BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

BC Gas Utility Ltd.

SOUTHERN CROSSING PIPELINE PROJECT

APPLICATION FOR A

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

DECISION

April 3, 1998

Before:

Lorna R. Barr, Deputy Chair
Kenneth L. Hall, P.Eng., Commissioner
Frank C. Leighton, P.Eng., Commissioner

EXECUTIVE SUMMARY

On May 30, 1997, BC Gas Utility Ltd. (“BC Gas” or “the Utility” or "BC Gas Utility") applied to the British Columbia Utilities Commission (“the Commission”) for a Certificate of Public Convenience and Necessity ("CPCN") to build the Southern Crossing Pipeline project ("the SCP"). The SCP consists of a 310 km (193 mile), 24-inch diameter pipeline, complete with compressor facilities, extending from near Yahk, British Columbia to Oliver, British Columbia at a cost of $348.2 million in 1997 dollars, including Allowance for Funds Used During Construction and overhead. BC Gas' September Engineering Update stated that the cost estimate is expected to have a variance range of approximately 10 percent.

On June 27, 1997, the Commission established a public hearing into the Application by Order No. G-75-97. The hearing commenced on October 14, 1997, with the evidentiary portion of the hearing completed on November 25, 1997, after 24 hearing days. During the hearing process, in early November, 1997, Town Hall meetings took place in Fort St. John, Castlegar and Oliver, British Columbia. The hearing concluded with reply argument filed on December 19, 1997. The Commission issued a Decision dated January 29, 1998 allowing, in part, an intervenor's request to file Rebuttal Argument to the Reply Argument of a second intervenor, and granting its request to file Reply Argument to the Argument of a third intervenor.

In its CPCN Application, BC Gas indicates that the SCP is required to meet incremental peak day and seasonal gas demand by BC Gas customers over the next 30 years. The hearing included, first, a detailed examination of the Utility’s Integrated Resource Plan (“IRP”), which examines options for meeting the projected growth in the demand for natural gas. Secondly, the hearing reviewed the Application for a CPCN for the SCP. As part of the review of the IRP, the Commission examined the merits of a number of other proposals, each designed to serve the core market (firm system sales) demand.

In Order No. G-75-97, the Commission established a timetable for proponents of competing proposals to file detailed evidence and provide witness panels to testify at the public hearing regarding their proposals. A number of alternatives to the SCP were presented to the Commission. Three of these involve new or expanded pipeline systems:

- Alberta Natural Gas Company Ltd. ("ANG") submitted a proposal to build the Kootenay Pacific Pipeline ("KPP") which would connect the existing ANG system at Yahk to the BC Gas system at Huntingdon.

- Northwest Pipeline Corporation ("Northwest" or "NWP") proposed that by expanding its pipeline facilities in the Columbia River Gorge, along the Washington-Oregon border, it could serve the growth requirements of BC Gas, its own customers and the growth in demand of other Pacific Northwest local distribution companies.

- Westcoast Energy Inc. ("Westcoast") submitted that expansion of its pipeline system between the producing fields of northeastern British Columbia, production areas in northern Alberta, and downstream markets in British Columbia, would enable BC Gas to meet its incremental market requirements until at least 2010.

Another four proposals involve the construction of Liquefied Natural Gas ("LNG") storage facilities:

- In the SCP hearing, BC Gas indicated that if LNG were the resource chosen and approved to meet the Utility's core market requirements, it was confident that it could find a suitable site for an LNG facility to serve the Lower Mainland and gain public acceptance for such a facility (Exhibit 4D).

- Pacific Gas Transmission Company ("PGT"), a U.S. interstate natural gas pipeline, proposed to construct an LNG facility at Cherry Point, Washington which would be connected directly by pipeline to the BC Gas pipeline system at a point near Livingston in the Fraser Valley.

- Westcoast Gas Services Inc. ("WGSI") proposed to construct and operate an LNG storage facility located on Centra Gas British Columbia Inc.'s existing 10-inch diameter, Vancouver Island pipeline at a location which is in the McNab Creek valley, 10 km northeast of Port Mellon.

- Williams International Pipeline Company ("WIPL" or "Williams") submitted a proposal to construct and operate a 3 Bcf LNG storage facility at Sumas, Washington which would connect at the Canada-U.S. border to the Sumas International Pipeline Inc. pipeline owned by BC Gas.

On the first day of the hearing, BC Gas introduced an alternative approach for financing the SCP ("the Alternate Approach") which evolved further during the proceeding. Under this proposal, the facilities requested by BC Gas in its CPCN application remain unchanged. BC Gas Inc. would establish a non-regulated subsidiary ("SCP Co."), to which BC Gas Utility would grant the rights to the capacity of the SCP for 50 years. BC Gas Utility would contract with SCP Co. for the full use of the SCP for 15 years. Thereafter, BC Gas Utility could contract for all, a portion, or none of the capacity of the SCP. In this way, BC Gas Utility could avoid the cost of service of the SCP after 15 years if it did not require capacity on the pipeline. Secondary gas transportation benefits would be shared between BC Gas customers and SCP Co. in varying proportions, depending on the capacity contracted.

The May IRP Update, as amended by the September IRP Update, constitutes the BC Gas 1997 IRP. The 1997 IRP is the basis on which BC Gas filed its Application for a CPCN for the SCP project. BC Gas relied heavily on its 1997 IRP Updates in an effort to show that (1) there is a need for new infrastructure to serve the BC Gas core market, and (2) that the SCP is the best project to meet that need.

To demonstrate the need for additional infrastructure, BC Gas developed forecasts for demand by its own customers and compiled forecasts of gas demand for the Pacific Northwest ("PNW") region from the Integrated Resource Plans ("IRPs") of other utilities in the PNW. Chapter 4 of this Decision examines the demand-supply balance for natural gas for the BC Gas service area as well as for the Pacific Northwest region. On the basis of the evidence examined in that chapter, the Commission is satisfied that the demand forecast indicates that a major new supply resource addition is required within the next five years to serve the growth in peak and seasonal demand, particularly in the Lower Mainland of British Columbia.

Chapters 5, 6, 7, 8 and 9 focus on the Resource Optimization Model ("ROM") used by BC Gas. The model analyses a variety of input assumptions and resource portfolios to determine the optimal resource portfolio for meeting the needs of the core customers of BC Gas. The results of the ROM analysis form the basis for the September, 1997 IRP Update and BC Gas' assertion that the SCP is the preferred next major infrastructure addition.

While acknowledging that there are limitations to the operation of the model, the Commission accepts the directional guidance the model provides in the selection of a resource portfolio. In Chapters 6, 7 and 8 the Commission reviews each of the model assumptions in turn. Generally, the Commission finds the majority of the assumptions to be reasonable for purposes of the modeling. However, the Commission revised the nominal discount rate from 6.18 percent to 10 percent to reflect the long time horizon used in the BC Gas analysis and the associated uncertainty of the assumptions. The Commission also reduced the third-party revenue generated by the SCP from $64 million to $44 million in 1997 NPV dollars, at the 10 percent discount rate.

On the basis of these adjustments, as presented in Chapter 9, three groups of resource options emerge as superior: the LNG option, the NWP expansion option and the SCP with WEI/NWP expansion option. All the LNG alternatives show very similar results and, based on the information provided by the hearing participants, no individual LNG proposal emerges as the preferred LNG option at this time. Therefore, the Commission considers LNG as a single class for further evaluation. The SCP plus LNG case is excluded from consideration in the LNG group because it ranks $40 to $60 million lower in NPV savings than LNG projects alone. BC Gas did not include the KPP proposal of ANG in its ROM analysis, and the evidence indicates that it is unlikely to have greater benefits for BC Gas customers than the SCP, without substantial support from other shippers. Also, the Commission finds that the Alternative Approach for financing the SCP would have fewer benefits than normal rate base treatment of the capital expenditure.

The three leading groups of resource options are then evaluated in Chapter 10 on the basis of other, non-ROM benefits. Again, the Commission makes several adjustments with respect to the benefits that BC Gas proposed. The addition of the non-ROM benefits brings the alternatives closer together but continues to show LNG as the preferred resource option. The adjusted ROM analysis and the adjusted non-ROM benefits plus ROM analysis both fail to show the SCP as ranking highest in NPV savings. Even if these results are not considered to be conclusive in themselves, they are directionally reinforced by other concerns of the Commission regarding the SCP project.

First, the Commission is concerned about making a large capital investment for core market customers to serve a peaking and seasonal load when there are less costly and lower risk alternatives to meet the need. BC Gas claims that there would be third-party revenues from transportation customers to increase the utilization of the pipeline and offset a portion of the costs of the project. However, BC Gas did not support these claims with any firm commitments or a market test.

Second, the 30-year demand forecast used to justify the SCP extends beyond the 15 to 20 year forecast planning horizon contemplated by the Commission in its IRP guidelines. Beyond 2016 the data has been trended out to 2026. The Commission questions the reliability of that data as well as the risks and uncertainties associated with a 30-year commitment. The gas industry in general, with the role of the LDCs in that industry in particular, is continuing to change which adds to the uncertainty of a long-term commitment. In the circumstances, core customers may be better served by an approach which is not so heavily dependent on forecast savings to be realized many years in the future. A more incremental approach to resource additions viewed over a shorter time horizon would reduce risk.

Third, with only 170 MMcfd of additional and alternate supply to the Lower Mainland, much of the benefit of this pipeline is limited to the Interior. There are implications for the Westcoast system such as the potential stranding of some Westcoast pipeline capacity on T-South above Kingsvale and uncertainties over toll rates that may be charged for transmission service between Kingsvale and Huntingdon.

Fourth, although BC Gas adopted an integrated approach to meeting gas supply requirements in the Lower Mainland and the Interior, transmission requirements are unique to the individual service area and there are solutions available to serve the needs in these regions separately and incrementally. The examination of alternatives for the Interior Transmission System, independent of requirements for the Lower Mainland, requires further analysis.

Fifth, the Commission is also aware from evidence presented in the hearing that there is the potential for new gas loads to develop to serve cogeneration plants on Vancouver Island and the Burrard Thermal Plant in the Lower Mainland. The Commission recognizes that firm commitments for bringing these projects to fruition have yet to materialize. However, these projects would have some important ramifications for gas demand and proposals for serving that demand. The Commission is of the view that the potential synergies between these proposed thermal generation projects and the peaking demands on the BC Gas system should be explored further to determine if these projects together could provide a lower cost option for utility customers.

Based on the evidence presented to the Commission and the analysis and conclusions reached in this Decision, the Commission concludes that the SCP is not the preferred resource option at this time. Therefore, the May 30, 1997 Application by BC Gas for a CPCN for the Southern Crossing Pipeline is denied.

From a review of all of the evidence, the Commission also concludes that BC Gas requires a peak shaving resource located in close proximity to the Lower Mainland. Further, the Commission concludes that the LNG option is preferable to the short-listed pipeline options and, under normal circumstances, would expect BC Gas to proceed directly to the LNG solution. However, the Commission also recognizes that investigation of potential peak shaving from thermal generation is incomplete. The Commission believes that it is in the public interest to allow BC Gas to examine this option with British Columbia Hydro and Power Authority ("B.C. Hydro") in more detail.

The Commission is very much aware that there is some urgency required in finding a resource alternative to meet the seasonal and peaking demand for natural gas, particularly in the Lower Mainland. In the absence of sufficient firm commitments by third parties for capacity on the SCP, the Commission is also of the view that BC Gas should develop separate strategies for meeting its transmission capacity needs in the Lower Mainland and Interior regions.

To ensure that the process continues to move forward, the Commission, therefore, expects BC Gas to expedite negotiations with B.C. Hydro to explore the benefits of peak shaving with the objective of filing a progress report by July 3, 1998 and presenting a firm proposal to the Commission no later than October 2, 1998. In this regard, the Commission notes that if there is a requirement for new pipeline infrastructure upstream of Huntingdon to serve these loads, BC Gas may wish to re-examine the SCP and attempt to obtain commitments from B.C. Hydro for capacity on the SCP which would make it a viable alternative.

At the same time that BC Gas is pursuing this peak shaving option, it is expected to proceed in parallel to finalize plans for an LNG storage plant to serve the Lower Mainland as a contingency plan in case the peak shaving option with B.C. Hydro does not materialize or the financial terms available to BC Gas are not in the best interests of its customers. In the event that efforts to reach a satisfactory peak shaving arrangement with B.C. Hydro are not successful by October 2, 1998, the Commission expects BC Gas to present a firm proposal to the Commission for a 3 Bcf LNG facility to serve its customers by January 29, 1999. In view of the interest shown in this proceeding in providing LNG service and the close ranking of the LNG options in all the analyses presented, the Commission concludes that BC Gas should issue a request for proposals ("RFP") for LNG service.

If, after an evaluation of the responses to the RFP, BC Gas considers that there is no reasonable expectation that an LNG facility can be in service by the date it is required for Utility customers, BC Gas should file a report by January 29, 1999 setting out the alternative course of action that it intends to pursue.

WGSI Exemption Request

In its August 15, 1997 submission, WGSI applied to the Commission pursuant to Section 88(3) of the Utilities Commission Act for an exemption from regulation for its proposed LNG facility. As the Commission has previously noted, no individual LNG project emerges as a preferred option at this time. Furthermore, in the absence of firm contracts that would allow the Commission to assess the monopoly power of the facility, and without an examination of other utility considerations, the Commission is not prepared to exempt the proposed WGSI facilities at this time.

The WGSI application is therefore denied. Should BC Gas bring forward a contract for LNG from the WGSI facility for approval by the Commission in the future, WGSI can make its application for an exemption at that time.

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1.0 INTRODUCTION

1.1 Background

BC Gas Inc. was formed as the result of an amalgamation of three affiliated companies (Inland Natural Gas Co. Ltd., Columbia Natural Gas Limited and Fort Nelson Gas Ltd.) with the former Gas Division of British Columbia Hydro and Power Authority. The latter entity became a part of the present corporate body as a consequence of a privatization initiative by the Provincial Government in 1988. Later, BC Gas Inc. incorporated BC Gas Utility Ltd. ("BC Gas" or "the Utility" or "BC Gas Utility") as a wholly-owned subsidiary. The Utility now operates two major transmission systems, the Interior Transmission System (the "ITS") and the Coastal Transmission System in the Lower Mainland. The Utility provides gas service to more than 710,000 customers in the Fort Nelson area, the Cariboo, the Okanagan and Kootenay regions, and throughout the Lower Mainland.

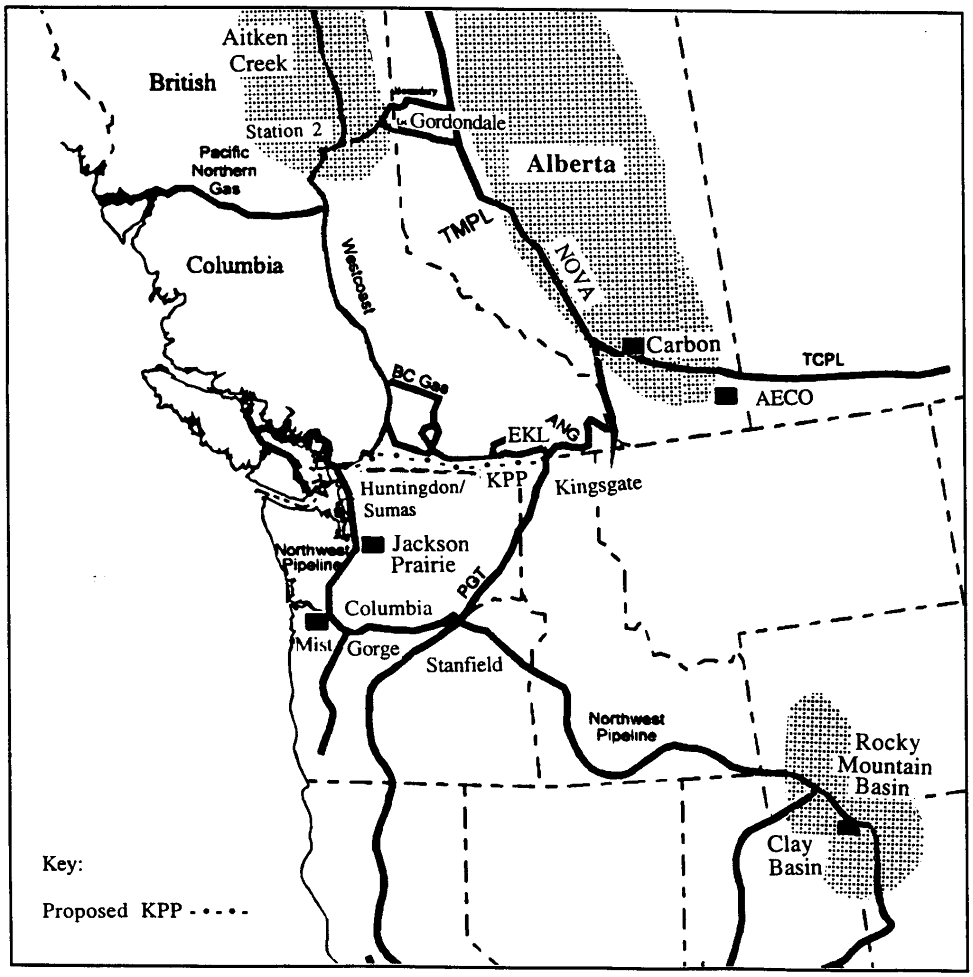
On May 30, 1997, BC Gas applied to the British Columbia Utilities Commission ("the Commission" or "BCUC") pursuant to Section 45 of the Utilities Commission Act for a Certificate of Public Convenience and Necessity ("CPCN") to build the Southern Crossing Pipeline project (the "SCP"). The SCP would extend from near Yahk, British Columbia to Oliver, British Columbia at a cost of $348.2 million in 1997 dollars, including Allowance for Funds Used During Construction ("AFUDC") and overhead (Exhibit 1, App. III, p. 18). Figure 1-1 shows the major gas supply basins and gas transmission pipelines that serve British Columbia and the U.S. Pacific Northwest. Figure 1-2 shows the existing ITS and the proposed SCP.

On June 27, 1997, the Commission ordered a public hearing into the Application by Order No. G-75-97. The hearing commenced on October 14, 1997. The evidentiary portion of the hearing, was completed on November 25, 1997, after 24 hearing days. During the hearing process, in early November, 1997, Town Hall meetings took place in Fort St. John, Castlegar and Oliver, British Columbia. The purpose of the Town Hall meetings was to provide the opportunity for communities that might be affected by the project to give submissions directly to the Commission, and to ask questions of the Utility and representatives of any alternative proposal who chose to be present, in a setting less formal than the traditional hearing process. Transcripts of the meetings were kept but there was no cross-examination of evidence presented.

The hearing concluded with written argument. The Utility filed its argument with the Commission, and distributed it to intervenors, on December 5, 1997. Intervenor arguments and reply to the BC Gas argument were submitted to the Commission and all other intervenors by December 12, 1997. The Utility filed its reply argument on December 19, 1997, as did intervenors to the arguments of other intervenors.

Figure 1-1

Major Supply Basins and Transmission Pipelines
Northwestern North America



Source: Cover Page of May IRP Update, Exhibit 1, Appendix II

Materials originally filed by BC Gas.

Subsequent to December 19, 1997, leave was sought by one intervenor to file Rebuttal Argument to the Reply Argument of a second intervenor and Reply Argument to the Argument of a third intervenor that was not served on a timely basis. The third intervenor also sought leave to file Rebuttal Argument. The Commission issued a Decision dated January 29, 1998 allowing, in part, the first intervenor's request to file Rebuttal Argument, granting its request to file further Reply Argument and denying the third intervenor's request to file Rebuttal Argument.

There were two aspects to the hearing. The primary focus was on a detailed examination of the Utility's Integrated Resource Plan ("IRP", "Plan"), which examines options for meeting the projected growth in the demand for natural gas. Secondly, the hearing reviewed the Application for a CPCN for the SCP. As part of the review of the IRP the Commission examined the merits of a number of other proposals, each designed to serve the core market (firm system sales) demand. One alternative proponent, Westcoast Gas Services Inc. ("WGSI"), argued that it was seeking approval for its LNG proposal from the Commission by way of exemption from regulation.

1.2. The CPCN Application

1.2.1 Facilities Applied For

In its CPCN Application, BC Gas indicates that the SCP is required to meet incremental peak day and seasonal gas demand by BC Gas customers over the next 30 years (Exhibit 1, p. 6). Core market daily demand on the system is approximately 600 TJ with a peak day system demand of approximately double that amount. BC Gas defines "core" to mean firm system sales customers, and excludes transportation customers who buy gas directly from producers or aggregators/marketers.

The Application, as amended by the September SCP Engineering Report Update, requests approval for 310 km (193 miles) of 24-inch 1440 psig (610 mm, 9928 kPa) pipeline (Exhibit 1, App. III, p. 2; T10: 1732). The proposed pipeline connects the Alberta Natural Gas Company Ltd ("ANG") system at Yahk with the existing Interior Transmission System at Oliver. The SCP would be constructed substantially within the right-of-way of the existing BC Gas pipeline between Yahk and Oliver. The Application identifies five significant deviations, totaling 49 km, from the existing right-of-way.

The Application includes an additional 8,800 hp (6.6 MW) of compression at the existing BC Gas Kitchener station near Yahk. The compression would be gas fueled, and consist of two Solar Centaur 40 units with a rating of 4,700 hp ISO per unit. The existing Kingsvale compressor station would be modified to permit flow west into the Westcoast Energy Inc. ("Westcoast" or "WEI") system. Custody transfer, pressure regulating and flow control equipment would need to be added or modified at several locations.

The total direct cost of the facilities covered by the Application is estimated at $330.6 million in 1997 dollars. Adding overheads and AFUDC brings the total estimated cost to $348.2 million. The September Engineering Update stated that the cost estimate is expected to have a variance range of approximately plus or minus 10 percent.

The capacity of the SCP is incremental to the 83 Million standard cubic feet per day ("MMcfd") capacity of the existing East Kootenay Link, and is constrained by the take-away capacity of the ITS at Oliver. The incremental peak day design capacity of the SCP is forecast to increase from 169 MMcfd in 2000 to 303 MMcfd in 2026. The increasing design flows will require the addition at the Kitchener compressor station of a third Solar 40 unit in 2005 and a fourth unit in 2019. Each of these additional units is estimated to cost $8.0 million in 1997 dollars, but the approval of the two additional units is not part of the subject Application. Although the cost of these compressors are in the BC Gas' financial analysis, they are not in the capital cost estimate of facilities being applied for (T10: 1701-1702).

The Application does not anticipate that BC Gas would contract for additional ANG or NOVA Gas Transmission Limited ("NOVA") transportation as a result of the SCP. The new pipeline would transport gas from storage in California which is delivered to Yahk by diversion, or gas purchased on the spot market. SCP gas would flow north from Oliver to serve Inland Division customers. Flow on the existing 12-inch pipeline between Oliver and Kingsvale would be reversed to permit deliveries of gas to the Westcoast system to serve the BC Gas customers in the Lower Mainland.

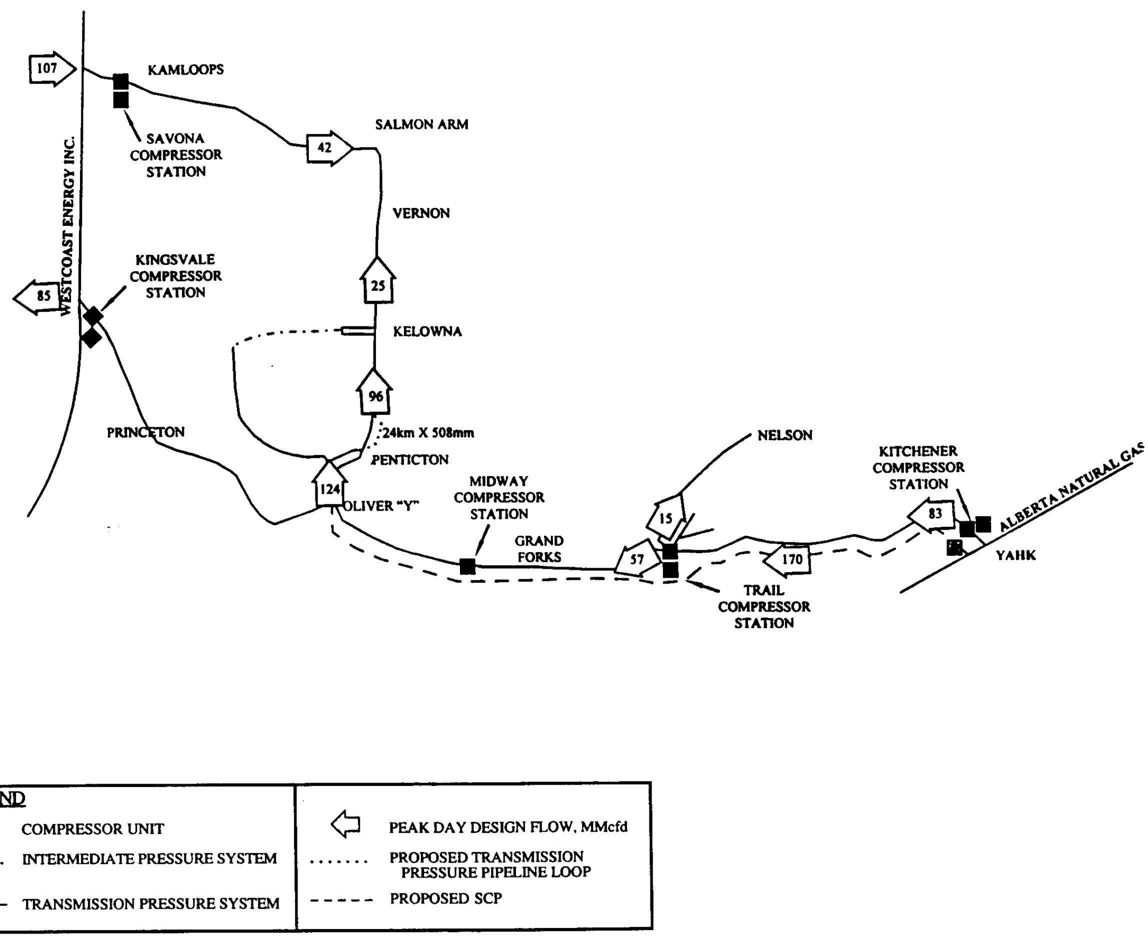
BC Gas based its cost estimate on a favourable decision on the subject CPCN Application by the end of 1997 and a target in-service date of November 1, 1999. The filed schedule anticipated that BC Gas would file a Project Approval Certificate ("PAC") application with the Environmental Assessment Office in late 1997, and receive Environmental Assessment Application ("EAA") approval by July 1, 1998.

The Southern Crossing Pipeline Project represents a major looping of a portion of the ITS. The initial system was constructed in 1957 by Inland Natural Gas Co. Ltd. to distribute natural gas to customers in the southern interior regions of British Columbia. The original facility consisted of a 12-inch mainline connection from the Westcoast pipeline at Savona east to the Okanagan valley. From Penticton a 10-inch line was constructed east to Trail with a smaller line north to Nelson. In 1971, to meet growth in demand, a second 12-inch line was constructed from Kingsvale on the Westcoast pipeline east to Oliver to tie in to the existing 10-inch mainline at Oliver.

In 1974, approval was given to construct a 12-inch pipeline through southeastern British Columbia which connected the ANG pipeline at Yahk to the 10-inch ITS at Trail. This East Kootenay Link (the "EKL"), with a capacity of up to 50 TJ daily, provided an additional source of supply to the Inland system. Figure 1-2 provides a schematic of the existing ITS as well as the proposed SCP route.

Figure 1-2

Existing Interior Transmission System Plus SCP
Peak Day Design Flows for 2000/01



Source: Exhibit 2D, response 6.1(a)

Materials originally filed by BC Gas.

1.2.2 Project Justification

The Application states that a major infrastructure addition is required to meet increasing peak day and winter seasonal demand for natural gas in the Lower Mainland and Interior areas served by BC Gas (Exhibit 1, p. 4). Based on its ongoing IRP analysis, the Utility concluded that the SCP is the best resource addition for satisfying this incremental demand over the next 30 years (Exhibit 1, p. 6). Additionally, BC Gas states that the SCP will:

- improve security of supply;
- increase supply diversity, competition and price transparency for BC Gas sales customers and also for other gas users in the area;
- enhance the operational and balancing flexibility on the BC Gas system;
- provide long-term system reinforcement and maintenance benefits; and
- be readily expandable to meet higher than forecast market growth.

