors and consultants as well as TGVI and TGI's extensive pipeline facility construction and project management experience.

5.3.1 Facility Description

The TGVI LNG facility is being designed with capacities as outlined in Figure 5.3.1:

FIGURE 5.3.1: FACILITY CAPACITY TABLE		
Design Capacity	**Units**	**Capacity**
Storage	Bcf	1.0
Liquefaction Rate	mmscfd	5
Send-out Rate	mmscfd	100

An LNG facility consists of six major elements each offering design options and alternative operational systems that need to be evaluated in the final design phase. The components are:

- feed gas purification
- liquefaction
- LNG storage
- send-out
- facility ancillary equipment and facilities
- connecting pipeline and utility connections

5.3.1.1 Feed Gas Purification

Liquefaction of natural gas requires process temperatures to -162^{o}C (-260^{o}F). Any impurities such as water, carbon dioxide, heavy hydrocarbons and odorant in the feed gas must be removed to prevent process equipment from fouling or plugging by the freezing of these impurities. A variety of purification systems are available with selection dependent upon the feed gas composition. Due to the expected carbon dioxide and water content of the feed gas, TGVI anticipates using a molecular sieve purification system. The impurities removed by the sieve are returned back to the gas transmission system to be mingled with the natural gas flowing downstream.

5.3.1.2 Liquefaction

Following the purification process, the clean gas stream is sent to a refrigeration unit where the gas is cooled and condensed to its liquid state for storage. The most commonly used liquefiers make use of one of the following designs:

- cascade cycle

- mixed refrigerant cycle
- expander cycle

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. This process requires a compressor of approximately 3 MW (4000 hp), which is expected to be electrically driven. A net liquefaction rate of 5 mmscfd will be specified.

5.3.1.3 LNG Storage

After liquefaction, the LNG is stored in a single containment, double walled, insulated tank. The internal tank pressure is limited to near atmospheric pressure (2 psig) while keeping the LNG at -162^{o}C. The LNG storage system also includes secondary containment (earthen dike) surrounding the tank. 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 to hold the insulation and act as a vapour holding vessel, is made of carbon steel.

The 1 Bcf (46,300 m^3 net useable volume) tank will be surrounded by an earthen dike constructed from locally sourced materials including shot rock made available on site from required site grading activities. The tank height is expected to be in the range from 30 m up to 50 m and the diameter up to 60 m.

The secondary containment (earthen dike), capable of holding the total volume of the LNG tank, will be constructed according to code. The height and diameter of the dike will be determined in the final design phase however TGVI believes the dike may be in the order of 3 m to 6 m in height.

Figure 5.3.1.3 provides a conceptual image of an LNG facility with an earthen dike.

Figure 5.3.1.3

Conceptual Single containment storage tank with secondary containment earthen dike

5.3.1.4 Send-out

A send-out system performs the following functions:

- pumping LNG from storage to transmission line pressure
- vaporizing LNG by heating to return LNG to natural gas vapour
- controlling natural gas flow and temperature
- odorizing and metering the send-out stream

The total send-out capacity is separated into independent send-out systems (trains) with interconnections. TGVI anticipates that two 50 mmscfd send-out trains will be utilized. This will provide redundancy for failure of any send-out train or component thereof at normal send-out rates, it will support send-out rates as low as approximately 10 mmscfd (20% of the smallest train capacity), and will provide total send-out capacity of 100 mmscfd.

5.3.1.5 Ancillary Equipment and Facilities

In addition to the basic functions of liquefying, storing and send-out of natural gas, other ancillary equipment systems are required. These systems include:

- **Boil-off compressors**
  - To compress gas which evaporates inside the tank, enabling delivery of the gas to the main transmission system flowing downstream. Boil-off is in the order of 0.05% per day.
- **Security**
  - Includes such items as fencing, lighting, closed circuit cameras (CCTV) and card locked gates as well as perimeter motion detectors.
- **Backup electrical power generation**
  - To ensure sufficient power to control the facility and send-out, (but not to liquefy). TGVI expects to install a diesel powered generator due to its lower capital cost.
- **Fire protection and control systems**
  - Water monitors at strategic locations within the facility fed from an onsite water storage tank, replenished from a pond to be constructed to collect runoff water.
  - Dry chemical fire extinguishers.
  - Independent monitoring and safety shutdown controls.
  - Remote control and computer assisted control and shut down systems to isolate and shut down as required.

5.3.1.6 Truck Loading Facility

TGVI intends to include provision for truck loading facilities to be added in the future for potential offsite sales to remote communities and industry.

An LNG semi trailer tanker and loading facilities are available at Tilbury for use to support the TGVI system in the event of a planned outage or emergency situation.

5.3.2 Pipeline and Utility Connections

Pipeline

The LNG facility must be connected to the transmission system for a number of purposes that typically requires two (2) pipelines. During liquefaction, the LNG facility must be connected to the transmission system for the supply of feed gas and also for the return of natural gas (the impurities from the purification process during liquefaction (tail gas), as well as the boil off gas, may be returned to the transmission system during liquefaction). The two pipelines required during liquefaction then serve to return natural gas to the transmission system during vaporization and send-out.

TGVI anticipates constructing 2 pipelines (8" and 10") approximately 5 km in length to connect the LNG facility to the transmission system.

Powerline

Electrical power is required for general plant utilities and to supply the liquefaction compressor, boil-off compressor and send-out pumps. TGVI will construct and own the electric transmission line and transformers (25 kV) which will be designed to applicable codes and BC Hydro standards.

Communications

A fibre optics communications line to serve the LNG facility will be installed on the electrical power poles.

5.3.3 Public Consultation and Siting

The primary purpose of the 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 send-out 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 and generally is optimal when located closest to major peak loads.

Given this purpose, studies were initiated to determine whether suitable areas within the TGVI service area, and eventually a site, could be identified to locate the facility. The area chosen for the study included a ten km wide band centered on the TGVI main transmission pipeline on Vancouver Island.

Approximately 25 Candidate Areas were identified that met TGVI siting criteria. Following this step, a helicopter supported field reconnaissance was undertaken to gain further understanding of the characteristics of the Candidate Areas in regard to terrain and geotechnical conditions as well as location within the viewshed of populated areas. Based on this study and further pipeline system hydraulic analyses, three potential sites were selected for further study.

These three sites were:

Site 18 – West of Mount Hayes
Site 21 – West of Mount Prevost
Site 25 – Duke Point Industrial Area

Meetings and presentations were held with local governments (municipal and regional) and First Nations to outline the rationale for the project and the site selection process. Open Houses were held in early December 2003 in Duncan and Cedar to introduce the public to the project and the characteristics of LNG, to answer any questions brought forward, and to solicit opinions on the candidate sites.

Based on further analyses of the three candidate sites and the information gained from the public at the initial Open Houses, Site 18 (the site west of Mount Hayes) was chosen as the preferred site for the facility. The Mount Hayes site was chosen because:

- The site offers good foundation and geotechnical conditions.
- The site is well hidden from the viewshed to the east, where people live, and is isolated from land uses other than commercial forestry.
- Most of the facility site has been clearcut logged.
- Potential environment and archaeological values were considered minor.
- The pipeline connection to the TGI transmission system does not significantly impact property owners and does not cross any fish-bearing streams.
- There is existing access to the site.
- Site related construction and operating costs are reasonable
- The public who attended the Open Houses in December did not voice a concern about the Mount. Hayes location.

Following the decision to select the site west of Mount Hayes for the LNG facility, TGVI held another Open House on January 14, 2004 at the North Oyster School on Cedar Road. The purpose of this meeting was to fully inform the public about the decision and to further respond to questions raised by the public as well as to provide those members of the public who did not attend the earlier Open Houses, an opportunity to learn about the project. The general view of the public who attended the Open House was that TGVI had made an appropriate decision in selecting Mount Hayes as the preferred site and that the construction and operation of an LNG facility at the location was generally acceptable.

On February 2, 2004, TGVI filed an application for rezoning with the CVRD for a portion of a property owned by Weyerhaeuser. Following a Town Hall meeting and Public hearing, the Application was approved by the CVRD on May 26, 2004.

The following Figure 5.3.3 illustrates the general location of the proposed LNG facility.

Figure 5.3.3

General Location of proposed LNG Facility

5.3.3.1 Site Size Requirements

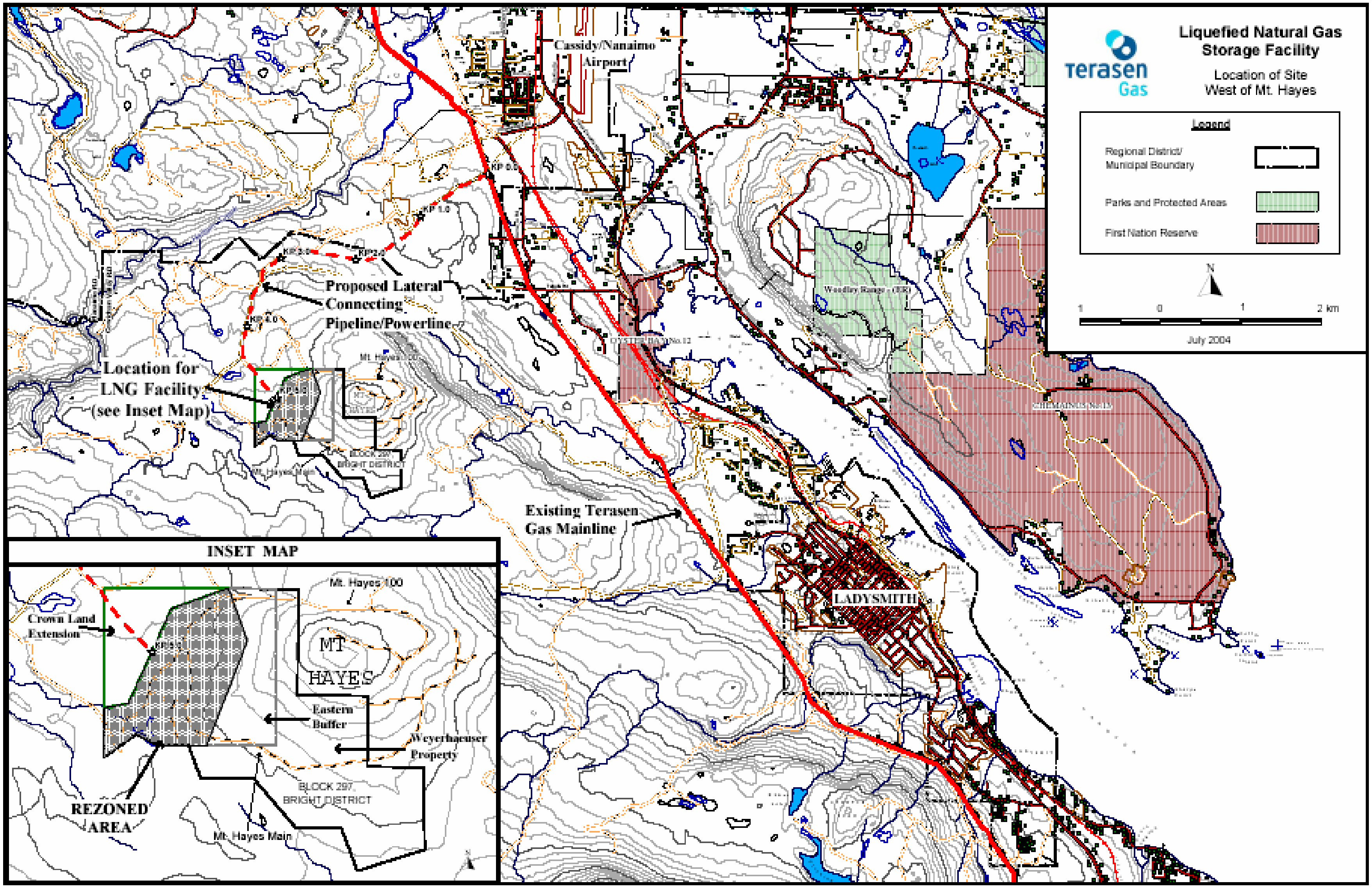
TGVI has optioned a block of property at the Mount Hayes site from the owner, Weyerhaeuser. The 142 ha (350 acre) site is shown in detail on the following Figure 5.3.3.1.

The inset in Figure 5.3.3.1 outlines the Weyerhaeuser property (142 ha), the area within the property that has been rezoned (42 ha), and the area of Crown land outside the property (20 ha) to the west, which TGVI seeks to control to ensure thermal radiation setback is maintained as per the CSA code. The option agreement with Weyerhaeuser anticipates a future subdivision of the 142 ha lands to allow TGVI to return to Weyerhaeuser the portions of the property not required by TGVI as operational area or buffer zone to enable Weyerhaeuser to maintain ownership of and resume forestry operations on that portion of the property. TGVI anticipates retaining an additional 20 ha of property to the east of the rezoned area, to contain the required buffer zone, and returning the remaining 80 ha to Weyerhaeuser.

Within the 42 ha rezoned area, the physical plant boundaries will encompass approximately 20 ha.

The location of the new connecting pipeline and powerline rights-of-way and the access road are also noted in the Figure 5.3.3.1. Each of these components is described below.

Figure 5.3.3.1



LNG Site and Utility Connections Locations

5.3.3.2 Buffer Zone

The CSA Z276 Code requires a series of thermal radiation setback zones to surround an LNG facility. The size of the setbacks is determined by code based on the size of the secondary containment which surrounds the LNG tank. These setback zones are required to ensure that the public gathering places and public buildings are located a specified distance from the LNG facility to manage potential impact should a fire result within the secondary containment area. TGVI's preliminary estimate indicates the buffer zones could extend to approximately 400 m from the center of the secondary containment area. A portion of such an extended buffer area extends beyond the Weyerhaeuser property onto Crown land to the west. TGVI intends to own or control all of the area required to maintain the code setback distances to ensure public use or development will not encroach upon the facility over time. TGVI has applied to the BC Oil and Gas Commission ("OGC") for a lease for approximately 20 ha to extend control over Crown land adjacent to the west of the Weyerhaeuser property as shown in Figure 5.3.3.1. As discussed in Section 5.3.3.1, TGVI will also retain 20 ha to the east of the rezoned 42 ha site.

5.3.3.3 Rights-of-Way

The approximately 5 km long, 18 m wide pipeline right-of-way and the 7 m electric transmission line right-of-way are intended to be parallel rights-of-way adjacent to the existing access road into the facility site. The access road will be relocated over a portion of its length to avoid a gravel extraction site and to remove some steep segments with tight turns and will be upgraded from its existing condition. The rights-of-way pass through private and Crown land requiring easement from both private landowners and the Crown. TGVI has made application to the OGC for the required Crown land easements for the pipeline and powerline and the access road improvements. The general location of the road and rights-of-way is indicated in Figure 5.3.3.1.

6. PROJECT JUSTIFICATION

Demand for natural gas on Vancouver Island and the Sunshine Coast has seen considerable growth since the construction of the TGVI system, and this growth expected to continue in the future. The Resource Plan assessed the future demand growth under different scenarios and concluded that expansion of TGVI's transmission system would be required as early as 2007. The Resource Plan also concluded that an LNG Storage Facility located on Vancouver Island is a common component of the preferred resource portfolios across the expected demand scenarios. Specifically, the Resource Plan concluded that the LNG Storage portfolio is competitive alternative to other options if no new gas fired generation results from the current BC Hydro CFT process and is the least-cost option if new generation loads are added to the system.

Since the TGVI Resource Plan was submitted on June 18, 2004, and in support of this Application, TGVI has refined its financial evaluation of supply alternatives for Vancouver Island. This section includes a summary of the TGVI Resource Plan as well as the results of further analysis conducted to address stakeholder concerns. In addition, an assessment of customer rate impacts is included in Section 7. Based on the results of the Resource Plan and this subsequent analysis TGVI believes that the best solution for meeting future demand is to construct the Mount Hayes LNG Storage facility on Vancouver Island.

6.1 TGVI RESOURCE PLANNING RESULTS

6.1.1 Demand Forecast

Section 3 of the Resource Plan examines a range of forecast demands for its different customer components in order to determine the preferred resource portfolio to meet the most likely demand forecast. In addition to long-term core customer growth, these forecasts are characterized by a step change as early as 2007 in demand due to firm requirements of the ICP, potential impact of the BC Hydro VI CFT process, potential contract changes for the VIGJV, and the potential conversion of the Whistler region to natural gas service.

As the outcome of BC Hydro's VI CFT will not be known later this year, for the purposes of this Application, two possible outcomes of the VI CFT were considered in addition to the base demand forecast. These scenarios are referred to Base + 0 and Base + 45 forecast scenarios where:

- Base + 0 represents the Base forecast with no new gas-fired generation load resulting from the VI CFT
- Base + 45 represents the Base forecast plus 45 TJ/day from new generation beginning in 2007 (250 – 300 MW of new gas-fired generation)

6.1.2 Supply Side Resources

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 supply side components required to satisfy these demand forecasts were identified. Considerations addressed by TGVI's 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 peak day (coldest day in an average year). In portfolios where it is assumed to be available, curtailment service provided by industrial customers 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.

This modelling process identified the supply side components used to develop the portfolios considered in the Resource Plan; six looping projects on the Mainland and Texada portions of the system, five compressor station projects, and an LNG facility located on Southern Vancouver Island.

6.1.3 Resource Portfolio Development

Resource Planning guidelines requires the development of resource portfolios to meet gross demand forecasts with consideration of both feasible supply side resources (e.g. pipe, compression, and storage) and feasible demand side resources. During the Resource Plan stakeholder consultation, both BC Hydro and the VIGJV indicated that they are prepared to continue to offer long-term peaking gas arrangements whereby they would curtail their use of gas. On this basis, the supply side portfolios were modeled both with and without the availability of peaking gas arrangements. In the scenarios where peaking gas arrangements are considered, it was assumed that it would be available over the entire planning period in order to meet colder than normal winter conditions.

Three types of resource portfolios emerged from this evaluation process 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 ("P&C") – phased pipe and compression additions
3. Pipe Compression & Curtailment ("PC&C") – phased pipe and compression additions with industrial curtailment

6.1.4 Resource Portfolio Evaluation

In section 6 of the Resource Plan the performance of these portfolios is measured against TGVI's planning objectives and the results show that the LNG Storage resource portfolio is preferred. LNG Storage Portfolio ranks first in terms of reliability and security of supply, least delivered cost, and reduced rate volatility. 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.

6.2 PORTFOLIO COSTS AND BENEFITS

The resource portfolios developed in the Resource Plan were based on the TGVI's requirements over the 20 year planning period beginning in 2007 when the first new facilities are required. The resource portfolios for the Base + 0 and Base + 45 scenarios discussed in this Application are the same as those developed in the Resource Plan. For this Application, however, estimates of the costs associated with the portfolios have been reviewed and updated to reflect the most current information. As well, in response to stakeholder comments received during the Resource Planning process, a more extensive analysis of the gas supply costs has been completed for each portfolio and is summarized in Section 6.3.

The LNG Storage Portfolios described in Section 5 of the Resource Plan include the addition of an LNG facility in 2007, followed by other compression and looping projects as required. This Application is seeking approval for the LNG facility. Future application for the additional facilities will be made when required, taking into account the outcome of the BC Hydro CFT and the project schedule required to put the new facilities in service. Capital and operating cost estimates for the Project are included in Section 14. Capital cost estimates and descriptions of pipeline and compression components are included in the Resource Plan; compressor projects are described in Resource Plan Appendix G, and pipeline looping projects are described in Resource Plan Appendix H. Capital schedules for each portfolio for the Base + 0, and Base + 45 demand forecasts, showing timing and capital cost of each component, are included in Appendix 4.

Appendix C of the Resource Plan assessed the net benefit of LNG to the TGVI gas supply portfolio based on the value of the marginal gas supply resource offset by the use of on-system LNG storage. For this Application, a forecast of gas supply portfolio costs has been developed using Sendout[4], a linear programming application. This more comprehensive analysis of gas supply costs associated with the different Supply portfolios has also been extended to consider the value of peaking gas as a gas supply resource. The result of this gas supply cost evaluation is discussed in section 6.3.

---

4 Sendout is a gas portfolio optimization application developed by New Energy Associates, a wholly owned subsidiary of Siemens Westinghouse Power Corporation and a division of Siemens Power Generation.

6.3 ASSESSMENT OF GAS SUPPLY COSTS

6.3.1 Description

Addition of the Project to the TGVI system impacts both the cost of service associated with the facilities required to move natural gas to all TGVI customers and natural gas supply portfolio costs for sales customers. As well, the Project will allow TGVI to provide natural gas storage services to TGI and other regional customers. As TGVI's core customer demand grows over time, TGVI's use of the capacity will increase, and less capacity will be available to third parties. In this way the cost of service associated with the Project is partially mitigated until such time it is needed to serve system loads.

This section evaluates the gas supply benefits the Project is expected to deliver by comparing the future gas supply costs of each of the different resource portfolios. In addition the value of providing third party services is discussed.

6.3.2 Valuation Assumptions

The approach used to value the net benefit of LNG to the TGVI gas supply portfolio that is summarized in Appendix C of the Resource Plan involved the analysis of the cost of the marginal resource that would be offset by the use of on-system storage resource provided by the Project. For this Application, the gas supply benefit was evaluated using the Sendout application. In addition, Stakeholder feedback during the Resource Plan consultation process indicated that there was a desire to further explore the use of peaking gas or curtailment as a resource. As a result, the gas supply analysis is extended to consider the benefit of peaking gas arrangements in both the P&C and LNG Storage portfolios.

The Sendout application is a linear programming model in which all of the supply resources available to TGVI are input with projected design demand in each year of the planning period. The application determines the least-cost gas solution for each portfolio. The present value of gas supply cost can then be compared for each portfolio to determine the effect of supply resources on gas supply costs. The result is a similar assessment of benefits as discussed in the Resource Plan, but employs a more bottom up approach involving the optimization of all supply resources rather than trading off one for another.

6.3.3 Gas Supply Cost

The present value of the expected gas supply costs was determined for the planning period for each supply portfolio for the Base + 0 and Base + 45 demand forecasts. The underlying natural gas price forecast for the various supply points is obtained from the Gilbert Laustsen Jung Associates Ltd ("GLJAL") report dated April 1, 2004 and is attached as Appendix 5.

Pipe and Compression ("P&C")

In the P&C Portfolio all the design day needs are met via supply resources upstream of the TGVI system. The costs for these resources are based on current costs to TGVI. In this scenario, gas from market area storage in the region is used to meet design day requirements[5]. The cost includes transportation to and from the storage facility. The scenario assumes there is enough pipeline capacity on the TGVI system to meet the core market design day demand with gas upstream of the system.

LNG Storage

Assessment of the LNG Storage portfolio is based on the assumption that LNG is used to meet system demands during peak periods when transmission capacity is constrained. In addition, when economic, LNG storage is used to displace other storage resources that TGVI would otherwise contract for in its portfolio.