According to the Utility, the SCP addresses a number of concerns that relate to the long-term needs of BC Gas customers. The evidence filed with the Commission also indicates various other alternatives, or combinations of alternatives, which could also meet these needs.

2.0 ALTERNATIVE PROPOSALS

In Order No. G-75-97, the Commission stated that "Based on commitments of the parties at the pre-hearing conference, the Commission expects that proponents of competing proposals will file detailed evidence and provide witness panels to testify at the public hearing". The timetable established by Order No. G-75-97 indicated that proponents of competing proposals were to file detailed evidence of their proposals by August 15, 1997.

A number of proposals to meet the increasing core market demand in the Lower Mainland were presented to the Commission as alternatives to the SCP. Some of these proposals had been under consideration or investigation for two or more years. Three of the proposals involve new or expanded pipeline systems and another four involve the construction of major new Liquefied Natural Gas ("LNG") storage facilities , either in the Lower Mainland or nearby in Washington State.

2.1 Pipeline Proposals

Figure 1-1 shows the major supply basins and existing gas transmission systems serving the northwestern part of North America, and the location of pipeline facilities described in this Decision.

2.1.1 Alberta Natural Gas Company Ltd.

Alberta Natural Gas Company Ltd., a subsidiary of TransCanada PipeLines Limited, submitted a proposal to build the Kootenay Pacific Pipeline ("KPP") which would connect the existing ANG system at Yahk to the BC Gas system at Huntingdon. ANG believes the KPP would provide increased benefits to the Province of British Columbia while reducing the risk to all potential customers. The KPP proposal involves the construction of a 560 km (348 mile) 20-inch pipeline at a cost of $530 million to provide additional capacity of 15.6 million cubic metres per day (550 MMcfd) into the Province of British Columbia.

In late 1995 and during 1996, ANG developed the conceptual basis for an extension of its transmission system from Kingsgate to the Lower Mainland. The proposed KPP extension would serve incremental base load requirements in the BC Gas service area and in the northern portions of Washington State and western Idaho. To verify the potential demand for new pipeline capacity, ANG commissioned an independent market study and initiated discussions with prospective baseload customers. The study provided some evidence of future market potential but did not result in any contractual commitments. As a result, in early 1997, ANG concluded that the KPP project was premature.

Since that time ANG has continued to monitor market developments in the Pacific Northwest generally. ANG believes that a pipeline extension from its system in Alberta to the Lower Mainland is a logical development in the infrastructure serving gas markets in the Pacific Northwest generally. ANG claims that the KPP would allow BC Gas and direct purchase customers to contract with an independent third-party for transportation capacity, limiting their financial exposure only to the payment of demand charges for the term of their contractual obligations.

The KPP would be built in two segments. The first segment parallels the existing BC Gas right-of-way from Yahk to Oliver, a distance of 294 km, and includes two compressor stations. The capital cost of this segment is estimated at $300 million. The second segment extends from Oliver to Huntingdon, a distance of 266 km, with a compressor station at Oliver. This segment will cost approximately $230 million. Based on the projected capital expenditure of $530 million and transportation contracts for the full capacity of 550 MMcfd from Kingsgate to Huntingdon, the first year toll on the KPP would be approximately 21 cents per Mcf to Oliver and 39 cents per Mcf to Huntingdon, dependent upon the facility configuration, contracted delivery points and toll methodology employed.

ANG based its KPP proposal on the assumption that its existing rolled-in volume distance based tolling methodology could be extended, but indicated that it would not go forward with the rolled-in methodology without a high level of shipper support (ANG Argument, p. 31). Several parties indicated ANG would face opposition to an application for rolled-in tolls if it were brought forward to the National Energy Board ("NEB") [Canadian Association of Petroleum Producers ("CAPP") at T17: 2934-2936; Export Users Group Argument, p. 2].

ANG initiated an “open season” on November 1, 1997 to run until January 1, 1998. ANG also intends to actively pursue the KPP project through discussions with prospective customers (Exhibit 96, p. 3). Subject to suitable contractual arrangements, ANG proposes to file an application with the NEB for approval to construct the KPP.

2.1.2 Northwest Pipeline Corporation

Northwest Pipeline Corporation ("Northwest" or "NWP") is a major open access pipeline transporter of natural gas. It utilizes its transportation system primarily to provide transportation services for both on-system and off-system customers in states from New Mexico and Nevada, through the Rocky Mountain states to Washington and Oregon. At the Canadian border near Sumas it interconnects with both Westcoast and Sumas International Pipeline Inc. ("SIPI"), a subsidiary of BC Gas Inc. It also connects with the ANG/Pacific Gas Transmission Company ("PGT") system near Stanfield, Oregon. The pipeline system is bi-directional. Northwest is also a one-third owner of the Jackson Prairie Natural Gas Storage

Project in Lewis County, Washington, ("Jackson Prairie" or "JPS") and owns and operates an LNG facility in Benton County, Washington ("Plymouth LNG Plant"). Both are used by Northwest to provide contract storage services.

Northwest believes that by expanding its pipeline facilities in the Columbia River Gorge, along the Washington-Oregon border, it can serve the growth requirements of BC Gas, as outlined in the BC Gas IRP, its own customers and the growth in demand of other Pacific Northwest local distribution companies ("LDCs"). Northwest notes that this alternative to the SCP can be built in phases to match pipeline capacity to market demand without inefficient overbuilding of facilities. Northwest claims that the Columbia River Gorge Project can provide additional volumes from 50 MMcfd up to 600 MMcfd from the Stanfield interconnect with PGT through to the Sumas interconnections with both BC Gas and Westcoast, at competitive prices. Expansion up to 300 MMcfd can be accomplished at an estimated cost of Cdn $234 million. Northwest offers a 15-year contract at rolled-in rates rising from Cdn $0.29 per Mcf initially to Cdn $0.47 per Mcf with further pipeline expansion in the future.

The project has sufficient design capacity to meet the needs of BC Gas, other LDCs, other end users and industrial users in the Pacific Northwest. Supply diversification is improved by enhancing access to the Alberta, Rocky Mountain and San Juan gas supply basins. Northwest believes the Columbia Gorge Project is a competitive option for serving new market growth because facilities can be built in phases and because service will be based on incremental rates at or near existing transportation rates.

2.1.3 Westcoast Energy Inc.

The Westcoast pipeline system connects the producing fields of northeastern British Columbia to downstream markets in British Columbia and the U.S. through its interconnections at Huntingdon on the British Columbia-Washington border near Sumas. BC Gas is 95 percent dependent on gas supplies through the Westcoast system. Westcoast, through northern British Columbia interconnections with NOVA, also provides access to the gas resource basin in Alberta.

Westcoast believes that a staged approach to meeting the future additional requirements of the BC Gas market is a more prudent and cost effective alternative to the proposed construction by BC Gas of a costly base load transmission pipeline to meet what is in the near term a need for additional peaking service. Under a staged approach, storage and pipeline infrastructure would only be constructed in increments as and when required by the market.

The Westcoast system presently has the capacity to transport approximately 2 Billion standard cubic feet ("Bcf") per day. In 1996, roughly 50 percent of total market deliveries were to customers within British

Columbia, with the largest share being taken by BC Gas customers in the central Interior and Lower Mainland areas. Westcoast can expand its transmission facilities in stages to meet incremental market needs as and when required. This can be accomplished by additional looping of existing pipelines or by adding compression. Westcoast believes that a further 100 MMcfd of mainline capacity will enable BC Gas to meet its incremental market requirements until at least 2010. This expansion can be installed in three phases of 40, 40 and 20 MMcfd at an estimated total cost of $100 million and with a competitive toll structure. Westcoast stated that the toll increase as a result of the expansion facilities would average approximately 0.4 cents per Mcf above tolls otherwise forecast to be in place (Exhibit 4E, p. 17).

2.2 Liquefied Natural Gas Storage Proposals

2.2.1 BC Gas Lower Mainland LNG

In 1994, the Commission accepted an IRP filed by BC Gas which concluded that an additional LNG facility in the BC Gas Coastal Region would provide the best long-term, least-cost, peak shaving service for BC Gas' customers. BC Gas conducted feasibility studies between September, 1994 and May, 1995 to determine the potential feasibility of constructing and operating a new LNG facility. BC Gas now owns and operates a 0.6 Bcf LNG facility located on Tilbury Island in the Fraser River in the municipality of Delta. Following the preliminary study, BC Gas undertook additional studies related to establishing potential sites in the Lower Mainland for the proposed facility. Eleven possible sites were evaluated.

BC Gas' LNG proposal summarizes the analysis, decisions, and outstanding issues relating to design, environmental concerns, siting, regulatory approvals, stakeholder consultations and costs of both a 2 and 3 Bcf capacity plant (Exhibit 4B). The capital cost of a 3 Bcf facility located somewhere in the lower Fraser Valley was estimated at approximately $120 million with operating costs of $2.85 per Mcf per year and with an in-service date of 2002. In the September IRP Update, BC Gas used a capital cost estimate of $139 million for a 3 Bcf LNG facility at Tilbury as its generic LNG case.

2.2.2 Pacific Gas Transmission Company - Cherry Point LNG

Pacific Gas Transmission Company is a U.S. interstate natural gas pipeline with facilities extending from ANG and Foothills Pipelines Ltd., at the Canada-U.S. border near Kingsgate, British Columbia to the Oregon-California border. PGT transports up to 2.5 Bcf per day of natural gas originating in western Canada to customers in the Pacific Northwest and California. The proposed SCP Project would impact the flow of Canadian gas supply into and out of the ANG system with corresponding effects on PGT. PGT believes that customer growth in the Lower Mainland and Pacific Northwest markets warrant incremental access to natural gas supply over the coming years.

PGT has been working with BC Gas since the fall of 1995 on a proposal to construct an LNG facility at Sumas or Cherry Point, Washington. PGT subsequently withdrew its proposal to site an LNG facility at Sumas (PGT Argument, p. 32). As designed, the 2 or 3 Bcf facility would provide 200 to 300 MMcfd for ten days per year of peaking capacity. The Cherry Point facility is described as potentially a regional facility that can serve multiple customers in the Pacific Northwest. It would be connected directly by pipeline to the BC Gas pipeline system at a point near Livingston in the Fraser Valley. The Cherry Point LNG project would be owned jointly through an alliance with HNG Storage Company, a major company in LNG facility construction and operation. PGT believes that its project provides secure access to supply and will accommodate very high but short-term natural gas peaking requirements for the growing Lower Mainland and Pacific Northwest markets.

The capital cost of a 3 Bcf facility at Cherry Point, Washington, together with a 26-mile direct pipeline connection to BC Gas, is estimated at $150 million Cdn with an in-service date of 2002[1]. The Cherry Point site is currently zoned for heavy industry. PGT offers a 25-year contract at a total cost of Cdn $8.148 per Mcf delivered to the BC Gas system. BC Gas is also free to negotiate an equity position in the project should it choose to do so.

2.2.3 Westcoast Gas Services Inc. - McNab Creek LNG

WGSI proposes to construct and operate an LNG storage facility located on Centra's existing 10-inch diameter Vancouver Island pipeline. The location is 7.5 km from the shore of Howe Sound in the McNab Creek valley, 10 km northeast of Port Mellon. In its 1994 IRP, as indicated in section 2.2.1, BC Gas identified LNG as the best option for meeting its peak shaving requirements. Westcoast, the parent company of WGSI, worked with BC Gas in mid-1994 through May, 1995 in response to a Commission directive to BC Gas to proceed with a preliminary study for the evaluation of a new LNG facility in the Lower Mainland. A project summary document was developed that included three possible sites, relevant technical details on several facility sizes, preliminary capital and operating costs and a project schedule.

In September, 1996, BC Gas requested that Westcoast update the May, 1995 report, include a larger facility (3 Bcf) and submit a revised report by mid-October, 1996. Westcoast responded with a single site on the Sunshine Coast, an "at-risk" project and schedule (that is, that all capital and operating cost risks are borne by WGSI) and an option to acquire additional Westcoast pipeline capacity in tandem with the LNG

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1 A 3 Bcf LNG facility at Cherry Point is estimated to cost U.S. $91.7 million (Cdn $123.9 million, at a currency exchange rate of U.S. $0.74/Cdn) in 1996 dollars, while a pipeline between Cherry Point and the BC Gas system at Livingstone would add U.S. $19.0 million (Cdn $25.7 million) (Exhibit 4D, Tables 1-A, 2-A).

facility. The location on the Centra gas system allows for delivery to BC Gas either by displacement or by a backhaul to Eagle Mountain, in Coquitlam, using a portion of the Centra gas pipeline system.

WGSI believes that LNG should be the next major natural gas infrastructure addition in British Columbia. It notes that information provided by BC Gas in support of the SCP project shows that the current and forecast market served by their system has a low load factor and significant and sustained growth in peak-day volumes. WGSI believes that LNG has long been recognized by the industry as one of the best resources to meet peaking requirements. WGSI points out that utilization of LNG storage would free up Westcoast pipeline capacity contracted annually by BC Gas to meet its peak demand. This capacity could then be used by BC Gas to meet forecast growth in the base demand thus deferring the need for major new pipeline system additions.

The capital cost for a 3 Bcf facility at McNab Creek is estimated at $120 million (Exhibit 5D3, IR 6.3; Exhibit 107, p. 1). The operation would be integrated with the Centra and BC Gas pipeline systems. WGSI offers a range of contract options at first year rates ranging from $9.36/Mcf for a ten-year term to $6.33/Mcf for a 25-year term. Rates escalate at 2 percent per year (Exhibit 109). An additional transportation charge on the Centra system would be incurred. WGSI stated that an equity position is also available to BC Gas.

2.2.4 Williams International Pipeline Company - Sumas LNG

Williams International Pipeline Company ("WIPL" or "Williams") submitted a proposal to construct and operate an LNG storage facility at Sumas, Washington. WIPL met on numerous occasions with BC Gas regarding this proposed facility. BC Gas was asked if it would be interested in an ownership interest in this project. WIPL stated that to date BC Gas has shown interest in both the project and the prospect of an ownership interest but has made no firm commitments.

The proposal is to build a 3 Bcf LNG storage facility for the primary purpose of serving the growing natural gas market in British Columbia served by BC Gas. The facility is designed to use gas from British Columbia but has the flexibility also to source gas from Alberta as well as from the Rocky Mountain and San Juan production areas in the U.S. The Sumas LNG facility would connect at the Canada-U.S. border to the SIPI pipeline owned by BC Gas. It could also be connected to the pipeline facilities of Westcoast and Northwest at the border. The proposal requires no transportation by either Westcoast or Northwest to deliver the gas to the BC Gas system. It is based on sufficient plant outlet pressure to transport stored gas to the BC Gas market area without the need for additional compression on either SIPI or the BC Gas system. WIPL stated that the proposal is subject to more detailed engineering studies, all regulatory approvals and entering into a binding agreement with BC Gas.

WIPL believes that the use of LNG storage to meet peaking needs will enable BC Gas to utilize currently contracted pipeline capacity on Westcoast (that is used to meet peak demand) to serve base load growth. They maintain that this is a more efficient approach than building incremental transmission capacity to meet base load growth and peak loads leading to under-utilization of pipeline resources.

The Williams LNG storage facility at Sumas has an estimated capital cost of U.S. $89.7 million (Cdn $121.2 million) in 1997 dollars at a 0.74 exchange rate (Exhibit 4G, p. 2; T15: 2608). The Company offers a ten-year fixed price contract at Cdn $8.379 per Mcf. WIPL estimates that the project could provide vaporization service by the 2001-2002 heating season. WIPL offered its proposal as complementary to, but separate from, the pipeline expansion proposal of its affiliated company, NWP.

2.3 Alternate Approach to Financing the SCP

On the first day of the hearing, BC Gas introduced an alternative approach for financing the SCP ("the Alternate Approach") which evolved further during the proceeding (Exhibits 11B, 11C, 26, 31, 32, 38, 39, 40, 126). The facilities requested by BC Gas in its CPCN application remain unchanged (T1: 39 and 40).

BC Gas prepared the Alternate Approach in response to several parties who wanted to explore approaches for reducing the risk to the core market and for insulating BC Gas Utility and its customers from cost impacts due to longer term rate base exposure. Under the proposal, BC Gas Inc. would establish a non-regulated subsidiary ("SCP Co."), to which BC Gas Utility would grant the rights to the capacity of the SCP for 50 years. BC Gas Utility would contract with SCP Co. for the full use of the SCP for 15 years. Thereafter, BC Gas Utility could contract for all, a portion, or none of the capacity of the SCP. In this way, BC Gas Utility could avoid the cost of service of the SCP after 15 years if it did not require capacity on the pipeline. Secondary gas transportation benefits would be shared between BC Gas customers and SCP Co. in varying proportions depending on the capacity contracted.

3.0 THE INTEGRATED RESOURCE PLAN

3.1 Background to 1997 Integrated Resource Plan

Integrated resource planning is an ongoing process within BC Gas, encompassing demand analyses; the creation and updating of annual gas contracting plans; and, the assessment of long-term resource alternatives which both respond to and shape customer demands. Through this process, the objective of BC Gas is to plan its resource acquisitions to satisfy customer demands in an efficient manner, at the lowest cost while still providing flexibility and security of supply.

3.1.1 1994 Integrated Resource Plan

The first BC Gas Integrated Resource Plan was completed in 1994. The Plan set out the Utility's natural gas resource acquisition strategy, including supply and demand-side options to maximize efficiency and respond effectively to changing customer needs, societal values and ongoing changes in the energy industry. The Utility's Gas Supply Optimization Model ("GSOM") was used to evaluate alternative supply resource portfolios.

The 1994 IRP identified an LNG facility expansion as the most cost effective supply option for providing additional peak shaving (Exhibit 17). In the BC Gas 1994 Revenue Requirements Decision, the Commission approved a phased approach for investigating the feasibility of a new LNG facility. BC Gas filed its LNG Peak Shaving Project - Preliminary Phase I Report with the Commission in October, 1996. Some additional siting studies were carried out later in 1996. This information formed the basis of the LNG Proposal Option that BC Gas filed in August, 1997 in this proceeding (Exhibit 4B).

3.1.2 1995 Integrated Resource Plan

The 1995 IRP re-visited many of the issues from the 1994 IRP, particularly in light of increasing competition and deregulation in the natural gas industry. In response to a directive regarding the 1994 IRP, BC Gas enhanced its analysis of risk and uncertainty in the examination of supply resource portfolios. The supply-side analysis evaluated a number of scenarios around the base case assumptions.

The 1995 IRP identified an LNG expansion as the most economic option available for BC Gas to meet its future demand requirements. The Plan also discussed a Southern Crossing Pipeline, 20 or 24 inches in diameter, connecting Yahk and Oliver. A preliminary analysis found that this expansion of the EKL could be economical. In addition to providing gas supply, the 1995 IRP indicated that SCP would have supply security and other strategic benefits.

In its July 2, 1996 Decision regarding the 1995 IRP, the Commission stated that:

> "... BC Gas must submit further substantive information to the Commission before the Commission will be able to provide any endorsement of the Company's long-term supply plans."

3.1.3 February, 1997 Resource Plan Update

Following the Decision on the 1995 IRP, BC Gas undertook a more comprehensive study of various resource portfolios, which included further scenario and sensitivity analyses. The work included a more detailed analysis of the feasibility of constructing the SCP to access supply and storage fields in Alberta and the U.S. The SCP study resulted in the SCP Project Engineering Report which BC Gas filed with the Commission in early February, 1997, and included in its SCP Application (Exhibit 1, App. I). In September, 1997, BC Gas filed an Update to the SCP Project Engineering Report which revised the scope, route and cost of the project (Exhibit 1, App. III).

The results of the more comprehensive study of resource alternatives were presented in the 1997 Resource Plan Update, which was filed with the Commission in late February, 1997. This document was reviewed with a broad spectrum of customer and community stakeholders in order to obtain feedback on BC Gas' initial resource planning conclusions. The analysis was further refined, and the input from the stakeholder consultation incorporated, to produce the May, 1997 IRP Update (Exhibit 1, App. II).

3.2 May, 1997 Integrated Resource Plan Update

The May, 1997 IRP Update (Exhibit 1, App. II), as amended by the September, 1997 IRP Update (Exhibit 1B), constitutes the BC Gas 1997 IRP. The 1997 IRP is the basis on which BC Gas filed its Application for a CPCN for the SCP project. Consequently, the review of the justification for the SCP project is largely a review of the IRP.

The May IRP Update states that the BC Gas IRP objectives with regard to resource selection are as follows:

- Provide quality energy service to customers at lowest cost;
- Optimize rates over the long term;
- Provide shareholders of the Utility value for their investments; and
- Balance social and economic impacts.

The IRP analyzed the growth in demand for BC Gas core (firm sales) customers, in the context of peak demand growth in the Pacific Northwest. The following alternative infrastructure additions to meet BC Gas' long-term demand requirements were studied in detail:

- Additional LNG storage in or near to the Lower Mainland.
- Expansion of the Northwest Pipeline system from Stanfield, Oregon. (Northwest can deliver Alberta and U.S. gas production to Huntingdon.)
- Expansion of Westcoast transmission facilities from Alberta (Gordondale expansion).
- Expansion of the Yahk to Oliver pipeline connection by means of the SCP project.

Prior to development of the 1997 IRP, BC Gas' GSOM software was enhanced and expanded into the two-stage Resource Optimization Model ("ROM") which optimizes resource costs over the study period. The ROM is able to consider Demand-Side Management ("DSM") in addition to the supply resources which were considered in the GSOM (T3: 463). In the May IRP Update, BC Gas estimated that the DSM programs which are currently in place will reduce the annual growth in core market peak day demand by 2 TJ/d. For analysis purposes, the total projected daily gas demand savings attributable to DSM are deducted from the daily load profile. The ROM then solves for the optimum supply portfolio which would meet the forecast load requirement net of the DSM savings.

BC Gas defined a Default portfolio against which all other proposals are measured. The Default portfolio assumes that growth in demand will be met by British Columbia sourced baseload gas delivered through the Westcoast System. The Utility then identified several alternative supply portfolios for detailed evaluation. The optimized net present value ("NPV") gas cost over 30 years was calculated for each portfolio, along with the NPV "savings" relative to the Default portfolio. The results are tested for sensitivity to changes in a number of the more critical assumptions that defined the Reference case.

Because the ROM analysis indicated that the optimal portfolio choice is to bring both the SCP and LNG on-stream as soon as possible, the Utility investigated the sequencing of these two alternatives. This analysis also steps beyond the ROM, and includes forecast market and operational benefits related to improved balancing and security, third-party transportation revenue and price shock protection. The May IRP Update recommended that the SCP should be the primary resource addition, and should be brought into service at the earliest opportunity.

3.3 September, 1997 Integrated Resource Plan Update

In the September IRP Update, BC Gas revised the May IRP Update to provide a consolidated report that incorporates new information and responds to a number of information requests (Exhibit 1B). The new information includes that filed by other proponents regarding their proposals for competing LNG and pipeline projects and updated cost estimates, as outlined below:

- Updated gas price forecasts;
- Updated pipeline tolls based on information provided by Westcoast and NWP in responses to information requests. The updated Westcoast tolls are based on Westcoast's forecast of tolls assuming a 300 MMcfd expansion and NWP's tolls are based on a phased 400 MMcfd expansion;
- Updated project costs for the SCP and a BC Gas LNG proposal;
- The in-service date of the SCP is advanced by one year, leading to an increase in ROM only benefits of $5 million (Exhibit 1B, p. 4; Exhibit 10, cover letter);
- The in-service date for all of the proposed LNG facilities is assumed to be November 2002, one year later than the assumption adopted in the May, 1997 IRP Update for a generic LNG plant located in the Lower Mainland;
- Revisions are made to the depreciation rates of BC Gas-owned facilities;
- BC Gas also applied a full-year of discounting to the first year cost streams, whereas the previous analyses applied no discounting to the first year cost streams (Exhibit 1B, p. 9, footnote); and
- All U.S. dollar costs are converted to Canadian dollars at a standard assumed exchange rate of $0.74 U.S./$1.00 Cdn.

The September filing provided new ROM results based on the foregoing Reference case input information, and added project-specific analyses for the WIPL, BC Gas, and PGT LNG proposals, leading to the following alternative portfolios:

- Westcoast pipeline expansion from Alberta (Gordondale expansion);
- Northwest pipeline expansion;
- SCP + Westcoast/Northwest expansion;
- 3 Bcf BC Gas Tilbury LNG + Westcoast/Northwest expansion;
- SCP + Phase 2 SCP expansion to connect with the Westcoast system at Kingsvale;
- 3 Bcf PGT Cherry Point LNG + Westcoast/Northwest expansion; and
- 3 Bcf WIPL Sumas LNG + Westcoast/Northwest expansion.

The ROM analysis for each portfolio minimizes the forecast gas supply costs for each year through 2015/16 (Exhibit 2D, IR 3.8). As well as the cost of gas supply resources and storage and pipeline tolls, the ROM results for each portfolio include the annual cost of service of the SCP and/or LNG facilities. BC Gas also includes credits for third-party transportation revenue from the SCP, and for the system reinforcement for the ITS and the Coastal Transmission System that can be avoided by major infrastructure additions.

In order to provide a basis for a 30-year economic evaluation, the ROM results are extrapolated from 2015/16 to 2025/26 (Exhibit 3D, IR 10.1). The NPV of the total net cost of gas supply to core market customers is calculated in 1997 dollars, and the total cost to core customers over 30 years is compared to the cost of the Default portfolio, to calculate the NPV “Net Savings”. The September IRP Update also includes a revised assessment of the potential burner-tip price impacts on core customers based on the LNG, Westcoast expansion, Northwest expansion and SCP portfolios.

BC Gas concludes in the September IRP Update, that a major resource addition is still desirable, and that the SCP is the preferred next major infrastructure addition for BC Gas customers. BC Gas does not include the WGSI LNG proposal in the September Update because it considered the publicly available data to be insufficient at that time. On receipt of specific data, BC Gas later ran a ROM analysis of the WGSI proposal (Exhibit 10).

BC Gas also included some additional ROM analyses in response to information requests and further revisions resulting from other information responses (Exhibits 10, 19). These new cases include:

- A one year earlier Tilbury LNG case run with a November 2001 in-service date which results in an increase of $9 million in ROM-only benefits;

- An SCP run using Reference case information, but assuming a "one-year delay" for a November, 2000 in-service date. This results in reductions in ROM related benefits of $5 million and non-ROM benefits of approximately $19 million to $30 million (Exhibit 10, cover letter and schedule 2, T2: 245-246); and

- A ROM case in response to Westcoast's Information Request, which combines several specific assumptions less favourable to SCP than those which BC Gas used in its earlier ROM analyses.

Results are included that show the impact on the burner-tip price of core customers.

The September IRP Update does not include an analysis of ANG's Kootenay Pacific Pipeline proposal. In BC Gas' view, "...the material filed by ANG and the responses to information requests by ANG, indicate that the KPP has not been sufficiently advanced to allow reliance to be placed on the costs and tolls contained in the material filed by ANG."

4.0 LOAD FORECAST AND RESOURCE DEFICIT

4.1 Load Characteristics and Customer Demand Projections

BC Gas developed forecasts for demand by its own customers and compiled forecasts of gas demand for the Pacific Northwest ("PNW") region from the IRPs of other utilities in the PNW.

BC Gas also considered what it described as the regional context for its IRP activities, meaning in this instance the PNW region (Exhibit 1, App. II, pp. 1-2). It is important to distinguish at this point between regional forecasts, meaning forecasts for various regions or service territories within the BC Gas service area, and the PNW regional forecasts which BC Gas developed from the IRPs of other utilities in the PNW in order to provide a context for discussing the capacity available to deliver gas to its own customers. For the purposes of this Decision, regional demand will refer to demand within BC Gas' own service area, while demand in the PNW region will be referred to as PNW demand. The capacity of the Northwest pipeline through the Columbia River Gorge constrains Northwest's ability to move gas to major markets in the Seattle and Portland area from its interconnect with the PGT system at Stanfield, Oregon. Thus, PNW demand generally refers to the demand of customers that are north and west of the Columbia Gorge.

This section discusses BC Gas' forecasts of demand in its own service area. The PNW supply demand balance will be discussed in section 4.2.

Forecasts of BC Gas' core market (firm sales) demand are used to drive its ROM analysis, given certain assumptions about which supply, pipeline and storage resources would be available to deliver gas supply to the core market. BC Gas defines "core" to mean firm system sales customers in Rate Schedules 1 through 6, and excludes transportation customers who buy gas direct from suppliers (Exhibit 2D, IRs 1.1, 19.1; T24: 4218). The core market typically consists of residential, institutional, commercial and some small firm industrial customers who individually tend to use smaller volumes of gas. BC Gas developed forecasts of core market annual requirements for a 30-year study period. BC Gas stated that the ROM analysis is based on core market demands and does not include firm direct purchase needs or any interruptible requirements for either sales or direct purchase. Since industrial customers tend to buy their own gas directly, their demand or demand shifts should not affect the analysis (Exhibit 2L, IR 4).

The core market demand forecast includes a Reference case forecast, 90 percent high and low confidence intervals, and forecasts based on high and low price scenarios. The Reference case forecast demand is shown in the table below.

Table 4-1

Long Term Annual Firm Sales Demand by Region
BC Gas Service Area
(PJ)

	Lower Mainland	Interior	Total
1995	98.4	32.5	130.9
2000	106.9	37.7	144.6
2005	116.0	41.1	157.1
2010	123.0	43.9	166.9
2015	129.7	46.9	176.6
2020	137.0	49.8	186.8
2025	143.1	52.3	195.4
Growth Rate: 1995-2000 1995-2015			 2.0% 1.5%

Source: Exhibit 2D, IR 1.7

Over the 30-year study period, the forecast average annual rate of growth of the core market is 1.3 percent. In the high and low cases, it is 1.7 percent and 0.9 percent, respectively (BC Gas final Argument, p. 5)[2].

Peak day requirements are expected to increase generally at the same rate as annual requirements (Exhibit 2D, IR 1.2), because the core market load is primarily heating load and because average day and peak day have grown at essentially the same rate in the past (Exhibit 3A, IR 16.2). BC Gas stated that its total core market peak day demand for 1997 was 1174 TJ/d (Exhibit 1, App. II, p. 15). Subsequently, BC Gas provided a forecast of core market peak day demand by division (Exhibit 3D, IR 12.1), which is reproduced below.

2 Note that the BC Gas CPCN Application (p. 15) stated that gas consumption by BC Gas customers is forecast to grow at an average annual rate of 1.2 percent. At the same reference, peak day demand is projected to increase from 1,174 TJ to 2,015 TJ in 2015, an average annual increase of 1.5 percent.

Table 4-2

Core Market Peak Day Demand by Region
(TJ/d)

Region Year	Lower Mainland	Inland	Columbia	Fort Nelson	Total
1999/2000	914	310	27	4	1,255
2004/2005	992	351	30	4	1,377
2009/2010	1,051	377	32	5	1,465
2014/2015	1,109	405	34	5	1,553
2019/2020	1,171	431	36	6	1,644
2024/2025	1,223	456	38	6	1,723

BC Gas indicated that the Fort Nelson volumes are excluded when pipeline requirements are being considered.

During the hearing, witnesses for both PGT and CAPP agreed that the demand forecasts and rate of growth put forward by BC Gas appear reasonable. A witness for WEI also indicated that except for the length and the inherent uncertainty of BC Gas' IRP forecast, there were no concerns (T12: 2071).

For allocating the overall core market demand to its four regional service areas, BC Gas uses two methods. One method bases growth in core market demand in a specific area on a population gas customer share model which allocates growth in gas demand in a region in proportion to the region's relative population growth rate. The other method forecasts regional growth using end use demand models which develop "bottom up" forecasts of demand using regional factors (Exhibit 2A, IR 5.1; T4: 543-544).

The ROM assumes that sufficient resources are available to meet demand, in that it assumes that all resources that BC Gas is contractually required to hold, plus any additional resources required, will be in the portfolio (T5: 840). However, outside of the model, sufficient resources will be available only if BC Gas or other parties provide them in response to analysis of demand, or the workings of the market.

4.2 The Pacific Northwest Regional Supply-Demand Balance

In addition to forecasting core market demand in its own service area, BC Gas also reviewed PNW demand to assist in determining the extent to which current and planned pipeline and storage facilities are sufficient to meet the forecast PNW demand.[3] To the extent that the resources are not adequate to meet forecast requirements, a resource deficit would exist in the PNW. In order to analyze its ability to meet its own supply requirement, BC Gas looked at the PNW demand in conjunction with the pipeline and storage resources available to serve that demand. Examining the PNW context could also help determine whether parties other than BC Gas would have an interest in utilizing the SCP and thus bearing some of the cost associated with the project. BC Gas indicated that forecast peak demand growth in the PNW, including BC Gas, would be something over 1100 TJ/d, between 1995 and 2010. BC Gas' analysis concludes that "With the existing PNW gas delivery systems operating at or near full capacity, it is evident that forecast growth in the customer base and increased winter heating demand can only be met through additional physical system infrastructure within the area" (Exhibit 1, App. II, p. 2).

BC Gas listed its existing and committed supply resources, along with its Reference case peak day firm demand (Exhibit 2C, IR 8). Some existing and committed resource contracts begin to expire immediately, and the total amount of resources that are committed to BC Gas continues to diminish further over time. By 2011 and thereafter, the total existing and committed supply resources amount to approximately 200 TJ/d and the Reference case BC Gas peak day demand is in excess of 1500 TJ/d, leaving a potential peak day supply contracting shortfall of over 1300 TJ/d. As noted by BC Gas, "The probability of renewing or replacing supply resources economically is dependent on the number of options and alternatives available to BC Gas customers. At some price all supplies could be renewed or replaced" (Exhibit 2C, IR 8, p.2).

ANG's expert witness, Dr. Oechsler, provided an independent analysis of the capacity supply-demand balance (Exhibit 8A). Dr. Oechsler's analysis (Exhibit 8A, p. 15 and Table 2) indicates that, although a current small capacity surplus exists, demand growth will soon cause this surplus to disappear leading to a peak day capacity deficit of 44 TJ/d in 1999 if only core market demand is considered, and 210 TJ/d if non-core demand is included as well. In both instances this capacity deficit is demonstrated to increase over time in the absence of additional capacity. However, Dr. Oechsler acknowledges that his analysis understates the existing resources slightly in that it does not consider the existing LNG or operational flexibility on the BC Gas system nor does it account for the gas currently taken directly off the ANG line in the Columbia region. With these adjustments taken into account, he disagrees with the implication that BC Gas could face serious problems if the Commission does not authorize construction of peak shaving facilities at the earliest possible date. He also stated that BC Gas has not considered the impact of future changes in the gas industry on the risks of the SCP to BC Gas rate payers.

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3 In determining the PNW demand for its May, 1997 IRP Update, BC Gas included forecast demand for Washington Water Power, Washington Natural Gas (now Puget Sound Energy), Northwest Natural Gas, Centra, Cascade Natural Gas, as well as BC Gas own demand (Exhibit 1, App. II, p. 2; Exhibit 2A, IR. 5.6). However, ANG's witness, Dr. Oechsler, tended to treat PNW demand and BC Gas demand as separate items.

BC Gas reviewed the PNW supply-demand balance in argument. BC Gas began its analysis by showing the current and potential peak day capability of the British Columbia and PNW infrastructure without construction of the SCP or any other resource alternatives reviewed in the hearing. BC Gas then reviewed the PNW peak day demand and deliverability to argue that a deliverability shortfall currently exists and will, following an initial decrease, grow over time (Argument, pp. 7-21). Figure 4-1 sets out the BC Gas view of the PNW deliverability shortfall in terms of present demand off the Westcoast system for BC Gas, Centra, Pacific Northern Gas Ltd. ("PNG"), and 881 MMcfd to NWP, plus growth in the PNW, including British Columbia.

BC Gas projected growth in NWP demand at Sumas by taking the current demand off of the NWP system north of the Columbia Gorge of 1881 MMcfd and increasing it by 1.87 percent per year which NWP witnesses had given as the expected peak demand growth over the next five years (Argument, p. 14). This growth plus the British Columbia demand growth was added to the NWP demand at Sumas of 881 MMcfd. Thus, the analysis assumes that the growth rate for the next 13 years will be the same as for the first five years and assumes that all of the growth will be met by NWP from gas imported at Sumas. Perhaps more importantly, the 1.87 percent NWP growth rate is derived from all utilities served by NWP including those such as Southwestern Gas Corporation serving Arizona, Nevada and California, and Intermountain Gas Company serving Southern Idaho (Exhibit 4C, App. B and D). It is unlikely that either of these utilities will have an impact on the growth rate at Sumas. BC Gas also included the current gas demand of PNG, although it did not include PNG demand in its earlier PNW analysis, and had previously stated that it did not believe that gas demands by LDCs such as Intermountain Gas and PNG were relevant [Exhibit 2A, IR 5.6(ii)].

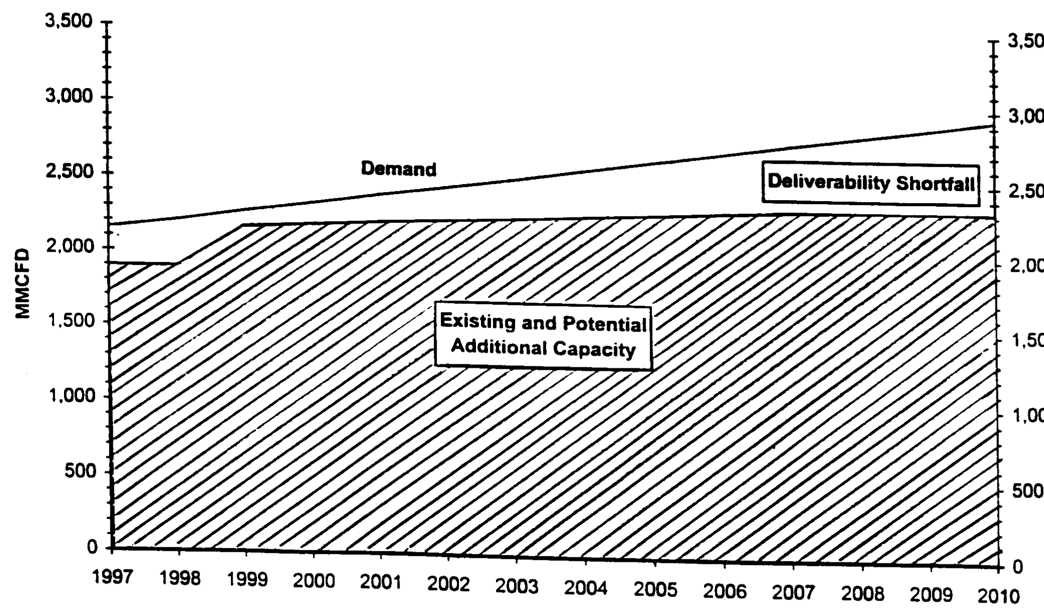
The next step in BC Gas' analysis is a discussion of the potential additional capacity available, limited to that "...which has been discussed in the hearing (JPS, Mist and 50 MMcfd of Columbia Gorge expansion)." Finally, BC Gas merged its analyses of the peak demand and the existing and potential additional capacity to derive two estimates of a deliverability shortfall, the first based on an assumption of 881 MMcfd of NWP demand at Sumas, and the second based on an assumption of 1,066 MMcfd demand at Sumas. Both estimates show a current deliverability deficit which grows over time.

ANG replied in argument that it disagrees with the BC Gas assessment, that it was unclear whether the deficiency was located "...in the Interior, at Huntingdon, or in the Pacific Northwest, as a whole.", and that it was difficult to interpret or discern the meaning of the assessment without it having been tested as evidence (pp. 20-21). Westcoast and the Consumers Association of Canada (B.C. Branch) et al. ("CAC (B.C.) et al.") also argued that the material should have been included in BC Gas' IRP May Update and subjected to testing during the hearing.

Figure 4-1

BC Gas Perspective on PNW Deliverability Shortfall

Peak Day Demand off WEI System for BC Gas, Centra, PNG, 881 MMcfd for NWP; plus Demand Growth in PNW, including British Columbia



Source: BC Gas Argument, Chart 4, p. 19

Materials originally filed by BC Gas.

Westcoast also disputes BC Gas' analysis and argued that numerous resource alternatives had been discussed in the hearing in addition to those included by BC Gas in its argument (WEI Argument, p. 52).

The Association for the Advancement of Sustainable Energy Policy ("AASEP") in argument (p. 3) quoted BC Gas' IRP which suggests additional resources are required *within the next five years* (AASEP emphasis), and argued that the Utility had not demonstrated an urgent need to build infrastructure based on core market demand (p. 11). AASEP went on to argue that the combined effects of DSM and other peak shaving resources could allow the Utility to postpone the need for infrastructure for five years (p. 22).

CAC (B.C.) et al. argued (pp. 4-5) that the BC Gas analysis leads to the following inescapable conclusions:

- LDCs in the PNW must also be seeking ways to meet their future gas needs and will wish to obtain contractual commitments for the required resources;

- If BC Gas is unable to obtain contractual commitments for the SCP, it must be because other shippers are making other contractual commitments leading to the development of infrastructure based on those commitments; and

- In non-peak periods, there is likely to be excess pipeline capacity, limiting the value of any pipeline capacity not pre-contracted, such as the SCP capacity assumed by BC Gas to generate third-party revenues for the Utility.

BC Gas in its Reply Submission argues that Dr. Oechsler's analysis understates the provincial demand for natural gas because it omits the demand of PNG and Centra (p. 5). However, BC Gas itself had earlier dismissed the demand of PNG in its regional demand analysis as irrelevant. Centra's forecast demand ranges from 83 TJ/d in 1995 to 126-141 TJ/d in 2010 (Exhibit 2A, IR 5.6), which represents a potential understatement by Dr. Oechsler of some 10 percent of the total demand at Sumas.

PGT agrees that additional resources are required to meet the peak day requirements of BC Gas, but argues that while the forecasted growth in non-core gas requirements appears large, it is highly uncertain (Argument, p. 4). PGT concludes that, with the development of new storage in the PNW plus a 3 Bcf LNG plant, BC Gas would have sufficient peak day resources to meet core market growth through at least 2015. PGT also provided analysis to argue that BC Gas has sufficient baseload pipeline capacity to meet average core and non-core market requirements until sometime past 2015.

BC Gas concludes that the peak day demand in the region in 1997 exceeds the supply available from the existing infrastructure by approximately 250 MMcfd, and concludes that a new infrastructure resource is required now (Argument, p. 14). The numbers that BC Gas uses in the analysis were discussed generally in the hearing, but the consolidated analysis and the conclusions drawn were not tested. For example, the peaking role of the line pack in the Northwest and Westcoast systems was not explored to any extent. Northwest provides its customers a 5 percent balancing tolerance (T19: 3403), which on deliveries of 1881 MMcfd in the Washington State, Oregon and British Columbia area (T19: 3346) indicates that shippers on Northwest can receive almost 100 MMcfd more than they deliver to the system.

Moreover, the evidence in the proceeding does not demonstrate that other players in the regional gas market believe that conditions are as critical as described in the written evidence of BC Gas Panel 1 (Exhibit 1A, p. 7).

Prices at Sumas in the winter of 1996/97 moved more or less in unison with those further south (Exhibits 25, 27). Moreover, for 1997/98 BC Gas contracted 111 TJ/d of seasonal and peaking supply at Huntingdon, which is more than the amount of 88 TJ/d that it expected to contract and the maximum availability of 70 TJ/d that it included in the Reference case ROM assumptions (T9: 1431; Exhibit 2D, IRs 4.1, 4.2; Exhibit 1, App. II, p. 47).

Commission Conclusion

In view of this contradictory evidence, the Commission is not persuaded that a significant resource deficit exists at this time. Moreover, the Commission observes that the evidence of BC Gas indicates that, with expansions at JPS, Mist and the Columbia Gorge, the regional balance of supply and demand will improve after 1998. Figure 4-1 indicates that, relative to the situation in 1997 and 1998, the apparent deliverability shortfall will become smaller until after 2002/03.

The Commission agrees that the BC Gas forecast of peak day firm demand over the next 10 to 15 year period is reasonable. The Commission also agrees with BC Gas that it is important to look outside its franchise territory to examine the demand-resource balance of the PNW region, insofar as it affects BC Gas' service area.

However, evaluation of the resources required to ensure deliverability of the forecast peak day gas needs is more problematic, and the Commission believes BC Gas' analysis tends to overstate the resource deficit at the Sumas hub in the early years.

The Commission notes that, in its May, 1997 IRP Update BC Gas concludes that the document showed "... a need for additional resource acquisition and replacement within the next five years..." to restore the demand-resource balance in its service area. The Commission concurs with this conclusion that additional supply resources will be needed in the 2002 to 2003 time period. Because of the lead times required for permitting and approval, the Commission recognizes that there is a clear need for BC Gas to move ahead on new resource infrastructure without prolonged delay.

5.0 THE RESOURCE OPTIMIZATION MODEL

5.1 ROM Origin and Objective

As indicated in section 3.2, the ROM is an enhanced version of the resource optimization model used in earlier IRP studies. BC Gas states that the ROM analysis was used in the current Application, to quantify gas cost impacts on the assumption that a major infrastructure addition, such as the SCP, does not affect the dynamics of the natural gas market. BC Gas adds that significant changes in the market environment, such as electricity deregulation, construction of an Alliance Pipeline, facility failure and non-core market demands will have a greater impact on future core market gas costs than will the variations in gas price or toll assumptions contained in the ROM analysis. In particular, the competitive benefits that come with the addition of alternative supply sources are not included in the ROM-only analysis (Exhibit 1B, p. 1).

BC Gas used its ROM to develop the lowest burner-tip rates for each of the alternative scenarios selected for analysis and then compared these on a quantitative NPV basis, assuming "a static market environment". BC Gas describes this as an environment where the relative cost of inputs (commodity, pipeline and storage) remain unchanged by changes to transmission and storage infrastructure, and major disruptions to supply do not occur in the future (Exhibit 1A, Panel 1 written evidence, p. 12). In the ROM analysis, the specific attributes implicitly examined for each scenario are:

- Peak Day Supply: The need to meet the peak day supply requirement (the coldest day) in the last 20 years.
- Seasonal Supply: The need to ensure that sufficient gas supplies will be available on a seasonal basis.
- Third Party Revenue: The extent to which a scenario provides off-peak or additional capacity that would have value to non-core users, either on-system users or others.
- Reinforcement Benefits: The extent to which a supply option can reduce the expected future costs of reinforcement of the BC Gas system.

BC Gas further states that in the recent IRP analysis it became evident that the simplifying assumption that a resource addition for British Columbia consumers will not affect, or be affected by, the external market environment is too narrow a view. It believes that a "dynamic" market reaction would result from a resource addition that materially alters the ability of BC Gas to access alternate gas supplies, storage facilities and pipelines (Exhibit 1A, Panel 1 written evidence, p. 11). BC Gas then identifies and quantifies in NPV savings what it describes as four significant non-ROM or "dynamic" benefits in the form of "Market and Operational Benefits" and four additional benefits that are specific to the SCP

(Exhibit 1B, pp. 10, 11). These “dynamic” benefits claimed for the SCP are described and discussed in Chapter 10.

5.2 Operation of the ROM

BC Gas' ROM is a two stage linear programming ("LP") model which the Utility uses to rank portfolios of supply, pipeline and storage resources in terms of their ability to meet forecast core market demand at the lowest NPV of gas resource costs over the study period.

Varying weather patterns can produce very different demand requirements on a daily, monthly or yearly basis and the ROM must optimize the total resource cost while meeting peak and annual demands under the different potential weather conditions. To do this, the ROM optimizes each portfolio of resources against five different load profiles based on the probabilities of occurrence of each load profile. The load profiles range from a design weather year which will result in the highest peak day demand to a very warm weather load pattern.

The Utility considers gas supply for its four service areas to be an integrated system requirement (Exhibit 1, App. II, p. 39). The same resource can be used to supply the Interior service area one day, and be delivered to the Lower Mainland on the next (presuming that sufficient Westcoast service and flexibility is available). Consequently, the ROM analysis typically treats the core market demand requirements of its entire service area as a whole.

For system capacity, each service area is independent and each transmission pipeline must be hydraulically capable of handling the design peak load. According to BC Gas, a major benefit of the SCP is a significant reduction in the cost of reinforcing the ITS (Exhibit 2D, IR 6.7; Exhibit 3D, IR 13.3). Similarly, LNG could provide some benefits to the Coastal Transmission system. As discussed in section 7.2, the ROM includes some cost adjustments to recognize benefits to its transportation system associated with specific alternatives. (Other potential benefits to the BC Gas transmission system, not considered in the ROM, are discussed in section 10.8.)

The ROM compares the costs associated with various resources, summing the fixed cost of each resource plus the variable cost of serving a particular load profile times the probability of that load profile occurring. Different resources will have different amounts of fixed or variable costs and different contractual or operational requirements, all of which must be considered in the ROM analysis. The assumptions used by BC Gas regarding the availability, costs and benefits of various resources are discussed in Chapters 6, 7, and 8.

The ROM employs two separate stages because of the difficulties in optimizing for resources such as the Southern Crossing Project or LNG facilities which involve large initial capital investments. The first stage uses the LP algorithm to minimize the expected annual costs of serving the load profiles of the firm core market load, while at the same time recognizing any lost interruptible revenues and satisfying all known and expected constraints on resource availability. For analyzing a portfolio such as the SCP plus WEI/NWP, it performs four sets of optimizations representing the various ways in which the resources can be combined with the Default portfolio: Default portfolio alone, Default portfolio plus SCP, Default portfolio plus WEI/NWP, and Default portfolio plus the SCP and WEI/NWP. A separate optimization is performed for each of the four combinations for each year of the analysis (Exhibit 2D, IR 3.6). The ROM analysis was only run for the first 20 years of the 30-year study period; beyond 20 years the results are trended to extend the analysis to 30 years (Exhibit 2D, IR 3.8).

The second stage of the ROM uses the first stage results to resolve staging or timing questions associated with resources requiring a large initial capital outlay. Such investments are included as resources in the ROM at the earliest opportunity and delayed or advanced incrementally to determine the optimal amount and timing of large "lumpy" investments to achieve the overall lowest NPV of the costs of supplying the anticipated demand profiles. The ROM analyzes all possible combinations of in-service year for each available resource and, for each combination, calculates the present value of the optimized gas supply costs and the present value of the cost of service and sums these to determine the NPV of all future costs. The second stage of the ROM limits the potentially large set of possible combinations by performing a sequence of steps to either locate a lower cost solution or eliminate a large subset of options from further consideration (Exhibit 2D, IR 3.6).

5.3 Default Portfolio

BC Gas uses the ROM analysis to evaluate several portfolios consisting of a number of specific gas supply resources. As a basis against which it measured the costs (and savings) of all other portfolios, the Utility created a Default portfolio based on "...the output of the first stage ROM results where no incremental resources are available." (Exhibit 3D, IR 9.1). Thus the Default portfolio assumes a continuation of the status quo by meeting growth through contracting for additional increments of WEI pipeline and gathering and processing resources, although it does not represent a WEI expansion alternative (Exhibit 1, App. II, pp. 59-61; T5: 872). The Default portfolio is comprised of the following resources:

- all existing storage, except Jackson Prairie Storage ("JPS");
- no new storage;
- 625 TJ/d additional baseload gas; and
- WEI expansion.

BC Gas agreed that the Default portfolio is a "straw man" which the Utility would likely never implement, and that if a different portfolio is used as the benchmark the relative savings would change although the rank ordering would not (Exhibit 3D, IR 9.1; T8: 1421). In other words, the use of the Default portfolio is somewhat arbitrary, however it provides a convenient base from which to compare all other alternatives.

5.4 Alternative Resource Portfolios

For the development of the portfolios, BC Gas made nine different supply-side resources and DSM available to its ROM, as follows:

- British Columbia Basegas Supply;
- Seasonal and Peaking Supply (NWP, WEI or SCP);
- U.S. Storage/Supply via NWP;
- U.S. Storage/Supply via SCP;
- British Columbia Storage/Supply via WEI;
- Alberta Storage/Supply via WEI;
- Alberta Storage/Supply via SCP;
- Pipeline Capacity (WEI, NWP, or SCP);
- Lower Mainland LNG; and
- DSM.

For these resources, the ROM determines optimal levels, mixes and scheduling of resources and yields nine portfolios for comparison with the base-case Default portfolio (Exhibit 1, App. II, p. 60):

- WEI expansion;
- NWP Expansion;
- 2 Bcf LNG plus additional pipeline resources on either NWP or Westcoast;
- 3 Bcf LNG plus pipeline resources;
- SCP plus pipeline resources;
- Expanded SCP;
- SCP plus 2 Bcf LNG;
- SCP plus 3 Bcf LNG; and
- DSM portfolio.

This analysis indicates that all of the nine other portfolios provide higher NPV savings than the Default portfolio. Moreover, in all cases, a 3 Bcf LNG plant provides greater savings than a 2 Bcf plant. Consequently, subsequent portfolios containing LNG are based on a 3 Bcf plant.

The remaining portfolios, except the "Aggressive DSM" which is considered slightly differently, are evaluated by subtracting the gas costs for each portfolio from the gas costs of the Default portfolio over the 30-year study period and summing the NPV of the differences. The Aggressive DSM program is analyzed by comparing all of the other portfolios (including the Default portfolio) with DSM to the same portfolios without DSM. The principal characteristics of each of the portfolios, based on information found in the May, 1997 IRP Update, is listed in the following Table 5-1.

Table 5-1

Portfolio Characteristics

No.	Portfolio Name	Existing Production and Storage	New Storage Operations	New Supply Options	Multiple Pipeline Expansions
1	WEI Expansion	ext. exist'g storage past expiry (except JPS)	add cost-effective BC storage and base level of Alta. storage	add'l base load and new Alta supply	exp'n of WEI (BC) and Gordondale pipelines
2	NWP Expansion	same as for WEI exp'n	200 TJ/d of add'l U.S. storage or supply	200 TJ/d of add'l U.S. storage or supply	NWP exp; add'l NWP cap. req'd; WEI exp req'd in long-term
3	3 Bcf LNG plus additional WEI or NWP pipeline resources	reduce basegas contracted supply	add 3 Bcf LNG in 2001	contract max cost-effective incremental baseload storage	exp. of either WEI or NWP or both req'd (but less than for 2 Bcf plant)
4	SCP plus additional WEI or NWP pipeline resources		contract all available baseload storage	(a) 200 TJ/d U.S. storage/ supply req'd 1st year (b) 90 to 180 TJ/d req'd at WEI system at Kingsvale	bring SCP on-stream in 2000
5	Expanded SCP		reduced need for baseload storage		WEI exp from Kingsvale to L. M. No NWP exp. required
6	SCP + 3 Bcf LNG	incremental baseload storage if available	3 Bcf LNG in 2001	200 TJ/d US store/supply in 1st yr	SCP in 2000
7	Aggressive DSM		8 TJ pk. day reduction/yr, cumulative. "with DSM" cases incl all cases, include default case	aggressive DSM does not delay need for other supply options	

5.5 General Comments on the ROM

The ROM is a useful tool for evaluating a wide range of potential supply options but, at the same time, its limitations must be recognized. In its evidence, BC Gas set out both the benefits and limitations of the model (Exhibit 2D, response 3.5). Among its strengths is the ability of the ROM to minimize gas costs over a range of weather patterns, to model the fixed and variable cost interaction of storage and supply resources, to accommodate various price "offsets" specific to BC Gas, and to account for complex interactions among supplies, storage, curtailment and variable load demands. The ROM's limitations include its treatment of BC Gas as a "price taker"; its non-recognition of regional (i.e., PNW) supply/demand interactions both outside of the BC Gas service area and those resulting from non-core requirements within the BC Gas service area; its potential requirement for several iterations of the model to obtain an optimal supply mix in some situations, and its computational complexity requiring a long development and testing period.