The addition of peaking gas arrangements to this portfolio, such as is currently available under the arrangements with VIGJV or BC Hydro, could reduce TGVI's requirement to reserve LNG capacity to meet colder than normal winter conditions, thereby increasing the amount available for sale to TGI or other regional market participants. While the gas portfolio cost would not change, additional mitigating revenue would result from the difference between the cost of the peaking gas resource and the market value of alternative storage resources.

Since the LNG capacity provided by the Project is greater than TGVI's initial requirements, available capacity can be used to provide storage services to TGI and other interested parties and obtain mitigating revenues to reduce the costs that must be recovered through customer rates. Over time TGVI's own use of the capacity would increase, and less capacity would be available to third parties.

The analysis of third party revenues remains the same as that described in Appendix C of the Resource Plan. The third party valuation is more straightforward process as it is based on the market value of other storage resources in the region. For example, TGI holds a much larger gas portfolio than TGVI, and the addition of available LNG storage resource will serve to displace other storage resources that TGI would otherwise require without impacting the remainder of the portfolio. A letter of interest from TGI confirming the resource plan valuation and its intention to contract for available storage capacity is included in Appendix 2.

Pipe Compression & Curtailment ("PC&C")

The PC&C Portfolio was developed by assuming industrial curtailment would be available to defer capital additions. For this assessment of gas supply costs, it was assumed that a peaking gas service similar to the current VIGJV Peaking Gas Management Agreement (PGMA) would be available from the transport customers on the system over the entire planning period. The commodity costs associated

[5] Within the I-5 corridor market area there are two underground storage facilities that provide service to third parties. These are the Jackson Prairie facility in Washington State, and the MIST facility in Oregon. TGVI currently holds storage capacity at the MIST facility.

with the PGMA service is equal to the Huntingdon Sumas monthly natural gas price plus Cdn$5.42/GJ and there is no fixed annual cost. If future curtailment arrangements did not include access to the transport customer's commodity, then the peaking gas requirement for TGVI's sales customers would have to be sourced separately upstream of TGVI's system. Therefore, while capacity associated with curtailment rights may defer capital additions, if reliable peaking gas supply is not associated with these arrangements, it would result in a gas supply cost equivalent to the P&C portfolio.

Aside from costs, the reliability and nature of the transport customer's underlying gas supply contracts is an important consideration when evaluating the value of peaking gas associated with curtailment as a supply alternative. TGVI must be assured of reliable and cost-effective supply in order to meet its core market obligations. Therefore TGVI must be sufficiently satisfied that the industrial customer has all the arrangements in place to have the gas supply flow on a peak day. In order to have the same benefit as LNG service, the gas to the industrial should be firm base load or backed by some firm supply resource. If the industrial relied on peaking or spot contracts to supply this gas with no commitment to upstream resources it would mean that on a peak day that this source would compete for scarce supply at Sumas. This would certainly drive up prices on the day and could have lasting impact on market pricing. Increased pricing impacts the entire gas supply portfolio for TGVI (and other Sumas market participants such as TGI).

Another important consideration with peaking gas arrangements is how this supply is delivered to the system. In the case of a large point source industrial, if exercising a curtailment right could result in must-take peaking gas volumes that exceed the amount required on a given day, gas supply cost would be higher than necessary. Since the transmission system is limited in its ability to handle large swings in demand, peaking gas arrangements that involve large must-take volumes are less efficient than those that can be varied to follow demand and reduces the effectiveness of the peaking gas resource. For the TGVI system transport demand represent a very high proportion of the gas throughput on the TGVI system on any given day. Currently the transport customers represent 71% of the annual throughput and 48% of the gross system demand.

The Sendout application did not take into account any implications of these considerations and modeled curtailment including the provision of the commodity as a resource with similar characteristics to LNG. However, consideration of these risks would be taken into account when valuing peaking gas arrangements versus other resources.

6.3.4 Conclusions

Based on TGVI's current assumptions, the expected gas supply costs in each year of the planning period as determined by the Sendout application are provided in Appendix 8. Table 6.3.4-1 compares the present values of each portfolio, using the P&C portfolio as the base. The results show that over the 20 year planning period the LNG Storage Portfolio will provide $58 million in gas supply savings to TGVI's sales customers versus the P&C Portfolio, and $23 million in savings over the

PC&C. In the Base + 45 scenario, the savings over the PC&C scenario increases to $30 million.

Table 6.3.4-1 PV (2007-2026) 2004$ Millions	Base +0			Base +45		
	LNG Storage	Pipe Compression	Pipe Compression Curtailment	LNG Storage	Pipe Compression	Pipe Compression Curtailment
PV @ 6%						
Total Gas Portfolio	981.3	1,039.5	1,004.4	981.9	1,039.5	1,011.9
Change from P&C	(58.2)	-	(35.0)	(57.6)	-	(27.6)
PV @10%						
Total Gas Portfolio	653.4	691.4	668.9	653.8	691.4	673.8
Change from P&C	(38.0)	-	(22.5)	(37.6)	-	(17.6)

Estimates of third party revenue from the sale of available LNG are also included in Appendix 8. The present values of these estimates are summarized in Table 6.3.4-2.

Table 6.3.4-2 PV (2007-2026) 2004$ Millions	Base +0	Base +45
	LNG Storage	LNG Storage
PV @ 6% **LNG Mitiation**	35.9	34.2
PV @10% **LNG Mitiation**	25.4	24.9

6.4 FINANCIAL PERFORMANCE MEASURES

To compare the incremental cost of each portfolio the following estimates of costs and benefits are considered:

<u>Incremental facilities</u>

The incremental cost of service associated with new facility additions over the planning period includes the cost of capital, depreciation, taxes, and operating cost. Schedules showing the annual incremental cost of service for each portfolio are included as Appendix 6 with key assumptions used in their calculation.

<u>Transport Fuel Differential</u>

The transport fuel differential is the difference between portfolios in the cost of system fuel to be provided in-kind by transport customers. System fuel includes compressor fuel, meter station fuel, unaccounted for gas, and where applicable, fuel consumed by the LNG facility. Annual fuel ratios are shown in the capital schedules of Appendix 4[6], and these values along with the gas price forecast and the annual demand assumptions for transport customers are used to estimate the fuel cost differential. P&C portfolio costs are used as the base for comparison.

[6] System Gas ratios shown in Appendix 4 differ from those shown in Resource Plan. Although allowances for meter station fuel (0.5%), unaccounted for gas (1%) and LNG fuel were included in Resource Plan calculations they were omitted in error from the values shown in the Resource Plan schedules.

Gas Supply Differential

The gas supply differential is the difference between portfolios in TGVI's cost for core market gas supply as summarised in Section 6.3. The gas supply costs include the cost of commodity, midstream assets such as upstream pipe and storage, and the core market's share of TGVI system fuel. In the Resource Plan the cost of system fuel for TGVI's sales customers was included as part of the fuel costs differential. In this Application, however it has been included as part of the gas supply cost and is included in the Sendout application results.

Mitigation - LNG

Since the size of the LNG facility will be greater than TGVI's immediate needs, TGVI will sell storage services to TGI and others in the region to mitigate some of the costs of the LNG facility. Overtime, as the core market demand grows, TGVI will use more of the LNG capacity, reducing the amount of LNG available to third parties. Mitigation of available LNG capacity is valued based on the cost of alternative storage resources, as described in Appendix C of the Resource Plan.

Taking into account all these components, in the following sections, the present value of net costs over the planning period is calculated in order to compare portfolios within each demand forecast. The results are expressed in millions of 2004 dollars using after tax nominal discount rates as follows:

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

6.5 RESOURCE PORTFOLIO COMPARISON

6.5.1 Comparison of LNG Storage and P&C Portfolios

Table 6.5.1 compares the LNG Storage Portfolio and P&C Portfolios before taking into account any peaking gas or curtailment resources.

In the Base + 0 forecast, demand over the planning period is limited to that of existing core and transport customers, including the expected change in firm service to ICP and the VIGJV, and after 2007, growth is limited to that of the core market. The table shows that both the incremental facilities cost and fuel differential are slightly higher for the LNG Storage portfolio. However, these differences are more than offset by avoided gas supply costs that result from TGVI's use of LNG to avoid alternative storage resources, as well as mitigation revenue from the sale of available LNG. The net benefit of the LNG Storage portfolio is approximately $88 million ($162 million less $74 million) compared to the P&C alternative.

In the Base + 45 scenario another 45 TJ/d of generation load is included in 2007 and additional facilities are added to TGVI's system. The LNG Storage Portfolio is the least-cost portfolio both before and after the consideration of gas supply and LNG storage services benefits.

Table 6.5.1 (PV 2004-2026 @ 6%, $M)	Base +0 TJ/d		Base +45 TJ/d	
	LNG Storage	Pipe Compression	LNG Storage	Pipe Compression
Incremental Facilities	165	162	250	277
Transport Fuel Differential	4	-	22	-
Gas Supply Differential	(58)	-	(58)	-
LNG Mitigation	(36)	-	(34)	-
Total (PV@6%)	**74**	**162**	**180**	**277**
Total (PV@10%)	**50**	**101**	**117**	**182**

The high cost of the P&C portfolio demonstrates that reliance on pipe and compression alone is an expensive means to meet seasonal demand requirements. As an alternative, LNG is used to defer expenditure on pipe and compression facilities and avoid gas supply costs associated with higher winter demand.

6.5.2 Comparison of P&C and PC&C Portfolios

This section assesses the use of curtailment or peaking gas arrangements with on-system industrial customers to defer the need for new facilities. Industrial curtailment as it is used here is where the industrial customer can curtail its use of gas in order to make its gas supply or capacity available to meet other system loads. Generally, such arrangements are based on the customer's ability to reduce production or switch to alternate fuels to meet its energy requirements, such as distillate oil, hog fuel, or coal.

TGVI currently holds peaking gas agreements with BC Hydro and the VIGJV. These agreements will expire concurrently with the current transport agreements; BC Hydro's agreements expire in October 2004, while the VIGJV 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 VIGJV indicated that they are prepared to continue to offer peaking gas arrangements 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 high demand to ensure dependable generation capacity criteria is met. The VIGJV mills can also switch a large part of their load to oil and/or other fuels or reduce their production levels enabling them to provide their natural gas supply to the Core market as peaking gas.

The opportunity for effective use of curtailment is a function of system load factor. On the TGVI system, load factor is a characteristic of the core market's weather sensitive demand. From a utility perspective, environmental permits, commercial considerations, as well as the physical requirements of process loads or fuel switching procedures typically restrict curtailment use. These restrictions complicate the dispatch of curtailment and result in poor load following capability, in terms of both energy and capacity. While these shortcomings are acceptable when use is infrequent, for regular use they make curtailment less desirable relative to storage alternatives.

For these reasons curtailment is assumed to be used as a peak-shaving resource to mitigate infrequent short-duration demand events. In portfolios where curtailment is considered, it is relied on to meet colder than normal winter conditions, thereby reducing the amount of transmission capacity that would otherwise be required.

The amount of peaking gas required to meet colder than normal weather is a characteristic of core market demand and is the same for both the Base + 0 and the Base + 45 forecasts. It is not affected by increased availability of peaking gas that might result from the addition of fuel-switchable base load demand. While the amount of curtailment required in the PC&C portfolios could vary from year to year due to the timing and extent of pipeline expansion over the planning period, the maximum does not exceed 180 TJ.

For the purpose of determining facility requirements and gas supply portfolio impacts it is assumed that TGVI would contract for peaking gas resources to meet colder than normal requirements over the entire planning period. For the purposes of this assessment the cost of this service to TGVI is assumed to be the same as the conditions of the existing VIGJV PGMA (the Huntingdon monthly price plus $5.42/GJ with no annual demand charge).

Based on these assumptions, Table 6.5.2 shows how contracting for curtailment capacity could reduce the cost of the P&C portfolio. By deferring investment in incremental facilities over the planning period, industrial curtailment reduces the facilities cost, while the use of associated peaking gas in favour of alternative regional storage resources reduces gas supply costs.

As would be expected with the addition of a new large baseload demand on the system, the net benefits provided by use of industrial curtailment in the Base + 45 demand scenario is less significant than in the Base + 0 scenario.

Table 6.5.2	**Base +0 TJ/d**		**Base +45 TJ/d**	
(PV 2004-2026 @ 6%, $M)	**Pipe Compression**	**Pipe Compression Curtailment**	**Pipe Compression**	**Pipe Compression Curtailment**
Incremental Facilities	162	88	277	214
Transport Fuel Differential	-	7		8
Gas Supply Differential	-	(35)		(28)
LNG Mitigation	-		-	
Total (PV@6%)	**162**	**60**	**277**	**195**
Total (PV@10%)	**101**	**38**	**182**	**126**

To the degree the future costs of peaking gas arrangements are higher than the current costs, the net cost of the PC&C portfolio would increase. In the absence of an LNG facility the value of curtailment and associated peaking gas would be defined by the difference between these portfolios. This illustrates that there could be upward pressure on the cost of curtailment and associated peaking gas in the future.

6.5.3 Comparison of LNG Storage and PP&C Portfolios

If on-system peaking gas resources are available over the entire planning period at current costs, they could also be used to reduce the net costs of the LNG Storage Portfolios as is shown in Table 6.5.3.

The addition of a curtailment resource to the LNG Storage Portfolios can be used to defer the addition of future facilities, this however has only a small impact on the present value of the cost of incremental facilities. For the Base + 0 forecast for example, industrial curtailment could delay the 2019 requirement for the Squamish compressor station by one year resulting in the $2 million reduction in facilities cost shown in Table 6.5.3 when compared to Table 6.5.1.

However, associated peaking gas could be used to increase LNG mitigation revenue by reducing the amount of LNG reserved to meet the core winter design conditions in favour of peaking gas arrangements. This would release up to 180 TJ of available LNG capacity to be sold based on the higher value of alternative storage. Based on the assumed value of market storage costs, an additional $16 million of revenue could be realized. This opportunity for mitigation demonstrates that industrial customers on TGVI's system could also use fuel switching capacity to offer peaking supply to TGI or other participants in the regional market.

Table 6.5.3	**Base +0 TJ/d**		**Base +45 TJ/d**	
(PV 2004-2026 @ 6%, $M)	**LNG Storage**	**Pipe Compression Curtailment**	**LNG Storage**	**Pipe Compression Curtailment**
Incremental Facilities	163	88	245	214
Transport Fuel Differential	4	7	22	8
Gas Supply Differential	(58)	(35)	(58)	(28)
LNG Mitigation	(36)	-	(34)	-
Peaking Gas Mitigation	(16)	-	(16)	-
Total (PV@6%)	**56**	**60**	**159**	**195**
Total (PV@10%)	**39**	**38**	**104**	**126**

This comparison shows that the net benefit of the LNG Storage Portfolio over the PC&C Portfolio is $4 million ($56 million versus $60 million) in the Base + 0 scenario, and $36 million in the Base + 45 scenario.

The comparison assumes that over the long term, the contract for peaking gas arrangements is no greater than what is currently available under the PGMA. To the degree that the costs of future peaking gas arrangements are higher, the value of the additional mitigation in the LNG Storage Portfolio is reduced, and the cost of gas supply portfolio associated with the PC&C Portfolio increases. For example, if the future cost of peaking gas was priced at the assumed value of market storage, the peaking gas mitigation in the LNG Storage Portfolio would decrease by $16 million, and $16 million would be added back to the PC&C gas costs, thereby decreasing the Gas Supply Differential benefit associated with the PC&C Portfolio. The net differences between the two portfolios would not change.

This comparison supports the conclusion that relative to the PC&C Portfolio, the LNG Storage Portfolio is a competitive alternative in the scenario where no new gas-fired generation is added on Vancouver Island (Base + 0), and it is the least-cost alternative if new generation loads are added to the system.

These results also illustrate how the LNG Storage Portfolio can be used to protect TGVI's customers from future increases in the costs of putting curtailment or peaking gas arrangements in place once the existing agreements expire. In the absence of an on-island storage facility, the value and subsequent costs of these arrangements could approach the value of the difference in the two pipe and compression portfolios summarized in Table 6.5.2.

6.5.4 Other Portfolio Considerations

The Resource Plan concludes that new facilities will be required in 2007 to meet expected demands. Delaying the Project with investment in other facilities puts the benefits of the LNG Storage Portfolio at risk for the Base + 0 forecast. Since subsequent expansion requirements are small, driven only by core market growth, they are less likely to support the level of investment required to add an LNG facility after 2007. For example, the capital schedules in Appendix 5 show that the 2007 requirement for the Project could be delayed by adding the Squamish compressor and curtailment service. Doing so, however, would introduce sunk costs and require a new step change in demand to justify the Project. Without additional demand from the VI CFT process or the extension of gas to Whistler the opportunity for on-system storage would be lost.

The schedule for the Project is based on meeting BC Hydro’s forecast requirements at ICP for winter 2007/08. This schedule, described in Section 13 of this Application, requires award of the EPC contract by January 1, 2005 to allow the time required to have a partially filled tank and facility ready for use in winter 2007. As such, the Project schedule represents the critical path of activities required to meet forecast requirements. Delays in receiving approval beyond this date will decrease the likelihood that the facility will be ready for November 2007. While the VI CFT may result in additional demand, delaying consideration of this application until results of the VI CFT are approved will jeopardize TGVI’s ability meet 2007 forecast demand with the lowest-cost portfolio.

The LNG Storage Portfolio is the lowest-cost solution to serve demand in addition to the Base + 0 forecast. Minimizing the cost to serve new loads will help ensure TGVI’s competitive position relative to alternatives for natural gas transportation and residential heating. The addition of high load-factor customers on Vancouver Island will assist in maximizing the efficient use of the TGVI system. This will benefit sales customers of TGVI while providing the lowest-cost transportation for industrial and generation demands. Section 7 shows that capturing these new loads, along with their associated revenues, presents an opportunity to decrease the average cost of service for all customers and adding more load in this way will help solidify the financial future of TGVI.

6.5.5 Portfolio Comparison Conclusions

The resource portfolio evaluation included in the Resource Plan concluded that the LNG Storage Portfolio is the preferred portfolio, independent of the outcome of BC Hydro's current call for new generation capacity on Vancouver Island. The analysis in this section provides a more comprehensive review of curtailment and/or peaking options as well as the gas supply cost impacts of the various portfolios. The analysis continues to support the conclusion that the LNG Storage Portfolio is the preferred solution. The LNG Storage Portfolio offers a competitive alternative to other resource options where no new gas fired generation results from BC Hydro's VI CFT, and guarantees that new loads can be added onto the system at the lowest costs. Specifically, conclusions from the analysis in this section 6.5 are:

- The LNG Storage Portfolio results in least-cost solution to meeting future requirements on the system in both the Base + 0 and the Base + 45 demand scenarios, where no long-term curtailment or peaking supply is considered.
- Where curtailment and peaking gas resources continue to be available at the current costs, the LNG Storage Portfolio remains a competitive alternative to the PP&C portfolios in the Base + 0 scenario and the least-cost alternative in the Base + 45 scenario.
- Choice of an alternative supply option that does not include an LNG facility to meet 2007 forecast demand will result in a lost opportunity for the Base + 0 forecast.
- The benefit of the LNG Storage Portfolio increases with higher demand and therefore helps to position TGVI to add new loads at the lowest cost.

6.6 ADDITIONAL BENEFITS

The Project offers additional benefits in terms of security of supply, reduced price volatility and increased operating flexibility. These benefits, which have not been included in the quantitative analysis, are described below.

6.6.1 Security of Supply

The Project will provide an additional source of on-Island supply that can be used to mitigate the consequence of both system and supplier failures. This provides a benefit to any customer on the TGVI system and is unique to on-system storage. In the event of an upstream failure that limits physical delivery capacity, the LNG facility can be used to maintain supply on Vancouver Island and to reduce delivery requirements on the TG CTS system. For example, under Force Majeure conditions the LNG facility could provide enough on-Island supply to meet roughly 25 days of average core market winter demand. In terms of gas supply, the LNG facility will increase the diversity of the supply options available to TGVI and can be used to mitigate the consequence if upstream suppliers fail to meet delivery commitments to TGVI.

From a regional perspective, the Vancouver Island, Sunshine Coast, and Lower Mainland markets are characterized by a lack of market area storage and dependence on a single supply corridor from North Eastern B.C. As it is located at what is effectively the tail-end of this regional system, use of LNG from this facility to mitigate the affect of a supply restriction would benefit all customers downstream of the restriction.

6.6.2 Reduced Rate Volatility

The Project will help reduce rate volatility for TGVI and other regional customers. A large storage facility close to a major market helps mitigate commodity price increases during periods of peak demand. The LNG facility will increase regional supply capacity and decrease the risk of regional price disconnects. Similarly, storage can provide a dampening effect on summer versus winter price differentials.

The following is an excerpt from the National Energy Board's Energy Market Assessment ("EMA") Report titled: "The British Columbia Natural Gas Market – An Overview and Assessment – April 2004" provides an independent view that storage is extremely limited in B.C. and that additional storage will help mitigate seasonal price spikes:

> *Section 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.*

6.6.3 Avoided Requirements for TGI Coastal Transmission Capacity

TGVI currently holds capacity on the TGI CTS to move gas from the Huntingdon delivery area to the beginning of the TGVI transmission system at Coquitlam. With the use of LNG to augment pipeline capacity during peak periods LNG Storage portfolios require less CTS capacity than the alternatives. Over the long-run this could allow TGVI to defer future cost associated with increased CTS capacity and in some cases the reduction could be sufficient to allow a short-term assignment of CTS capacity back to TGI. While TGVI's CTS capacity is not large relative to other TGI customers, such an assignment could allow TGI to delay CTS expansion projects such as the Nichol-Coquitlam Loop. An assignment of this nature will benefit both parties; it will allow TGVI to mitigate the cost of holding CTS capacity and allow TGI to defer the cost of expansion.

In a similar way the LNG service on offer from TGVI could be used by TGI to defer expansion of the CTS. Since delivery of this supply would be by displacement[7], when dispatching LNG from the Mount Hayes facility TGI would reduce demand on the CTS. Since peak events typically occur simultaneously on both systems, use of the LNG service in this way would not detract from its value as a gas supply resource.

The value of this benefit to TGI will largely depend on the future requirement for TGI to serve Burrard Thermal under the Bypass Transportation Agreement.

6.6.4 Operational Flexibility

6.5.4.1 Balancing

The LNG facility will provide an efficient means to balance supply on the system compared to TGVI's current resource options. LNG is not hindered by re-nomination schedules or by TGVI's contracted capacity agreements. As an on-system resource, dispatched directly by the TGVI, LNG provides greater flexibility for upward nominations to eliminate imbalances on the system.

The LNG facility does not have to follow third-party 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. As an on system resource, the LNG facility can be dispatched on short notice in response to transient flow conditions that may develop on the pipeline. Similar service could be provided to TGI as well.