A number of intervenors expressed specific concerns about the operation of the ROM model. Of concern to several intervenors is the fact that the ROM treats the capital costs of new BC Gas resources differently from the fixed and variable costs of existing resources and expansions to existing pipeline facilities. BC Gas explained that while the ROM treats large capital investments differently (i.e., in a second stage optimization), those capital investments are fully considered in the ROM (Exhibit 1, App. II, p. 37; Exhibit 2D, IR 3.6; Exhibit 3D, IRs 9.1 and 9.2; T2: 239-240, T8: 1318-1320).

A further concern expressed by intervenors relates to the ROM's lack of transparency. As a proprietary model which BC Gas cannot or will not share, the ROM is unavailable to the Commission or intervenors for independent verification of model results [Exhibit 2L, IR 28(h)]. Several intervenors argued that the ROM is a "black box", and that ROM inputs or results cannot be independently tested or verified by the Commission or other intervenors [AASEP Argument, pp. 22-23; CAC (B.C.) et al., p. 11; WEI, p. 24]. The lack of transparency of the ROM model was discussed by a witness for AASEP (T9: 1562-63) regarding the potential for peaking supply from U.S. industrial consumers, and his inability to determine what specific peaking or seasonal resources were included in the ROM. AASEP noted that utilities such as West Kootenay Power Ltd. use resource optimization models that intervenors can examine and use to test results and submits that, in future, the Commission should request that utility CPCN Applicants provide the same level of verification for their supporting models (AASEP Argument, p. 23). CAC (B.C.) et al. suggested that, to the extent that BC Gas relies on a "black box" model to support its application, it should bear a heavier onus of proof [CAC (B.C.) et al. Argument, p. 12].

Northwest Pacific Energy Marketing Inc. ("NORPAC") stated that the ROM is seriously flawed in that it does not necessarily reflect either "...the legal and practical constraints that BC Gas is under with respect to its existing resources or the actual resource options available to BC Gas" (Argument, pp. 5-6). In NORPAC's view, since the resource portfolios used in the ROM are flawed, the results must also be flawed. BC Gas disputed NORPAC's claim, stating that the resources available to the ROM are resources that could be available to it, even if not necessarily through an existing contract. BC Gas supported its position by quoting its May, 1997 IRP Update regarding Aitken Creek storage: "The cost structure and unit costs of the existing Aitken Creek storage are used as a proxy for generic new British Columbia storage" (BC Gas Reply, p. 62).

Commission Conclusions

The Commission shares many of the reservations of the intervenors concerning the operation of BC Gas' ROM model. For any future CPCN applications, the Commission expects BC Gas to use a model which can be independently verified by intervenors and the Commission.

The Commission concludes that, in this instance, though the model is cumbersome and less than ideal, it does provide directional guidance. This does not mean that the Commission believes the ROM should be depended upon to definitively rank portfolios where differences in NPV savings are small – in several cases as little as 1 percent and rarely more than 10 percent. Instead the Commission believes that the ROM output must be used as a guide to the application of judgment which takes into account the intangible issues not quantified in the model itself.

6.0 ROM ASSUMPTIONS: DEMAND AND PRICE FORECASTS

6.1 Natural Gas Demand and Demand-Side Management

6.1.1 ROM Treatment of Customer Demand Projections

The ROM is used to analyze BC Gas options for serving its core market demand, and uses as inputs daily firm and interruptible loads. An objective of the ROM is to meet the firm demand of the core market under all possible weather conditions. In a warm year, all firm load plus some or all interruptible load would be served throughout the year. Under a design weather year condition, the available resources should be sufficient to serve all of the available core market firm load at all times and the firm or interruptible load of other customers throughout most of the year.

6.1.2 IRP Treatment of DSM

Demand-Side Management ("DSM") represents a broad range of initiatives which can affect customer demands and usage patterns. BC Gas did not specifically include DSM as a potential resource available to the ROM. Instead, in the Reference case analyses, BC Gas assumes peak day demand reductions, based on current DSM programs, of 2 TJ/d per year. For its "Aggressive DSM" analysis, BC Gas assumes 8 TJ/d per year of peak day demand reductions beginning in 1999. The DSM reductions are assumed to be cumulative, leading to a demand reduction of 147 TJ/d in 2016 (Exhibit 1, App. II, pp. 43, 70).

The results of the Aggressive DSM sensitivity show that the NPV benefits of all portfolios decrease relative to the Default portfolio. The ranking of the portfolios is only slightly changed, with the SCP plus WEI/NWP expansion replacing the SCP plus Phase 2 portfolio as the third ranked portfolio. BC Gas indicated that the Aggressive DSM analysis shows no reduction or delay in the requirement for the SCP or LNG resources, but that it would result in lower utilization of northern British Columbia storage, Clay Basin storage, and 365 day basegas (Exhibit 1, App. II, pp. 70, 79).

AASEP argued that BC Gas has not conducted any analysis to arrive at 8 TJ/d as a reasonable level of demand savings to include in the aggressive DSM portfolio (Argument, p. 20). BC Gas replied that it used its experience and information regarding DSM along with a previous conservation study ("Marbek study") to establish the "aggressive DSM" savings as an appropriate upper bound for achievable DSM savings (BC Gas Reply, p. 13). An AASEP witness conceded that the Marbek study was a "...very competent and thorough study...", but went on to say that the Marbek study did not include some potential DSM measures (T9: 1584-1585). AASEP estimated that 16 TJ of DSM savings are achievable after five years, but BC Gas argued that reductions of that magnitude will not replace the need for new resource infrastructure.

AASEP further argued that BC Gas did not integrate its supply and demand-side analysis as directed by the Commission in its July 2, 1996 Decision regarding BC Gas' 1995 IRP and that BC Gas' entire treatment of DSM is mishandled (AASEP Final Argument, pp. 8, 19). Both CAC (B.C.) et al. as well as AASEP noted that BC Gas did not analyze DSM in the ROM on the same basis as a pipeline or an LNG facility, and AASEP added that equal consideration of DSM and supply-side resources was not an objective in the 1997 IRP Update [AASEP Argument, pp. 8, 23; CAC (B.C.) et al. Argument, p. 39].

AASEP also argued that there is no reason why BC Gas could not have included a proper DSM portfolio in its IRP for comparison to supply-side resources (AASEP Argument, p. 22). Although the ROM is able to quantify avoided costs to aid in DSM program analysis (Exhibit 2D, IR 3.5), AASEP noted that avoided gas cost savings are not found in the IRP analysis, thus missing the NPV savings associated with avoided gas costs (AASEP Argument, p. 23). AASEP also argued that BC Gas, by not including savings from its current DSM programs, understates the demand reductions available from DSM (AASEP Final Argument, p. 19). AASEP stated that DSM provides such benefits at an average cost, less than the BC Gas' current system avoided cost of $5.71/GJ, even without considering the avoided cost of any new peaking resource or any environmental cost.

Finally, AASEP argued that BC Gas has not given adequate consideration to the potential for peak-sharing[4] arrangements and that BC Gas should have analyzed the potential British Columbia thermal generation peaking supply as resources in its ROM analysis rather than simply as sensitivities on demand (AASEP Argument, pp. 13, 16). In AASEP's view, BC Gas clearly intended to demonstrate that an infrastructure addition could not be delayed, which led it to overlook the possibility that DSM could be combined with other *non-infrastructure alternatives* (AASEP emphasis) to delay the need for infrastructure (AASEP Argument, p. 20).

BC Gas conceded that the NPV savings associated with avoided gas costs are not found in the IRP analysis, but replied that the relative rankings of the various portfolios are not affected since the gas supply savings would accrue equally to the NPV's of all the portfolios evaluated (BC Gas Reply, p. 12). BC Gas argued that it assumed all DSM is available at zero cost (i.e., it all passed the Ratepayer Impact Measure ("RIM") test that measures the impact of DSM programs on non-participating rate-payers) which

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4 'Peak sharing' is often used to refer to the purchase of gas from a gas consumer for use by the utility during its peak period. Peak shaving resources are dedicated to trimming the utility peak loads by alternate gas supply, shifting to alternate fuels or curtailing peak loads.

is a "generous" assumption since all of BC Gas' current efficiency programs fail the RIM test (BC Gas Reply, p. 12).

Commission Conclusion

While the Commission accepts many of AASEP's arguments it believes that, for purposes of the ROM model only, the simplifying assumptions with respect to DSM, when taken together with the maximum 8 TJ/d per year sensitivity test, deal adequately with this resource for modeling purposes.

6.1.3 Industrial Customer Curtailment

In its ROM analyses, BC Gas includes 26 TJ/d of transportation service curtailment (September, 1997 IRP Update, App. C). AASEP suggested that potentially 80 TJ of peaking capacity is available to BC Gas from the voluntary interruption of industrial customers outside of the BC Gas service area (e.g., Tenaska, Intalco, and refineries at Cherry Point). Prices for such peaking supply are estimated by the AASEP witness to be in the range of $5.51/Mcf to $6.38/Mcf if used for a full 12 days (Exhibit 8B, Evidence of J. Lazar, pp. 6-8 and attached Exhibit JL-2, p. 7; T9: 1571). BC Gas indicated that whether it would be interested in such supplies in the future depends on the circumstances at the time, but that such sources of supply had been purchased and consumed by diversion in the Lower Mainland in the winter of 1996/97 during peak periods (T8: 1417).

AASEP also suggested that even more attractive resources could be made available in British Columbia through a "pre-emption" provision in its tariffs, similar to that in the tariffs of Northwest Natural Gas, which allows the utility to divert gas delivered to the utility by a transportation customer's supplier in exchange for a price of about $20/GJ (Exhibit 8B, Evidence of J. Lazar, p. 8). AASEP acknowledged that BC Gas currently has the right under rate schedule 22A to interrupt up to one half of an industrial customer's daily transportation quantity for five days per year, and suggested that this implied that there could be a price at which more than one-half could be interrupted (T9: 1595). Council of Forest Industries ("COFI") and Cominco Ltd. ("Cominco") are not opposed to voluntary purchases of short-term peaking supply from willing industrial customers, and noted the provisions under schedule 22A, but strongly oppose any options that involve the involuntary diversion of firm supply (COFI/Cominco Argument, pp. 4-5).

Commission Conclusions

BC Gas may have underestimated the potential for industrial curtailment. However, the Commission is prepared to accept the amount of curtailment that BC Gas included for the purposes of the ROM analysis.

6.1.4 Level of Interruptible and Off-System Sales

BC Gas tested the Reference case results against increased levels of Off-System Sales and Interruptible load. In both cases, the NPV benefits increase relative to the Reference case, but the ranking of the portfolios do not materially change. With increased interruptible load, the SCP plus Phase 2 SCP portfolio falls to fourth place in the rankings to be replaced by the SCP plus WEI/NWP portfolio (Exhibit 1, App. II, App. B).

6.2 Gas Price Forecasts and Gas Storage Resource Costs

6.2.1 Gas Price Forecasts

The ROM uses a fieldgate price of gas as its input and, in the May, 1997 IRP Update (section 5.3), BC Gas explained that its long range fieldgate price forecasts are based on BC Gas' actual 1995 firm load supplier price escalated according to yearly growth in the CanWest Gas Supply Inc. ("CanWest") aggregator field price. The BC Gas firm baseload supplier price at the fieldgate which forms the basis of the reference price forecast was $1.50/GJ in 1995 at a 100 percent load factor (Exhibit 3D, IR 2). The reference forecasts of the CanWest field price were developed by ARC Financial Corporation ("ARC") and Gilbert Laustenson Jung ("GLJ"). The ROM assumes the price of basegas delivered at Huntingdon would be the same as the price of basegas delivered to Yahk (Exhibit 3D, IR 3.4).

Monthly fieldgate prices are derived from the annual forecasts by setting the November through March price at 115 percent of the annual price and the April through October price at 89 percent of the annual price (Exhibit 1, App. II, p. 44). The plantgate price is derived by adding the Westcoast gathering and processing tolls to the fieldgate price (Exhibit 3D, IR 3.4)

For its September, 1997 IRP Update, BC Gas updated its gas price assumptions based on more recent ARC and GLJ forecasts (Exhibit 1B, p. 3). The more recent ARC forecasts used in the September Update are plantgate price forecasts, so that BC Gas derived the fieldgate forecast by deducting gathering and processing costs, also using a forecast provided by ARC (Exhibit 1B, App. A; T6: 1031).

The Reference case fieldgate gas price forecasts used in both the May and September IRP Updates show significant price increases for 2001 and 2002, decline slightly through 2006 and then increase gradually (Exhibit, 1, App. II, p. 44; Exhibit 1B, App. A). BC Gas also filed information about forward market prices at Sumas for 2000/01 and 2001/02, but noted that these are subject to market changes (Exhibit 3D, IR 5.3)

There was little debate about the gas price forecasts specifically; however a Westcoast witness indicated some concern with the way in which the prices were entered into the ROM:

> "The only concern that we have about the forecast of gas commodity prices is explained in the evidence and it has to do with the treatment of our GNP tolls and the use of field gate versus plant gate, which we believe has resulted in the ROM runs associated with Westcoast capacity with loading our gathering and processing tolls in as a fixed cost as opposed to a variable cost, thereby increasing the total cost of the portfolio" (T12: 2071).

There was also considerable debate about relative Sumas vs Alberta prices both on and off-peak. However, this debate took place mainly in the context of the additional (non-ROM) benefits of the SCP, and is discussed in section 10.4.

6.2.2 Gas Storage Resource Costs

Two types of natural gas storage resources are commonly used: LNG storage and underground storage. Each tends to be used in a different way with LNG being more useful in serving needle peaks and underground storage more useful for seasonal peaks (T14: 2506).

Initially, BC Gas used generic LNG storage costs for a plant somewhere in its service area (Exhibit 2D, supplemental IRs, IR 3.1). In the September IRP Update, BC Gas uses the specific costs of four distinct LNG proposals, the characteristics of which are summarized in the table below. A currency exchange rate of U.S. $0.74/Cdn $1.00 has been applied.

Table 6-1

Proponent	**LNG Location**	**Size**	**Liquefaction Capacity**	**Capital Cost** ($ millions)
BC Gas	B.C. Lower Mainland	3 Bcf	12 MMcfd	$139
PGT	Cherry Point, Washington	3 Bcf	8-12 MMcfd	$124*
WGSI	McNab Creek, near Port Mellon, B.C.	3 Bcf	16 MMcfd	$120
WIPL	Sumas, Washington	3 Bcf	12-16 MMcfd	$121

* The PGT facility would require an additional capital expenditure estimated at $26 million for a pipeline to Livingston on the BC Gas system. Other LNG facilities may require additional capital costs or tolls related to delivery of gas to the BC Gas system

Sources:

BC Gas: Exhibit 4B; the capital cost used in the ROM from September IRP Update, p.4;
PGT: Exhibit 4D, Sept. 4, 1997 revision;

WGSI: Exhibit 4F; and
WIPL: Exhibit 4G; Exhibit 5E, IR BCUC-1.3; T15: 2610-11.

The cost of incremental British Columbia storage is based on BC Gas' current storage contract with Unocal Canada Limited ("Unocal") at Aitken Creek. The cost of storage accessed via the SCP and new storage accessed via a NWP expansion are based on current storage arrangements with Southern California Gas Company ("SoCal"). BC Gas is unwilling for reasons of commercial confidentiality to provide information on those costs, but did provide evidence to the Commission that Unocal and SoCal agree with the costs which BC Gas uses in its modeling. BC Gas provides the cost of new Alberta storage to be accessed through WEI (Exhibit 2D, supplemental IRs, IR 3.1). BC Gas does not consider the possibility of extending existing JPS storage contracts in its Reference case analyses although evidence in the hearing indicates that JPS storage could possibly be available and it would be compatible with the SCP (AASEP Argument, p. 16; T19: 3387-3389).

6.2.3 ROM Sensitivity to Peaking Supply from Thermal Generation Fuel Curtailment

BC Gas relied heavily on information from British Columbia Hydro and Power Authority's ("B.C. Hydro") 1995 Integrated Electricity Plan to estimate the potential for electric generating capacity (Exhibit 3A, IR 16.10). In the May, 1997 IRP Update, BC Gas analyzed the sensitivity of its ROM results to the addition of 40 or 100 MMcfd of peaking supply or of a combination of JPS renewal and cogeneration peaking (Exhibit 1, App. II, pp. 89-93). The analyses based on either 40 or 100 MMcfd of cogeneration peaking assumes that the cogeneration facilities would be able to provide up to 15 days curtailment supply during peak periods. The results indicate that all portfolios show increased net benefits with the additional peaking but that the portfolios which include new LNG show the smallest increase while the WEI/Gordondale expansion portfolio shows the greatest increase followed by the NWP expansion and the SCP plus WEI/NWP portfolio.

During the hearing, B.C. Hydro gave evidence on the potential natural gas demand related to cogeneration facilities on Vancouver Island, and for its Burrard Thermal Plant (Exhibits 14B, 14C). A B.C. Hydro witness indicated that one or both of the cogeneration facilities currently proposed for Vancouver Island would help it meet its system needs and that B.C. Hydro projects it could require such facilities by 2002 (T23: 4062-4064). Such facilities would require baseload gas supply for most of the year, but could potentially provide peaking supply to BC Gas.

B.C. Hydro states that it may arrange for 90 TJ/d of firm gas supply over 1999 to 2002 for the cogeneration facilities on Vancouver Island, and for up to 240 TJ/d of firm supply for Burrard Thermal Plant by 2001 (Exhibits 14B, 14C). Any peaking supply offered to BC Gas would be dependent on alternate arrangements for replacement electricity or electric system capacity. Such arrangements could include short-term energy purchases in electricity markets, dual fuel capability, advancement of hydroelectric capacity projects or the implementation of DSM (Exhibit 14C, p. 3).

B.C. Hydro expects the peaking supply that it could offer would be flexible, and would be less costly on a dollar per gigajoule basis than the alternatives considered in the hearing (T23: 4059-60). The supply would be available year-round and would include the ability to change delivery rates during the day. The company would be prepared to offer firm peaking supply under contracts with multi-year terms "if the price is right", but did not quantify the price that would be needed (T23: 4036, 4047). The Island Cogeneration Project at Elk Falls anticipates ten days per year of alternate fuel operation. Witnesses for B.C. Hydro state that economic, environmental and fuel supply considerations would need to be dealt with, but anticipate that further dispatchability could be negotiated (T23: 3945, 3948, 3985, 4059-60).

Commission Conclusions

The Commission notes that the two cogeneration projects under active consideration for Vancouver Island, with a total gas demand of approximately 90 TJ/d, may eventually be designed with alternative fuel facilities which would allow them to release most of their normal gas demand for peak-shaving use by the Utility. Such an event could have a significant impact on Lower Mainland peak shaving requirements, as well as for baseload gas supplies to serve the new facilities.

At the same time, changes contemplated for B.C. Hydro's Burrard Thermal Plant would require a major expansion of infrastructure to deliver the incremental volume of firm baseload gas to Huntingdon. It would also have a major impact on the gas distribution system in the Lower Mainland through the introduction of new facilities to deliver large volumes of firm gas to the plant. Nevertheless, providing B.C. Hydro is able to curtail its gas consumption on peak gas demand days, the facility could offer BC Gas an additional significant volume of peaking supply. Whether such an offer will be attractive to BC Gas will depend to a significant extent on the price and other terms of the peaking gas arrangement that B.C. Hydro may offer.

The Commission is concerned that it is currently being called upon to make an important decision vis a vis the SCP and/or competitive LNG proposals for the Lower Mainland, with the above-described major events pending. The Commission would have expected BC Gas to have aggressively pursued negotiations on this potential joint opportunity for the ratepayers of both utilities. Under these circumstances, the potential advantages of conservatism may well outweigh the gains from aggressive action on the decision before the Commission.

6.2.4 ROM Sensitivity to Jackson Prairie Storage Renewal

As noted in section 5.4, BC Gas assumed in its Reference case analyses that both of its existing JPS agreements will not be renewed when they expire in 2000 and 2001. However, the Utility also indicated that it was discussing the potential provision of up to 100 TJ/d at Sumas with two parties, and that it is continuing to explore the possible extension of the JPS agreements (Exhibit I, App. II, p. 77).

The Utility ran a sensitivity case assuming that either JPS would be renewed at the same cost and higher deliverability or that 100 TJ/d would be available at Sumas (in the latter case also assuming that some NWP expansion would be required). The results of this sensitivity case indicate that JPS or its equivalent replaced more costly sources of peaking and seasonal supply, thus increasing the NPV savings of all portfolios. Further, although the ordering of the portfolios is not greatly altered, the additional storage or peaking supply did show relatively greater benefits for the portfolios which include Westcoast or NWP expansion (Exhibit 1, App. II, p. 78).

In its September, 1997 IRP update, BC Gas provided two additional sensitivity analyses. The first included the following assumptions:

- 60 TJ/d of British Columbia and Alberta peaking supply (rather than 20 TJ/d);
- 80 TJ/d of British Columbia and Alberta seasonal supply (rather than 55 TJ/d); and
- maintaining JPS at its current availability of 80 TJ/d.

BC Gas cautioned that it does not anticipate the additional volumes of peaking and seasonal gas would be available without additional pipeline capacity.

The second sensitivity analysis includes the assumptions in the first analysis plus the further assumption that an additional 53 TJ/d of SoCal storage would be available (bringing the total amount to 106 TJ/d). For this analysis, BC Gas further cautioned that the ability to deliver supplies by diversion to Huntingdon is already constrained and could become more so without infrastructure additions (Exhibit 1B, pp. 13-14). BC Gas stated that it had been discussing potential gas supply arrangements with Duke Energy Trading and Marketing, L.L.C. ("Duke") and that it expected Duke might offer a supply of gas at Sumas broadly equivalent to increased supply from SoCal storage. The earliest date that the expansion capacity on Northwest would be available for making such supply available would be 1999 (T8: 1414-5).

The results of these sensitivity analyses indicate that as additional low cost winter supply is made available, the ranking of portfolios shifts to favour NWP/WEI expansion options, alone or in conjunction with either LNG or SCP.

6.3 ROM Sensitivity to Load Growth and Gas Burner-Tip Price Changes

Sensitivity analyses were carried out by BC Gas to determine the impact of higher or lower forecast load (Exhibit 1, App. II, pp. 74-5; T4: 692). Higher or lower load growth materially changes the absolute level of NPV savings, but does not significantly change the relative rankings of the various alternatives. The sole change to the portfolio rankings is that the SCP plus Westcoast/Northwest portfolio becomes more favourable than the SCP Phases 1 and 2 portfolio under conditions of low load growth.

The burner-tip price assumptions are based on the sum of the projections for fieldgate prices, pipeline tolls and BC Gas distribution margin. The sensitivity test reflects the price elasticity of demand, that is, changes in the core market load forecast which result from high and low burner-tip prices. The gas burner-tip price assumptions provided by BC Gas are summarized in the table below.

Table 6-2

Gas Burner Tip Price Assumptions ($/GJ)

	Residential			Commercial			Large Industrial		
Year	Low	Reference	High	Low	Reference	High	Low	Reference	High
1997	5.55	5.71	5.80	4.47	4.63	4.71	1.83	1.98	2.09
2001	7.15	7.58	7.64	5.72	6.15	6.21	2.39	2.85	2.86
2006	7.78	8.01	8.71	6.22	6.45	7.15	2.54	2.80	3.43
2011	8.55	8.81	9.54	6.85	7.12	7.84	2.81	3.12	3.77
2016	9.33	9.64	10.45	7.48	7.79	8.60	3.05	3.42	4.14
2021	10.18	10.54	11.45	8.17	8.53	9.44	3.32	3.74	4.55
2026	11.11	11.53	12.54	8.92	9.34	10.35	3.61	4.09	5.01

Source: Exhibit 2L, IR 1(d)

The foregoing burner-tip price assumptions are built up from the fieldgate price and toll pipeline forecasts in the May, 1997 IRP Update plus the projected distribution margin of BC Gas (Exhibit 1, App. II, p. 75). The significant increase from 1997 to 2001 reflects the increase in forecast fieldgate prices and pipeline tolls contained in the filing.

The results of the burner-tip price sensitivity cases indicate that the NPV savings are highest for the high burner-tip price case. However, the ranking of the portfolios remains unchanged (Exhibit 1, App. II, pp. 75-76).

7.0 ROM ASSUMPTIONS: PIPELINE TOLL FORECASTS AND COSTS

7.1 Transmission Toll Forecasts

As discussed in section 2.1, ANG's Kootenay Pacific Pipeline, NWP's Columbia River Gorge expansion, and expansion of the Westcoast Energy Inc. pipeline were all proposed as alternatives to the SCP. Two of these alternatives, NWP expansion and WEI expansion could either serve BC Gas markets in lieu of the SCP or occur in conjunction with it. Whether or not the expansion of each system occurs, the forecast tolls of the Westcoast, NWP and ANG pipelines are important ROM inputs in determining which resources will be selected by the ROM and hence in estimating the economic viability of the SCP.

7.1.1 Westcoast Pipeline Tolls

The Westcoast toll forecasts used in the ROM for the May 1997 IRP are a blended toll of gathering, processing and transportation escalated at an average 3.7 percent per year until 2002 and at 2 percent annually thereafter [Exhibit 2D, IR 3.3; Exhibit 2L, IR 20, 28(b)]. In the May, 1997 IRP, the toll forecast also assumes a 125 TJ/d expansion of Westcoast Transportation-South ("T-South") capacity in 2002, increasing the cost of service by $43.5 million and increasing the combined Westcoast Transportation-North ("T-North") and T-South tolls by 17 percent from 2001 to 2002 (May IRP Update, p. 45; Exhibit 2L, IR 20). This forecast was later tempered by subsequent evidence.

Westcoast supplied two transmission toll forecasts, a base case assuming no expansion and an expansion case assuming a phased 100 MMcfd expansion. The Westcoast forecast assumes that the base toll would escalate by 1.7 percent per year between 2001 and 2010. The expansion case toll would escalate by an average of approximately 2 percent per year over the same period (Exhibit 4E, pp. 16-17). Westcoast later supplied a toll forecast based on a 300 MMcfd expansion case which escalates at 3 percent per year between 2001 and 2016.

BC Gas updated the pipeline toll forecasts used in its September, 1997 IRP Update ROM analyses. The updated Westcoast toll forecasts are based on the later information provided by Westcoast (Exhibit 5C1, IRs 6 and 8) reflecting "...the impact of Westcoast's T-North and T-South forecast for a 300 MMcfd expansion" (Exhibit 1B, p. 3). However, Westcoast stated during the hearing that Westcoast does not believe that it needs to build 300 MMcfd, and that therefore the Westcoast tolls used by BC Gas are overstated (T12: 2028-29).

Kingsvale to Huntingdon Toll

In the ROM model, BC Gas assumes a $0.106/Mcf toll for transportation on the portion of T-South required to transport gas delivered to the Westcoast system at Kingsvale to the BC Gas system at Huntingdon (Exhibit 3I, IR 39; Exhibit 48, p. 1; T12: 2069). This assumes that the toll would be equivalent to the difference in the toll between the Interior and Lower Mainland zones on Westcoast (T5: 834). BC Gas also stated that, if it assumes a point-to-point toll based on demand distance, an increase in the NPV savings of $34 million would result (Exhibit 1A, Panel 1 written evidence, p. 23; Exhibit 3I, IR 39).

Westcoast argued that the point-to-point toll is understated and that as Kingsvale to Huntingdon service would strand upstream capacity on the Westcoast system, the full $0.26 T-South toll from Station 2 to Huntingdon is more appropriate. Westcoast also noted that if the toll for moving 85 MMcfd from Station 2 to Huntingdon is only two times the $0.106/Mcf assumed by BC Gas (i.e., $0.212/Mcf), the NPV of the ROM benefits of the SCP portfolios is reduced by $53 million (WEI Argument, p. 33).

Commission Conclusion

The Commission notes that the use of a toll based on a 300 MMcfd expansion increases the toll escalation to more than the 2 percent used in the May, 1997 IRP Update and that this change will tend to favour SCP.

With respect to the Kingsvale to Huntingdon toll, it is apparent to the Commission that future tolls to be charged on the T-South Westcoast pipeline segments, should the SCP be constructed, are likely to be controversial and will require a regulatory ruling. Nevertheless, the Commission accepts the toll forecast used by BC Gas in its ROM modeling assumptions as being satisfactory for this planning purpose, but notes that the issue of the Kingsvale to Huntingdon toll is revisited by BC Gas as a non-ROM benefit and is discussed further in section 10.7.