Other than the physical capabilities of the LNG facility, there are essentially no limitations on the number of hours or days in the year that the LNG supply can be used. The send out rate can be varied continuously which will allow TGVI 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.

[7] TGI would take TGVI's gas at Huntingdon and TGVI would use TGI's gas from the LNG facility to serve Vancouver Island loads.

6.5.4.2 Operations and Maintenance

From an operational perspective LNG will provide greater flexibility to deal with the requirements of planned maintenance on the TGVI transmission system. LNG will be used to as a source of secondary supply to extend the duration of that pipeline facilities can be removed from service.

Currently, during maintenance on the transmission system that requires the sections of the pipeline to taken out of service, downstream customers rely solely on line-pack and service to transport customers must be restricted. These requirements restrict the windows for operation and maintenance work. The LNG facility would provide a secondary source of supply to that would allow greater flexibility for scheduling this work so that restrictions could be avoided.

6.6.5 Satellite LNG Service

The LNG facility could be used as a source of supply for satellite distribution systems should they be developed on Vancouver Island. In this case, LNG could be transported by truck from the Mount Hayes facility to serve remote communities or industrial loads. LNG delivered by truck would be transferred to a small satellite tank were it would be stored, vaporized as required.

6.6.6 Truck Loading

The Mount Hayes Facility will incorporate allowance for an LNG truck filling station for loading LNG trucks that may be required to transport LNG to provide local natural gas system reinforcement for maintenance or emergency repair of any supply pipeline on Vancouver Island or to serve potential customers isolated from the gas transmission who may desire gas service.

TGI owns an LNG truck, based at the Tilbury LNG facility in Delta, to provide such support throughout the TGI service area. Initially, no transportation service is anticipated on Vancouver Island other than for emergencies or to support planned maintenance outages. Support will be provided from Tilbury until such time as the TGVI requirements justify installation of the complete truck loading facilities.

7. CUSTOMER RATE IMPACT

Section 6 compares the net present value of the incremental costs associated with the LNG Storage Portfolio with other resource choices. The analyses show that LNG Storage Portfolio is the preferred alternative for meeting TGVI’s requirements in the future because it supports the Company’s ability to provide natural gas services to its customers at the least delivered cost. While the allocation of cost and design of rates required to recover the cost of these facilities will be the subject of a future rate review, this section examines the expected rate impacts based on the current approved rate design principles for TGVI.

7.1 SYSTEM COST ALLOCATION ASSUMPTIONS

Use of the LNG facility in conjunction with other TGVI transmission assets was modeled to make the most efficient use of the combined system and thereby minimize costs that need to be recovered from core and transport customers. The general principles that were applied are as follows:

- TGVI's total system demands are met using available pipeline transmission capacity fully, and subsequently meeting the winter design requirements using the LNG send-out as well as peaking gas arrangements if available.
- Any available LNG capacity that is not required to meet total firm demand is used to provide third party services to TGI and/or other third party customers. As Core market demand grows over time, more of the LNG capacity will be required by TGVI and less will be available to provide third party services.
- The cost of service and the third party mitigating revenue (i.e. the net revenue requirement) associated with the LNG facility are allocated on a system wide basis.
- The total system costs are allocated to the transport customers based on their firm contract demand, and to the core market based on its design day peak, after deduction of the gas available to the core under peaking gas arrangements that may be in place at the time.
- Cost allocation includes an amortized recovery of the current balance of the Revenue Deficiency Deferral Account ("RDDA") consistent with the current approved methodology. The VIGJV and TGS are not required to contribute to the RDDA. The RDDA is forecast to be fully recovered by end of 2011.

7.2 RATE DESIGN OBJECTIVES

One of TGVI’s key objectives for rate design is to maintain competitive rates for Core customers which in turn supports a long-term financial sustainability of the utility. Under current approved TGVI rate design, this is achieved using a soft cap pricing mechanism to set core customer rates relative to competing alternate fuels of electricity and oil prices.

Given the soft cap mechanism, in order to assess impact of the LNG Storage Portfolio on TGVI’s ability to continue to provide competitive rates to serve core customers, the relative long-term costs of natural gas, oil and electricity must be assumed. For the purpose of this evaluation, the following assumptions were made:

- Gas commodity costs are based on expected gas portfolio costs as discussed in Section 6. The underlying natural gas price forecast for the various supply points is obtained from the GLJAL report dated April 1, 2004 and is attached as Appendix 5.
- Oil price forecasts are also based on the GLJAL report dated April 1, 2004 attached as Appendix 5.
- Electricity prices are assumed to increase by 8.9% over 2003 tariffs by 2005, consistent with BC Hydro's current Revenue Requirement Application. Thereafter it is assumed electricity tariffs increase at 50% of the change in CPI.
- Forecast of future changes in the CPI is assumed to be Bank of Canada's inflation control target of 2%.
- Long-term commodity US dollar price forecast figures are converted to Canadian dollars using a long-term foreign exchange assumption of US$0.71/Cdn$ beginning in 2006.

7.3 EXPECTED CORE UNIT COST IMPACT

Based on the principles and assumptions described above, the figures 7.3.1 and 7.3.2 illustrate the expected burner-tip cost to serve a typical residential customer versus the relative cost of alternate fuels adjusted for efficiency differences. The allocated costs include a contribution to the RDDA consistent with current approved principles.

This burner-tip cost is illustrated for the two demand forecasts: Base + 0 where no new gas fired generation is built on Vancouver Island and Base + 45 where a new generation load of 45 TJ/d results from BC Hydro's VI CFT process. The costs associated with both demand scenarios are based on the LNG Storage Portfolios.

The main conclusions drawn from these results are:

- Over the long term, TGVI's costs to provide natural gas service to the core market customers are competitive with the costs of alternate fuels. This allows the Company to continue to offer competitive rates to these customers and supports TGVI's long-term financial sustainability.
- With the LNG facility, incremental costs to serve additional loads on the system will reduce the average unit cost to provide natural gas services to core customers. For the Base + 45 forecast, the expected average unit cost for service to core customers is decreased by approximately $0.20 per GJ compared to the Base + 0 case.

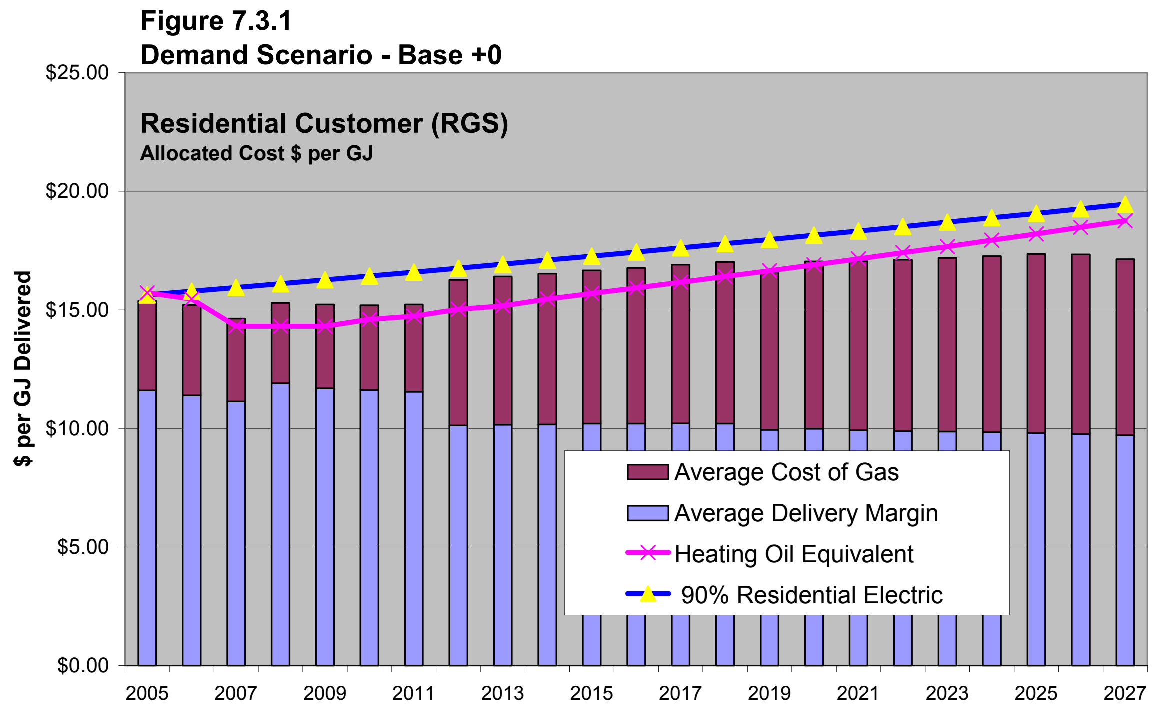


Figure 7.3.1
Demand Scenario - Base +0
Residential Customer (RGS)
Allocated Cost $ per GJ
$ per GJ Delivered
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
Average Cost of Gas
Average Delivery Margin
Heating Oil Equivalent
90% Residential Electric

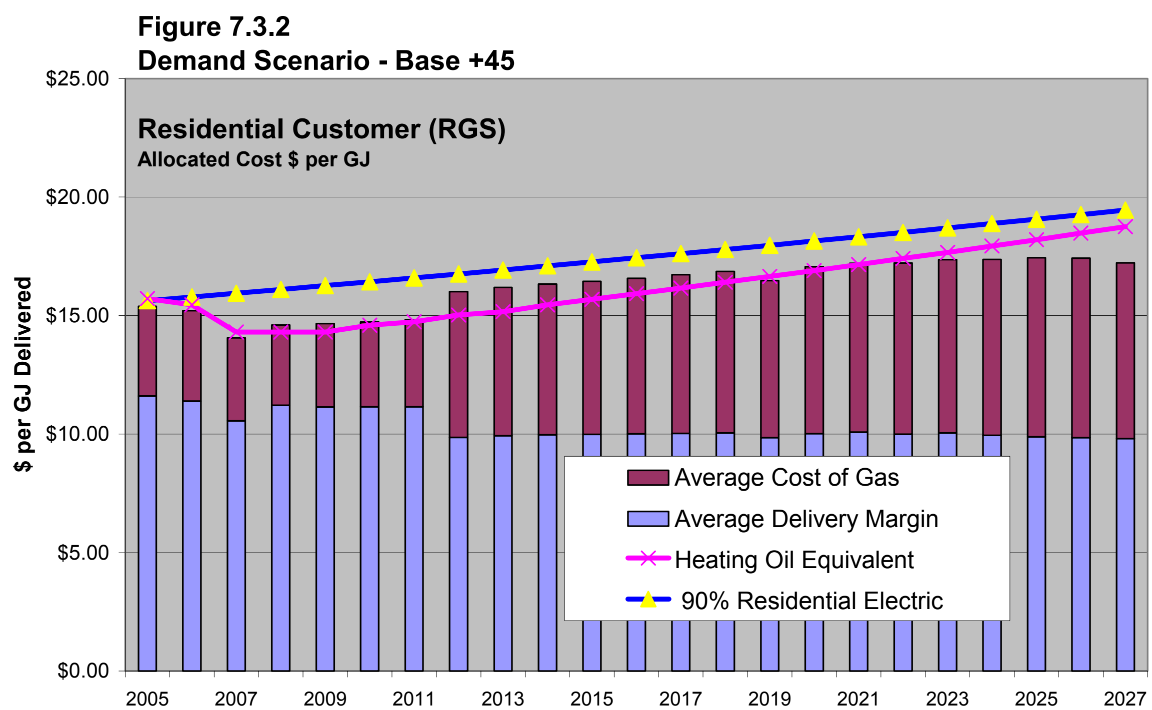
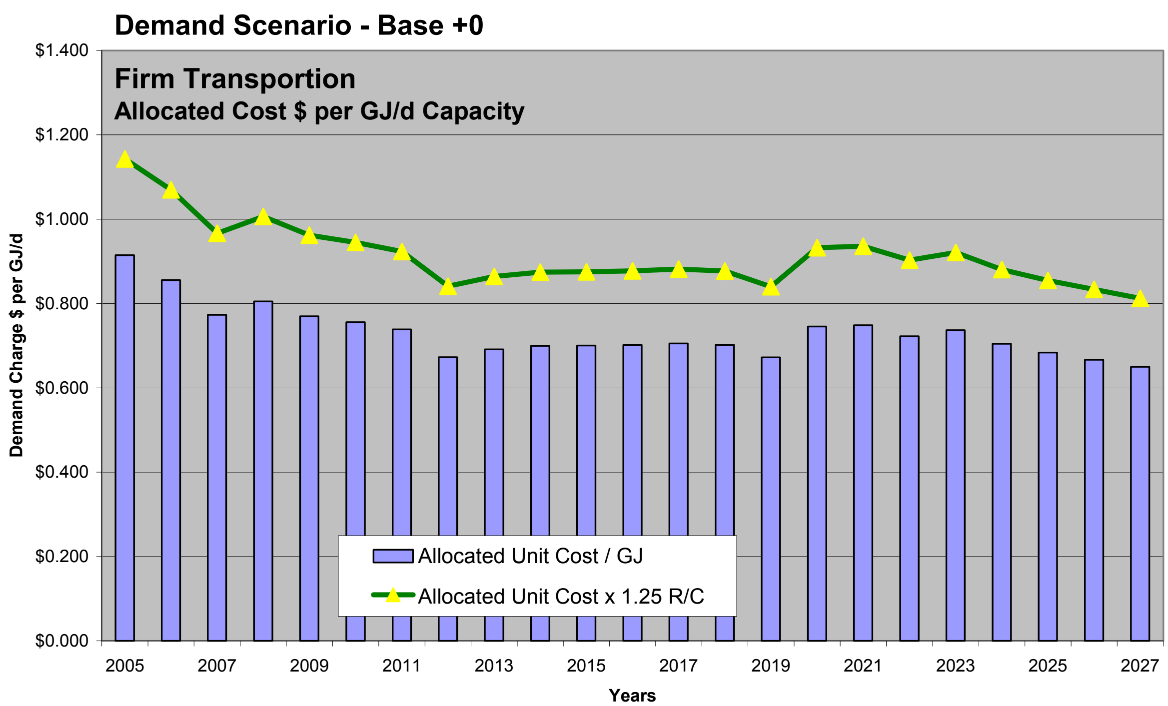
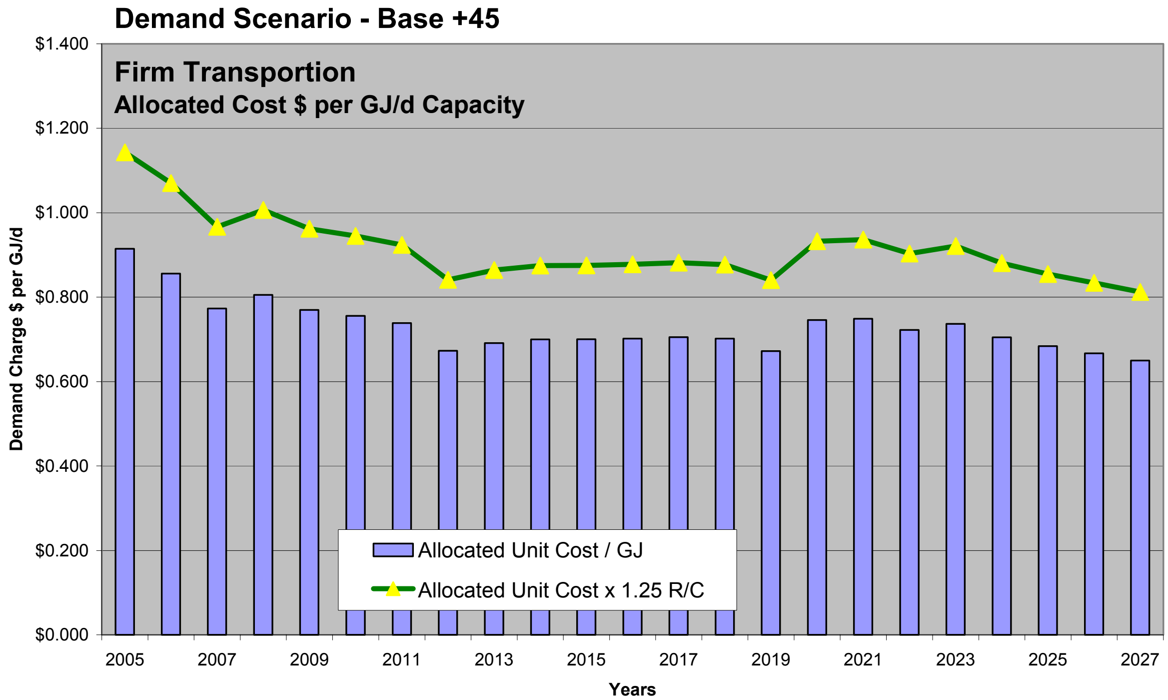


Figure 7.3.2
Demand Scenario - Base +45
Residential Customer (RGS)
Allocated Cost $ per GJ
$ per GJ Delivered
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
Average Cost of Gas
Average Delivery Margin
Heating Oil Equivalent
90% Residential Electric

7.4 FIRM TRANSPORT SERVICE

Similarly, the expected average cost to provide firm service to the transport customers is illustrated in the following figures for the two demand scenarios. For illustrative purposes, also shown on the figures is the indicative toll assuming the current revenue to cost ratio of 1.25 for firm transmission service is applied over the entire period. The results show that the LNG Storage Portfolio will allow TGVI to offer firm transport services at comparable or lower rates than is currently available. As is the case for the core customer, this benefit is expected to increase if new generation or other loads are added to the system.





7.5 CUSTOMER IMPACT SENSITIVITY ANALYSIS

The unit costs for the core and transport customers shown in Section 7 are expected costs based on TGVI's current assumptions for the LNG Storage Portfolio. The actual unit costs and subsequent sales or transport tariffs will be dependant on several factors, including but not limited to future loads, capital costs, and the relative costs of electricity, oil and natural gas. The sensitivity to some of these factors is shown in the following table:

Demand Scenario	Base plus 0		Base plus 45	
Levelized Unit Costs 2007-2026	Sales[1] $ per GJ	Transport[2] $ per GJ/d	Sales[1] $ per GJ	Transport[2] $ per GJ/d
Base Assumptions	$12.724	$0.920	$12.524	$0.900
Increase Capital Cost $10 million	$12.765	$0.942	$12.608	$0.917
Increase gas commodity cost $0.50 per GJ	$13.344	N/A	$13.086	N/A
Decrease Firm Transport Demand by 14 TJ/d beginning in 2012	$12.791	$0.940	$12.634	$0.918

[1]*Based on average allocated unit cost to serve all sales customer classes*
[2]*Assumes the 1.25 R/C ratio applies to the Firm Transportation Rate over the entire planning period*

8. ENVIRONMENTAL ASSESSMENT

TGVI has confirmed an application under the BC Environmental Assessment Act ("BCEAA") is not required for the 1.0 Bcf LNG facility as the project falls below the threshold for energy storage projects.

A Canadian Environmental Assessment Act ("CEAA") assessment is also not required as no CEAA triggers were found during the site assessment.

TGVI completed an Environmental Assessment for the Project and this formed a significant component of the public consultation program in support of the site rezoning application to the CVRD. The Environmental and Social Review ("ESR") concluded that "With the successful implementation of the mitigation measures recommended in this report, no residual post-mitigation significant impacts are expected to occur." A summary of the "Project Impact Significance" results of the ESR are repeated here as Table 8-1.

Environmental Assessment Summary of Project Impact Significance

Impact Topic	Impact Significance*	
	Unmitigated	Mitigated
PHYSICAL ENVIRONMENT		
• Geology and Soils	N	N
• Natural Hazards	N	N
• Water and Aquatic Systems	S	N
• Air Quality and Climate	N	N
BIOLOGICAL ENVIRONMENT		
• Vegetation	S	N
• Wildlife	N	N
• Fish and Fish Habitat	N	N
HUMAN ENVIRONMENT		
• Urban and Rural Settlement	N	N
• Transportation	N	N
• Forestry	N	N
• Recreation	N	N
• Archaeology	N	N
• Aesthetics	N	N
• Noise	N	N
• Domestic Water Supply	N	N
• Economic Effects	B	B
FACILITY AND PUBLIC SAFETY		
• Forest Fires	N/A	N
• Seismicity	N/A	N
• Facility Integrity	N/A	N
• Pipeline Integrity	N/A	N
• LNG Transportation	N/A	N
• Site Security	N/A	N
CUMULATIVE EFFECTS		
• Construction	N	N
• Operation	N	N

*

N =	Not Significant
S =	Significant
B =	Beneficial
N/A =	Not applicable; project design and construction standards incorporate these requirements
U =	Unknown due to lack of information

9. OTHER APPROVALS

9.1 DESIGN, CONSTRUCTION AND OPERATIONS

The design, construction and operation of LNG facilities and connecting pipelines is regulated by the OGC. The project will conform to the standards, codes and regulations in Figure 9.1 and others as applicable.

Figure 9.1 Primary Codes and Regulations

Code	Edition	Description
B.C. Pipeline Act and Pipeline Regulation	2002	Provincial Regulation of the Design, Construction and Operation of Pipeline Facilities
CSA Z 276	2001	LNG Production, Storage, and Handling
CSA Z 662	2003	Oil and Gas Pipeline Systems
NBC	1995 & Revisions	National Building Code of Canada
C.E.C.	2002	Canadian Electrical Code Part 1, 19th Edition
API 620 App. Q	10th	Design and Construction of Large, Welded, Low Pressure Storage Tanks
CSA B51	1997	Boiler, Pressure Vessel, and Pressure Piping Code
CAN/CSA A23.3-94 (R2000)	2000	Design of Concrete Structures
Terasen Standards	As Applicable	Standards for Equipment, Materials, Construction Procedures, Inspection, Testing, Security and Safety

The powerline will be designed and constructed to BC Hydro Engineering and Construction Standards. The design and construction of the electrical substation will conform to the Canadian Electrical Code CSA 22.1

9.2 SITE REZONING AND LAND PURCHASE

TGVI applied to the CVRD for rezoning of a block of land owned by Weyerhaeuser to allow construction and operation of an LNG facility. The CVRD gave approval to that rezoning application on May 26, 2004. A copy of the approval bylaw which allows for two 1.5 Bcf LNG tanks is included in Appendix 7. TGVI has optioned the property by means of a two-year option agreement.

9.3 PRIVATE LAND RIGHTS

The LNG facility is to be located entirely on land which will be owned by TGVI and will require no private easements. The connecting facilities will cross land primarily owned by Weyerhaeuser, TimberWest Forest 1 Limited ("TimberWest") and the Crown. Only one other private land holding will be impacted. All impacted land owners are aware of TGVI's requirements and no difficulties are anticipated in securing any of the private land easements.