7.1.2 ROM Sensitivity to Westcoast Toll Variances

The analysis testing for sensitivity to higher Westcoast tolls is based on annual increases in gathering processing and transportation costs 0.5 percent higher than the May IRP Update Reference case after 2002 (i.e., a 2.5 percent annual growth rate). The low case sensitivity is based on tolls which are assumed to remain constant in nominal dollars until 2002 and then to increase at the rate of inflation (1.7 percent). The ranking of the portfolios does not change with different Westcoast toll assumptions, although the magnitude of the NPV savings increases with increased Westcoast tolls (relative to the Default portfolio) and decreases with lower Westcoast toll assumptions (Exhibit 1, App. II, pp. 76-77). Analysis done in response to a Westcoast information request assuming Westcoast tolls based on no expansion of facilities showed that the NWP expansion portfolio would replace the SCP plus Phase 2 portfolio as the fourth ranked portfolio but that otherwise the ordering of portfolios remained unchanged (Exhibit 19).

For the SCP portfolios, BC Gas assumes the use of the Westcoast T-South mainline from Kingsvale to Huntingdon and uses a toll of $0.106/Mcf (Exhibit 2L, IR 20). Westcoast requested a sensitivity run which included, among other changes to the Reference case inputs, the assumption that the toll for moving 85 MMcfd from Kingsvale to Huntingdon would be two times the rate assumed by BC Gas (i.e., $0.212/Mcf). That sensitivity run shows reduced NPV benefits for all scenarios except WEI/Gordondale expansion, but has the greatest negative impact on the SCP portfolios [Exhibit 19, Westcoast IR 89(e)].

7.1.3 Northwest Pipeline Tolls

Northwest indicates that the total transportation cost from Kingsgate to Sumas is similar whether BC Gas purchases gas supplies at Stanfield, obtains transportation capacity on PGT through existing capacity release options or obtains service on PGT through its proposed expansion (Exhibit 6D, IR 10.5).

The Northwest tolls that BC Gas used in the September IRP Update are reported in App. B of the Update. The rate for 1999 to 2003 is the rolled-in firm FT-1 rate of U.S. $0.2776/MMBtu filed by Northwest, plus applicable surcharges [Exhibit 6C, IR 5.2; Exhibit 6A, IR 4(c); T19: 3382-3383]. The toll number was converted to Cdn $0.367/GJ using a 0.74 currency exchange factor, and after 2003 was escalated at 2 percent per year (T6: 950).

In its August 15, 1997 Proposal, Northwest stated that it would charge the higher of the foregoing rolled-in rate, or the incremental cost of service of expansion facilities (Exhibit 4C, p. 13, T19: 3384). If the incremental rate becomes lower than the rolled-in rate, Northwest intends to continue to charge the incremental rate [Exhibit 6A, IRs 6(b) and 6(d)].

Duke committed to the first 50 MMcfd block of Columbia Gorge expansion capacity as part of a Northwest open season (T19: 3297, 3382). The project cost of an expansion from 50 to 400 MMcfd is U.S. $194.4 million in 1997 dollars, and the annual cost of service for the 350 MMcfd block of expansion is U.S. $42.6 million (Exhibit 120). The average incremental toll of U.S. $0.33/Mcf is equivalent to approximately Cdn $0.42/GJ in 2000, including surcharges.

The rolled-in Northwest toll of $0.367/GJ that BC Gas uses in the ROM understates the cost of Columbia Gorge expansion capacity in the early years. If the incremental Northwest toll were used in the ROM, it is likely to increase the NPV total cost to core consumers for the Northwest Expansion portfolio and the

LNG + WEI/NWP portfolio, which use more Northwest capacity than does the SCP + WEI/NWP portfolio.

Commission Conclusion

The Commission recognizes the possibility that incremental tolls will apply to BC Gas' future use of NWP capacity and that these will be higher than the rolled-in tolls assumed in the ROM model. However, the Commission recognizes that the impact of the incremental tolls will be small relative to the total portfolio NPV cost and will have little impact on NPV savings relative to the Default portfolio.

7.1.4 ANG Pipeline Tolls

BC Gas indicates that the SCP would facilitate the diversion of gas into the BC Gas system at Yahk from the ANG system without the obligation to contract for upstream commitments (Exhibit 1, p. 4). BC Gas also notes that the SCP requires ANG to expand the capacity of its East Kootenay flow control station to accommodate the SCP volumes, but expects that the cost of this would be nominal and would be rolled into ANG's tolls, consistent with the prevailing ANG toll methodology (Exhibit 1, p. 6).

For its ROM analysis, BC Gas escalated the existing ANG toll at 5 percent for 1998 and at 2 percent per year thereafter until the end of the study period in 2026 (Exhibit 1B, App. B). No party in the hearing took serious issue with BC Gas' forecast of ANG tolls.

7.2 Transmission System Avoided Reinforcement Costs

7.2.1 Interior Transmission System

In the September IRP Update, BC Gas includes a $46 million NPV credit for avoided ITS reinforcement costs when the SCP goes into service in 1999 (Exhibit 1B, p. D4). This credit reduces the total cost to core customers of these portfolios, and increases the NPV savings.

BC Gas forecasts the Interior Transmission System peak day design flows (for both firm sales and transportation customers) will increase from 272 MMcfd in 2000 to 421 MMcfd in 2026 (an average of 1.7 percent per year) [Exhibit 2D, IRs 6.1 and 6.7, Exhibit 2L, table 8(b)]. The cost of the additional pipeline loops and compression needed to reinforce the ITS through 2026, without and with the SCP, are as follows:

	Without SCP	With SCP	Difference
Capital Cost, millions 1996 $	163.7	75.4	88.3
30-year NPV Cost of Service, millions 1997 $	148.8	98.5	50.3

Source: Exhibit 2D, IR 6.7; Exhibit 1B, pp. F4 and F5

The credit that BC Gas uses in the ROM is the core market's 91 percent share of $50.3 million (T2: 201).

In 1994, BC Gas installed 32 km (20 miles) of 406 mm (16-inch) pipeline loop between Oliver and Penticton (Exhibit 1B, Panel 3 written evidence, p. 2). The SCP would require further looping from Penticton toward Kelowna. The cost of the further ITS looping is reflected in the foregoing comparison of costs, but is not included in the cost estimates for the SCP or the CPCN application. BC Gas indicates the following planned 508 mm (20-inch) looping would be needed:

Year	Description	Cost
2000	24 km, 508 mm	$29.1 million
2001	15 km, 508 mm	18.2 million
2008	13 km, 508 mm	15.8 million

Source: Exhibit 2D, IR 6.7(b).

This indicates that, even with the SCP, at least another $63 million will need to be invested in ITS reinforcement within the first few years.

Several scenarios which potentially could reduce the cost of ITS reinforcement were discussed in the hearing. Higher delivery pressures from Westcoast at Savona and Kingsvale would eliminate the need for additional BC Gas compression at these locations, and would defer the need for further ITS reinforcement until 2002 (T11: 1847; Exhibit 90, IR 15). Westcoast states it could provide BC Gas with firm delivery pressures that are higher than the 500 psig contract pressure, by making modifications to its compression facilities (Exhibit 116). Westcoast proposes that the price of this higher pressure be determined through negotiation between the parties, and notes that the charges would be subject to the approval of the NEB. In Argument, BC Gas states that it will make efforts to come to reasonable terms with Westcoast, but submits that the higher pressure may only be available under terms that are not economically attractive.

In a second scenario, BC Gas is investigating the construction of a satellite LNG facility to reinforce the Salmon Arm lateral. If the satellite LNG facility proceeds, it would reduce the ITS reinforcement benefit of the SCP to $23 million in 1996 NPV dollars (Exhibit 3D, IR 13.3). Westcoast and PGT argue that satellite LNG could defer the need for ITS reinforcement and that it would reduce the savings that should be credited to the SCP. BC Gas responded that satellite LNG is one of several alternatives that it is considering to reinforce the Salmon Arm lateral, and that no decision has been made to proceed with satellite LNG.

An alternative reinforcement strategy would be to partially loop the existing Yahk to Oliver pipeline. A witness for BC Gas explained that, to meet its 2005 peak day, the Utility would need to loop two-thirds of the distance and install a large amount of compression. It considered that this approach provided very little increase in capacity for the cost incurred (T11: 1883-1885).

Commission Conclusion

The Commission recognizes that there are several alternatives available to BC Gas which could defer the need to reinforce the ITS until at least 2002, and which could negatively impact the value of SCP with respect to the avoided cost of these reinforcements. Moving to the discharge side of the Savona compressor station has been encouraged by the Commission previously, but BC Gas and Westcoast have been unable to complete a satisfactory contract. BC Gas will be expected to fully consider all such alternatives and opportunities when it requests approval of projects to reinforce the ITS. The Commission accepts for ROM modeling purposes BC Gas' $46 million estimate of the avoided ITS reinforcement cost that would result should the SCP be built.

7.2.2 Coastal Transmission System

An LNG facility has the ability to reduce the need to reinforce the Coastal Transmission System, depending on where it is connected to that system (T11: 1810). In the September IRP Update, BC Gas included the following Coastal Transmission System reinforcement credits in its ROM analysis:

LNG Facility	Avoided Cost, Millions 1997 $
Tilbury	6
Cherry Point, to Livingstone	1
Sumas	0
McNab, to Eagle Mountain	5

Source: Exhibit 1B, App. D; Exhibit 10; Exhibit 5B2, IR 6.

These numbers are based on 200 MMcfd of supply from LNG. BC Gas reduced the supply for a 3 Bcf LNG facility from 300 to 200 MMcfd for its calculation of the reinforcement credit. (For example, using 300 MMcfd for Tilbury LNG yields a credit of $9 million.) Although the operating reliability of an LNG facility is high, the Utility felt that this discount is needed to recognize the risk that LNG may not be available in the tank, compared to a more sustained supply from a pipeline (T11: 1855).

PGT argued that Cherry Point LNG would avoid $6 million of reinforcement costs, but the basis for this claim is unclear (Exhibit 95). WGSI argued that the avoided reinforcement credit for McNab LNG increases to $10.7 million with two cogeneration facilities on Vancouver Island (Exhibit 105). BC Gas responded that WGSI assumes 300 MMcfd would be delivered to BC Gas at Eagle Mountain. The Utility argued that the $10.7 million figure should be reduced, both in recognition of the 200 MMcfd system reinforcement value for LNG, and because part of the McNab supply is delivered by diversion at Huntingdon.

Commission Conclusion

The Commission considers the Lower Mainland reinforcement credits which BC Gas proposes for the LNG options to be reasonable for the purposes of the ROM analysis.

7.3 Third-Party Transportation Revenue on the SCP

Within the ROM analysis, BC Gas includes $9.5 million per year (30-year NPV of $103 million) for third-party transportation revenue from the SCP (Exhibit 1B, p. D4). The Utility offered several alternatives for estimating the revenue stream (Exhibit 1, App. II, p. 56; Exhibit 2D, IR 12.1; Exhibit 1A, App. A; T9: 1458-1459; T18: 3096-3097; T22: 3918-3919). BC Gas refers to the estimate as order of magnitude (Exhibit 3D, IR 33.2), and a witness for the Utility agreed that there was a lot of uncertainty in the estimate (T8: 1342).

BC Gas notes that the $9.5 million per year includes $2.5 million per year which the Utility estimates it would recover from non-core (on-system) customers as a result of a future rate design proceeding (Exhibit 2K, IR 2a; T24: 4214; BC Gas Argument, pp. 32-33). In earlier evidence, BC Gas had referred to this "third-party" revenue which would be recovered in the rates of BC Gas customers (Exhibit 3I, IR 46).

BC Gas expects that the remainder of the $9.5 million will come from producers and marketers moving gas at market-based rates to markets through Sumas and Kingsgate (Exhibit 1A, Panel 1 written evidence, App. A). BC Gas used two approaches to estimate third-party revenues. The first approach looked at firm west-to-east movements of British Columbia gas production to Kingsgate. Compared to the cost of moving the gas through Alberta, BC Gas calculates the value of SCP service at $0.26/GJ and estimates annual net revenue of $8.5 million.

The second approach assumes that gas would move on a spot (interruptible) basis in an easterly or westerly direction, depending on the market opportunities offered by the differential between Sumas and Kingsgate market prices. BC Gas estimated that the market differential averaged $0.16/GJ from 1991-1997 and $0.22/GJ from 1996-1997. Witnesses for CAPP stated that they expect prices at Sumas and Kingsgate will continue to move up and down together. They indicated this generally was with regard to annual average prices, and agreed that there are daily variations between Sumas and Kingsgate prices. Prices generally are higher at Kingsgate than at Sumas in the summer, and the reverse tends to be the case in the winter (Exhibit 27; T17: 2915, 2945-2947).

BC Gas assumed an average flow of 90 TJ/d, and calculated annual revenues of $5.3 to $7.2 million. The physical shipping limit of the SCP is 90 TJ/d (Exhibit 3D, IR 12.2), and larger volumes could be delivered through displacement. BC Gas stated that, when capacity was available, it delivered 20 to 25 MMcfd over the existing link between Kingsvale and Yahk during the summer of 1997 (T8: 1343). BC Gas assumes that the firm and interruptible activities would occur simultaneously, thereby supporting its total revenue estimate of $9.5 million.

In the hearing, the rationale for crediting third-party transportation revenue in the ROM analysis was described by the BC Gas policy witness:

> "In the first instance the 9.5 million in part, something in excess of two million dollars, would relate to the illustrative example that we'd use for what might fall out of a rate design allocation where one-third was allocated to, say, transmission costs and two-thirds to gas supply costs. So that would have been one block or component. And the balance then really was simply taking the price differential spreads between two locations and saying if we did more of the same in the future as to that which we have done in the past, that's what one might reasonably expect to be able to recover in terms of cost mitigation..." (T9: 1458).

CAC (B.C.) et al. argued there are risks, considering the potential for changes in the market and regulatory environment over 30 years, that the predicted levels of third-party revenue will not be realized. Many other parties argued that, in the absence of contracts or other evidence of market support, there is no certainty that the forecast levels of third-party revenues will materialize. Westcoast also questioned the ability of BC Gas to collect all the economic rent represented by the price differential between Huntingdon and Kingsgate.

Commission Conclusion

BC Gas has not provided evidence of any expressions of interest from potential firm shippers (Exhibit 2H, IR 13). With the small price differentials that are typical between Sumas and Kingsgate on an annual basis (Exhibit 2D, IR 2.7; T17: 2946) and, notwithstanding the view of BC Gas' witness that this is not an apt comparison when contemplating firm service contracts (T8: 1336), the Commission does not consider that the potential revenue from firm contracting is sufficiently reliable to be included in the ROM analysis. In future, BC Gas may wish to hold an open season to demonstrate the interest of potential third-party shippers in capacity on a pipeline such as this.

Eliminating firm transportation leaves revenue from spot movements of gas and, when using this approach, the longer term average of spot price differentials of $0.16/GJ appears more reasonable for projections over a 30-year period. Considering that some sharing of financial benefits is likely and that some transportation charges on Westcoast and/or ANG may be incurred (and not including the cost of any incentive payments to the Utility), it is reasonable to expect that the differential recovered by the Utility will not exceed three-quarters of the full amount, or $0.12/GJ. Adopting spot sales averaging 90 TJ/d gives a transportation revenue benefit of $4.0 million per year. Adding in the credits from on-system non-core customers gives a total of $6.5 million per year, for a 30-year NPV saving of $70 million rather than the $103 million NPV saving projected by BC Gas. The Commission believes that an adjustment to the ROM model results to reflect the conditions described above is required, and therefore the Commission has reduced the benefit to the SCP by $33 million as discussed further in section 9.5.

7.4 ROM Sensitivity to SCP Capital Cost Variances

BC Gas' initial estimate of the capital cost for the SCP was approximately $299 million, excluding AFUDC and overhead. In the May, 1997 IRP Update, BC Gas reported results of a sensitivity test which indicates that if the capital cost of the SCP is 10 percent lower or higher than the $300 million estimate, the NPV benefit would be increased or decreased respectively by about $40 million (Exhibit 1B, p. 89). The sensitivity test results also indicate that a 25 percent cost over-run would reduce the projected SCP benefits by approximately $100 million. In September, 1997, BC Gas updated the cost estimate for the SCP to approximately $348 million including AFUDC and overheads (Exhibit 1, App. III, p. 18).

Commission Conclusion

The Commission accepts the BC Gas estimate of $348 million for the capital cost and of 10 percent for the potential variances for the purposes of the ROM analyses.

7.5 ROM Sensitivity to Delay or Advance of SCP Timetable

During the hearing there was considerable discussion about the ability of various proponents to meet the timetables set out in their proposals, and the consequences of advancement or delay of their projects.

BC Gas described what it saw as the benefits of advancing the SCP from the base case assumption of an in-service date of November, 2000 to November, 1999, and indicated that meeting the advanced deadline is feasible (Exhibit 2H, IR 12).

BC Gas' May, 1997 IRP Update indicated that a one year advance or delay in the in-service date would increase or decrease, respectively, the gas cost savings net of cost of service by an estimated $30 million dollars in total (Exhibit 1, App. II, p. 89). BC Gas subsequently stated that a November 1, 1999 in-service date would allow market and operational benefits quantified at $17 to $31 million per year to commence one year earlier (Exhibit 3F, IR 18.1). BC Gas further indicated that the reduction in single year market and operational benefits associated with a one-year delay in the SCP timetable would be approximately $19 to $30 million, and that the ROM related NPV would decrease by about $5 million (Exhibit 10, cover letter and schedule 2; T2: 244-246).

Commission Conclusion

Although the Commission accepts the November, 1999 in-service date for the SCP for ROM modeling purposes, it comments further on schedule risk in section 11.5.

8.0 ROM ASSUMPTIONS: FINANCIAL ISSUES

8.1 Term of Analysis

BC Gas adopted a 30-year term for its analysis of the SCP and the other proposals. However, the ROM analysis is based on data which extends only until 2016 with results being trended beyond this point to 30 years (Exhibit 2D, IR 3.8). The selection of such a lengthy term and its impact on decision making was the subject of considerable discussion during the hearing. As a BC Gas witness agreed, the accuracy of the assumptions in the analysis becomes subject to progressively greater uncertainty as the planning horizon is extended (T6: 1027). Westcoast, in Argument, expressed its view of the 30-year term as follows:

> "BC Gas used a 30-year period for its ROM NPV analysis. It did so despite the fact that it used 20 years or less in its earlier IRP's (Vol. 6, T. 1023) and the Commission's IRP Guidelines which suggest that demand forecasts and resource portfolios should cover a time period generally between 15 and 20 years (Volume 6, T. 1022).
>
> It is clear that the 30-year period of analysis used by BC Gas, when combined with the 6.18% discount rate, casts alternative projects which can be staged so as to defer capital expenditures to future periods (such as an expansion of Westcoast's or Northwest's pipeline facilities) in a less favourable light compared to the SCP whose costs are all front-end loaded." (Westcoast Argument, pp. 29-30.)

BC Gas supplemented its May, 1997 IRP Update analysis with some additional work based on a 20-year term (Exhibit 3I, IR 78). The 20-year term reduces the NPV benefits of all portfolios by $300-400 million, but reduces those of the SCP-related portfolios slightly more than the alternatives. As a result, the portfolio showing the greatest NPV benefits for the shorter term becomes the 3 Bcf LNG plus WEI/NWP expansion rather than the SCP plus 3 Bcf LNG.

In argument, Westcoast used BC Gas evidence to derive a graph which shows that the use of a 15-year term causes the ROM NPV savings for the SCP plus WEI/NWP expansion to be the lowest of the alternatives shown (Exhibit 43, Argument, p. 30).

Throughout the hearing, BC Gas maintained that a 30-year analysis was appropriate and that, if a shorter term was used, a terminal value for residual assets would need to be included. However, as BC Gas agreed, the further out into the future the analysis goes the harder it becomes to establish a terminal value (T6: 1025). This was, in its view, a good argument for extending the period of the analysis rather than using a terminal value.

<u>Commission Conclusion</u>

The Commission has major reservations about the validity of an evaluation based on projections of a wide range of input variables 30 years into the future, and notes that its IRP Guidelines suggest a time horizon of 15 to 20 years. This is especially so when in some cases the potential benefits, in terms of burner-tip gas cost savings, may not be seen by BC Gas customers until many years after construction. In the view of the Commission, if the 30-year evaluation is to be maintained, then the added risk must at least be reflected in the discount rate adopted for the evaluation.

8.2 Discount Rate

For its analysis, BC Gas used a nominal discount rate of 6.18 percent, based on its incremental cost of capital. BC Gas suggested that this is the only discount rate that is appropriate. However, BC Gas indicated that, as stakeholders could view future discount rates differently, it included an examination of the sensitivity of results to increasing discount rates in its May, 1997 IRP Update [Exhibit 2L, IR 27 (d)]. Therefore, BC Gas did sensitivity tests using discount rates of 10 and 12 percent (Exhibit 1, App. II, App. B).

As the discount rate in the sensitivity tests increases, the overall NPV savings decreases and the difference in NPV savings between options narrows. At a 12 percent discount rate the NPV savings of the LNG plus NWP/WEI option surpasses that of the SCP plus NWP/WEI option. BC Gas agreed during the hearing that the results are somewhat sensitive to the discount rate used in the analysis, and also agreed that the apparent cost advantage of the SCP is more favourable over time if a lower discount rate is used (T2: 181, 197).

BC Gas states that it had not tested the analysis using a social discount rate as it does not view the use of a social discount rate as appropriate (T6: 1052-1053). However, in evidence on discount rates prepared for, and in part by, BC Gas, the recommendation was that BC Gas should use two discount rate tests - one a private or shareholder based discount rate and the other a public interest or social evaluation (Exhibit 34). BC Gas witnesses stated that the conclusion in that regard was meant in the context of a social cost-benefit analysis and, therefore, was not applicable to the current situation. BC Gas did agree with the suggestion in that evidence that a social discount rate of 7.5 or 8 percent (real) was appropriate, and probably remains appropriate now (T6: 1055-1057). Finally, BC Gas agreed that adding approximately 2 percent inflation to an 8 percent real social discount rate would result in a nominal rate of approximately 10 percent, but the Utility witness also indicated that it would be incorrect to conclude that the 10 percent sensitivity run included in the May IRP Update is comparable to a sensitivity using an

8 percent real social discount rate, because of the inclusion of tax effects, particularly since the U.S. proposals would have markedly different tax impacts on British Columbia ratepayers.

CAC (B.C.) et al.'s witness stated that a higher discount rate diminishes the attractiveness of alternatives such as the SCP, where the benefits are further into the future, even if the quantum of benefits remains the same (T22: 3884).

Westcoast suggested that given the inherent uncertainty of a 30-year forecast, the discount rate used by BC Gas was inappropriately low (T12: 2071).

BC Gas agreed that it had not evaluated the project using a risk adjusted discount rate, as it considered all of the portfolios to be equally risky based on the sensitivity analyses which suggest that the SCP is preferable even if the input assumptions of the analyses are changed (T8: 1290-1292). BC Gas also agreed that it had not evaluated the SCP using a higher discount rate specifically to represent the option value of delaying the project, but noted that it ran sensitivity analyses of all portfolios using higher discount rates.

CAC (B.C.) et al. argued that the 6.18 percent discount rate used by BC Gas in its analyses (other than the sensitivity case specifically examining the impact of higher discount rates) is unrealistically low for three reasons. First, the rate used by BC Gas is based on its after-tax cost of capital, whereas customer rates are based on the before-tax cost of capital. Second, the incremental weighted average cost of capital used by BC Gas represents the rate for minimal risk, which is not, in the view of CAC (B.C.) et al., a characteristic of the SCP. Third, ratepayers, who would ultimately support the cost of the project, have a higher discount rate than the utility (Final Argument, p. 13).

BC Gas responded that the discount rate it used is consistent with other Commission directions and decisions and is consistent with the approach used by other utilities. BC Gas also argued that the use of a pre-tax or after-tax cost of capital is immaterial since the two approaches will yield the same result given the appropriate adjustment. Further, BC Gas replied that its weighted average cost of capital represents the Utility's average risk, making it appropriate for evaluating projects such as the various resource options examined in its IRP process. Finally, BC Gas stated that the SCP is essentially the looping of an existing transmission line and as such is: "...reflective of similar investments already made by BC Gas, and others to be made in the future" (Reply Argument, p. 33).

In Exhibit 34, prepared by BC Gas as evidence for an earlier hearing, there is discussion of a method available to deal with certain types of risks faced by the SCP (Exhibit 34). To the extent that a key risk of the SCP was the risk that third-party revenues would be less than assumed in the NPV analysis, the undiscounted expected revenues could be decreased to a "certainty equivalent" amount, as an alternative to adjusting the discount rate (Exhibit 34, p. 9). BC Gas, in using the mid-points of the expected ranges of revenues for the SCP, made no attempt to use the "certainty equivalent" methodology as a means of adjusting for risk.

This evidence also discusses the "option value" of a project, which results from the notional treatment of a project as an option which if not used (constructed) today may be used (constructed) in the future (Exhibit 34). Thus, even if the NPV of a project started today is positive, it is possible that waiting might allow the project to proceed on even more favourable terms in the future. Incorporating the loss of the option value into the NPV analysis could mean that the project may no longer appear desirable. In theory the option value can be included in the analysis by adding a premium to the costs or the discount rate, although in practice the inclusion of an option value is relatively complex (Exhibit 34, paragraph 29, pp. 9-10). BC Gas apparently chose not to consider any option value for the SCP project in this manner.

Commission Conclusion

On the issue of the relative risk level of the SCP, although BC Gas indicated during the hearing that it considers the SCP to be an intermediate risk project similar in risk profile to the other projects proposed in this proceeding and similar to the average risk of the utility, there was little evidence provided to support that view. Even if, as BC Gas contends, the SCP reflects the same risk profile as investments to be made in the future, the Utility's cost of capital may change in the future based, in part, on the investments that the Utility chooses to make.

It is the view of the Commission that, because of the very large capital outlays required in many portfolios and because of the uncertainties inherent in the 30-year projection period, the projects are significantly more risky for BC Gas' ratepayers than the more conventional small scale incremental investments normally pursued by a Utility. The Commission therefore concludes that a nominal discount rate in the order of 10 percent is more appropriate than the 6.18 percent used by BC Gas in its ROM analysis.

At the same time, the Commission notes that the total NPV of incremental fixed costs for those portfolios having a large front-end capital component ranges between 3 percent and 9 percent. That is, non-utility gas supply related costs represent from 91 percent to 97 percent of the total NPV cost of these portfolios. While theoretically, it could be argued that a smaller adjustment to the discount rate risk premium should be made for the incremental pipeline portfolios, the Commission concludes that any such adjustment would not be meaningful within the accuracy of the ROM model results.

8.3 Foreign Exchange Rate and Inflation Rate

8.3.1 Exchange Rate

In the September IRP Update, BC Gas uses a U.S./Cdn dollar exchange rate of 0.74. For the previous IRP Update it used an exchange rate of 0.745 (Exhibit 1B, p. 5). BC Gas did not look at currency exchange as a risk factor as, in BC Gas' view, currency exchange fluctuations will be reflected in commodity prices (Exhibit 2D, IR 3.7). Nevertheless, BC Gas indicated during the hearing that currency exchange fluctuations are a concern, and acknowledged that it manages the currency risk when entering into arrangements with Jackson Prairie Storage, SoCal storage and purchases of California gas. BC Gas agreed that hedging mechanisms are available to mitigate such risks, and that it has hedged against fluctuations in gas prices (T4: 624-625).

PGT suggested that it might attempt to mitigate exchange rate risk associated with its Cherry Point LNG facility by attempting to borrow the debt portion of the financing for the facility in Canadian dollars. Another way of limiting risk would be for BC Gas to take an equity position in the facility provided that the Utility shared both costs and benefits with the core market (T16: 2840-2841).

WIPL indicated that it was not willing to accept the risk of fluctuations in exchange rate, but suggested that over the long-term, fluctuations should move both above and below the current rate, and that BC Gas and its customers would both bear the burdens and enjoy the favourable consequences of those fluctuations (T15: 2633-2634).