9.4 CROWN LAND RIGHTS

Crown land easements will be required for portions of the connecting facilities and in addition, TGVI requires a lease over a segment of crown land immediately adjacent to the west of LNG facility property. This 20 hectare crown lease is required to enable TGVI to maintain control over lands which fall within the code required thermal setback buffer. TGVI does not intend to construct any facilities on this crown segment other than the connecting facilities rights-of-way which pass through and will not impact the current utilization of the crown land. The lease in favour of TGVI will provide a barrier to development of buildings and places of public gathering of 50 or more people as required by the CSA code.

9.5 ACCESS ROAD USE

TGVI requires the use of existing access roads owned and operated by Weyerhaeuser and TimberWest in order to access the Mount Hayes Site. The access road(s) will need to be relocated in some sections and improved and both companies have indicated that a road use agreement with TGVI to enable access to the LNG facility is acceptable. Work is currently underway to complete the agreement.

10. SAFETY AND INTEGRITY

10.1 FIRE PROTECTION

A pond will be constructed on the site of the LNG facility to collect water to initially be utilized for testing of the LNG tank. The pond will be maintained over the life of the LNG facility to supply the fire safety system at the facility and can be used to respond to fires that may occur during construction and operations.

10.1.1 Construction – Risk to the Forest

Construction of the LNG facility, with the attendant process work areas and pipeline, powerline and road construction, poses little risk of forest fire. Heavy equipment with firefighting capability will be onsite in case a fire starts accidentally. The sites will be cleared early in the season (low fire hazard period) prior to construction activities. Piling and burning of the slash will be conducted under provincial regulations, and will result a reduced fuel load at the site.

The construction phase will include the development of an Emergency Response Plan ("ERP"). Construction workers will be briefed on the need for fire safety and proper response in case of fire.

10.1.2 Operation – Facility Risk to the Forest

The risk to the surrounding forest area from a fire at the LNG facility is minimal. TGVI's facility is designed to fail safe by isolating equipment, containing spills and accommodating fire without harm to surroundings. The facility design, combined with fire warning and suppression systems that meet or exceed CSA requirements and industry standards, provide a high level of protection against fire risk to the forest. At ambient temperatures, without a source of ignition, the LNG would rapidly evaporate and dissipate. In the event of ignition, water and dry chemical fire fighting equipment is available on site to fight potential facility fires and keep adjacent facilities cool. The code designated thermal setback areas will mitigate potential impacts to the public.

TGVI proposes to remove trees within a minimum of 100 m of the tank dike to mitigate the potential for a fire at the LNG facility from impacting the adjacent forest.

10.1.3 Operation – Fire Risk to the Facility

Protection of the LNG tank from forest fires is an important consideration in TGVI's design, construction, and operation of the LNG facility sited in the forest environment. The fire potential on south-eastern Vancouver Island is highly seasonal and protection services are available.
The following mitigation measures will minimize the risk to the LNG facility from forest fires.

- Maintain an appropriate separation distance (minimum 100 m) between the tank dike and the forest.
- Ensure that the ERP includes cooperation with the Weyerhaeuser, the regulators, and local fire departments.
- Use non-flammable materials for construction of all facilities on site.
- Install a firewater storage and pumping system with underground piping, fire hydrants, fire monitors and hose cabinets installed in critical areas to cool facilities in the event of a surrounding forest fire.

Given the specifics of project design, impacts resulting from a forest fire are considered to be of low magnitude.

10.2 SEISMICITY

South-western British Columbia including Vancouver Island is located within a seismically active area. One of the mechanisms that results in earthquakes is continental drift, which involves the slow movement of various continental and oceanic plates relative to one another. Movement along a subduction zone involving the oceanic Juan de Fuca plate tending to slide down under the edge of the continental plate which includes Vancouver Island is an important factor in the seismicity of southern Vancouver Island and nearby parts of the coast.

10.2.1 Seismic Design and Mitigation

Earthquakes near the study area could potentially result in relatively high seismic motions. Such earthquakes could occur as a result of fault movements along or close to the subduction zone, or along faults within the continental plate overlying the subduction zone, such as the Cowichan System.

The current edition of the Canadian Standard CSA Z276, which applies to LNG production, storage, and handling, specifies two levels of earthquake motions that need to be considered during facility design:

1. Operating Basis Earthquake ("OBE") based on a 10 percent probability of exceedence within a 50-year period (corresponding to a 1:475 year event or approximately 1:500 years). This is the same as the design basis earthquake used in the present National Building Code. The structures and systems will be designed to remain operable during and after the OBE.

   A draft of the proposed 2005 Canadian National Building Code ("NBC") increases building design requirements from 1:475 years to 1:2500 years.

2. Safe Shutdown Earthquake ("SSE") based on a 5 percent probability of exceedence within a 50-year period (approximately 1:1000 years return period). There will be no loss of containment capability of the tank and it will be possible to isolate and maintain the LNG container during and after the SSE.

The CSA Z276 code proposes to increase the return periods for an SSE from the current 1:1000 years to either 1:2500 or 1:5000 years.

The LNG facility will be designed to the higher standards encompassed in the proposed revisions of the various codes incorporating the most recent knowledge and predictions of the potential seismic motions. The proposed CSA Z276 requirements for the OBE and SSE seismic events will be used as a minimum standard. Further site specific seismic studies will be carried out to define local seismic design parameters. Such studies will include consideration of both regional conditions as well as local conditions such as nearby faults within the Cowichan Fold and Thrust Zone.

It should be further noted that the shaking that would be experienced in a very large subduction earthquake could last much longer than the shaking from a smaller event, although the local ground motions might be similar depending on the distance and attenuation characteristics. The longer period of shaking will be considered in the design of the facilities.

There are about three hundred LNG storage tanks of this size and type in the world. Many of these tanks are located in parts of the world that are more seismically active than the Mount Hayes location, such as Japan, Korea, Turkey and Greece. Because of the significant industry experience, the methods for seismic design are well known and well accepted in the international engineering community. The LNG storage tank, buildings, equipment and piping proposed for the Mount Hayes location are all well within the industry's seismic design and construction experience, practice and capabilities.

10.3 LNG FACILITY INTEGRITY

LNG has been safely handled for many years throughout the world and has an excellent safety record. Over the last 50 years, there have been no impacts to any member of the public as a result of any incidents arising from LNG operations of the kind envisioned herein.

Worldwide, there are currently about 240 peak shaving LNG storage facilities[8] (three in Canada), some operating since the mid-1960s. The U.S.A. has the largest number of LNG facilities in the world with 113 active spread across the U.S.A., with a higher concentration of the facilities in the north-eastern region.

10.4 LNG FACILITY INTEGRITY METHODOLOGY

Facility integrity is addressed through a combination of regulatory compliance and industry standards, resulting in multiple layers of safety in design and operation of the proposed facility.

- The first layer is provided through LNG specific design of the storage and piping systems, employing suitable materials and proven design throughout the facility. The

[8] University of Houston Law Center Institute for Energy, Law & Enterprise, Introduction to LNG, An Overview of Liquefied Natural Gas (LNG) Its Properties, the LNG Industry, Safety consideration, January 2003.

inner storage tank holding the LNG will be constructed of 9 percent nickel steel. No LNG tank constructed of 9 percent nickel steel has ever failed.

- The second layer is isolation and containment systems in the unlikely event a leak or spill of LNG should occur. The facility is divided into numerous process segments that can be automatically isolated from each other. The storage tank and facility LNG piping will be surrounded by earthen dikes that can contain the entire contents of any spill or leak, including the entire contents of the tank.
- The third layer is the use of safety systems to detect abnormal conditions to shut off the flow of LNG to any leak or spill, to isolate the section and minimize the lost volumes. The facility will employ gas, liquid and fire detection systems activating automatically and remotely-activated shut-off, shut-down, fire-fighting systems in the event of any emergency. These systems are also continuously monitored by on-site personnel who can also activate any safety system. In addition, the LNG facility will be monitored 24/7 at TGI's gas control center located in Surrey, British Columbia.
- The fourth layer is the establishment of safe separation distances as required in the regulatory codes and standards. TGVI will maintain control over land around the facility so that the required buffer zone is maintained for the life of the facility.
- The fifth layer is the employment of proven and well-established operating and maintenance procedures, standards and practices. These documents, in use at the existing TGI LNG facility, will be adapted to the specific requirements of the proposed facility at Mount Hayes. Participation in industry organizations and ongoing review of these documents allows TGI to keep up with developments in technology and the industry practices. Incorporated in these documents are clear requirements for training of personnel, emergency preparation and safety procedures.

10.5 LNG FACILITY HAZARDS

The hazard most recognized in connection with the siting of an LNG facility is the potential for a large-scale spill of LNG and the potential of a subsequent fire which could threaten the public and employees and/or damage adjacent properties and the facility. The design of the LNG facility, per Section 5.3., minimizes this hazard. The safety systems are designed to minimize any spill or leak and isolate and make safe the entire facility.

The proposed LNG storage tank contains the greatest volume of product in the facility. The inner tank (the LNG primary containment) will be constructed on 9 percent nickel steel which has been proven to withstand the low temperature
(-162^{o}C) of the cryogenic liquid. An earthen dike will provide secondary containment, and will be designed to hold the entire contents of the inner tank in the extremely unlikely event of a leak in the LNG tank.

Design of the LNG facility, per the codes, addresses a sustained pool fire which could result if the LNG in the storage tank were to leak, empty into the earthen dike and catch on fire. Such an event would create a large steady state pool fire for a sustained period of time. The maximum thermal radiation hazard from such an event at any point around the facility is determined through computer modeling[9] and is a function of the size of LNG

[9] Determined by computer simulation program "LNG FIRE 3", developed by Risk & Industrial Safety Consultants for Gas Research Institute, 1996.

pool, wind direction and speed, relative humidity, ambient temperature and distance. The heat radiation effect drops rapidly as the distance from the fire increases. The radiation zone for the proposed 1.0 Bcf LNG facility is expected to extend to a maximum of approximately 400 m from the centre of the containment dike. TGVI will control use of the land and the activity of public and personnel in all radiation areas considered within the codes. Since 1960, the world’s LNG facilities (approximate 240) have recorded about 7,500 facility-years of experience. During this time there has been no large spill of LNG.

LNG that is spilled or leaks will act much like water, and flow to the low spots in the surrounding area, where it will gradually evaporate. Along with a multitude of systems and equipment which are designed to prevent any such spills or leaks from occurring in the first place, the proposed LNG facility design also will utilize the natural properties of LNG and rely on “passive” safety systems (e.g. channelling to specifically sited sump within the dike) which do not require the operation of equipment or human intervention to function. In addition, the facility will incorporate many hazard detection systems which will detect any spill, leak or fire as soon as possible and allow equipment to be shut down and isolated so as to minimize the scale of such an event.

Once collected, any spilled LNG will evaporate slowly and can be monitored by the operating staff at the facility to ensure no further hazard arises as a result of the spill. Initially the gas is colder and heavier than the surrounding air and can create a fog or vapour cloud above the release liquid. As the gas warms up it mixes with the surrounding air and begins to disperse. If the vapour cloud encounters an ignition source, it can ignite only if the methane/air mixture is in the 5 to 15 percent flammability range. The CSA code sets out the design criteria for the control of the vapour to mitigate any impacts.

10.6 OTHER LNG PLANT SAFETY ISSUES

LNG facilities present other safety issues that are of relatively lower significance and consequence than a fire, as far as the protection of the public is concerned. The facility design and specific operating procedures will address these other hazards, which include:

- Personnel exposed to direct contact with LNG (liquid at -162^{o}C) or very cold LNG vapours could sustain severe frostbite (or freeze burns). The potential extent of this cryogenic hazard is limited to the immediate area around equipment, piping and tanks containing LNG. Protective clothing and shields will be used to mitigate this hazard.
- Methane gas, the primary component of LNG, is colorless, odourless and is classified as an asphyxiate (when released and it displaces air). Separation distances and gas detection systems will be used to mitigate this hazard.
- The process of liquefying natural gas removes almost all of the components that give LNG any detectable odour. All vapourized LNG leaving the LNG facility will be odorized to meet government and pipeline standards. Fuel gas used in the LNG facility will also be odorized. Additional hazard mitigation includes gas detection in areas of possible leaks.
- Distances between property lines, buildings, electrical equipment, process equipment, impoundments, and the proposed LNG storage tank will meet or exceed the spacing requirements of CSA standards.

- The LNG facility will utilize continuous monitoring equipment to detect hazardous conditions. Hazard detection will include: evidence of combustible gas, cold temperatures from LNG spills, fire, smoke, and high pressure in tanks and vessels.
- Quantities of other compounds may be stored on site as part of the liquefaction or back-up systems (e.g. diesel, propane, etc.) depending on the final specific design that is approved. TGVI will ensure all appropriate and required safety systems are in place for these compounds.

10.7 LNG FACILITY FIRE PROTECTION SYSTEMS

To reduce the effects of a fire, the proposed LNG facility will have a fire water system. A pond will be constructed on site to collect runoff water. Water from the pond will be utilized to fill an onsite fire water tank that will supply the fire water system. An underground firewater pipe will encircle the facility. Branches will feed various fire fighting locations with multiple hydrants to keep any equipment cool in the event of fire at any adjacent location. Water is not used to fight an LNG fire, as the warm water will increase the rate of vapourization of the cold liquid. Water is also not typically used to fight or extinguish a natural gas vapour fire but is generally used to cool and protect facilities adjacent to a fire and to fight non-gas related fires.

Dry chemical fire extinguishing equipment to directly fight any natural gas (or other compound) fire will be located throughout the facility. Dry chemical skidded, wheeled and hand held units will be incorporated in the fire protection plan for the LNG facility.

10.8 LNG FACILITY SECURITY

The security strategy for the facility will include controlling all access by individuals and vehicles onto the site. The entire boundary of the facility site, including the LNG storage and vapourization facilities will be fenced with chain link and a top guard that meet or exceed recognized industry standards as to gauge and height. The number of access points to the LNG-related facilities will be limited to an absolute minimum, but will include at least one emergency gate. The access points will have video monitoring, with feeds into the facility control room. An employee will be required to manually or remotely unlock gates to allow access to any persons or vehicles.

The monitoring and detection systems at the proposed facility will function on a “24/7” basis and consist of intrusion detection alarms, CCTV, regular (but random) patrols and lighting. These systems, as well as the security communication system, will be operated and monitored at the control room.

TGVI facility management will establish liaison with all appropriate government security and emergency response agencies. TGVI is prepared to protect the public, employees and the LNG facility from all threats or potential damage that can be defined as reasonable, credible and defensible. The design of the facility, including the TGVI controlled separation zone around the facility and the earthen dikes will minimize any potential impacts to the public. TGVI will ensure that training is provided to LNG facility personnel and that the LNG facility is operating in continuous compliance with Canadian regulations.

10.9 PIPELINE INTEGRITY

The LNG facility is expected to be connected to the TGVI transmission system by two laterals, 219 mm (8") and 273 mm (10") diameter pipelines of approximately 5 km length.

The pipeline laterals to the LNG facility will be designed in accordance with the code requirements of the Canadian standard "CSA Z662 Oil and Gas Pipeline Systems". The design, construction and operation of TGVI's pipeline systems are reviewed and approved by the BC OGC, which is the responsible for regulations related to construction, operations and maintenance for natural gas pipelines which operate at over 100 psig.

The laterals to the proposed LNG facility will be buried a minimum of 0.7 m within a proposed 18 m wide right-of-way. The pipeline right-of-way is patrolled periodically via helicopter, in addition to ground patrols. TGVI is a member of BC One Call, a notification service for anyone wishing to dig in the vicinity of the pipeline. TGVI also maintains a complete list of all land owners impacted by the pipeline right-of-way, and has a yearly pipeline awareness program.

The pipeline valves and the current pipeline conditions of the entire pipeline are monitored centrally for all of TGVI's transmission pipeline systems by a SCADA (Supervisory Control and Data Acquisition) system which is manned 24/7. Emergency actions may be initiated remotely by the SCADA operator in the event of a pipeline incident.

TGVI pipelines and laterals are capable of being internally inspected and once placed into operation they become part of a systematic integrity inspection program.

10.10 EMERGENCY RESPONSE PLAN

TGI has an existing LNG facility in Delta, B.C. which has operated successfully for over 30 years as well as thousands of kilometres of transmission pressure pipelines. TGI considers safety and emergency response to be of prime importance and remains proactive in improving its ERP and the safe operation of its facilities. TGVI is committed to:

- Developing a site and location specific ERP for the proposed Mount Hayes LNG facility
- Operating the connecting pipelines in accordance with TGVI's existing well proven procedures
- Meeting or exceeding relevant laws and regulations and cooperating with local authorities
- Regularly testing and improving emergency response plans
- Ensuring appropriate resources and training to implement the plans
- Monitoring industry development of improvements to emergency response issues.

The ERP will clearly lay out the methodology for TGVI employees to effectively manage any emergency at the LNG facility. The ERP is developed to minimize injury to the public and employees, to minimize damage to property and the environment, and to promote rapid return to normal operation.

The ERP lays out the organization, duties and responsibilities of all facility and off-site support TGVI personnel, including corporate emergency response centers. Chains of command are clarified, including appropriate contact and communication with local and provincial emergency response agencies.

10.11 LOCAL NOTIFICATION AND INVOLVEMENT

TGVI is committed to working with local and provincial authorities on all aspects of the proposed LNG facility. Specific to the ERP, TGVI will work with the local Fire Department(s), emergency response and regulatory authorities to achieve a high level of comfort and communication, including ongoing dialogue on emergency preparedness and responsibilities for response and cooperation and involvement in facility emergency exercises on a regular basis.

11. PUBLIC CONSULTATION

11.1 PUBLIC CONSULTATION PROGRAM

Section 5.3.3 outlined the comprehensive site selection and public consultation program that was undertaken by TGVI to engage the public and locate a suitable site for the project. This program culminated in the successful rezoning of the subject Mount Hayes property. Public (including First Nations) consultation will continue through the permitting, construction and operation phases of the project to ensure that project developments are communicated in a timely fashion, that any potential negative impacts are mitigated and that positive benefits of the project for the local community are realized.

11.2 FIRST NATIONS

Although the majority of the lands affected by the LNG facility and rights-of-way involve private lands, with only a small impact to crown lands, all of the facilities fall within the traditional territory of the Chemainus First Nation ("CFN"). TGVI is in communication with the CFN and will consult with the CFN to ensure their interests are taken into account. Applications for rights to crown land have been made to the OGC and the OGC has referred the applications to the CFN for comment. TGVI has considerable experience working with First Nations in British Columbia and expects to reach a mutually acceptable understanding with the CFN with respect to the use of crown land which will provide project benefits to the Band and mitigate any potential negative impacts to the CFN traditional use of the land that could result from the project.

11.3 SOCIO ECONOMIC ASSESSMENT

The construction of a 1 Bcf LNG facility and connecting facilities (estimated cost of $94.4 million) will provide positive benefits to local Vancouver Island communities as well as to British Columbia and Canada.

Construction of the LNG project is estimated to generate 700 person years (direct and indirect) of employment in BC of which 240 person years will be in local communities. Of the estimated $28.7 million to be spent in the local area, $10.1 million will be on labour and $18.6 million on goods and services (including land acquisition).

Once in operation the facility is expected to employ 9 full time employees and generate approximately $150,000 in local expenditures annually (not including electricity and fuel).

12. PROJECT MANAGEMENT, ENGINEERING AND CONSTRUCTION

TGVI and TGI have considerable experience in managing and completing major projects on time and on budget. A TGVI project manager, who in turn will report to a TGVI project sponsor, will direct all phases of the LNG project after CPCN approval. TGVI will execute the overall LNG project utilizing experienced contractors, consulting professionals and TGVI personnel.

TGVI will enter into a turnkey Engineering, Procurement and Construction ("EPC") contract for the major portion of the LNG facility, basically including all work inside the facility fence after site grade is established. The EPC contractor will manage the design, procurement and construction of the major portion of the LNG facility according to performance specifications and contract conditions contractually agreed to with TGVI.

TGVI has completed an Expression of Interest review with major contractors and is in the process of selecting an EPC contractor(s) to negotiate a sole source contract for the main LNG facility. TGVI has begun the development of contract terms and conditions and performance specifications for the facility in support of entering an EPC contract. TGVI expects the successful contractor to provide an operational LNG facility, to be in-service June 30, 2007 (schedule as outlined in Section 13) to allow the LNG tank to be at least one-third full at November 01, 2007.

Connecting facilities and likely some portions of the project such as site preparation, grading, restoration, gas metering and odourization will be designed and constructed separately from the EPC contractor by a TGVI project manager(s) and local contractors.

The TGVI project manager will implement a project execution plan for the development of each segment of the overall project including design and construction quality assurance for all phases. TGVI operating personnel will be deployed to various projects as required to ensure all facilities can be efficiently placed into operation upon completion of construction and are completed in conformity with TGVI and industry practices. The majority of specialized services required for environmental management and design and construction inspection will be contracted to individuals and companies with the demonstrated skills and experience to complete the work. TGVI expects to implement a project office team with the resources to manage overall project costs and provide procurement, accounting and administration support to the project managers.

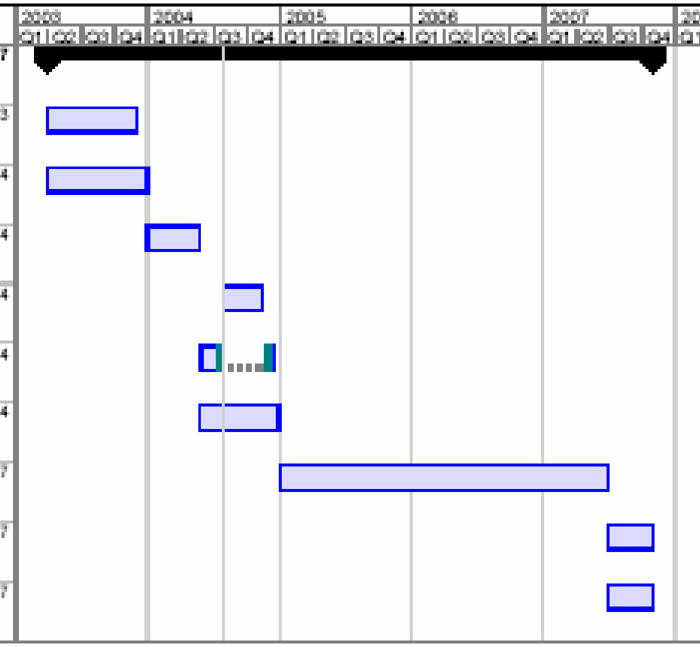
13. PROJECT SCHEDULE

The following Figure 13 outlines the timing of major elements of the project. TGVI is confident that if the major LNG contract (for Engineering, Procurement and Construction) is awarded by January 1, 2005, TGVI is confident the 1 Bcf LNG facility can be constructed in 30 months or less leaving a minimum of 4 months to secure a partial tank fill sufficient for the first heating season's requirements. Other components of the project including connecting facilities are not on the critical path and can be readily completed within the overall schedule.

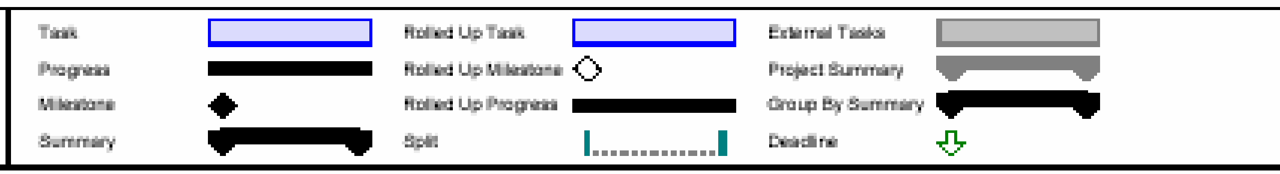
Figure 13

LIQUIFIED NATURAL GAS STORAGE PROJECT SCHEDULE
2007 IN-SERVICE

ID	Task Name	Duration	Start	Finish
1	**LNG STORAGE FACILITY**	**54.4 mons**	**Tue 4/1/03**	**Wed 10/31/07**
2	GENERAL ENG. & SPEC. DEVELOPMENT	8 mons	Tue 4/1/03	Tue 12/2/03
3	SITE SELECTION incl. ENVIR'N ASSESSMENT	9 mons	Tue 4/1/03	Thu 1/1/04
4	SITING AND ZONING APPROVAL	4.7 mons	Fri 1/2/04	Wed 5/26/04
5	CPCN APPROVAL	3.5 mons	Thu 7/29/04	Mon 11/15/04
6	SITE ACQUISITION (Option & Purchase)	2.2 mons	Thu 5/27/04	Wed 12/15/04
7	EPC CONTRACT DEVELOP/BID/NEG/AWARD	7 mons	Wed 5/26/04	Tue 12/28/04
8	CONSTRUCT & COMMISSION (EPC)	29.5 mons	Mon 1/3/05	Fri 6/29/07
9	OPERATION & PARTIAL FILL	4 mons	Fri 6/29/07	Wed 10/31/07
10	RESTORATION	4 mons	Fri 6/29/07	Wed 10/31/07



Project: Section 13
Date: Wed 7/28/04



14. PROJECT COST ESTIMATE

14.1 CAPITAL COSTS

TGVI has completed a cost estimate for the Project based on information supplied by consultants and contractors and utilizing TGVI and TGI experience in project management of other major capital projects. Figure 14.1 provides a break down of the estimated direct capital cost of $ 94.4 million ($2004).

Figure 14.1 LNG Facility Capital Costs (2004$millions)

EPC Costs	73.8
Owners Costs	
Land	1.6
Interconnecting Facilities	9.3
Project Services	7.9
Contingency	1.8
Total	94.4

14.2 LNG OPERATING COSTS

Operating costs for the LNG facility have been determined from experience operating the Tilbury LNG facility in Delta, B.C. and in operating transmission pipelines throughout B.C.

Figure 14.2 LNG Facility Operating Costs (2004$000)

Fixed Operating	$ 930
Variable Operating (excl gas)	$ 557
Total	$1,487

14.2.1 Fixed Costs

Fixed costs include regular staff required to operate and maintain the facility, utility costs, materials and contractors for routine preventive maintenance, annual licensing and inspection fees, right-of-way maintenance for interconnecting pipelines, and staff training costs.

14.2.2 Variable Costs

Variable costs include electricity consumed during liquefaction, send-out and holding operations. Variable costs exclude natural gas fuel costs.

APPENDIX 1

DESCRIPTION OF LIQUEFIED NATURAL GAS

LIQUEFIED NATURAL GAS ("LNG")

WHAT IS IT?

When natural gas is cooled to a temperature of approximately -260°F (-162°C) at atmospheric pressure, it condenses to a liquid called liquefied natural gas ("LNG"). One volume of this liquid is formed from approximately 620 volumes of gas at atmospheric pressure and ambient temperature. Conversely when vaporized, 620 cubic feet of gas are produced from every cubic foot of liquid. This clear liquid weighs about half as much as the same volume of water.

USEFULNESS

The large ratio of the volume of gas to the volume of liquid (620:1) makes storage of natural gas in the liquid state attractive. The reduced volume and liquid state also makes possible alternate methods of transportation where conventional gas pipelines are not practical.

COMPOSITION

LNG is composed primarily of methane and may also contain ethane and some heavier hydrocarbons. Small quantities of nitrogen, which often occur in natural gas, may also be dissolved in LNG. Prior to liquefaction to produce LNG, natural gas must be treated to remove carbon dioxide, water, sulphur compounds an all such constituents that could form solids at LNG temperatures and plug process equipment.

SAFETY

LNG will not burn or explode and must be returned to its vapour state and then mixed in a ratio of 5% to 15% gas in air before it is capable of supporting combustion.

TEMPERATURE EFFECTS

At atmospheric pressure, LNG boils at approximately 260°F (162°C) below zero. This is classified as a "cryogenic" temperature. The field of cryogenics includes: the processes and equipment used to produce liquefied gases such as LNG; the equipment used to store, transport, and handle them; and all the phenomena that are produced by the cold temperature.

Marked changes in the physical behaviour of many materials occur at LNG temperatures. Rubber at cryogenic temperature, for example, loses its resiliency and shatters like glass if dropped or struck by a hammer. Carbon steel undergoes a change from a ductile material that fails by stretching at warmer temperatures to a brittle material that fails by cracking at cryogenic temperatures. While some of the familiar materials of construction are not suitable at LNG temperatures, many materials such as 9% nickel alloy steel, aluminum, stainless steel and concrete are well proven in use at these frigid temperatures.

APPENDIX 2

LETTER OF COMMITMENT FROM TGI
FOR LNG SERVICE

Douglas Stout
Vice President
Gas Supply & Transmission

16705 Fraser Highway
Surrey, B.C. V3S 2X7
Tel: (604) 592-7850
Fax: (604) 592-7890
Email: douglas.stout@terasengas.com
www.terasengas.com

August 3, 2004

Terasen Gas (Vancouver Island) Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Attention: Mr. Scott Thomson

Dear Sir:

Re: Terasen Gas Vancouver Island Inc. LNG Proposal

We understand that Terasen Gas (Vancouver Island) Inc. ("TGVI") is proposing a Liquefied Natural Gas ("LNG") facility on Vancouver Island at Mount Hayes near Ladysmith that should be available for third party usage by the spring of 2008. Terasen Gas Inc. ("TGI") is interested in LNG for peaking supply for both the near term and the longer term for its core market.

TGI understands that TGVI does not initially require the entire facility storage volume and wishes to gradually grow into the capacity at the LNG facility. The LNG capacity not required by TGVI will then be available for third party contracting. TGVI has provided a preliminary schedule of the amount of LNG capacity and deliverability that will be potentially available to TGI over the period April 1, 2008 through March 31, 2028.

In addition, TGI and TGVI have had discussions with respect to the nature and availability of transportation to and from the Huntingdon Pool/Eagle Mountain to the proposed facility. Transportation for injection will be on a firm basis for the period April through October and will be on an interruptible basis for the period November through March. Transportation will be a physical flow to the facility on TGVI's facilities while transportation from the facility will primarily be by displacement, with the gas supply taken at either Eagle Mountain or at Huntingdon Pool by TGI.

TGI understands that TGVI does not, at this time, have fixed rates either for storage or transportation. However, TGI, in turn, requires a price for the storage including transportation which it less than or equal to the avoided cost of the alternatives taking into account the relative operational flexibility of the alternatives. Initial estimates by TGI indicate that this avoided cost is between $70 and $80 per GJ of withdrawal capability including all fixed and variable costs depending on the capacity available in the tank.

Access to a new storage resource creates commodity and supply diversity benefits for TGI customers. From a regional perspective, the new storage resource will help to mitigate price volatility that characterizes the regional market by providing additional peak day supply to the region. Because of TGI's relatively large exposure to the regional gas market, this is an important commodity benefit beyond the direct storage benefit. In addition, because the TGI and TGVI systems are directly interconnected, TGI will realize facility benefits from effectively having a new LNG facility connected to its system. The location of the Eagle Mountain interconnect provides a resource at a point on the TGI system that is currently constrained, offering the opportunity to delay future expansions on the TGI Coastal Transmission System.

Based on the assumptions above, TGI will contract either on a short-term or long-term basis for any capacity that TGVI will have available at the facility once that quantity is known. TGI proposes to enter into an LNG agreement between TGI and TGVI under the following terms:

Term:	20 years from April 1, 2008 to March 31, 2028
Unit Cost:	TGI proposes that there is a rolled-in cost for LNG service and redelivery to the Huntingdon Pool. The unit cost will not include the variable costs for fuel gas for the liquefaction, vaporization and transportation of gas to and from the LNG facility.
Withdrawal:	Up to 90 TJ/d
Liquefaction:	0.5%/day of contracted capacity.
Capacity:	Up to 900 TJ
Special Provisions:	Because of the uncertainty surrounding TGVI capacity requirements, TGI proposes establishing a schedule with annual withdrawal and capacity contract demand for the initial five years followed by an annual addition of contract demand for the fifth year on a rolling basis for the term of the contract.

Any agreement will be subject to approval by the British Columbia Utilities Commission.

Yours very truly,

TERASEN GAS INC.

Douglas Stout

APPENDIX 3

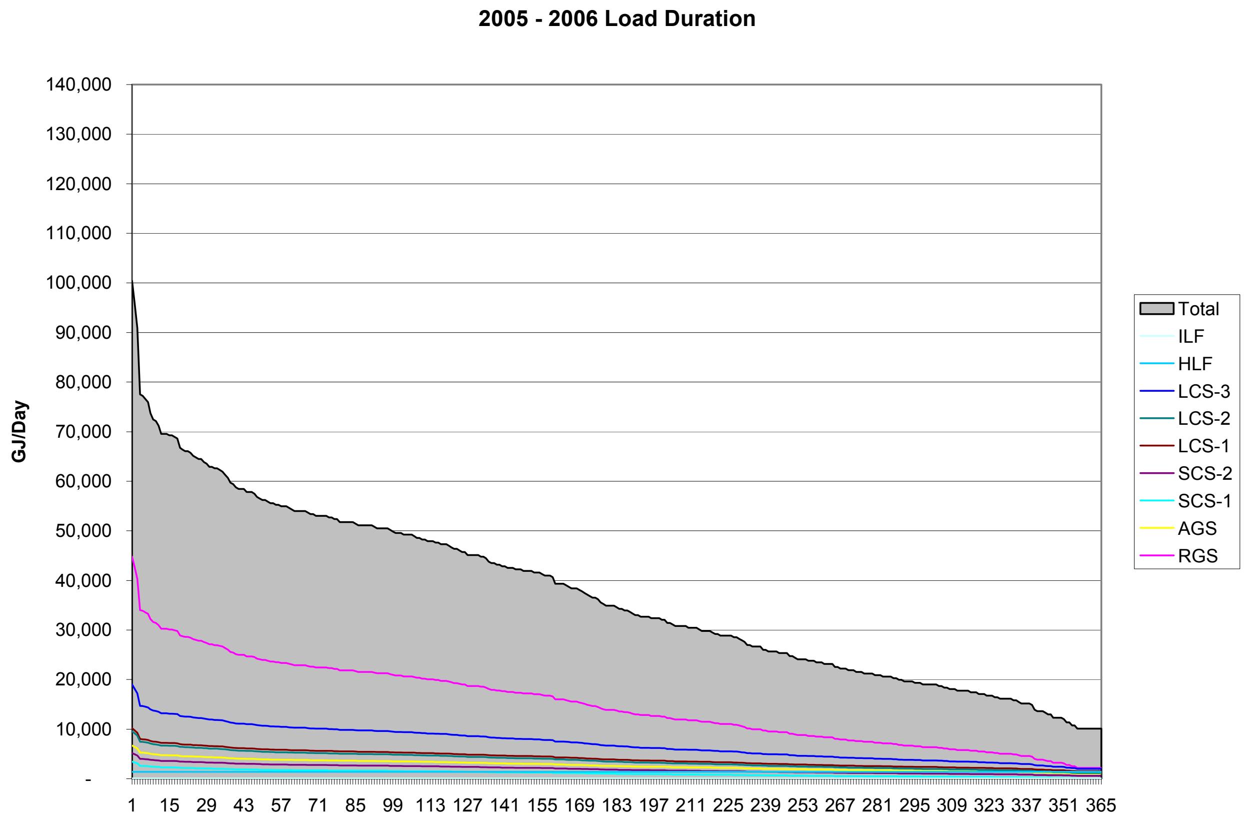
DEMAND FORECAST

Design Day Base Forecast Scenario

Year	Core Customers	Joint Venture	BC Hydro	Squamish
2005	100.4	37.6	38.0	4.8
2006	103.9	33.6	38.0	5.0
2007	107.3	33.6	45.0	5.1
2008	110.5	33.6	45.0	5.3
2009	113.6	33.6	45.0	5.5
2010	116.4	33.6	45.0	5.7
2011	119.0	33.6	45.0	5.9
2012	121.5	33.6	45.0	6.1
2013	123.9	33.6	45.0	6.3
2014	126.4	33.6	45.0	6.4
2015	129.0	33.6	45.0	6.6
2016	131.5	33.6	45.0	6.8
2017	134.2	33.6	45.0	7.0
2018	136.9	33.6	45.0	7.1
2019	139.6	33.6	45.0	7.3
2020	142.4	33.6	45.0	7.5
2021	145.2	33.6	45.0	7.7
2022	148.1	33.6	45.0	7.8
2023	151.1	33.6	45.0	8.0
2024	154.1	33.6	45.0	8.2
2025	157.2	33.6	45.0	8.4
2026	160.4	33.6	45.0	8.5

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. 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 Celsius or 28.4 heating degree days (HDD).

A design year load duration curve is provided for reference below using the results of the regression analysis extrapolated against the HDD for each day of 1989, the coldest year in the last 25 years. The duration curve provided is sorted from the coldest to warmest day.


2005 - 2006 Load Duration
GJ/Day
140,000
130,000
120,000
110,000
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
1 15 29 43 57 71 85 99 113 127 141 155 169 183 197 211 225 239 253 267 281 295 309 323 337 351 365
Total
ILF
HLF
LCS-3
LCS-2
LCS-1
SCS-2
SCS-1
AGS
RGS

APPENDIX 4

CAPITAL SCHEDULES

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	3.5%	V1U4, V2, V3b, spares	61	3.9%	V2, spares	27	4.0%
2008			3.5%			3.9%			4.1%
2009			3.6%			3.9%			4.1%
2010			3.6%			3.9%			4.1%
2011			3.6%	loop 25km d/s WS	23	3.9%			4.1%
2012			3.6%			3.9%	V3b	20	4.1%
2013			3.7%	loop 12km d/s V2	12	3.9%			4.1%
2014			3.7%			3.9%	V1	15	4.1%
2015			3.7%	V5	20	3.9%			4.1%
2016			3.7%			3.9%			4.1%
2017			3.8%			3.9%			4.1%
2018			3.8%			3.9%			4.2%
2019	V2	22	3.8%	loop 27km d/s V3b	25	3.9%			4.2%
2020			3.8%	loop 40km d/s WF	36	3.9%			4.2%
2021			3.9%			3.9%	V5	20	4.2%
2022			3.9%			3.9%			4.2%
2023			3.9%	V1U5	15	3.9%			4.2%
2024			3.9%			3.9%			4.3%
2025			4.0%	loop 19km d/s PM	17	3.9%	loop 25km d/s WS	23	4.3%
2026			4.0%			3.9%	loop 12km d/s V2	12	4.3%

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 Compressor Engines	WF	'Woodfibre'
V1U4	4th unit to VI - Coquitlam Compressor Station	WS	'Watershed'

Notes

System fuel includes compressor fuel plus 0.5% for meter station fuel, 1% for UAF, and LNG fuel where applicable

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), spares	156	4.7%	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	4.1%	V1U4, V2, V3(b), V5, spares, loop 12km d/s V2, loop 25 km d/s WS	117	4.5%
2008			4.7%	V1U5	15	4.1%			4.5%
2009			4.7%			4.1%			4.4%
2010			4.8%			4.1%			4.4%
2011			4.8%	loop 19km d/s PM	17	4.1%			4.4%
2012			4.9%			4.1%			4.4%
2013			4.9%			4.1%	loop 27km d/s V3b	25	4.4%
2014			5.0%			4.1%	loop 40km d/s WF	36	4.4%
2015			5.0%			4.1%			4.4%
2016			5.0%	loop 13km d/s WS	12	4.1%			4.4%
2017			5.1%			4.1%			4.4%
2018			5.1%	loop 10km d/s V4	12	4.1%			4.4%
2019	loop 25km d/s WS	23	5.2%			4.1%			4.4%
2020	V5	20	5.1%			4.1%	loop 19km d/s PM	17	4.4%
2021	loop 12km d/s V2	12	5.1%			4.1%	V1U5	15	4.4%
2022			5.1%	loop 4km d/s V4, loop 7km d/s V5	12	4.1%			4.4%
2023			5.1%	loop 5km d/s V3b	5	4.1%			4.4%
2024			5.1%			4.1%			4.4%
2025			5.0%	loop 5km d/s V5	5	4.2%	loop 7km d/s V5	7	4.5%
2026			5.0%			4.2%			4.5%

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 Compressor Engines	WF	'Woodfibre'
V1U4	4th unit to VI - Coquitlam Compressor Station	WS	'Watershed'

Notes

System fuel includes compressor fuel plus 0.5% for meter station fuel, 1% for UAF, and LNG fuel where applicable

APPENDIX 5

GAS PRICE FORECAST

Gilbert Laustsen Jung Associates Ltd. Petroleum Consultants

PRODUCT PRICE AND MARKET FORECASTS FOR THE CANADIAN OIL AND GAS INDUSTRY

Quarterly Update

April 1, 2004

Prepared by
Carol A. Crowfoot, B.A. Econ.
Senior Energy Economist

4100, 400 - Third Avenue S.W., Calgary, Alberta, Canada T2P 4H2
Internet: http://www.GLJA.com

April 1, 2004

Gilbert Laustsen Jung Associates Ltd. has prepared the enclosed price and market forecasts after a comprehensive review of information available through to March 2004. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The accuracy of all factual data, from all sources has been accepted as represented without detailed investigation by Gilbert Laustsen Jung Associates Ltd. The forecasts presented herein are based on an informed interpretation of currently available data. While they are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change. These future revisions may be significant.

**GILBERT LAUSTSEN JUNG ASSOCIATES LTD.
PRODUCT PRICE AND MARKET FORECASTS
FOR THE CANADIAN OIL AND GAS INDUSTRY
April 1, 2004**

Gilbert Laustsen Jung Associates Ltd. has completed a quarterly update of our commodity price forecasts as presented on the attachments. Revisions in the forecasts reflective of current market conditions have been incorporated. A summary of near-term forecasts follows:

NATURAL GAS PRICES

	January 1, 2004 Calendar Year	April 1, 2004 Calendar Year
Henry Hub Gas Price - ($US/MMBTU)		
2004	5.10	5.70
2005	4.50	4.80
Chicago 30 Day Spot Gas Price – ($US/MMBTU)		
2004	5.30	5.80
2005	4.70	5.00
Sumas 30 Day Spot Gas Price - ($US/MMBTU)		
2004	4.55	5.10
2005	4.00	4.30
AECO-C 30 Day Spot Gas Price – ($Cdn/MMBTU)		
2004	5.85	6.65
2005	5.15	5.55
Average Alberta Plant-Gate Gas Price - ($Cdn/MMBTU)		
2004	5.50	6.30
2005	4.85	5.25
Aggregator Plant-Gate Gas Price - ($Cdn/MMBTU)		
2004	5.20	6.00
2005	4.70	5.15
B.C. 30 Day Spot Plant-Gate Gas Price - ($Cdn/MMBTU)		
2004	5.55	6.35
2005	4.90	5.30

CRUDE OIL PRICES

	January 1, 2004 Calendar Year	April 1, 2004 Calendar Year
WTI @ Cushing Price - ($US/BBL)		
2004	29.00	34.25
2005	26.00	29.00
Light, Sweet @ Edmonton Price - ($Cdn/BBL)		
2004	37.75	44.75
2005	33.75	37.75

Gilbert Laustsen Jung Associates Ltd.

Table 1

Gilbert Laustsen Jung Associates Ltd.

Crude Oil and Natural Gas Liquids

Price Forecast

Effective April 1, 2004

Year	Inflation %	Bank of Canada Average Noon Exchange Rate ($US/$Can)	WTI Crude Oil at Cushing Oklahoma Constant 2004 $ ($US/bbl)	WTI Then Current ($US/bbl)	Brent Blend Crude Oil FOB North Sea Constant 2004 $ ($US/bbl)	Brent Then Current ($US/bbl)	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Constant 2004 $ ($Can/bbl)	Light, Sweet Then Current ($Can/bbl)	Bow River Crude Oil Stream Quality at Hardisty Constant 2004 $ ($Can/bbl)	Bow River Then Current ($Can/bbl)	Heavy Crude Oil Proxy (12 API) at Hardisty Constant 2004 $ ($Can/bbl)	Heavy Then Current ($Can/bbl)	Medium Crude Oil (29 API, 2.0%S) at Cromer Constant 2004 $ ($Can/bbl)	Medium Then Current ($Can/bbl)	Spec Ethane ($Can/bbl)	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Propane ($Can/bbl)	Edmonton Butane ($Can/bbl)	Edmonton Pentanes Plus ($Can/bbl)
1993	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
1994	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
1995	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
1996	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
1997	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
1998	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
1999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
2000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
2001	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
2002	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
2003	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
2004 Q1 (e)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]
2004 Q2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Q3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Q4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Full Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Q2-Q4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2005	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2006	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2007	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2008	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2009	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2010	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2012	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2013	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2014	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2015+	[illegible]	[illegible]	[illegible]	+1.5%/yr	[illegible]	+1.5%/yr	[illegible]	+1.5%/yr	[illegible]	+1.5%/yr	[illegible]	+1.5%/yr	[illegible]	+1.5%/yr		Escalate at 1.5% per year		

Revised March 3, 2004 11:38 AM

Gilbert Laustsen Jung Associates Ltd.