8.3.2 Inflation Rate

In its analysis, BC Gas generally uses an inflation rate of 1.7 percent, although for a few items it uses an inflation rate of 2 percent (Exhibit 2D, IR 3.3). There was little discussion of the inflation rate during the hearing.

Commission Conclusions

The difference between the current exchange rate (0.70 approximately) and the assumed 0.74 exchange rate demonstrates the difficulty of even short-range projections. Nevertheless, the Commission accepts the assumed exchange rate as reasonable for long-term ROM modeling purposes. Qualitatively, the Commission notes that, since the major investments occur early in the LNG project cost streams, the current rate spread, if maintained for a number of years, may tend to depress the relative ranking of the U.S. LNG portfolios.

The Commission accepts the assumed inflation rate as reasonable for a long-term modeling assessment. However, the Commission observes that this rate is relatively low and that, if the rate of inflation increases, both interest rates and the allowed return on utility rate base are likely to increase as well. Alternatives such as WGSI and Williams LNG, where the proponents are prepared to offer fixed-price LNG service contracts, would offer some protection from higher rates of inflation.

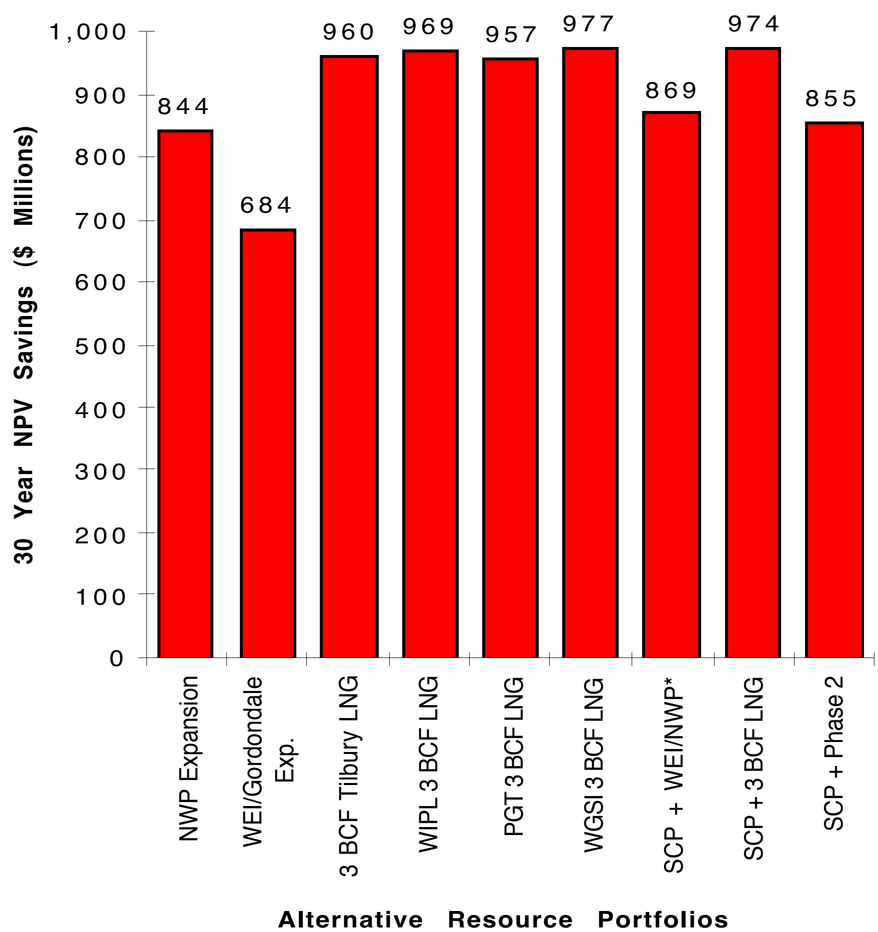
9.0 ROM RANKING OF SELECTED SUPPLY PORTFOLIOS

9.1 ROM Reference Case Ranking of Portfolios

The ROM outcomes of all the above described cases, as revised by BC Gas up to October 17, 1997, are summarized in Figure 9-1 which shows the ROM-only NPV savings of each portfolio measured against the default case. All calculations represented in Figure 9-1 are at the discount rate of 6.18 percent assumed by BC Gas.

Figure 9-1

BC Gas ROM Analysis of
NPV Savings of Alternative Resource Portfolios Compared to Default Portfolio
(6.18 percent Discount Rate)



Source: Exhibit 10, October 11, 1997 revision to p. H1 of September IRP Update.

Note: SCP + WEI/NWP is the SCP Project in the CPCN Application.

9.2 ROM Sensitivity Case Ranking of Portfolios

Chapters 6, 7 and 8 describe, in general terms, the impact of various sensitivity tests on the ROM output. The full range of these tests and their numerical impact on the ROM-only NPV savings, from the sources described in the footnote, are summarized in Table 9-1.

Table 9-1

Ref.	Sensitivity	Impact on Results	Change in NPV Savings ($Million)
1.	Higher load forecasts.	No change in portfolio ranking.	+ 95 to + 175
1.	Lower load forecasts.	SCP plus WEI/NWP responded better than SCP plus Phase 2 although neither were as good as the LNG options.	- 131 to - 220
1.	Higher and lower burner-tip prices.	No change in portfolio ranking.	+ 77 to - 59
1.	Higher and lower Westcoast tolls.	No change in portfolio ranking.	+ 64 to + 74
1.	Renewal of JPS or equivalent storage.	JPS renewal supports NWP options reducing the advantage of SCP plus LNG (first ranked portfolio) and moving SCP plus WEI/NWP to third place over SCP plus Phase 2.	+ 73 to + 162
1.	With aggressive DSM.	Overall NPV savings go down; SCP plus WEI/NWP moves to third place over SCP plus Phase 2.	+ 83 to + 156
1.	With 40 and 100 MMcfd thermal generation.	Overall NPV savings go up; the rankings change in the same manner as for aggressive DSM. (See Exhibit 3I, Response No. 52).	+ 33 to + 180
1.	One year delay or advance of SCP from projected November 2000 in-service date.	Decrease or increase, respectively, NPV benefits by $30 million.	- 30 to + 30
1.	Impact of changes in capital cost.	10% increase (decrease) in $300 million capital cost decreases (increases) NPV benefits by about $40 million, 25% increase in capital cost decreases benefit about $100 million.	± 41 to - 103
1.	Combined sensitivities: load growth, burner-tip price and capital cost over-runs.	The best case (high burner-tip price, high demand, capital cost 10% below estimate) leads to an overall increase in NPV benefits but no change in portfolio ranking; the worst case (low burner-tip prices, low demand, capital cost 10% above estimate) leads to an overall decrease in NPV benefits and a change in portfolio rankings favouring LNG and WEI/NWP options.	+ 443 to + 611 - 300 to - 400
1.	Combination of JPS renewal and addition of cogeneration peaking.	Overall NPV savings go up; SCP plus WEI/NWP moves to third place over SCP plus Phase 2.	+ 71 to + 162

2.	Addition of off-system sales.	Increased overall NPV savings, but did not change the ranking of the portfolios.	+ 62 to + 70
2.	Addition of interruptible load.	Increased the NPV savings in all cases, and the SCP plus WEI/NWP portfolio moved up to the third best ranking, replacing the SCP plus Phase 2 portfolio.	+ 142 to + 199
2.	Increase in the discount rate.	Materially reduces the NPV benefits of all portfolios; at 10% the ordering of portfolios does not change, at 12% the 3 Bcf LNG plus WEI/NWP replaces the SCP plus LNG portfolio as the portfolio showing the highest savings.	- 402 to - 614
3.	Sensitivity to the Fieldgate Price.	NPV savings increase assuming a high fieldgate price and decrease assuming a low fieldgate price; however, the rank ordering of the alternatives does not change.	+ 570 to - 210
3.	Sensitivity to the availability of additional winter peaking and seasonal supply, and JPS storage.	As additional low cost winter supply is made available, the ranking of portfolios shifts tending to favour NWP/WEI expansion options, alone or in conjunction with either LNG or SCP.	+ 118 to + 266
3.	Secondly, sensitivity to the above plus additional SoCal storage.		+ 151 to + 389
3.	Updated sequencing analysis showing the impact of delaying LNG or SCP.	If both LNG and SCP were going to be constructed, proceeding with the SCP first showed the greatest NPV savings. However, this advantage disappears if the second plant is deferred past 2010.	
4.	Tilbury LNG with a November 2001 (one year earlier) start-up.	NPV savings for that resource increased by about $9 million.	
4.	SCP start-up delayed one year to 2000/01.	Decrease in NPV savings of about $5 million.	
5.	Westcoast scenarios: - capital cost of $364.2 million plus 10 %; - lower WEI tolls; - removal of G & P tolls; - renewal of JPS; - inclusion of on-system revenue - third-party transportation revenue reduced to $5 million from $9.5 million; - Kingsvale to Huntingdon to 2 times that assumed in September Update.	Under the Westcoast scenario, the SCP alternatives compare very poorly to other alternatives. The first-ranked portfolio in the Reference case (SCP plus 3 Bcf LNG) shows a NPV benefits in the Westcoast scenario as $243 million lower than the Reference case. The second highest ranked portfolio in the Westcoast scenario is the NWP expansion case. The impact of the lower WEI tolls alone reduced NPV savings for most portfolios and moved the NWP expansion portfolio to fourth place over SCP plus Phase 2.	- 395 to + 15 -71 to +33

References:
1. May 1997 IRP Update
2. May 1997 IRP Update Appendix B
3. September 1997 IRP Update
4. Exhibit 10, Westcoast Information Request No. 3, Question No. 89
5. Exhibit 19

Table 9-1 demonstrates that there is a wide range in the model's response to the various sensitivity checks. Some variables, such as burner-tip gas prices and WEI tolls have relatively small impacts, while others such as the discount rate and fieldgate gas prices have very significant impacts.

In those cases where sensitivities are combined, their impact can also be very large where a number of impact parameters combine in a supportive or adverse direction.

Several important general observations emerge from the wide range of scenarios:

- With few exceptions the ranking of portfolios tends to remain unchanged for any one sensitivity;
- In general, high load growth and high burner-tip gas prices tend to improve the relative position of the SCP/LNG alternatives, whereas low growth, low gas cost scenarios tend to narrow the spread between SCP/LNG and those options emphasizing the WEI and NWP pipeline solutions; and
- The addition of further peaking supply from the extension of the existing Jackson Prairie Storage and/or from co-generation curtailment, show a greater improvement in NPV savings for the WEI and NWP pipeline solutions than for the SCP and LNG alternatives.

9.3 SCP Alternate Financing Approach Ranking

As noted in section 2.3, BC Gas introduced the Alternate Approach as a means of reducing risk to the core market customers and to protect the Utility and its shareholders from cost impacts resulting from longer term stranded rate base exposure (Exhibit 11A; BC Gas Argument, pp. 68-69). Under the Alternate Approach, "...BC Gas Utility and its core market customers will be able after 15 years to eliminate, or reduce, risks of stranded costs while retaining the right to continue to make use of the SCP if the SCP remains the preferred source of supply from the perspective of core market customers". At the end of the initial 15-year term, the Utility may reduce its SCP capacity. If BC Gas Utility reduces its SCP capacity by 25 percent or less, it would pay only the cost of service for the capacity it continues to hold. The Utility may also reduce its capacity, and its financial commitment to SCP Co. to zero at the end of 15 years. If the Utility reduces its capacity to less than 75 percent but greater than zero, then it would pay a pro-rata share of the SCP cost of service based on the percentage of capacity retained by the Utility plus the 25 percent share committed to by SCP Co. (BC Gas Argument, pp. 69-70; Exhibit 126).

Although the physical facilities of the SCP would remain unchanged in BC Gas' Alternate Financing Approach, the costs to be absorbed by the Utility and its ratepayers would be different. The primary reason for the cost difference results from the use of an average 2.1 percent depreciation rate if the SCP were in the Utility rate base versus the use of a 3 percent (levelized) depreciation rate under the Alternate Financing Approach where SCP Co. is granted the rights to the SCP capacity and revenues. The proposal for sharing of third-party revenues between SCP Co. and the Utility would also impact on the net costs to be recovered by the Utility through its ratepayers.

To balance the additional risk accepted by SCP Co., the Alternate Approach would compensate SCP Co. in a number of ways. The first of these is through the increased depreciation rate used in calculating the SCP cost of service to be paid by the Utility; the second is through the additional cost of service commitment by the Utility if it were to reduce its capacity obligation on the SCP to an amount between 0 percent and 75 percent, as described above.

The third means of compensating SCP Co. for the risk it would accept is through the sharing or foregoing of third-party revenues generated by the SCP. Under the Alternate Approach, while the Utility is committed to take and pay for 100 percent of the capacity of the SCP, it shares up to 20 percent of third-party revenues generated by eastward gas movements and up to 10 percent of third-party revenues generated by "... other firm, interruptible, miscellaneous and new service offerings ..." (Exhibit 11B). When the Utility is committed to take and pay for less than 100 percent of the SCP capacity, SCP Co. retains all third-party revenues. In the event that third-party revenue from the SCP is below $7 million in a year, SCP Co. would credit BC Gas Utility with 15 percent of the shortfall (Exhibit 11B).

BC Gas undertook additional financial analyses comparing the Alternate Financing Approach to the Reference case analyses for the SCP option (Exhibit 26). In addition, these analyses also considered two hypothetical cases: first, where the arrangement between the Utility and SCP Co. is renewed after 15 years to cover a total term of 30 years, and second where the Utility terminates the arrangement with SCP Co. after 15 years and moves to the next best option.

Table 9-2

SCP Alternate Approach (Levelized)
(30 Year NPV, Millions, 6.18 percent Discount Rate)

Portfolio	Reference Case	Alternate Approach 30 Year Contract	Alternate Approach Terminate after 15 years
SCP+WEI/NWP	869	832	693
SCP+ 3 Bcf LNG	974	938	804
SCP + Phase 2	855	809	663

Source: Exhibit 26

Table 9-2 above shows that the NPV savings of the Alternate Financing Approach, whether for a full 30-year term or for an initial 15-year term to be replaced by the next best alternative at the end of that time, are lower than for the Reference case in which the SCP is owned by the Utility[5].

Commission Conclusion

The Commission believes that, given the costs incurred for de-contracting below 75 percent, and the loss of potential third-party revenues by the Utility for any de-contracting of SCP capacity, the risk mitigation benefits of the Alternate Approach are likely to be outweighed by its disadvantages. Therefore, the Commission concludes that, overall, the Alternate Approach for financing the SCP would have fewer net benefits than the normal rate base treatment of the SCP.

9.4 Kootenay Pacific Pipeline Proposal of ANG

As discussed in section 3.3, BC Gas did not include the KPP proposal of ANG in the September IRP Update because the Utility did not consider KPP was sufficiently advanced for its costs and tolls to be reliable. During the hearing, BC Gas submitted an estimate of the rate impact if the Utility contracted for KPP service to Oliver (Exhibit 121). ANG argues that it is unable to replicate the KPP costs that BC Gas used to calculate the rate impact (ANG Argument, pp. 12-13).

ANG proposes the KPP as a 508 mm (20-inch), 2160 psig pipeline, and argues that its design would result in a less expensive facility (Exhibit 4A, p. 3; ANG Argument, p. 12). BC Gas provides evidence indicating that its 24-inch, 1440 psig design results in a slightly lower estimated cost for the SCP (Exhibit 90, IR 12).

ANG states that its pipeline all the way to Huntingdon would provide greater third-party revenues and better security of supply than the SCP, and would do more to improve the competitive gas market at Sumas. ANG also argues that it can provide ITS reinforcement and balancing benefits that are equal to the SCP (Exhibit 93).

The SCP Phase 2 would extend the SCP from Oliver to the Westcoast system at Kingsvale, and so has some similarities with KPP to Huntingdon. BC Gas states in its May IRP Update that the SCP and Phase 2 SCP could become practical given a higher-than-forecast level of third-party transportation revenue (Exhibit 1, App. II, p. 97). ANG expressed the view in its August, 1997 KPP Proposal that

5 Although the ROM analyses were produced by BC Gas prior to some amendments to the revenue sharing mechanism of the Alternate Approach, the Commission is not convinced that the amendment would materially improve the ROM results of the Alternate Approach relative to the Reference Case.

more time is needed before market conditions are ripe for a major expansion to service markets around Huntingdon and the adjacent areas (Exhibit 4A, p. 7).

ANG, CAPP, NORPAC, CAC (B.C.) et al. and others argue that rather than relying on the ROM and other analyses presented in the hearing, the fundamentally different approach of a market test should determine whether a major pipeline addition like the SCP or the KPP goes ahead. These parties state that such a project should only proceed if sufficient customers are willing to enter into service contracts for capacity on it. BC Gas responds that, in the case of the SCP where the Utility is both the proponent and the customer (on behalf of its core customers), the present IRP and CPCN proceeding fulfills a similar function. The Utility believes that the Commission's role is to determine if it is in the best interests of core consumers for the SCP to be constructed, and that there is no need for further market testing (BC Gas Reply, pp. 25-28).

Commission Conclusion

An open season or other market test to support the level of third-party shipper interest in service on the SCP would have reduced the uncertainty about third-party revenues. As discussed in section 1.1, the examination of options for meeting the growth in gas demand of BC Gas' customers is the primary focus of this hearing, and the hearing is the appropriate forum for dealing with that issue. With respect to the KPP, the Commission must consider whether it is likely to be superior to the SCP as the next major supply resource addition.

The Commission accepts that a new pipeline to Huntingdon would develop a new pipeline corridor and so provide greater security of supply benefits than a pipeline that stops at Oliver. KPP would also avoid Westcoast tolls on deliveries to Huntingdon, and arguably would provide increased liquidity and competition in the gas market at Sumas. The results of ANG's open season will provide a current view of the market with respect to a pipeline from Yahk to Huntingdon, and if other shippers express significant interest, some amount of KPP capacity may be of interest to BC Gas.

With regard to the KPP from Yahk to Oliver, the Commission notes that ANG would need to acquire new right-of-way for the full distance, and this would be an additional cost for the KPP. The KPP should be able to provide substantially the same ITS reinforcement and operational flexibility benefits as the SCP, but common ownership of the SCP and the ITS is expected to give the Utility-owned alternative some advantage. Lastly, the arguments do not support the likelihood that tolls for the KPP will be rolled-in with those of the existing ANG system.

On the basis of the evidence presented, the Commission is not persuaded that the KPP provides greater benefits than the SCP to the customers of BC Gas, without substantial participation by other shippers.

9.5 Commission Adjustments to ROM Ranking

In examining the ROM inputs, the Commission made two changes to the input assumptions. The first is a change in the discount rate from 6.18 percent to 10 percent, and the second is a reduction in assumed third-party revenues from $9.5 million per year to $6.5 million per year. The latter change reduces the NPV value of third-party revenues included in the ROM results from $103 to $70 million at the 6.18 percent discount rate, to $64 to $44 million at the 10 percent discount rate.

The Commission has undertaken an analysis of the resource portfolios incorporating these two adjustments to the model inputs. The ranking outcomes in NPV savings measured against the Default portfolio, are presented in Figure 9-2.

From Figures 9-1 and 9-2, it is clear that, within the limits of the ROM model, and with the adjustments to the ROM analysis considered necessary by the Commission, all the portfolios incorporating LNG in association with existing pipelines are so close in NPV savings value as to be virtually identical. Furthermore, the information on each LNG proposal is not sufficiently detailed for the Commission to select the best LNG alternative for the needs of BC Gas. Each of the LNG alternatives has specific uncertainties such as the Centra delivery for WGSI, the Livingston pipeline for PGT and siting issues for most proposals. The Commission, therefore, proposes to treat them as a single class for further discussion within this Decision.

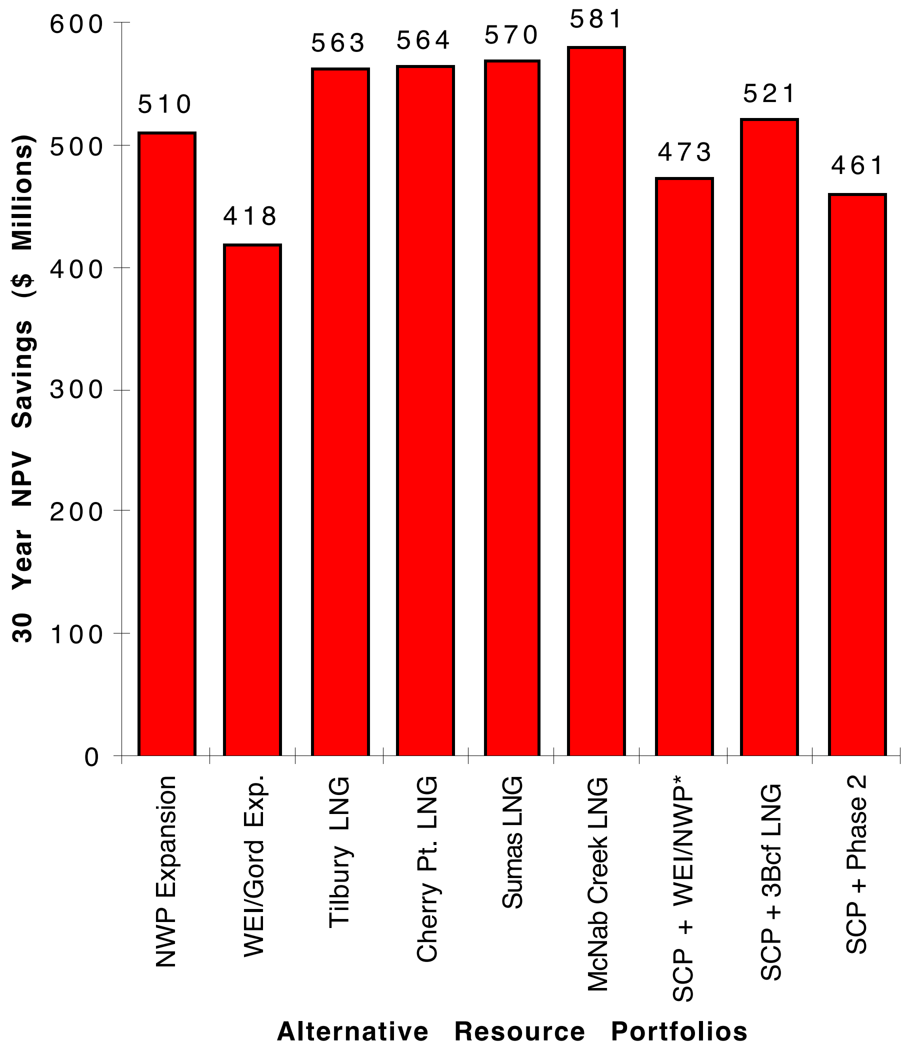
In the Commission adjusted ROM only analysis, the NWP Expansion option follows behind the LNG alternatives with some $50 to $70 million less in NPV savings over the 30-year term. The SCP alternative, in association with WEI/NWP expansion ranks in third place, behind the NWP expansion portfolio with some $37 million less in NPV savings.

The SCP/LNG portfolio is a special case; it is the only hybrid involving both a major new pipeline (SCP) and a Lower Mainland LNG plant. Despite its LNG component it ranks some $40 to $60 million NPV lower than the LNG cases using existing, but expanded, pipeline resources. BC Gas has indicated that the NPV benefits of constructing both the SCP and LNG at the same time relative to the NPV benefits of one addition alone are not significant enough to warrant constructing both immediately (Exhibit 1, App. II, p. 81). If either LNG or the SCP were delayed in this option, BC Gas' ROM analysis indicated at the NPV savings would be further reduced (Exhibit 1B, p. H-4). Should the LNG + WEI/NWP portfolio or the SCP + WEI/NWP portfolio emerge as the front ranking alternative, the option to construct the other component at a later date is still available, at which time the specifics of what are now only potential cogeneration load possibilities may be much clearer.

Figure 9-2

COMMISSION-ADJUSTED ROM ONLY NPV SAVINGS

- 10% Discount Rate
- $44 Million NPV (at 10 percent) for Third-Party Revenues credited to SCP options



Source: September, 1997 IRP Update, App. D, Exhibit 10, adjusted for discount rate and third-party transportation revenues per section 9.5 herein.

Note: SCP + WEI/NWP is the SCP Project in the CPCN Application.

Thus, from the Commission adjusted ROM-only results shown in Figure 9-2, the Commission concludes it is possible to reduce the complex array of alternatives to three groups of solutions. From this "coarse sieve" procedure, the three options for further consideration are:

1. All portfolios incorporating LNG, as a group, except the combined SCP/LNG case;
2. The Northwest pipeline expansion option; and
3. The SCP with WEI/NWP expansion alternative.

It should be noted that the spread between these three options is in the order of 10 to 15 percent, and it is important to remember that there are many material assumptions underpinning the ROM which are highly speculative over a 30-year planning horizon.

BC Gas indicated that it did not choose one resource or another based on the ROM output only. The ROM points in a certain direction and is a starting point. BC Gas provides further justification for the SCP on the basis of other benefits not included in the ROM analysis. The SCP and the two other options are examined in the context of the non-ROM benefits in the following chapter.

10.0 NON-ROM BENEFITS

In an attempt to demonstrate the robustness of the SCP proposal, BC Gas looked beyond the confines of the ROM and attempted to evaluate, in dollar terms, a series of eight operational and market benefits of the SCP which were not otherwise taken into account within the ROM. Throughout the hearing this group of benefits were characterized as "non-ROM benefits". The non-ROM benefits are identified and the basis for their quantification is described in the Utility's May and September 1997 IRP Updates. The benefits are discussed in this Chapter in the order in which they were presented by BC Gas in its Application.

Table 10-1

Non-ROM Benefits of SCP as Estimated by BC Gas

Market and Operational Benefits			
• Improved Balancing	$	8 to 33	million
• Increased Security		0 to 24	
• Incremental Transportation Revenues		0 to 108	
• Price Shock Protection		173	
TOTAL NPV Savings	**$**	**181 to 338**	**million**
Additional SCP Benefits			
• Additional Compression	$	13	million
• Gas Delivered at Yahk		30	
• Westcoast Point-to-Point tolls		34	
• Maintenance of Existing Transmission Pipelines		4 to 13	
TOTAL NPV Savings	**$**	**81 to 90**	**million**
Combined TOTAL NPV Savings	**$**	**262 to 428**	**million**

Source: Exhibit 1B, pp. 10, 11.

The eight primary non-ROM benefits attributed to the SCP are recognized by BC Gas to have counterparts in some of the alternative supply resource projects (Exhibit 1, pp. 18-23). The comparable non-ROM benefits of the alternative scenarios are summarized in Section 10.9.

10.1 Improved Balancing and Operational Flexibility with SCP

BC Gas is required to deliver gas to sales customers, and also to transportation customers, in the amounts that are required to meet the constantly changing demands of its customers. Gas supplies generally must be requested (nominated) one day in advance from connecting pipelines. Customers typically use somewhat more or less gas than predicted, principally because the temperature frequently turns out to be different than forecast. The Utility must also be able to react immediately to facility outages and to supply interruptions.

Operational flexibility describes the Utility's ability to immediately react to changing conditions. This differs from supply diversity considerations insofar as one day of lead time is normally required to change gas nominations made to connecting pipelines.

BC Gas quantifies flexibility in terms of improved balancing, as a non-ROM benefit. The Utility assigned an annual value of $1 to $4 million or $11 to $44 million NPV, and considered that the SCP would provide 75 percent of the total amount ($8 to $33 million NPV), through increased line pack (T8: 1364).

The standard error in BC Gas' daily temperature forecast is just over one degree Celsius, and is equivalent to 40 MMcfd of load (T8: 1287, 1367). The Utility must "balance" its actual demands each day with the supplies it has requested (nominated) from interconnecting pipelines. In the winter of 1996/97, BC Gas had a total imbalance of 7,000 TJ. This is about 40 MMcf on an average day, and can be as high as 120 MMcf for a particular day (T8: 1287). BC Gas had a net imbalance of 1200 TJ in the winter of 1996/97, and estimates its cost at $2 million, calculated as the loss suffered on the return of the net imbalance (Exhibit 2C, IR 15, T8: 1362).