Table 2

Gilbert Laustsen Jung Associates Ltd

Natural Gas and Sulphur

Price Forecast

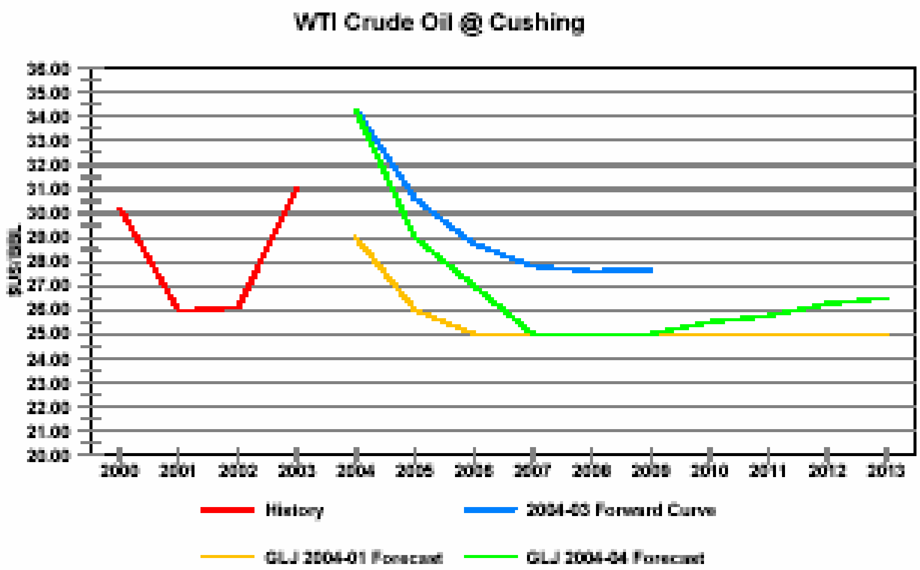
Effective April 1, 2004

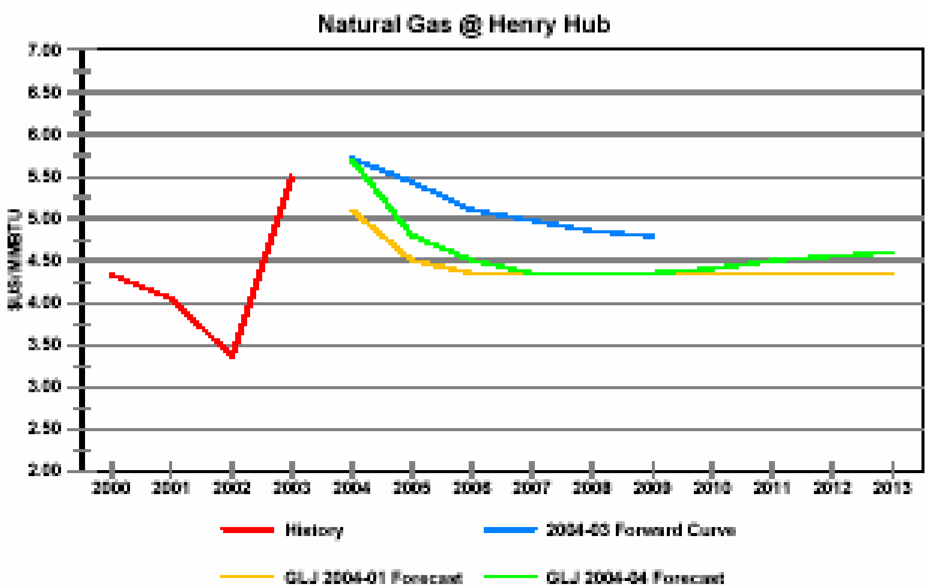
Year	US Gulf Coast Gas Price @ Henry Hub Constant 2004 $ $US/MMbtu	US Gulf Coast Gas Price @ Henry Hub Then Current $US/MMbtu	Midwest Price @ Chicago Then Current $US/MMbtu	AECO-C Spot Then Current $Cdn/MMbtu	Alberta Plant Gate Spot Constant 2004 $ $Cdn/MMbtu	Alberta Plant Gate Spot Then Current $Cdn/MMbtu	Alberta Plant Gate ARP $Cdn/MMbtu	Alberta Plant Gate Aggregator $Cdn/MMbtu	Alberta Plant Gate Alliance $Cdn/MMbtu	Saskatchewan Plant Gate SaskEnergy $Cdn/MMbtu	Saskatchewan Plant Gate Spot $Cdn/MMbtu	Sumas Spot $US/MMbtu	British Columbia Cam-West Plant Gate $Cdn/MMbtu	British Columbia Spot Plant Gate $Cdn/MMbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gate $Cdn/LT
1993	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	n/a	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1994	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	n/a	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1995	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	n/a	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1996	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	n/a	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1997	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	n/a	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1998	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	n/a	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	n/a	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	n/a	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2001	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2002	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2003	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Q1 (e)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Q2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Q3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Q4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Full Year	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2004 Q2-Q4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2005	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2006	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2007	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2008	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2009	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2010	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2011	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2012	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2013	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2014	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2015+	[illegible]	+1.5%/yr	+1.5%/yr	+1.5%/yr	[illegible]	+1.5%/yr				Escalate at 1.5% per year					+1.5%/yr	

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
Spot refers to weighted average one month price.

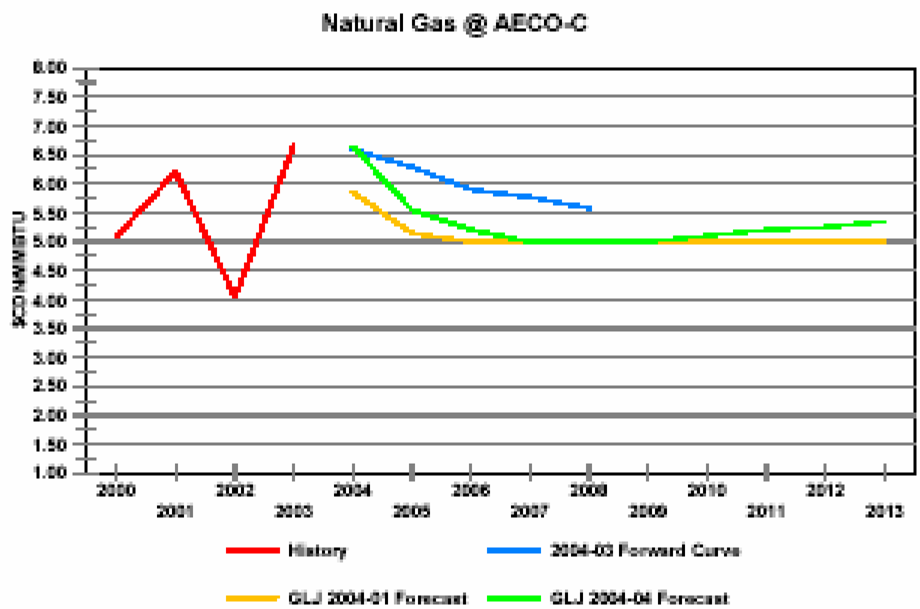
Revised March 3, 2004 11:39 AM

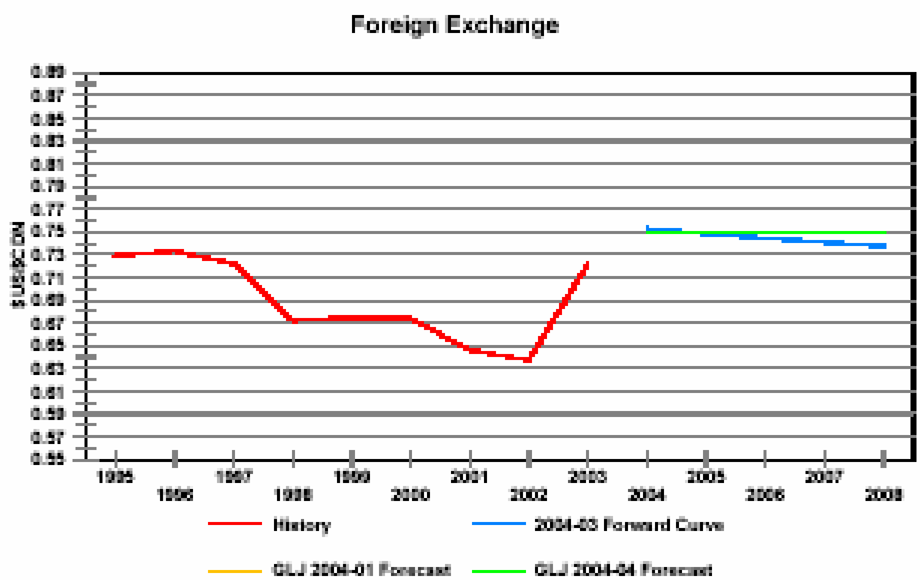
Gilbert Laustsen Jung Associates Ltd.





Gilbert Laustsen Jung Associates Ltd.





Gilbert Laustsen Jung Associates Ltd.

APPENDIX 6

COST OF SERVICE SCHEDULES

Vancouver Island Supply Alternatives

Cost of Service Summary for Incremental TGVI Facilities
Base + 0 Forecast
LNG Storage Portfolio
(Million Cdn Dollars)

Gas Contract Year Begin November

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Operating Expenses (excl Fuel)	0.0	0.0	0.0	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.3
Other Taxes	0.0	0.0	0.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2
Depreciation	0.5	0.5	0.5	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Return on Rate Base	1.2	1.1	1.1	9.5	9.3	9.0	8.8	8.5	8.3	8.0	7.7	7.5	7.2	7.0	6.7	8.6	8.3	7.9	7.6	7.3	7.0	6.7	6.4
Income Taxes	(0.2)	(0.7)	(0.5)	2.2	1.1	1.4	1.6	1.7	1.9	2.0	2.0	2.1	2.1	2.2	2.2	2.0	1.1	1.5	1.8	2.0	2.2	2.3	2.4
Total Cost of Service (excl Fuel)	1.5	0.9	1.1	17.9	16.6	16.7	16.7	16.6	16.5	16.4	16.3	16.1	16.0	15.8	15.6	19.1	17.9	18.1	18.1	18.1	18.0	17.9	17.8

Terasen Gas (Vancouver Island)
Vancouver Island Supply Alternatives

Cost of Service Summary for Incremental TGVI Facilities
Base + 0 Forecast
Pipe & Compression Portfolio
(Million Cdn Dollars)

Gas Contract Year Begin November

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Operating Expenses (excl Fuel)	0.0	0.0	0.0	1.7	1.7	1.7	1.8	1.8	1.9	1.9	2.0	2.7	2.8	2.9	2.9	3.0	3.1	3.2	3.2	3.9	4.0	4.1	4.2
Other Taxes	0.0	0.0	0.0	0.4	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.8	0.9	0.9	0.9	1.0	1.3	1.3	1.4	1.5	1.5	1.7	1.7
Depreciation	0.5	0.5	0.5	2.4	2.4	2.4	2.4	3.0	3.0	3.3	3.3	4.1	4.1	4.1	4.1	4.8	5.9	5.9	5.9	6.6	6.6	7.2	7.2
Return on Rate Base	1.2	1.1	1.1	5.9	5.7	5.6	5.4	7.2	7.0	8.0	7.8	9.4	9.2	8.9	8.6	10.9	14.3	13.9	13.6	14.7	14.3	16.0	15.6
Income Taxes	(0.2)	(0.7)	(0.5)	(0.9)	(3.1)	(2.0)	(1.2)	(0.0)	0.2	1.0	1.2	1.3	0.7	1.2	1.6	2.5	3.4	3.1	3.3	3.1	2.3	3.3	3.4
Total Cost of Service (excl Fuel)	1.5	0.9	1.1	9.4	7.1	8.0	8.8	12.5	12.7	14.9	14.9	18.3	17.7	18.0	18.2	22.2	28.0	27.4	27.3	29.7	28.7	32.3	32.0

Terasen Gas (Vancouver Island)
Vancouver Island Supply Alternatives

Cost of Service Summary for Incremental TGVI Facilities
Base + 0 Forecast
Pipe & Compression & Curtailment Portfolio
(Million Cdn Dollars)

Gas Contract Year Begin November

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Operating Expenses (excl Fuel)	0.0	0.0	0.0	0.6	0.6	0.7	0.7	0.7	1.4	1.4	1.9	2.0	2.0	2.0	2.1	2.1	2.2	3.0	3.1	3.2	3.2	3.3	3.4
Other Taxes	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.8	0.9
Depreciation	0.5	0.5	0.5	1.3	1.3	1.3	1.3	1.3	2.0	2.0	2.6	2.6	2.6	2.6	2.6	2.7	2.7	3.5	3.5	3.5	3.5	4.3	4.7
Return on Rate Base	1.2	1.1	1.1	3.2	3.1	3.1	3.0	2.9	4.5	4.4	5.6	5.4	5.3	5.1	4.9	4.8	4.6	6.4	6.2	6.0	5.8	8.1	9.4
Income Taxes	(0.2)	(0.7)	(0.5)	(0.5)	(1.4)	(0.9)	(0.5)	(0.2)	(0.0)	(0.6)	(0.4)	(0.8)	(0.2)	0.3	0.7	1.0	1.2	1.2	0.4	0.9	1.2	2.2	2.4
Total Cost of Service (excl Fuel)	1.5	0.9	1.1	4.8	3.8	4.3	4.6	4.9	8.2	7.5	10.0	9.6	10.1	10.4	10.7	10.9	11.0	14.7	13.8	14.1	14.3	18.6	20.8

Terasen Gas (Vancouver Island)
Vancouver Island Supply Alternatives

Cost of Service Summary for Incremental TGVI Facilities
Base + 45 Forecast
LNG Storage Portfolio
(Million Cdn Dollars)

Gas Contract Year Begin November

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Operating Expenses (excl Fuel)	0.0	0.0	0.0	3.3	3.3	3.4	3.5	3.6	3.6	3.7	3.8	3.8	3.9	4.0	4.1	4.2	5.1	5.2	5.3	5.4	5.5	5.6	5.8
Other Taxes	0.0	0.0	0.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.5	1.6	1.8	1.8	1.8	1.8	1.8	1.8
Depreciation	0.5	0.5	0.5	5.4	5.5	5.5	5.5	5.5	5.5	5.5	5.6	5.6	5.6	5.6	5.6	6.3	7.1	7.5	7.5	7.6	7.6	7.6	7.6
Return on Rate Base	1.2	1.1	1.3	14.0	13.7	13.3	12.9	12.6	12.2	11.8	11.5	11.1	10.7	10.4	10.0	11.9	13.5	14.4	13.9	13.4	12.9	12.5	12.0
Income Taxes	(0.2)	(0.7)	(0.4)	1.8	(1.4)	(0.3)	0.5	1.2	1.8	2.2	2.5	2.8	3.0	3.1	3.2	3.9	3.5	3.0	3.2	3.5	3.8	3.9	4.1
Total Cost of Service (excl Fuel)	1.5	0.9	1.4	25.7	22.3	23.1	23.7	24.1	24.3	24.5	24.5	24.5	24.5	24.4	24.2	27.8	30.8	31.9	31.8	31.7	31.6	31.5	31.3

Terasen Gas (Vancouver Island)
Vancouver Island Supply Alternatives

Cost of Service Summary for Incremental TGVI Facilities
Base + 45 Forecast
Pipe & Compression Portfolio
(Million Cdn Dollars)

Gas Contract Year Begin November

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Operating Expenses (excl Fuel)	0.0	0.0	0.0	2.4	2.9	2.9	3.0	3.1	3.2	3.2	3.3	3.3	3.4	3.5	3.6	3.7	3.7	3.8	3.9	4.0	4.1	4.1	4.2
Other Taxes	0.0	0.0	0.0	1.2	1.2	1.2	1.3	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.6	1.7	1.7	1.7	1.8	1.9	1.9	1.9	2.0
Depreciation	0.5	0.5	0.5	5.1	5.6	5.7	5.7	6.2	6.2	6.2	6.2	6.3	6.6	6.7	7.0	7.1	7.1	7.1	7.5	7.7	7.7	8.0	8.0
Return on Rate Base	1.2	1.1	1.3	15.2	16.1	15.7	15.4	16.6	16.3	15.9	15.5	15.1	15.9	15.5	16.3	15.9	15.5	15.1	15.9	16.0	15.6	15.7	15.3
Income Taxes	(0.2)	(0.7)	(0.4)	1.0	(3.2)	(2.4)	(1.1)	0.5	1.1	1.8	2.4	2.8	3.5	3.6	4.1	4.1	4.3	4.4	4.8	4.8	4.8	5.0	4.9
Total Cost of Service (excl Fuel)	1.5	0.9	1.4	25.0	22.7	23.2	24.3	27.7	28.1	28.5	28.8	29.0	30.9	30.8	32.7	32.4	32.3	32.1	33.9	34.4	34.1	34.7	34.4

Terasen Gas (Vancouver Island)
Vancouver Island Supply Alternatives

Cost of Service Summary for Incremental TGVI Facilities
Base + 45 Forecast
Pipe & Compression & Curtailment Portfolio
(Million Cdn Dollars)

Gas Contract Year Begin November

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Operating Expenses (excl Fuel)	0.0	0.0	0.0	2.3	2.4	2.4	2.5	2.5	2.6	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.8	3.8	3.9	4.0	4.1	4.2
Other Taxes	0.0	0.0	0.0	0.7	0.7	0.7	0.7	0.7	0.7	0.9	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.6	1.6	1.6	1.6	1.7	1.7
Depreciation	0.5	0.5	0.5	3.8	3.8	3.9	3.9	3.9	3.9	4.5	5.5	5.5	5.5	5.5	5.6	5.6	6.2	6.8	6.8	6.9	6.9	7.2	7.2
Return on Rate Base	1.2	1.1	1.3	10.4	10.2	9.9	9.7	9.5	9.2	11.2	14.2	13.9	13.5	13.2	12.9	12.6	14.1	15.2	14.8	14.4	14.0	14.4	14.0
Income Taxes	(0.2)	(0.7)	(0.4)	(0.2)	(3.5)	(2.2)	(1.1)	(0.3)	0.4	1.5	2.5	2.4	2.7	2.9	3.1	3.3	3.9	3.4	2.7	3.1	3.4	3.8	3.9
Total Cost of Service (excl Fuel)	1.5	0.9	1.4	17.1	13.6	14.8	15.7	16.4	16.9	20.9	26.2	25.8	25.9	25.9	25.9	25.8	28.7	30.8	29.7	29.8	29.9	31.2	31.0

The following key assumptions are used to calculate the incremental cost of service associated with new facility additions over the planning period:

Depreciation

- LNG Storage: 3% per year
- Compression: 3% per year
- Pipe: 2% per year
- Buildings: 3% per year

Inflation:

- Capital 2% per year
- O&M 2% per year
- Municipal Tax 2% per year

Taxes

- Combined Federal/Provincial: 34.5%
- Capital Cost Allowance:
  - Buildings: Class 1
  - Pipe: Class 1
  - Compression: Class 8

Debt/Equity Split: 65/35

Return on Equity: 9.92%

Debt Costs: 6.2%

Exchange Rate (US$/C$)

2004-2005: 0.75

2006+: 0.71

APPENDIX 7

CVRD APPROVAL BYLAW

CVRD

May 28, 2004

Terasen Gas
16705 Fraser Highway
Surrey, BC V3S 2X7

Attention: Bill Manery, P. Eng.

JS //

Dear Mr. Manery:

RE: CVRD Zoning Amendment Bylaw No.2499 – Utility 1 Zone (Terasen LNG)

I am pleased to advise you that the Cowichan Valley Regional District Board of Directors, at the meeting of May 26, 2004, adopted the above-noted Zoning Amendment Bylaw.

Below is the relevant Board resolution:

B2 Moved: Director B. Hodson
(04-318) Seconded: Director R. Spencer

That "CVRD Zoning Amendment Bylaw No. 2499, 2004, Electoral Area H – North Oyster/Diamond (Terasen LNG), Amendment to CVRD Bylaw No. 1020", be adopted.

MOTION CARRIED

Accordingly, the subject lands are now zoned as U-1 and the construction of a LNG plant is now allowed thereon, subject to a building permit application.

For your records I have enclosed a copy of the amendment bylaw with its map schedule.

Should you have any questions about the foregoing, please feel free to contact me.

Yours truly,

Mike Tippett, MCIP
Deputy Manager
Development Services

MT/ta
Encl.

pc: Mark Walmsley, M. Sc., P. Ag., P. Geo, Wetland Resource Group
Director M. Marcotte, Electoral Area H – North Oyster/Diamond

CVRD

COWICHAN VALLEY REGIONAL DISTRICT

BYLAW NO. 2499

A Bylaw for the purpose of amending Zoning Bylaw No. 1020, Applicable to Electoral Area H – North Oyster/Diamond

---

WHEREAS the Local Government Act, hereafter referred to as the "Act", as amended, empowers the Regional Board to adopt and amend zoning bylaws;

AND WHEREAS the Regional District has adopted a zoning bylaw for Electoral Area H – North Oyster/Diamond, that being Zoning Bylaw No. 1020;

WHEREAS the Board of Directors has received an application to amend the zoning of a parcel of land in Electoral Area H for a liquefied natural gas storage facility;

AND WHEREAS the CVRD Board of Directors voted on and received the required majority vote of those present and eligible to vote at the meeting where the vote was taken, as required by the *Local Government Act*;

AND WHEREAS notices were published in consecutive issues of the "Nanaimo News Bulletin" on Tuesday, April 6, 2004, and Thursday, April 8, 2004, setting forth notice of a public hearing to be held on Tuesday, April 13, 2004, at the North Oyster Elementary School, 13470 Cedar Road, Ladysmith, BC, to hear all those people who deem themselves affected by the amendments as required by the Act;

AND WHEREAS after the close of the public hearing and with due regard to the reports received, the Regional Board considers it advisable to amend Zoning Bylaw No. 1020;

NOW THEREFORE the Board of Directors of the Cowichan Valley Regional District, in open meeting assembled, enacts as follows:

1. **CITATION**

   This Bylaw shall be cited for all purposes as "**CVRD Zoning Amendment Bylaw No. 2499, 2004, Electoral Area H – North Oyster/Diamond (Terasen LNG), amendment to CVRD Bylaw No. 1020**".

2. That CVRD Zoning Bylaw No. 1020, as amended from time to time, is hereby amended in the following manner:

   a) That Section 6.1, Creation of Zones, be amended by adding "U-1 UTILITY (LNG)".

. . . /2

b) That the following be added after Section 11.2(b) 4:

11.3 U-1 ZONE – UTILITY (LNG)

Subject to compliance with the General Requirements in Part Five of this Bylaw, the following provisions apply in this Zone:

(a) Permitted Uses

The following permitted uses and no others are permitted in a U-1 Zone:

1. Management and harvesting of forest products, including silviculture, excluding sawmilling, manufacturing and dry land log sorting;
2. Storage and transportation of liquefied natural gas (LNG);
3. Transmission, liquefaction, vaporization, transportation and storage of natural gas;
4. Water storage for firefighting and other purposes;
5. Buildings, structures and uses that are required for, accessory to or customarily incidental to, the operation of a liquefied natural gas storage facility.