The SCP would increase usable line pack in the ITS by about 120 MMcf, to 160 MMcf. This represents an increase of about 200 percent for the entire BC Gas system (Exhibit 2D, IR 14.1; Exhibit 3D, IR 20). The Utility would use this line pack to handle load swings, and more closely match actual receipts from connecting pipelines with nominations. Since actual loads can be higher or lower than predicted, the Utility would target a mid-range of line pack, and could then "draft" or "pack" up to 80 MMcf.

Both the Westcoast and ANG systems would place constraints on the use of the SCP for balancing, but BC Gas expects that diversion capability and, potentially, the ability to renominate will permit the Utility to dampen load swings (Exhibit 2D, IR 14.2; Exhibit 3D, IR 20.1). BC Gas was uncertain how the new nominating and balancing provisions on Westcoast would affect diversions between the Interior and Lower Mainland (T8: 1370).

Line pack is immediately available, and is the first resource that BC Gas uses for balancing (T3: 437). Gas from JPS has a lead time of one hour, and is also used for balancing. Deliveries off other pipelines, including ANG, generally have lead times of 24 hours (Exhibit 2D, IR 14.3). Later and during-the-gas-day renominations are becoming available, and provide useful flexibility.

LNG is available with one to two hours lead time in the winter, and with about 12 hours in the summer (Exhibit 8M, p. 3; T6: 975). BC Gas considers balancing as a secondary benefit of LNG (T6: 946). The Utility reserves 25 percent (150 MMcf) of Tilbury capacity for balancing, but considers LNG a limited resource that costs about $9/GJ. BC Gas prefers to avoid using LNG for balancing, but will use it as a last resort and has used as much as 100 MMcf of LNG from Tilbury in a day for balancing (T3: 437; T6: 998-1005; T8: 1368). One advantage which BC Gas identifies for LNG is that it can be used at a higher hourly rate for part of the day (T6: 966, 987).

BC Gas argues that its temperature-sensitive core market load is growing, and so balancing demand in response to weather fluctuations will also increase (Argument, p. 43). Line pack is the Utility's primary resource for balancing, and SCP line pack would provide much more balancing than the 12 to 16 MMcfd available from LNG (as determined by the liquefaction rate). Using more LNG for balancing would down-rate an LNG plant's capacity to meet peak day loads. BC Gas also argued that operational balancing agreements with other major pipelines would not provide the balancing benefits of SCP line pack, because the other pipelines are not under BC Gas control.

ANG argues that a pipeline into the Lower Mainland would provide superior physical balancing capabilities to the SCP (Argument, p. 34). CAC (B.C.) et al. argues that the balancing benefit of the SCP will be realized by *any* pipeline solution (Argument, p. 23).

Northwest permits shippers 5 percent tolerance in terms of balancing daily nominations with daily takes, and may permit operation outside of this tolerance without penalty (T19:3403). It also permits flexibility in terms of receipt and delivery points (Exhibit 6C, IR 5.12; T19:3328). Northwest argues that Northwest expansion would provide the same flexibility as the SCP.

PGT estimated that using 50 MMcfd of LNG for balancing on 25 days would have a benefit of $0.35 million per year or $4 million NPV, and indicated that this could be increased with more liquefaction capacity (Exhibit 8I, p. 12; Exhibits 95 and 119). The turnaround cost for liquefaction was stated by BC Gas to be only about $0.50/GJ (T8: 1369). However, a representative of Chicago Bridge & Iron Company who appeared on behalf of Williams indicated that 15 other LNG projects which he evaluated were unable to justify larger liquefaction plants that would provide for cycling of storage capacity (Exhibit 5E2, IR 2.4; T15: 2681-2684).

PGT also states that pipeline balancing penalties are $30 to $60 per Mcf in much of North America, and suggests that using 300 MMcfd of LNG for two days once each five years would save $56 million NPV in penalties (Exhibit 72, p. 2, T16: 2824, Exhibit 95).

WGSI argues that LNG has a much greater ability than the SCP to deliver gas to the Lower Mainland, on a daily and hourly basis, and that the number of pipeline nominations required to divert SoCal gas reduces the operational flexibility of the SCP (Argument, p. 4-5; T16: 2809). A witness for WGSI stated that in his experience, the gas company did not reserve LNG capacity for balancing (T21: 3664). WGSI expects LNG will have some balancing benefit, but only a marginal amount (Exhibit 112, T21: 3682).

Williams states that balancing is a secondary benefit of LNG, and argues that the SCP would not provide balancing benefits that cannot be provided by Northwest or Westcoast.

Commission Conclusion

Witnesses for BC Gas provided convincing evidence that balancing is an important requirement for the efficient and reliable operation of its system, and that the Utility is relatively short of resources for balancing. Moreover, growth in demand is expected to increase the size of imbalances, and more stringent balancing requirements with interconnecting pipelines may increase the penalties for not complying with balancing tolerances. More flexible operating procedures between pipelines are being developed, specifically renominations, but balancing actual demand with forecast will remain a challenge for BC Gas.

Further, the significant addition of usable line pack from the SCP would aid balancing. The usefulness of SCP line pack would be limited by the amount available, and potentially by the need to transfer much of the effect to the Lower Mainland service area.

The Commission recognizes the difficulty of setting out a supportable calculation of the balancing benefit. The substantial volume of gas stored in the SCP, and which can quickly be replenished when used, provides a source for balancing throughout the year. The potential for higher imbalance penalties in the future and the values that have been put forward for balancing from LNG, all support a significant value for this benefit. The Commission accepts the high end of BC Gas' range of balancing benefits for the SCP of $3 million per year, or $33 million NPV.

10.2 Increased Security Through Supply Diversity with SCP

Diversity of supply means that gas is available from several different sources, which reduces the reliance on an individual supply basin, production facility, gas processing plant or pipeline delivery system. The ability to access alternative sources provides customers with the flexibility to obtain gas in the event of a physical interruption in supply from one source, or to use lower cost gas in the event there are significant cost differentials between sources. It is apparent from Figures 1-1 and 1-2 that the SCP provides a large diameter pipeline connection from the NOVA/ANG/PGT system to the Interior service area, and a somewhat less direct connection to the Lower Mainland.

The Application discusses reliability and security of supply, and attributes a value of $0 to $3 million per year or $0 to $32 million NPV. In the May IRP Update, BC Gas notes that in 1996/97 it paid approximately $1 million for backstopping supply (Exhibit 1, App. II, p. 86). The Utility indicates the value would be $3 million in the event of an extended winter period plant or pipeline outage [Exhibit 2D, IR 13.2; Exhibit 3A, IR 15.1(b)]. BC Gas provided information about recent Westcoast Force Majeure events and the impact of these events on gas prices at Sumas [Exhibit 2D, IR 2.3, graph 2.3(c), IR 13.1]. A BC Gas witness agreed that $1 million per year is the amount of saving that can be counted on each year from not needing to buy as much backstopping "insurance", while $3 million is illustrative of the potential cost in a winter when the Utility purchases sizable quantities of gas on the spot market (T6: 1043-1048).

The Application claims that the SCP is able to provide 75 percent of the estimated Security of Supply value, or $0 to $24 million NPV over 30 years.

In argument, BC Gas emphasizes that security of supply is a significant factor in the determination of which resource option is in the public interest, and notes that the Utility is dependent on Westcoast for 80 percent of its peak day requirements (Argument, pp. 42, 44). The Utility asserts that the possibility of a major disruption on the Westcoast system should not be ignored, and that if it were to occur, the consequences could be enormous. BC Gas has not ascribed any value to the security of supply benefits of the SCP in the event of a catastrophic failure on Westcoast, but the SCP will lower the dependence of BC Gas customers on the Westcoast system, and the Utility feels this aspect of the SCP should not be ignored by the Commission.

BC Gas argues that LNG would provide some improvement in security of physical supply when the supply shortage resulted from a short-term disruption (Argument, p. 59).

There was widespread acknowledgment in final argument that diversity of supply is important to consumers. COFI and Cominco state: "The benefit (of the SCP) of increasing the reliability and security of supply to British Columbia consumers of gas is substantial." A more cautious view of the value of this attribute came from a representative of customers who will pay much of the cost of the SCP. CAC (B.C.) et al. claims that a disruption in delivery of gas is mainly a concern at peak periods, when all facilities are relatively fully utilized, and that the SCP would only slightly reduce the impact of a serious interruption (Argument, p. 23).

Westcoast argues that there is no evidence that there has, in 40 years of Westcoast service, been any supply disruption to BC Gas core consumers (Argument, pp. 45-47). Westcoast considers that its system provides significant supply flexibility and reliability, and questioned whether the amount of supply diversity that the SCP would provide justified its cost. Northwest is of the view that the Columbia Gorge expansion represented a new source of supply that is independent of Westcoast and would be equivalent to the SCP in its impact (T19: 3402).

PGT, WGSI and Williams express the view that an LNG plant in the Lower Mainland is a more secure resource than the SCP, since the SCP would not be directly connected to the Lower Mainland (T15: 2704-2705). LNG can be vaporized and delivered directly to the Utility's system, while a pipeline is susceptible to several concerns, including landslides and third-party encroachments. PGT estimates security of supply benefits of $15 million NPV for LNG and forecasts greater savings with increased liquefaction capacity (Exhibits 8I and 95, T16: 2784, 2820-2823).

WGSI estimates a benefit of $0 to $85 million NPV for LNG based on the benefit BC Gas claims for the SCP, and WGSI's view that the SCP only provides 85 MMcfd of supply to the Lower Mainland (T21: 3682-3683).

Commission Conclusion

The Commission concurs that supply reliability and security are important public convenience and necessity considerations when assessing the SCP, LNG and other supply resource additions. It is apparent that the SCP would provide improved supply diversity to the Interior service area, and less diversity to the Lower Mainland. Assuming the new supply is fully utilized in planning for a design day, none of the alternatives would prevent disruption if supply were to be interrupted on a design day. However, more diversity of supply would make such an event less catastrophic.

Considering the foregoing, and the difficulty of quantifying this attribute, the Commission considers that the high end of the range that BC Gas proposes in its Application is reasonable under the circumstances.

It, therefore, accepts the increased security of supply non-ROM benefit as having an NPV of $24 million. In addition, the Commission is of the view that the SCP has additional qualitative values related to security of supply for the Interior service area and has minimal increased security benefits for the Lower Mainland.

10.3 Incremental Third-Party Transportation Revenue on the SCP

BC Gas included some third-party revenue from the SCP in its ROM analysis, as discussed in section 7.3. BC Gas later looked at the potential for additional third-party revenue arising from the bi-directional capability of the SCP. This additional revenue would likely require firm commitments and, as no one has signed for firm service on the SCP, BC Gas recognizes that this potential revenue has a different level of risk (T9: 1459). Transportation benefits included in the ROM relate primarily to gas movements from Kingsvale to Kingsgate, while the additional revenue discussed here relates mainly to east to west movements (T8: 1353). The Utility projects $0 to $10 million per year ($0 to $108 million NPV) of additional third-party revenue from the SCP, and estimates that LNG or a Northwest expansion would have no similar benefits (Exhibit 1, pp. 22-23; Exhibit 1A, Panel 1 written evidence p. 21; Exhibit 1B, p. 10).

BC Gas assumes that half of the 100 TJ/d potential generation gas demand (for two cogeneration facilities on Vancouver Island) will contract firm or interruptible SCP service at an average rate of $0.13/GJ, giving an annual revenue stream of about $2.5 million. A further $2.5 million per year may be generated through parking, lending and exchange services offered to third parties and on-system industrials (Exhibit 2D, IR 12.2; Exhibit 3A, IR 18.5; T2: 286-287). This gives the average of $5 million per year estimated for this attribute.

BC Gas generated $3.6 million of capacity release revenue in 1995/96 and $17.8 million in the winter of 1996/97. The Utility currently carries out exchanges, and offers parking and lending services. Parking and lending revenues were negligible in 1995/96 and 1996/97, but the SCP should enhance the Utility's ability to offer these services (T9: 1430, 1462).

BC Gas argues that its forecast of $0-10 million per year of third-party revenues is conservative (Reply, p. 36). The Utility responds to assertions that market-based SCP tolls are predatory pricing and anti-competitive, by drawing a comparison to the mitigation revenue that it currently earns by releasing Westcoast capacity to third parties at market-based rates.

CAC (B.C.) et al. argues that the assumptions about the ability of the SCP to earn third-party revenue is a major weakness of the IRP, pointing to evidence that potential customers had not expressed much interest in a pipeline similar to the SCP which PGT proposed (Argument, pp. 17-20; T14: 2512-2513). Both

CAC (B.C.) et al. and NORPAC note that the BC Gas estimate assumes market-based prices for SCP service, and questions this assumption.

Westcoast notes that deliveries to cogeneration loads via the SCP would require firm NOVA, ANG and Westcoast capacity (Argument, p. 39). B.C. Hydro states in evidence that a cost of service toll on the SCP plus the connecting pipelines would probably be expensive in relation to current price differentials between Alberta and Huntingdon, but that it has not analyzed the alternative pipeline routes (T23: 3969, 4015, 4029).

Northwest permits shippers on its system to release and segment capacity, and gave evidence that current shippers have been able to earn significant third-party revenue. Expansion shippers could use their capacity for deliveries to LDCs in its service area and as alternate firm capacity in a southbound direction (T19: 3400-3401). The existence of a pipeline constraint (to southbound deliveries) near Chehalis could limit third-party revenue (T19: 3315-3316).

WGSI and Williams do not consider that their LNG projects offer significant third-party revenues to BC Gas (Exhibit 112, T15: 2703). Cherry Point LNG is different because the pipeline to Livingstone could be used to deliver gas to other customers and to LDCs in the Cherry Point area. PGT estimates third-party revenue of $109 million NPV between Huntingdon and Cherry Point (Exhibit 8I, Table 1; Exhibit 95; T16: 2822). PGT argues that third-party credits would offset much of the cost of its pipeline.

In argument, WGSI, Williams and BC Gas each dispute the third-party revenue that PGT claims. BC Gas points out that PGT assumes only 15 percent of the cost of the interconnecting pipeline will be allocated to BC Gas, and that only $0.68 million of the $4.3 million annual cost of service has been included in the Cherry Point LNG costs used in the ROM (Exhibit 7B, IR 12; T16: 2762-2767, 2831).

Commission Conclusion

The Commission accepts that there is potential for third-party transportation revenues in addition to those which have been included in the ROM, but is concerned that BC Gas has not been able to produce any expressions of interest in this capacity. An open season or other test of the market would have helped to clarify the potential for such revenue. Also, BC Gas' experience to date is that relatively little revenue is derived from the parking and lending services referred to by the Utility.

The Commission notes that, for this incremental transportation revenue to occur, a price differential must exist between gas delivered at Kingsgate and similar gas delivered at Sumas. The evidence suggests that, over the long term, such a differential, if it exists at all, is likely to be slight. Moreover, the very existence of the SCP, were it to be built, would likely still further reduce the probability of a significant differential between the two hubs.

The Commission concludes that a reasonable allowance for a non-ROM benefit on this account is in the range of $0 to $3 million per year, resulting in an NPV benefit of $0 to $33 million.

10.4 Price Shock Protection: Gas Cost Benefits of Diversity with SCP

Diversity of supply which provides competitive supply choices and improves the liquidity and competitiveness of the gas market at Sumas should provide core and other gas consumers access to lower cost supplies. The SCP is expected to provide surplus supply capacity to the BC Gas service area, and BC Gas expects that this will have the effect of reducing prices (T8: 1308). It is difficult to quantify the benefits that are likely to result from the enhanced competition, but BC Gas attempts to do so in terms of price shock protection.

The Utility values the price shock protection provided by the SCP at $16 million per year or $173 million NPV. The value for the SCP is based on the abnormally high price differential between Alberta and Sumas prices in November 1996 through February 1997 which increased costs to BC Gas customers and gas customers on Vancouver Island by $98.5 million. BC Gas' core customers had an exposure of $88 million (Exhibit 3I, IR 47). BC Gas assumes that, in the absence of the SCP, a similar price run-up will occur once in five years (Exhibit 1, App. II, pp. 83-84, T2: 227).

A similar calculation based on the differential between Sumas and Kingsgate prices gives a total cost of $25 million, or a core market exposure of $22 million, in the period November, 1996 through February, 1997 (T8: 1307-1308).

BC Gas argues that there is insufficient capacity to meet the demands of the region in a design year, and that increases in demand or reductions in supply will affect the price of gas in the region (Argument, pp. 45-47). Given the absence of storage and little access to additional supply from other sources, the Utility believes its estimate of $16 million per year is reasonable. BC Gas argues that if the Alliance Pipeline Ltd. ("Alliance Pipeline") proceeds, there is the potential for a serious disruption in the existing supply/demand balance in the markets served by Westcoast and that the SCP provides protection against such supply and price disruptions. The Utility argues that it is in the public interest to ensure that sufficient pipeline capacity is available, otherwise the market that supplies BC Gas customers will not be price-connected to North American gas markets during periods of high demand.

Many parties disagree with BC Gas' estimate for price shock protection. The witnesses for CAPP observe that the price shock mitigation which BC Gas attributes to the SCP is predicated on the belief that there is a lower cost source of gas at the other end of the pipe. The Utility does not intend to obtain firm upstream NOVA and ANG transportation and, without NOVA and ANG capacity, it would be looking to buy gas at Kingsgate or some other downstream point, rather than in Alberta (T5: 719, T6:884). Moreover, CAPP expects that gas prices in Alberta will "connect" with market prices in the North American gas grid, assuming that projects like the Northern Border expansion and the Alliance Pipeline proceed (T17: 2910). CAPP expects Alliance Pipeline will be completed in 2000 (T17: 2984).

CAPP considers that the BC gas producing basin is already well connected to the North American grid via Sumas, and the Alliance Pipeline would provide a second link (T17: 3011). A witness for Westcoast anticipates that Alliance Pipeline will permit BC Gas to access gas from Alberta via an upstream diversion (T12: 2109).

To obtain gas on the ANG system for diversion to the SCP, CAPP expects that BC Gas will have to pay the going market price for that day in the U.S. market to which the gas was originally destined (T17: 3014-3016). Similarly, access to ANG capacity for deliveries at Yahk may be available, but the cost could be high (T17: 3021).

CAPP feels that prices at Sumas and Kingsgate are well connected now, and track each other (T17: 2945). Nevertheless, the witness agreed that the price in a particular market at any point in time will represent the prevailing supply and demand forces (T16: 2877). In the hypothetical situation of a supply shortfall at Sumas, CAPP agreed that Sumas prices would disconnect from the rest of the grid and become higher than those at Kingsgate (T17: 3012-3013).

CAC (B.C.) et al. argues that, as the gas market becomes more efficient, the market will respond by increasing interconnecting pipeline capacity where price differentials indicate it is needed (Argument, p. 3). This position was re-iterated by CAPP, who felt that the market has demonstrated it will respond to a shortage of supply, both through the introduction of new production and through infrastructure to bring that supply to market.

Non-core customers (COFI and Cominco, Vancouver Island Gas Joint Venture) generally anticipate that the SCP will improve the range of competitive choices and have a stabilizing effect on prices. The Lower Mainland Large Volume Gas Users Association ("LMLVGUA") is concerned that the SCP proposal is not market driven and does not access the Lower Mainland directly.

Northwest is of the view that its Columbia Gorge expansion proposal provides a second source of supply to BC Gas, as will the SCP.

WGSI feels that LNG may provide some price shock protection in a particular event, but that the benefit will be small, about $10 million NPV (Exhibit 112, T21: 3683). PGT calculates a larger benefit for LNG, based on using LNG for this purpose on five days per year (Exhibit 95, T16: 2823). Williams anticipates that LNG will offer price shock protection through its ability to store cheap gas for redelivery at peak load periods (T15: 2706). BC Gas acknowledges this effect, but indicates the dollar benefit is relatively small and is already captured in the ROM analysis (T4: 528).

Commission Conclusion

The SCP and the other major resource projects would provide access to additional supplies, and should enhance the competitive options available to customers, but the Commission is not persuaded that the effect will be nearly as large as the non-ROM price shock benefit that BC Gas claims. The BC Gas calculation depends on holding firm pipeline capacity to access Alberta gas, which BC Gas does not include as part of its Application.

The calculated price shock protection value also depends on prices in Alberta being disconnected from the North American grid. Considering Alliance Pipeline and the other new pipeline capacity that is proposed, it seems unlikely that inexpensive supplies of gas will be available in Alberta over the foreseeable future. Moreover, if prices in both the British Columbia and Alberta supply basins are working in unison with the North American grid, it seems reasonable to expect, as the witnesses for PGT and CAPP stated, that prices in Alberta and at Sumas and Kingsgate will move up and down together (T16: 2781; T17: 2915). The weight of evidence supports the view that Alliance Pipeline is likely to impact price levels, but is unlikely to cause price differentials between these points which the SCP could mitigate in a significant way.

Nevertheless, a continuation of the synchronous relationship between Sumas and Kingsgate prices depends on sufficient supply being available at Sumas. With growing demand on the BC Gas system and in the Pacific Northwest, additional pipeline capacity or storage/LNG will undoubtedly be needed.

Since growing demand will inevitably cause a resource deficit in the absence of supply additions, the Commission considers it reasonable to attribute some gas cost savings to the additional supply from the SCP, so long as competing pipeline expansions are not in place. One estimate that is in the evidence is $22 million based on the differential between Sumas and Kingsgate prices in the winter of 1996/97. If one accepts that a similar situation would occur once in five years, absent the SCP, it results in an NPV benefit of $48 million for the SCP. However, the Commission believes it may be difficult to realize such savings over the long term, given that the SCP would have to create a surplus of supply over-demand at Sumas for the SCP to achieve the indicated benefit (T8: 1305-1307). In summary, the Commission concludes that it would be prudent to reduce the $48 million by half, to $24 million NPV.

10.5 SCP and Additional Compression on Oliver to Kingsvale Pipeline

BC Gas estimates that by adding compression costing about $14 million at Princeton and Kingsvale on the existing 12-inch pipeline from Oliver to Kingsvale, it could increase the capacity of this line by 20 MMcfd to 105 MMcfd. The additional capacity would increase the supply of peaking and seasonal gas to the Lower Mainland, and the September IRP Update estimates this would reduce the cost of gas for the core market by $13 million NPV (Exhibit 1B, p. 11; Exhibit 1A, Panel 1 evidence, p. 22, App. B; T8: 1381-1385). The estimate of savings is net of the additional $20 million NPV cost of service of the compression, and does not include any incremental transportation revenue.

Westcoast notes that this compression is not included in the SCP Application, and argues that the amount of benefit depends on the assumed value of the Westcoast toll from Kingsvale to Huntingdon (Argument, p. 42). BC Gas responds that additional compression is an “option” which will only be exercised at a future date if it has value at that time (Reply, p. 40).

Commission Conclusion

The Commission considers that the potential to expand the SCP in the future is a positive attribute. However, since the SCP Application does not include the additional compression facilities and there are no assurances that they will ever be economic, the Commission is not prepared to assign a monetary value to this benefit.

10.6 Gas Delivered to the SCP at Yahk

The BC Gas claim of a non-ROM benefit for the SCP is the expected result of the purchase of spot gas at Yahk, as an alternative to the repatriation of gas from its SoCal storage.

BC Gas estimates that by relying on spot gas purchases at Yahk rather than SoCal storage (including the cost of transporting gas to California and back), total gas costs for the SCP portfolio could be reduced by $30 million NPV (Exhibit 1B, p. 11; Exhibit 1A, Panel 1 written evidence, p. 23). BC Gas calculated this benefit by comparing the cost of spot gas at Kingsgate during the winter of 1996/97 relative to the cost of peaking supply from SoCal storage (Exhibit 3A1, IR 18.2).

The policy witness for BC Gas clarified that this approach was put forward as an alternative to the numbers used in the ROM, to indicate that there was some potential upside to the ROM results (T8: 1386-1388). The witness stated the ability of Northwest expansion to offer a similar benefit would be a function of what capacity was added to Sumas in terms of diversion capability (T8: 1390-1391).

Westcoast argues that there is no evidence to support BC Gas' claim that it will be able to buy spot gas on reasonable terms, and that it is not feasible to rely on spot gas as a source of supply for the SCP (Argument, pp. 12-13, 43). PGT states that during the highest demand day, PGT's take-away capacity at Kingsgate exceeds ANG's delivery capacity (T14: 2454). Moreover, there are not a lot of transactions at Kingsgate and the gas market at Kingsgate is not as liquid as that at Sumas (T4: 566; T14: 2528). Westcoast argues that spot market prices at Kingsgate last winter would have been substantially higher if BC Gas had been attempting to buy significant quantities of gas.

Northwest argues that shippers on its system could obtain the same benefits of Alberta supply by purchasing gas at Stanfield as SCP shippers can realize by buying gas at Kingsgate.

BC Gas responds that the use of SoCal storage costs in the ROM analysis establishes a maximum for the cost of supply at Yahk, and that it intends to utilize spot gas or other cost effective options that may emerge.

Commission Conclusion

The Commission accepts that with the SCP, BC Gas would, on occasion, find it advantageous to buy spot gas at Kingsgate. However, it seems likely that BC Gas would still consider it prudent to make firm arrangements with SoCal or other suppliers for the larger part of the peaking gas needed at Yahk. Also, aside from the supply security issue, the Commission believes that the relative lack of market liquidity at Kingsgate might well result in higher prices with any significant new spot gas demand.

Moreover, the Commission is reluctant to accept, as an SCP benefit, the result of what is essentially a sensitivity case for the cost of one of the supply resources that was an input into the ROM. A more comprehensive testing of the costs that were assumed in the ROM for storage, peaking and seasonal supply may or may not favour the SCP over LNG or a Northwest expansion. Therefore, the Commission finds that while the ability to purchase spot gas at Yahk may offer some modest benefit for the SCP, it is not prepared to include in the analysis a dollar amount for this non-ROM benefit.

10.7 Point-to-Point Tolls from Kingsvale to Huntingdon in the SCP Case

As discussed in section 7.1.1 under ROM assumptions, BC Gas assumes a toll of \$0.106/Mcf to transport gas on the Westcoast system from Kingsvale to the BC Gas system at Huntingdon (Exhibit 3I, IR 39; Exhibit 48, p. 1; T5: 834, T12: 2069). BC Gas calculates this rate as the difference between the Westcoast T-South tolls for the Interior and Lower Mainland delivery areas. BC Gas also states that, as soon as the SCP is certificated, it will request 85 to 110 MMcfd of service from Kingsvale to Huntingdon (Exhibit 2D, IR 6.4). If the NEB approves a point-to-point toll based on a demand distance methodology for this service, BC Gas estimates that this would reduce the cost of the SCP portfolio by \$34 million NPV. BC Gas claims this saving as a non-ROM benefit for the project (Exhibit 1A, Panel 1 written evidence, p. 23).

Counsel for BC Gas and witnesses for Westcoast had an extensive discussion about the cost of expanding the Westcoast pipeline from Kingsvale to Huntingdon to handle an additional 85 MMcfd (Exhibit 5C1, IR 9; T12: 2042-2062). A 300 MMcfd expansion would require about \$19.3 million of compression and \$45 million of looping (Exhibit 91). An expansion of only 85 MMcfd, by itself, would require about \$10 to \$12 million of compression (T12: 2058-2062). Westcoast filed evidence which indicates that a \$12 million expansion would have an incremental cost of service of \$0.041/Mcf in 2002 and of \$0.074/Mcf in 2010 (Exhibit 91).

BC Gas argues that the evidence of Westcoast shows an incremental cost of service that is in line with the \$0.05/Mcf point-to-point toll, supporting a benefit of \$34 million NPV relative to the ROM analysis.

NORPAC argues that if the SCP is built and if third-party volumes do not materialize, BC Gas will have an incentive to use the SCP to displace other supplies of gas, which could lead to further decontracting on the Westcoast system upstream of Kingsvale and a relative shift to gas sources outside of British Columbia (Argument, pp. 7-8).

Westcoast argues that transporting gas from Kingsvale to Huntingdon could strand Westcoast facilities upstream of Kingsvale, and that Westcoast is not prepared to provide this service absent a direction from the NEB (Argument, pp. 21-22 and 33; T12: 2139-2140). A witness for Westcoast stated that the full toll of approximately \$0.26/Mcf from Station 2 to Huntingdon might be more appropriate than a point-to-point toll (T12: 2140).