(b) Conditions of Use

For any parcel in a U-1 Zone:

1. The parcel coverage shall not exceed 20 percent for all buildings and structures;
2. The height for all buildings and structures, including a liquefied natural gas storage tank, shall not exceed 65 metres from natural grade;
3. The minimum setback from all lot lines for Liquefied Natural Gas storage tanks is 30 metres from all parcel lines;
4. The minimum setback for all other buildings and structures is 7.5 metres from all parcel lines.
5. Not more than two liquefied natural gas storage tanks shall be located on a parcel, and the size of each storage tank shall not exceed a nominal volume of 70,000 m^3.

c) That Section 13.1 (Minimum Parcel Size Table) be amended by adding U-1 Utility (LNG) to the list of zones and inserting a 10 hectare minimum parcel size under all three "servicing level" columns.

d) That Schedule B (Zoning Map) to Zoning Bylaw No. 1020, be amended by adding "U-1 Utility (LNG) Zone" to the list of zones.

. . . /3

e) That All that part of Block 297, Bright District, commencing at the most Westerly corner of said Block (the Point of Commencement) then North along the West boundary 281.700 metres at 0°08'47", then East 141.379 metres at 78°56'41", then Northeast 596.142 metres at 24°25'51", then East-Northeast 343.511 metres at 70°34'22", then Southeast 328.813 metres at 160°48'13", then Southwest 644.155 metres at 204°25'51", then West 69.386 metres at 270°40'58", then West 180.417 metres at 270°40'58", then Northwest 134.190 metres at 297°42'24", then Southwest 227.004 metres at 223°45'46" to the Point of Commencement, containing 42.76 hectares more or less, as shown outlined in a solid black line on the Plan numbered Z-2499, attached hereto and forming Schedule "A" of this Bylaw, be rezoned from F-1 (Primary Forestry) to U-1 (Utility - LNG); and the Official Zoning Map of Zoning Bylaw No. 1020 be amended accordingly.

3. This bylaw shall take effect upon its adoption by the Regional Board.

READ A FIRST TIME this 24th day of March, 2004.

READ A SECOND TIME this 24th day of March, 2004.

SECOND READING RESCINDED this 28th day of April, 2004.

READ A SECOND TIME AS AMENDED this 28th day of April, 2004.

READ A THIRD TIME this 28th day of April, 2004.

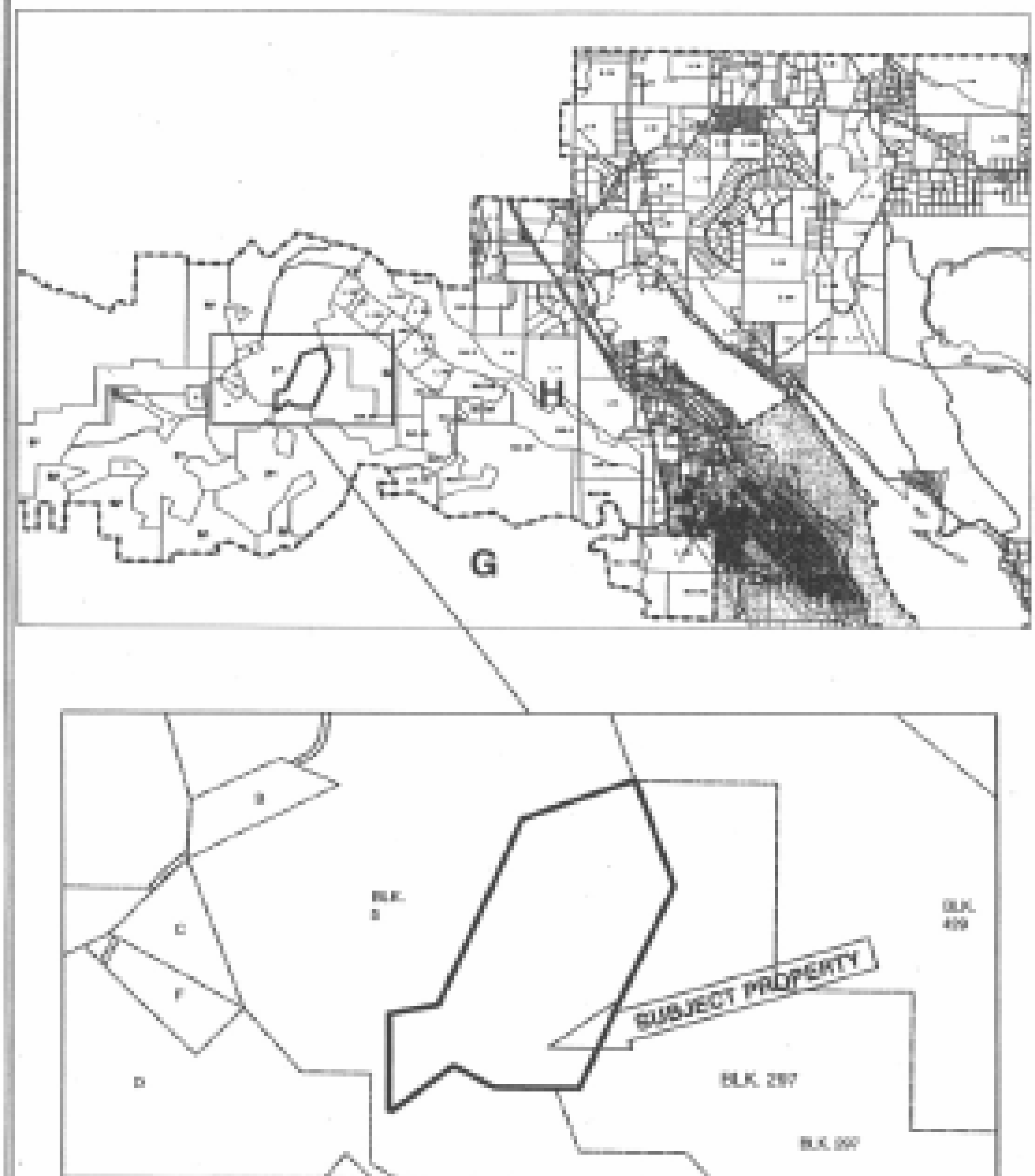
ADOPTED this 26th day of May, 2004.

Chairperson

Secretary

PLAN NO. Z-2499

SCHEDULE "A" TO PLAN AMENDMENT BYLAW NO. 2000
OF THE COWICHAN VALLEY REGIONAL DISTRICT



THE AREA OUTLINED IN A SOLID BLACK LINE IS REZONED FROM

F-1 (PRIMARY FORESTRY) TO

U-1 (UTILITY-LNG) APPLICABLE

TO ELECTORAL AREA H

APPENDIX 8

CORE MARKET GAS SUPPLY COSTS

Appendix 8
Terasen Gas (Vancouver Island)
Vancouver Island Supply Alternatives

Core Market Gas Supply Costs
(nominal Cdn$ millions)

Year	Base +0			Base +45		
	LNG Storage	Pipe Compression	Pipe Compression Curtailment	LNG Storage	Pipe Compression	Pipe Compression Curtailment
2007	75.7	78.3	76.6	75.7	78.3	76.2
2008	75.6	79.7	77.6	75.6	79.7	78.1
2009	78.6	82.8	80.8	78.6	82.8	81.7
2010	81.6	86.1	83.8	81.6	86.1	84.5
2011	84.4	89.4	86.7	84.4	89.4	87.6
2012	87.5	92.8	89.8	87.5	92.8	90.6
2013	90.6	96.4	93.1	90.6	96.4	94.0
2014	93.8	100.0	96.6	93.8	100.0	97.5
2015	97.1	103.6	100.0	97.0	103.6	101.0
2016	100.9	107.5	103.8	100.8	107.5	104.6
2017	104.9	111.3	107.4	104.7	111.3	108.3
2018	108.9	115.3	111.1	109.0	115.3	112.1
2019	112.9	119.4	114.8	113.8	119.4	116.0
2020	117.3	123.9	119.1	118.9	123.9	120.1
2021	121.1	128.3	123.3	121.4	128.3	124.3
2022	125.1	132.8	127.5	125.1	132.8	128.6
2023	129.3	137.6	132.1	129.3	137.6	133.1
2024	134.1	142.9	137.2	134.0	142.9	138.1
2025	138.7	147.8	141.9	138.3	147.8	142.9
2026	140.3	150.8	143.6	139.6	150.8	143.7
Present Value (2004$ millions)						
6.1%	981	1,039	1,004	982	1,039	1,012
10.0%	653	691	669	654	691	674

Appendix 8
Terasen Gas (Vancouver Island)
Vancouver Island Supply Alternatives

LNG Mitigation
(nominal Cdn$ millions)

Year	Base +0 LNG Storage	Base +45 LNG Storage
2007	3.2	3.2
2008	3.9	4.1
2009	5.1	5.3
2010	4.9	5.1
2011	4.6	4.8
2012	4.3	4.6
2013	4.1	4.2
2014	3.9	4.0
2015	2.8	3.7
2016	2.5	3.1
2017	1.7	2.3
2018	0.9	1.4
2019	2.4	2.0
2020	2.8	2.0
2021	3.9	0.2
2022	4.0	1.4
2023	3.8	1.1
2024	3.5	2.8
2025	3.3	3.3
2026	3.2	3.2
Present Value (2004$ millions)		
6.1%	36	34
10.0%	25	25

APPENDIX 9

LOAD DURATION AND PRESSURE PROFILES

Load duration curves which outline the load duration for the initial year, the year before the next capital addition and the year after the next capital addition and **pressure profiles** which show the profile for the design peak day, the last day LNG is sent out and the day after LNG has stopped being sent out including an overlay profile for all three years are included as follows:

- Base + 0 Forecast
  - Figures 1, 2 and 3 illustrate load duration curves for 2007 (initial year), 2018 (before next addition), and 2019 (after next addition).
  - Figures 4, 5 and 6 show the pressure profile during the design peak day, during day 74 of the design year (the last day that the LNG is sent out), and during day 75 (after the LNG has stopped being sent out). Figure 7 overlays all three pressure profiles to show the relative differences.

- Base + 45 Forecast
  - Figures 8, 9 and 10 illustrate load duration curves for 2007 (initial year), 2018 (before next addition), and 2021 (after next additions).
  - Figures 11, 12 and 13 show the pressure profile during the design peak day, during day 74 of the design year (the last day that the LNG is sent out), and during day 75 (after the LNG has stopped being sent out). Figure 14 overlays all three pressure profiles to show the relative differences.

Figure 1

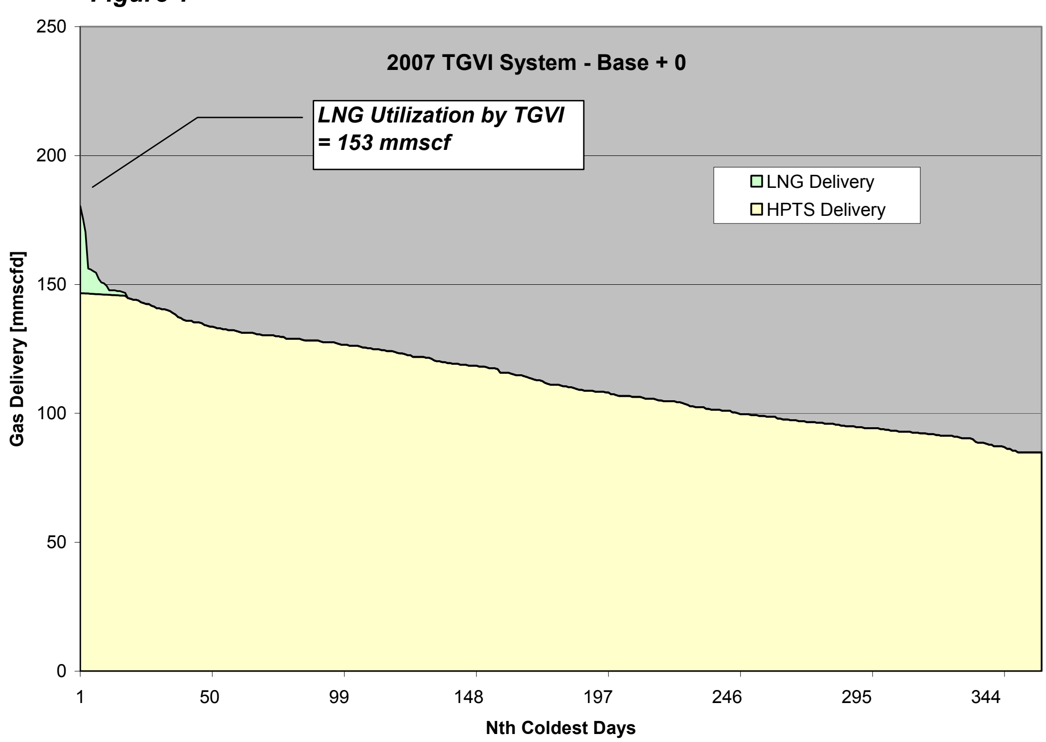


Figure 2

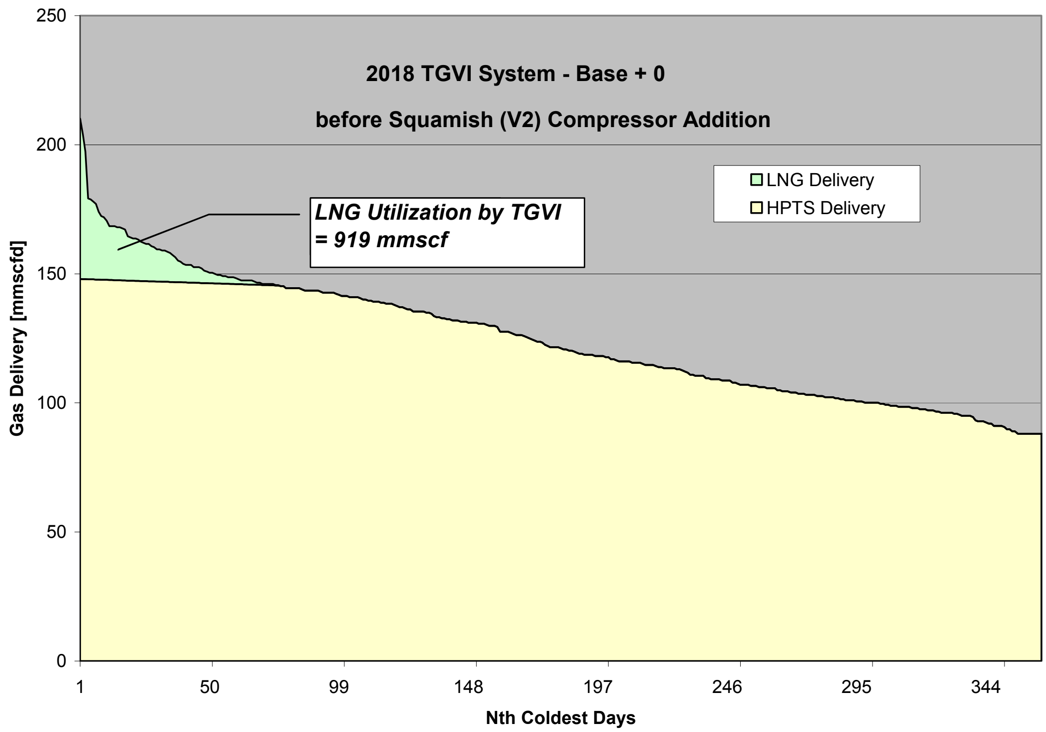
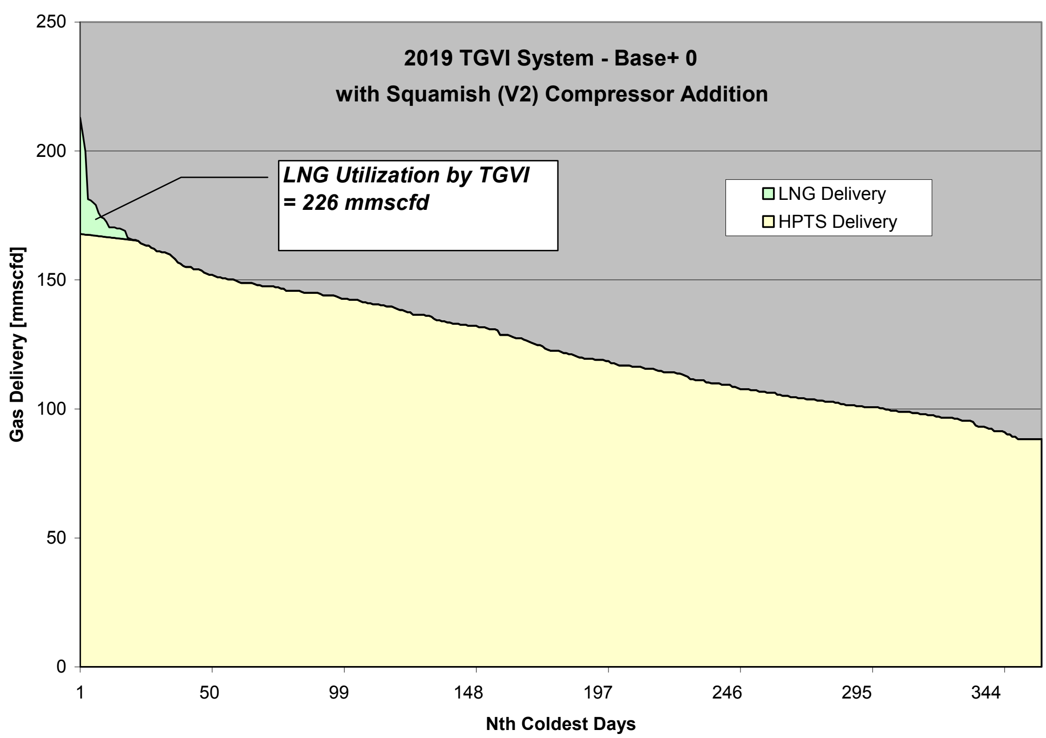
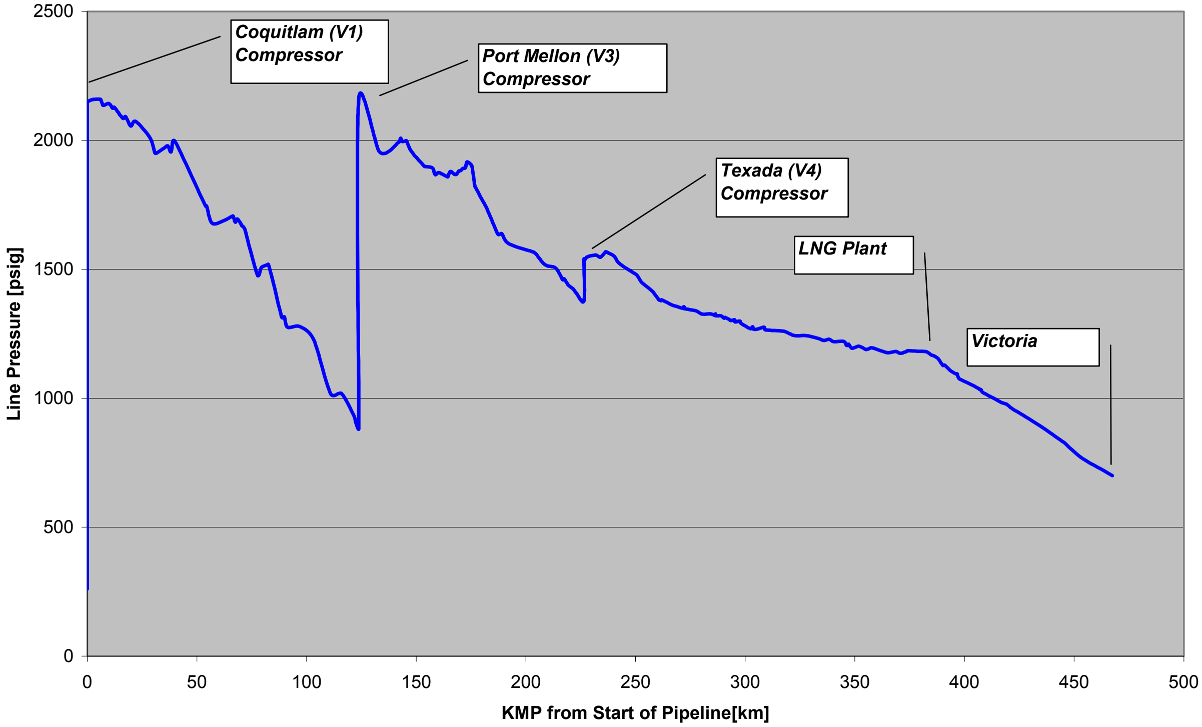


Figure 3



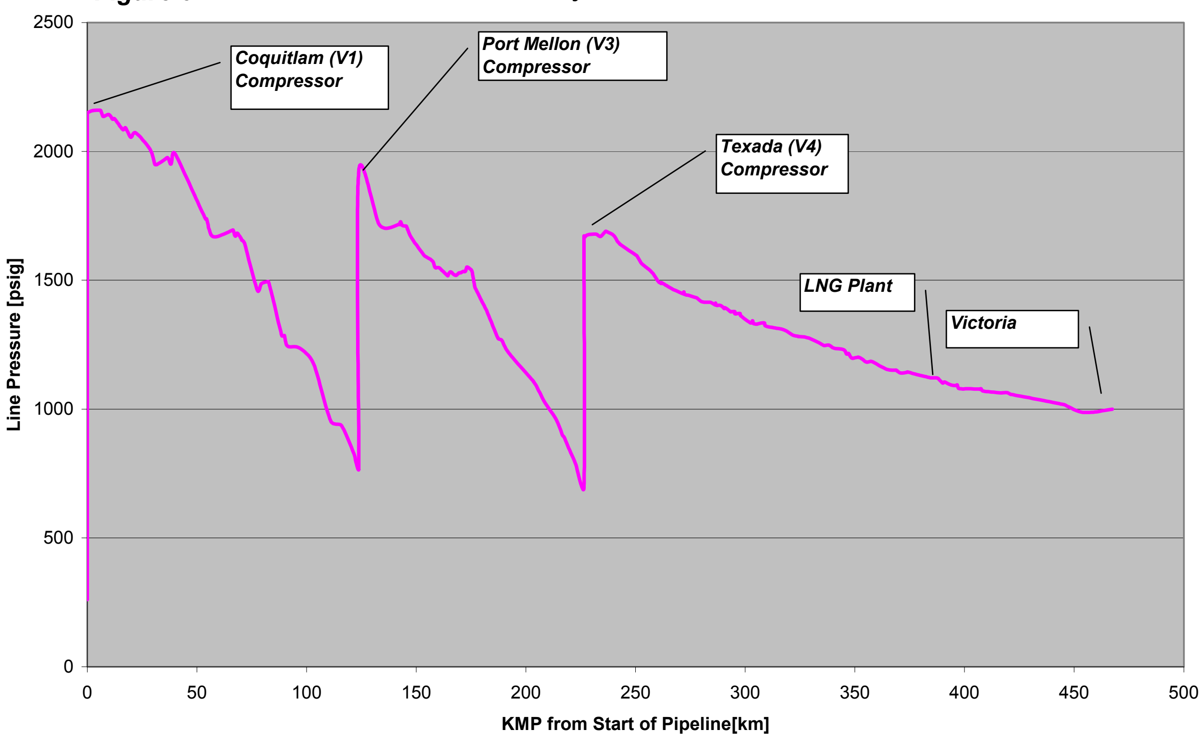
2018 TGVI System Pressure Profile - Base +0

Figure 4 ***Peak Day with LNG Sendout***



2018 TGVI System Pressure Profile - Base + 0

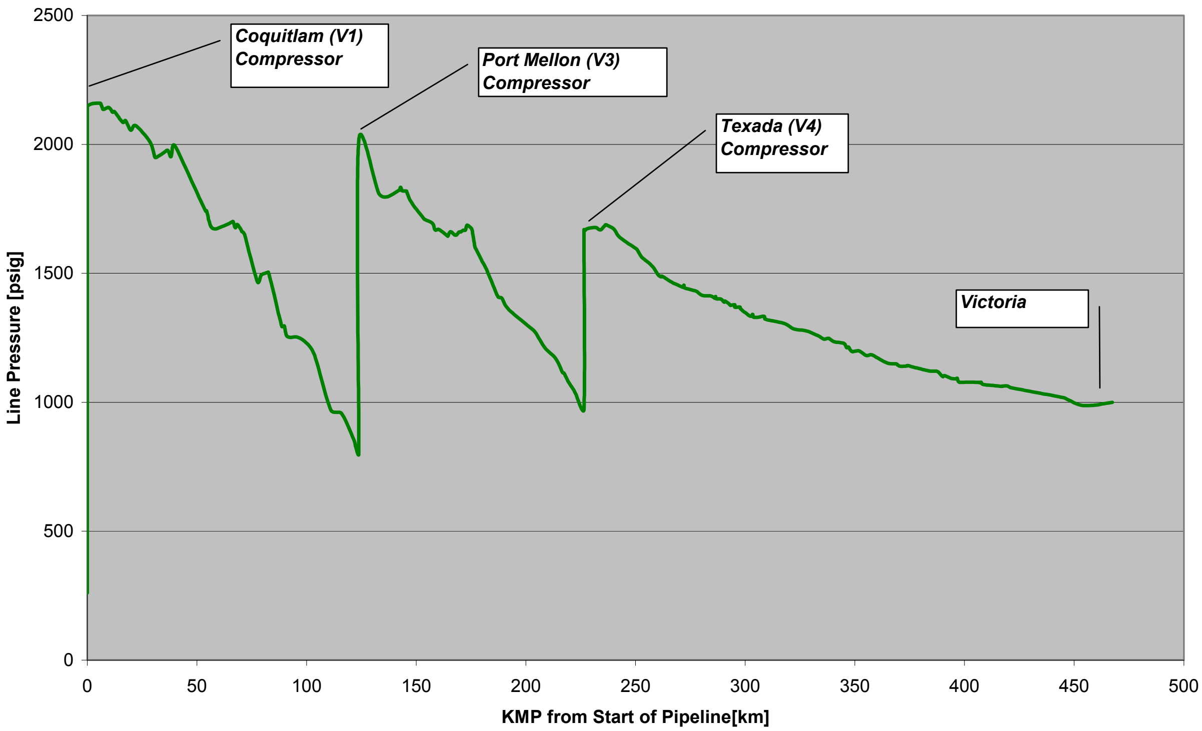
Figure 5 ***74th Coldest Day with LNG Sendout***



2018 TGVI System Pressure Profile - Base + 0

Figure 6

75th Coldest Day with no LNG Sendout



2018 TGVI System Pressure Profiles - Base + 0

Figure 7

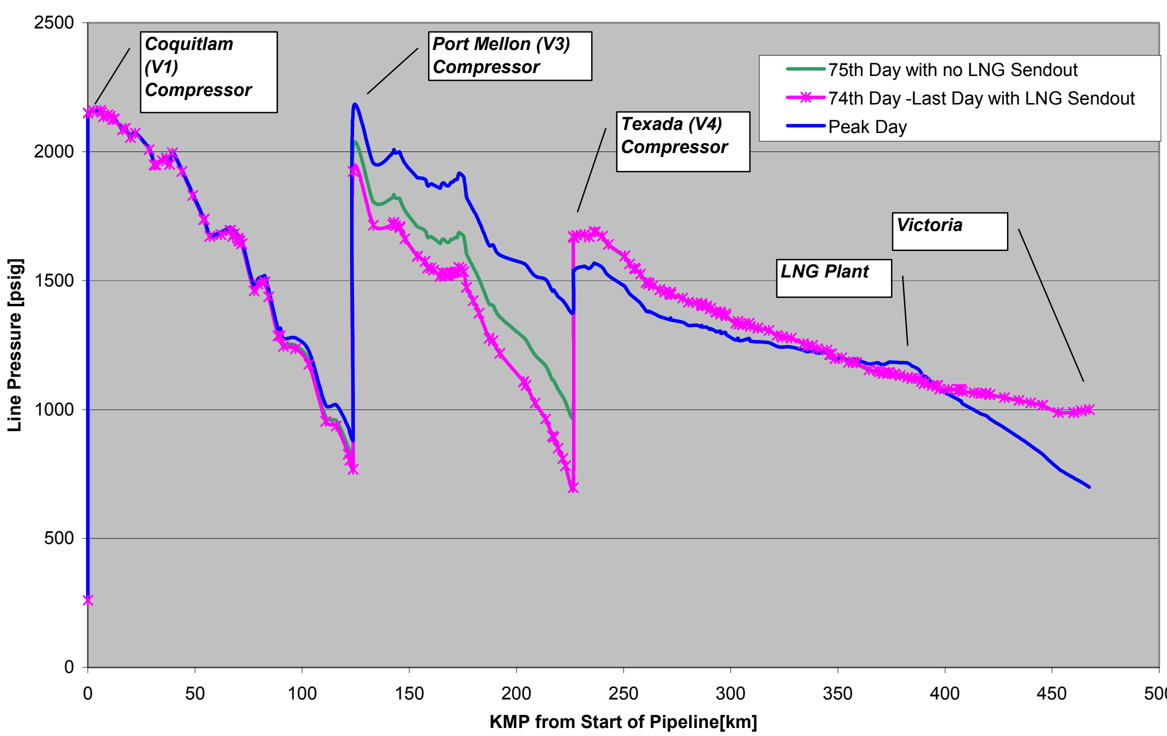


Figure 8

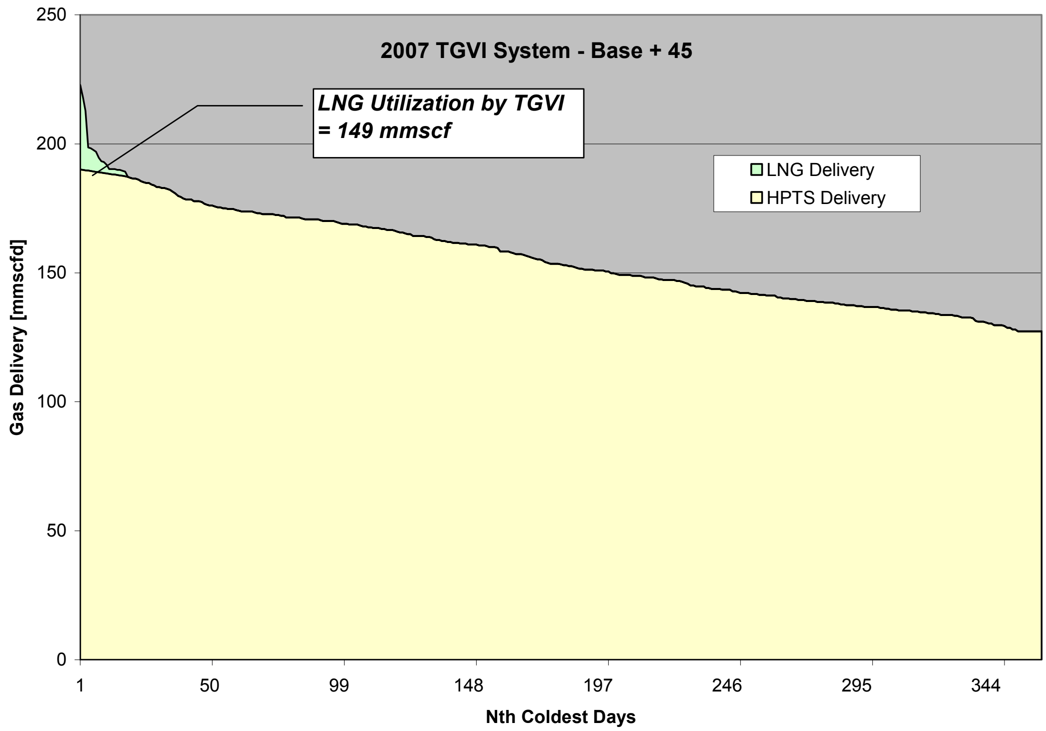


Figure 9

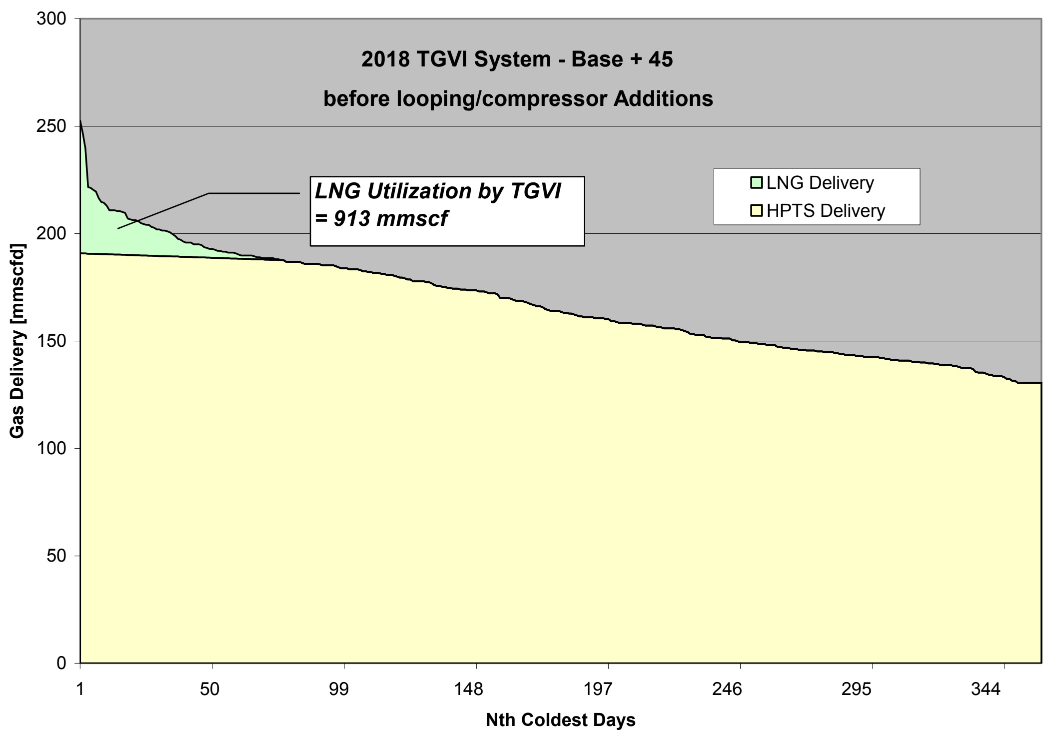


Figure 10

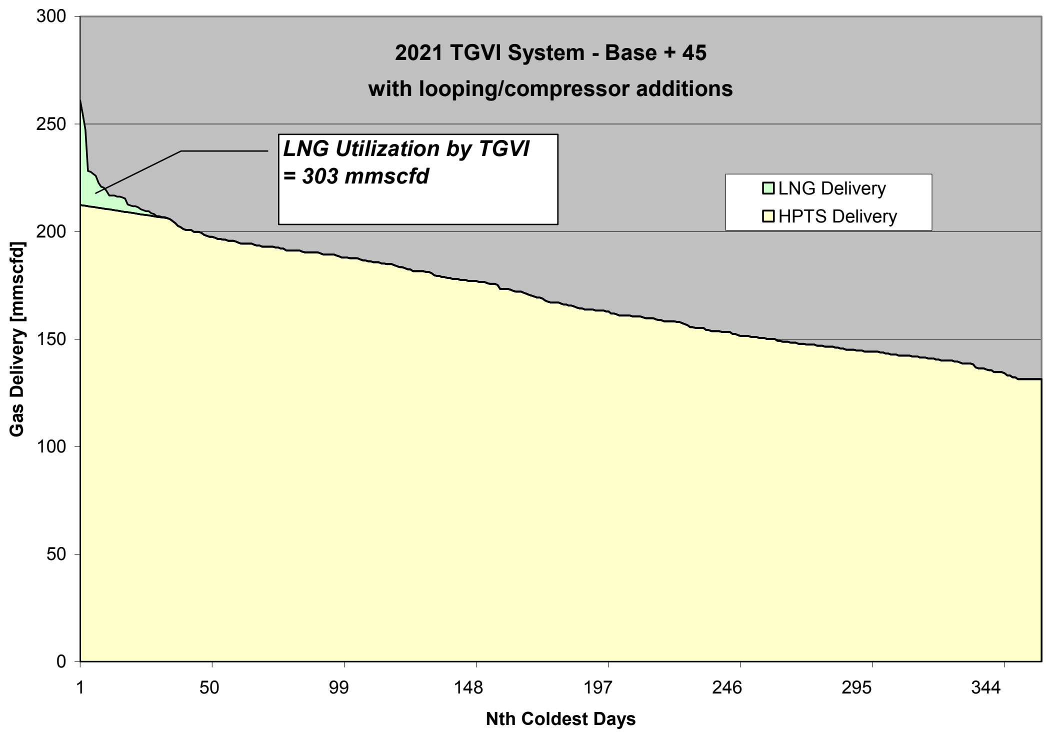
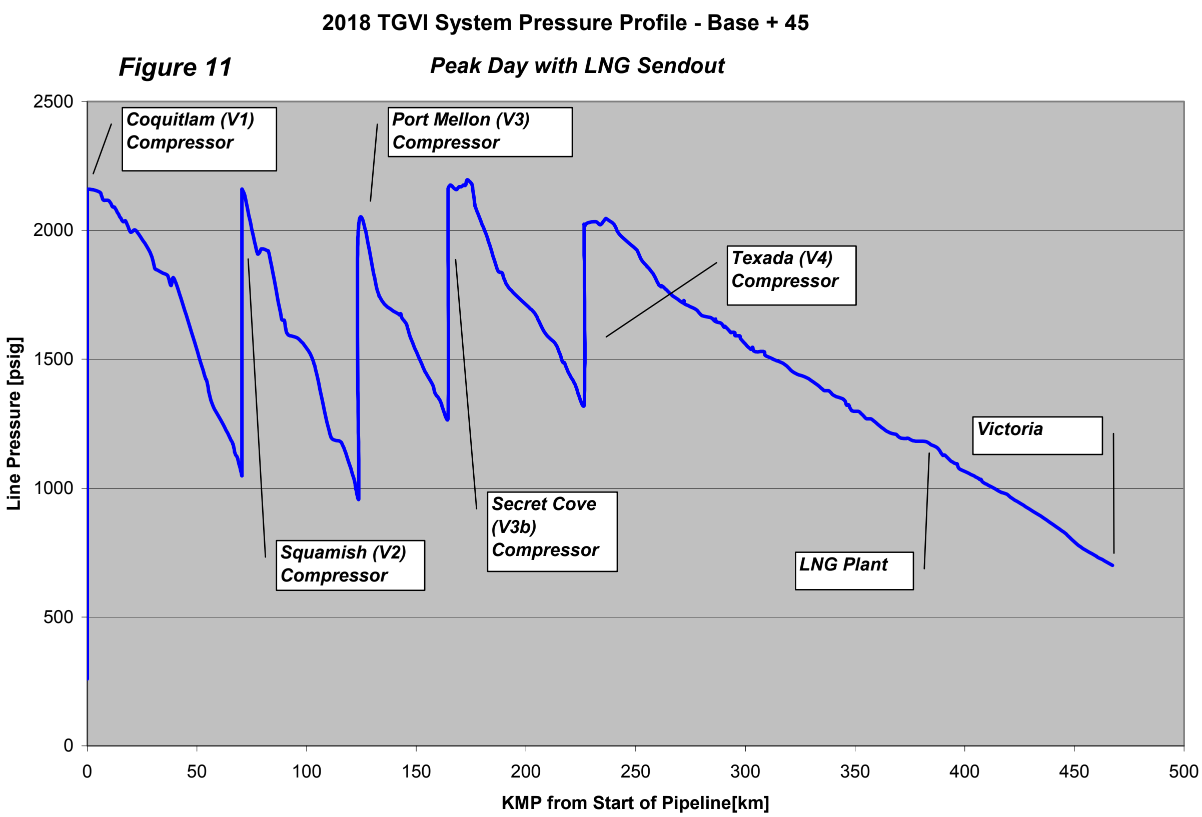


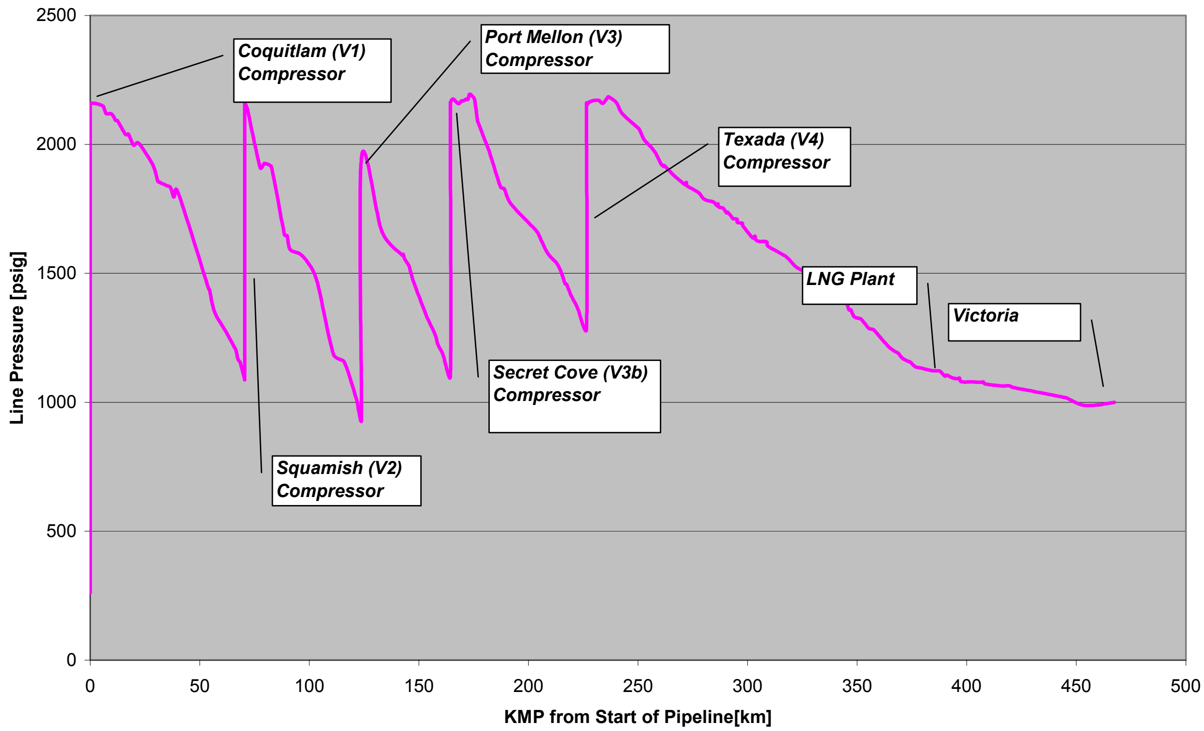
Figure 11



2018 TGVI System Pressure Profile - Base +45

Figure 12

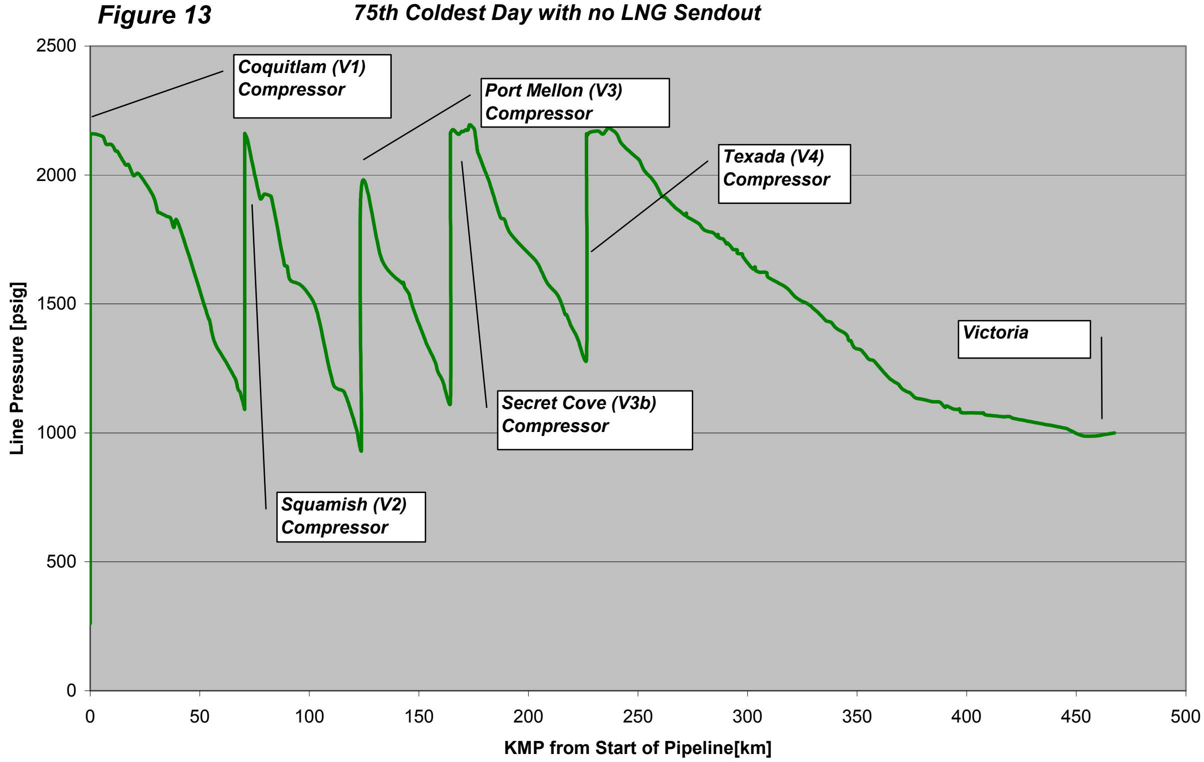
74th Coldest Day with LNG Sendout



2018 TGVI System Pressure Profile - Base + 45

Figure 13

75th Coldest Day with no LNG Sendout



2018 TGVI System Pressure Profiles - Base + 45

Figure 14