Commission Conclusion

The Commission recognizes the uncertainty with respect to the Westcoast toll for transporting gas from Kingsvale to Huntingdon, and the significance of the toll in the total gas cost that is calculated for a portfolio which includes the SCP. When placed in service, the SCP could result in a surplus of supply at Huntingdon (T8: 1305). It would also initially reduce the amount of Westcoast transportation that BC Gas requires upstream of Kingsvale (Exhibit 1B, p. C7; Exhibit 8L, p. 3). Thus, in the early years, it is possible that the SCP could lead to some stranding of Westcoast capacity, and it is possible that BC Gas customers would bear some of the costs of any stranded capacity.

Over the longer term and considering the potential for natural gas thermal electrical generation and cogeneration projects, it is likely that expansion of the Westcoast transmission system will take place. The incremental cost of expanding the system from Kingsvale to Huntingdon, and the point-to-point tolls that would result from the demand distance methodology that Westcoast currently uses to determine T-South tolls, both give rates that are less than $0.106/Mcf.

Recognizing that the ROM-assumed toll of $0.106/Mcf is near the low end of the range between a demand distance or an incremental toll of about $0.05/Mcf and a maximum toll of $0.26/Mcf to avoid stranded costs, the Commission is not persuaded that an additional SCP credit should be included at this time.

10.8 Maintenance of Existing Trail to Oliver Pipeline with SCP

The September IRP Update includes a non-ROM SCP benefit of $4 to $13 million NPV to account for the saving on maintenance of existing transmission pipelines (Exhibit 1B, p. 11; Exhibit 1A, Panel 1 written evidence, p. 24). This benefit relates to the existing 10-inch pipeline between Trail and Oliver, which was built in 1957 and operated for ten years without cathodic protection. A high resolution inspection tool was run in the pipeline in 1993, and a second run is scheduled for 1998. An updated rehabilitation plan is expected to be available by the fall of 1998 (T11: 1827).

The existence of the SCP would permit the abandonment of portions of the old pipeline (Exhibit 1, App. III, pp. 13-14). BC Gas estimated the cost of maintaining the existing Oliver to Trail pipeline under several scenarios (Exhibit 3D, IR 48.2; Exhibit 90, IR 13). The Utility calculated an NPV benefit of $4 to $13 million for the SCP by subtracting the best and worst case costs for a selective abandonment scenario (which would be possible with the SCP) from the corresponding costs if the Oliver to Trail pipeline remains in service (which is necessary without the SCP).

Westcoast argues that until the internal inspection of the pipeline in 1998 is conducted, the estimated benefit is speculative (Argument, pp. 43-44). BC Gas responds that there can be little doubt that significant expenditure or abandonment of the existing pipeline will be required.

Commission Conclusion

BC Gas will have more current information about the condition of the Oliver to Trail pipeline, and the rehabilitation work that is needed, later in 1998. Whatever the outcome, the Commission expects that a new, large diameter pipeline paralleling the old line, if built, would significantly reduce rehabilitation costs on the original line over the long term. It therefore accepts the high end of the BC Gas range, $13 million NPV, as a potential measure of this non-ROM benefit.

10.9 Non-ROM Benefits of Projects other than the SCP

Many of the non-ROM benefits claimed by BC Gas for the SCP have parallels in the alternative competing proposals. Throughout the hearing and in argument, BC Gas and the proponents of the alternative projects discussed the level of comparable benefits which their particular project offered. These discussions have been largely summarized in the preceding sections.

In order to fairly adjust the ROM output of all projects, it is necessary not only to add non-ROM benefits to the SCP case as assessed by the Commission in the preceding sections, but to add non-ROM benefits to the ROM output of the competing LNG group of proposals and the NWP case. This section discusses the Commission's evaluation of the appropriate level of non-ROM benefits to be assigned to the two groups. These benefits are listed under the same headings used by BC Gas in its assessment of non-ROM benefits.

10.9.1 Balancing, NWP and LNG

BC Gas assigned an annual value from $1 million to $4 million, or $11 to 44 million NPV, for the improved balancing which would result from the construction of the SCP. It considered LNG or NWP expansion projects to provide some 25 percent of this level of benefit. This translates to $3 million to $11 million in NPV savings (Exhibit 1, pp. 22-23; Exhibit 1A, Panel 1 written evidence, pp. 19; Exhibit 1B, p. 10).

Northwest

A Northwest expansion would seem to provide useful balancing (15 MMcfd from 300 MMcfd of expansion capacity), and there is no evidence that a Northwest shipper needs to replace one day's imbalance before using it again. The Commission is of the view that NWP expansion does provide a balancing benefit but that this benefit to BC Gas would not be equal to that of the SCP. Therefore, the Commission assesses a balancing benefit of $16 million NPV to NWP, which equals half that assigned to the SCP.

Liquefied Natural Gas

LNG provides excellent flexibility to react to a sudden and large increase in demand, but can only do so for a limited period. Replacement gas can be liquefied whenever there is space in the tank, but the rate is limited by a typical liquefaction capacity of 12 to 16 MMcfd. The relatively small liquefaction capacity also means that the LNG is of limited balancing assistance when actual demands are less than forecast.

In the ROM, BC Gas reserves 10 percent (300 MMcf) of the incremental LNG capacity for operating trim, as well as 100 MMcf of the existing capacity at Tilbury (Exhibit 3D, IRs 1, 6.2; T8: 1367). [There is some evidence that BC Gas anticipates using the full 3 Bcf in a design year, but the reservation of a portion of the LNG capacity for balancing is consistent with present utility practice (T3: 467; T4: 511-512; T6: 998]. On the basis that the ROM reserves 10 percent of incremental LNG capacity for balancing, it is reasonable to consider the value of this LNG to be at least equal to its cost in the order of $9/GJ (T8: 1368). The Commission uses this value to assign a balancing benefit to LNG of $2.7 million per year, or $29 million NPV.

10.9.2 Increased Supply Security, NWP and LNG

BC Gas expressed the view that an LNG plant in the Lower Mainland or a NWP expansion would have approximately equal benefits in enhancing supply security to BC Gas' system. It estimated this benefit to result in an NPV saving from $0 to $16 million for each of these cases. The $15 million figure submitted by PGT is at the high end of the BC Gas range. NWP suggested an expansion of its system would provide benefits equivalent to SCP ($0-24 million NPV).

A new LNG facility would improve security for the Lower Mainland, and to a lesser extent for the Interior, in the event of a short-term disruption. Supply up to 300 MMcfd would be readily available; LNG plants are reliable, but deliveries at the full rate could be sustained for ten days at most. In some cases, the delivery period would be considerably less, either because the LNG tank was only partly full, or because the LNG could not be released due to impending cold weather. It is also the case, however, that a transmission pipeline break or other disruption can generally be put back into temporary service quickly, as indicated by the record of recent Westcoast Force Majeure events (Exhibit 2D, IR 13.1). Only a major failure at one of Westcoast's largest processing plants would result in a prolonged outage.

The Commission concludes that a non-ROM benefit at the high end of BC Gas' estimate for the cases of LNG and NWP expansion is appropriate and, accordingly, assigns an NPV value of $16 million as an enhanced security benefit for each alternative.

10.9.3 Third-Party Transportation Revenue, NWP and LNG

Northwest

The evidence about the mitigation revenue earned by current Northwest shippers, and that earned by BC Gas through capacity release on the pipelines serving its market areas, indicates that the potential for third-party revenue from Northwest expansion capacity is real and may be substantial. The Commission determines that a value for additional third-party transportation revenue from Northwest expansion at least equal to the additional benefit considered reasonable for the SCP, or $0 to $33 million NPV, is reasonable as a non-ROM addition to the NWP case.

Liquefied Natural Gas

LNG does not appear to offer significant potential for third-party revenues. With regard to the Cherry Point location of LNG, the ROM analysis implicitly includes $3.6 million per year of third-party revenue from the interconnecting pipeline. Notwithstanding PGT's claim for a larger benefit, the Commission is not persuaded that a larger amount of revenue is likely. Accordingly, the Commission accepts $3.6 million per year of transportation revenue for PGT in the ROM analysis, and determines that zero additional third-party non-ROM benefit is appropriate for LNG.

10.9.4 Price Shock Protection, NWP and LNG

BC Gas estimates that a NWP expansion would provide price shock protection benefits to the Utility equal to 50 percent of the SCP allocation. It attributed no price shock protection benefit to LNG (Exhibit 1, pp. 21-23; Exhibit 2D, IR 8.2; Exhibit 2L, IR 33; T4: 518; T8: 1302-1304). By contrast, WGSI suggests a benefit of $10 million NPV for LNG (Exhibit 112).

If one accepts that the SCP helps prevent a supply resource deficit in the Lower Mainland and, hence, protects BC Gas consumers from price shock effects, it is reasonable to expect that either a NWP expansion or LNG would have a modifying effect also. Since Northwest involves the expansion of an existing pipeline, it is reasonable to assign it a slightly lower potential protection benefit than a new pipeline such as the SCP. Because LNG availability will be constrained by the amount of LNG in the tank, the Commission concludes that it is also reasonable to significantly discount the value of this resource as a price shock modifier.

In summary, the Commission determines a non-ROM benefit for NWP equal to 75 percent of that which it has assigned to the SCP, and a non-ROM benefit for LNG equal to 25 percent of the assigned the SCP benefit. These translate to non-ROM price shock protection benefits of $18 million NPV for NWP and $6 million NPV for LNG.

10.9.5 Additional Compression, Oliver to Kingsvale; NWP and LNG

There is no comparable benefit to be considered for the NWP and LNG cases.

10.9.6 Gas Delivered at Yahk, NWP and LNG

There is no situation involving LNG which is directly comparable to this SCP benefit. Northwest attempted to make a comparison for its system, with BC Gas purchasing spot Alberta gas at Stanfield. However, considering the concerns with regard to the SCP that are discussed in section 10.6, the Commission concludes that there is no evidence to support a significant non-ROM benefit for NWP on this account.

10.9.7 Westcoast Point-to-Point Tolls, NWP and LNG

There are no comparable additional benefits available to either NWP or LNG in this category.

10.9.8 Trail to Oliver Pipeline, NWP and LNG

Neither the expansion of NWP nor the construction of LNG in the Lower Mainland would have any impact on the Trail to Oliver pipeline segment. Additional non-ROM credits are therefore not applicable.

10.10 Financial Impact of Non-ROM Benefit Adjustments

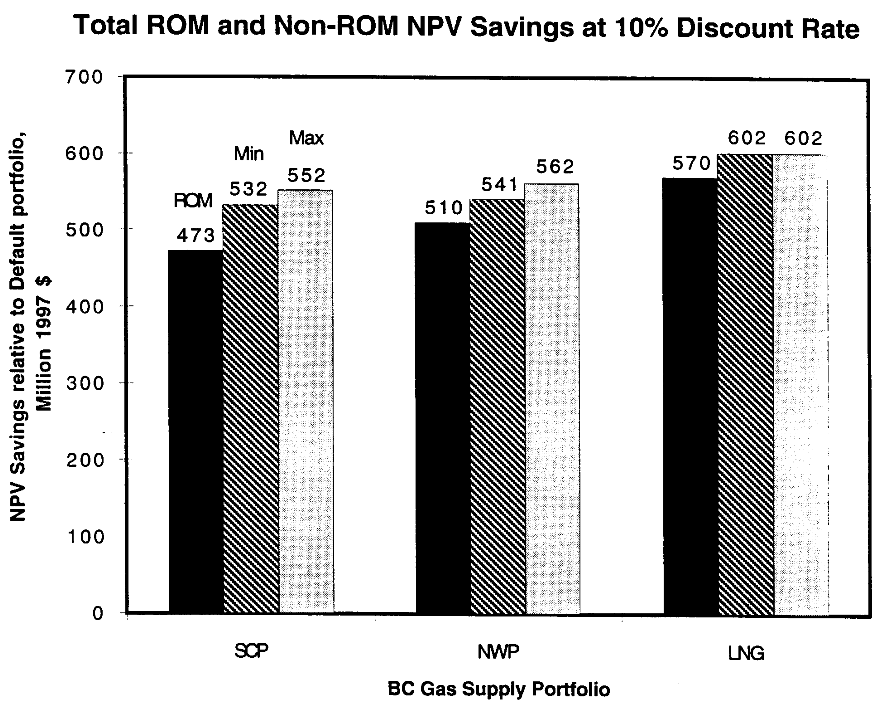
In the foregoing paragraphs, the Commission has determined the value of the non-ROM benefits which it believes should be added to the ROM output for the three leading resource options. For ease of reference to the Application and other evidence, this information has been expressed as the NPV of customer savings, relative to the baseline Default portfolio, in 1997 dollars, using a 6.18 percent discount rate over a 30-year period. To be consistent with the NPV calculation of the ROM results and to reflect the uncertainty of the non-ROM benefits over the 30-year time horizon, the Commission has also discounted the non-ROM benefits at 10 percent. These have then been added to the ROM NPV saving values, to arrive at the total NPV saving value of each of the three resource alternatives. Where a range of probable NPV values has been assigned, both the minimum and maximum values have been entered in the following Table 10-2.

Table 10-2

Total ROM and Non-ROM NPV Savings

	Total NPV Savings, millions of 1997 Dollars					
	SCP		**Northwest**		**LNG**	
	Min	Max	Min	Max	Min	Max
Adjusted ROM Savings (at 10% discount rate, from Figure 9-2)	473	473	510	510	570	570
Non-ROM Benefits (at 6.18% discount rate)						
Improved Balancing	33	33	16	16	29	29
Increased Security	24	24	16	16	16	16
Incremental Transportation Revenues	0	33	0	33	0	0
Price Shock Protection Benefits	24	24	18	18	6	6
Additional Compression on ITS	0	0	0	0	0	0
Spot Gas Bought at Yahk	0	0	0	0	0	0
Point-to-Point Westcoast Tolls	0	0	0	0	0	0
Maintenance of Trail to Oliver Line	13	13	0	0	0	0
Total non-ROM benefits (at 6.18% discount rate)	94	127	50	83	51	51
Total non-ROM benefits (at 10% discount rate)	59	79	31	52	32	32
Total ROM and non-ROM NPV Savings (at 10% discount rate)	532	552	541	562	602	602

Figure 10-1



LNG is average of LNG alternatives

Using the data in Table 10-2, Figure 10-1 has been constructed to show a direct comparison of the three leading portfolios, namely construction of the SCP, an expansion of the Northwest system and LNG in or close to the Lower Mainland. The addition of the non-ROM benefits brings the alternatives closer together but continues to show LNG as the preferred resource option. However, with the large amount of uncertainty in the factors underpinning the analysis, each of the options remain competitive within the margin of error of the analysis.

11.0 OTHER CONSIDERATIONS

This Chapter deals with issues which received considerable attention during the hearing but which have not been explicitly covered elsewhere in this Decision document.

11.1 Customer Rate Impacts

In the September IRP Update, and subsequently, BC Gas updated the burner-tip rate information in its Application based on the revised ROM results (Exhibit 1B, App. G; Exhibit 10). The Utility included the market and operational benefits that it estimated for SCP and other resource options with respect to improved balancing, increased security, incremental transportation revenues and price shock protection. Results were presented in graphical form for the Reference (base) Case, for high and low gas prices, different load growth assumptions, and with the SCP capital costs depreciated at 3 percent (Exhibit 1B, App. G, p. 1; Exhibits 10 and 118).

Before considering the burner-tip impacts of the resource alternatives, it is necessary to address the large “bump” in rates for 2001 and 2002. BC Gas points out that this is largely due to the projected increase in the price of gas over these years for the Reference case (Exhibit 1A, p. 30; Exhibit 1B, App. A; Exhibit 3L, IR 82). In contrast, the high case gas price forecast indicates little if any price increases in 2001 and 2002, and the burner-tip prices for this case show very small changes over these years (Exhibit 1B, App. G, p. 5). In summary, when comparing supply resource alternatives, the relative change in burner-tip rates is the measure that is significant.

<u>Burner-Tip Rates Based on ROM Results</u>

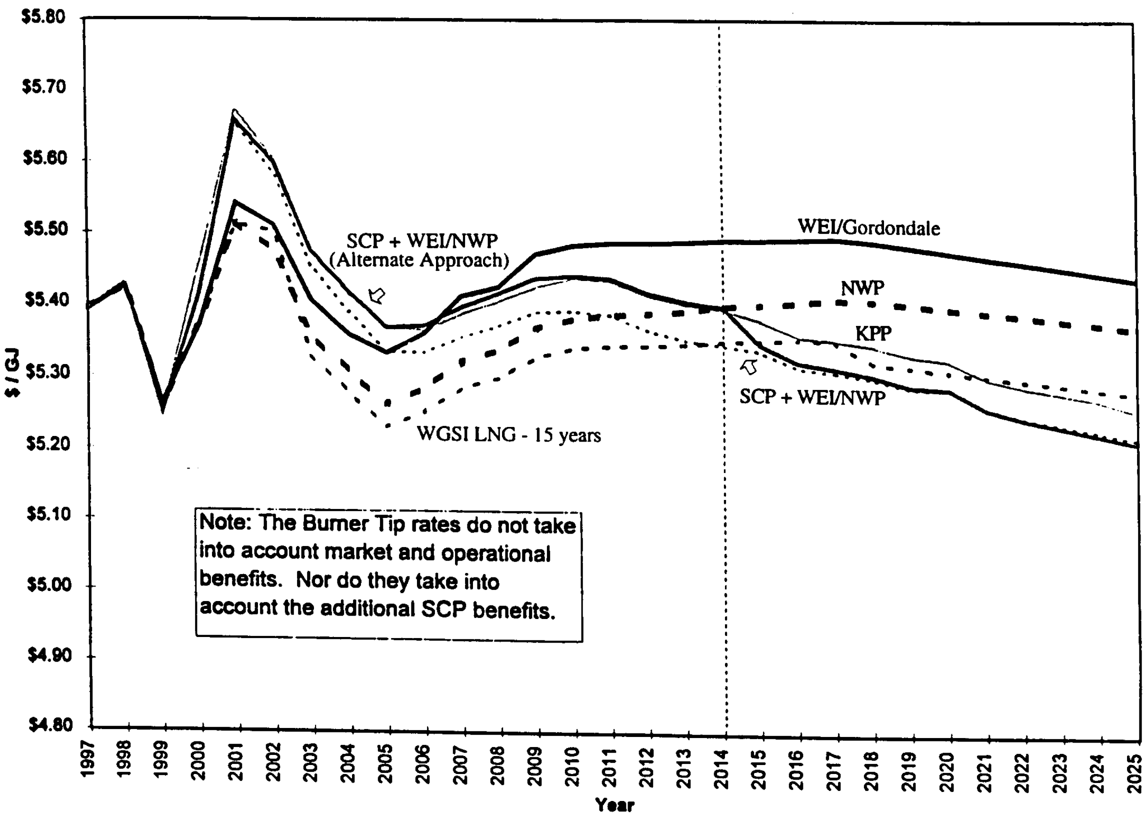
BC Gas also filed evidence about burner-tip rates which are based on the ROM results only, and do not include any additional operational and market benefits (Exhibit 121). Figure 11-1 summarizes this evidence. The evidence states that the third-party transportation revenue from the SCP within ROM is reduced from $9.5 to $7 million per year, but a comparison of the supporting information with that in the September IRP Update indicates that this was not done.

Figure 11-1

Core Burner-Tip Rates for Reference (Base) Case

ROM Results Only

Rates in Real 1997$/GJ



Source: Exhibit 121

Materials originally filed by BC Gas.

The ROM-only evidence deals with the following alternatives:

- Scenario I SCP Alternate Proposal;
- Scenario II SCP + Westcoast/Northwest expansion;
- Scenario III KPP from Yahk to Oliver, in service in 1999;
- Scenario IV Northwest Expansion;
- Scenario V Westcoast Expansion; and
- Scenario VI LNG + Westcoast/Northwest, using 15-year tolls.

The Commission notes that ANG argued that BC Gas significantly overstated the cost of KPP service from Yahk to Oliver when it prepared Exhibit 121 (ANG Argument, pp. 12-3).

Average core market burner-tip rates based on ROM-only results have been extracted from the evidence and are shown in Table 11-1.

Table 11-1

Burner-Tip Rates Based on ROM Results

		Average Firm Sales Rate, 1997$/GJ					
Scenario		1997	2001	2005	2010	2015	2025
II	(SCP Base Case)	5.39	5.65	5.33	5.39	5.34	5.18
IV	(Northwest)	5.39	5.51	5.26	5.38	5.40	5.36
VI	(LNG)	5.39	5.51	5.23	5.34	5.35	5.27

This BC Gas evidence shows only very small differences between the rates resulting from these alternatives. The SCP is $0.14/GJ (3 percent) more expensive in 2001, and is less costly by about the same amount by the end of the study period. The SCP provides lower rates than a Northwest expansion after 2010, and than an LNG facility after 2013. Over the ten-year term from 2001 to 2011 the LNG solution, as represented by the WGSI proposal, shows a burner-tip rate saving averaging some $0.07/GJ compared with the SCP base case. The Northwest Pipeline alternative over the same time frame shows savings averaging some $0.03/GJ. This difference in gas cost is of the order of 1 or 2 percent of total gas cost.

Commission Conclusion

The Commission recognizes the difficulty of attempting to predict the many factors that can affect burner-tip prices for core customers over 30 years. It shares many of the concerns that Intervenors have expressed about individual components of the burner-tip projections in the September IRP Update. On the other hand, it considers that the projections in Figure 11-1 present a relatively conservative measure of the benefits of the SCP insofar as they are based on ROM only and do not consider non-ROM benefits. This evidence supports the claim of BC Gas that: "... there is no significant difference in the burner-tip price of delivered cost of gas to our customers." (T4: 627)

The evidence is inconclusive, except to indicate that if the non-ROM benefits of the SCP are totally discounted, customers will have to wait some 10-15 years to see a reduction in burner-tip prices below what they would be if one of the other proposals was adopted.

11.2 Capital Risk

Even though the effects of the capital expenditures required for each project are taken into account in the ROM model and the risk issue may be considered to be addressed in the selection of an appropriate discount rate, the specific capital risk of the projects and their potential for cost over-run received a great deal of attention during the hearing. In anticipation of these concerns, as they relate to the SCP, BC Gas ran a sensitivity test to show the impact of capital cost parameters, as reported in section 7.4. Nevertheless, the Commission considers it important to separately examine these issues.

11.2.1 Capital Costs of the Projects

The total cost of the SCP is estimated by BC Gas to be $348.2 million (Exhibit 1, App. III, p. 18).

Exhibit 120 provides information about expansions of the Northwest system by up to 400 MMcfd, of which the first 50 MMcfd block has already been committed. Blocks II, III and IV, totaling 150 MMcfd, have an estimated capital cost of U.S. $97.5 million (Cdn $131.7 million, at a currency exchange rate of 0.74) in 1997 dollars.

With respect to LNG, in the September IRP Update, BC Gas used a capital cost estimate of $139 million in 1997 dollars for a 3 Bcf LNG facility at Tilbury as its generic LNG case. This cost appears reasonably consistent with the cost of the other LNG proposals. A 3 Bcf LNG facility at Cherry Point is estimated to cost Cdn $123.9 million in 1996 dollars, while a pipeline between Cherry Point and the BC Gas system at Livingstone would add Cdn $25.7 million. The WGSI LNG facility is estimated to cost $120 million in 1997 dollars. The Williams LNG facility cost estimate is Cdn $121.2 million in 1997 dollars.

For convenience, these cost numbers are assembled in Table 11-2 below, together with an evaluation of the impact of each capital expenditure on the burner-tip price.

Table 11-2

Capital and Annual Costs of Resource Alternatives

Resource		Capital Cost Millions 1997$	Cost of Service, 1997 $ 2002	2005	2015
Firm System Sales, PJ			146.6	154.8	175.2
SCP,	Million $	348	34	28	14
	$/GJ		$0.23	$0.18	$0.08
NWP(150),	Million $	132	15	13	9
	$/GJ		$0.11	$0.09	$0.05
LNG,	Million $	139	10	16	8
	$/GJ		$0.07	$0.11	$0.04

To place these figures in perspective, the cost of service of the foregoing resource additions in 2005 represents 2 to 3 percent of the average core market rates that are shown in section 11.1.

BC Gas responds to concerns about the higher capital cost of the SCP by stating that the appropriate perspective is the relative impact on the customer's burner-tip cost of gas, together with consideration of security of supply and other benefits which are not represented in the burner-tip price.

ANG and Westcoast raise a concern that approval of the SCP to Oliver is only the first step, and would shortly lead to the SCP Phase II to Kingsvale [at a cost of approximately $200 million (T10: 1726)] and perhaps on to Huntingdon. ANG also argues that the design of the SCP will make it more costly than the alternative KPP pipeline which it proposes (Argument, p. 12).

AASEP, CAC (B.C.) et al., LMLVGUA and others express concern that the relatively high capital cost of the SCP increased the financial risk of core and other customers. PGT and others argue that the Commission should place great weight on the up-front capital costs of the SCP and LNG as an indicator of economic efficiency of the projects (PGT Argument, p. 18).

Westcoast filed evidence which shows that the total facility costs of the SCP, including those required to deliver gas to the SCP at Yahk and to redeliver the gas to Huntingdon, is at least $532 million NPV (Exhibit 48). It pointed out that the comparable facility cost for WGSI LNG is estimated at $189 million.

Commission Conclusion

In an uncertain world it is prudent to minimize capital exposure. The SCP requires an up-front capital investment that is more than twice the cost of the alternatives without demonstrating substantially improved benefits.

11.2.2 Potential for Cost Over-Runs

BC Gas states that its SCP cost estimate should be accurate within plus or minus 10 percent (Exhibit 1, App. III, p. 13). While discussing the need to negotiate a right-of-way agreement with the Osoyoos Indian Band, BC Gas confirmed it was confident that, in a worst case scenario, the SCP can be built within 10 percent of its estimate (T11: 1885-1886). However, its policy witness stated BC Gas has not contemplated taking on the capital cost risk for over-runs (T8: 1402).

ANG's construction expert witness, Mr. Kraft, suggested that if the level of pipeline construction activity in Canada is extremely high, the installation portion of the estimate for the SCP could increase by 25-30 percent and the materials portion could increase by 10-15 percent. In such an event, the capital cost will increase to a range of $388 million to $403 million, some 17 percent to 22 percent above the $330 million current estimate[6] (T7: 1273).

Northwest states that it completed two recent system expansions under budget, and that it has a high level of confidence in its cost estimate. Nevertheless, the incremental toll for expansion capacity will be based on the actual cost of the project (Exhibit 6C, IR 5.13).

BC Gas expects its LNG cost estimate to be accurate within plus or minus 20 percent (Exhibit 4B, p. 6-4). BC Gas maintains that the Tilbury site is feasible for LNG expansion (Exhibit 5B2, IRs 2.3 and 5.2; T13: 2363-2364). The consultant for BC Gas continues to support a study which concluded

6 The overall cost increase was calculated from pp. 16-17 of the BC Gas's September Engineering Report Update, App. III of Exhibit 1. If the installation costs increased by 25-30 percent these costs would increase to $251 to $262 million. Similarly if the material cost increased by 10-15 percent then these costs would increase to $87 to $91 million. Assuming, conservatively, that the following cost categories - Project Services, Land Acquisition, and Restoration - remain the same at about $50 million, the total costs would increase to be in the range of $388 to $403 million.

that a suitable site could be found in the Lower Mainland, but acknowledges that the study did not take into account local zoning restrictions or regional planning guidelines (T13: 2201, 2216-2218, 2253-2254).

The WGSI LNG proposal places the risk of capital cost over-runs on the proponent unless it can recover the extra costs through contracts. However, the Commission notes that the WGSI offer expired on February 1, 1998 (T21: 3695). Also, WGSI expects that BC Gas would pay the actual, approved Centra tolls for deliveries to and from McNab Creek (Exhibit 5D3, IR 12.1). Moreover, WGSI faces some opposition to its McNab Creek proposal from Howe Sound residents (Exhibit 88, T24: 4089-4160) and there is, therefore, a risk that the site may not be approved.

Williams and PGT believe that their estimates are accurate within plus or minus 15 percent, and appear to anticipate that the Federal Energy Regulatory Commission ("FERC") approved fees will be based on actual construction costs (Exhibit 7B, IR 14; T15: 2615). The Williams site near Sumas would require a change to the current agricultural zoning. While Williams anticipates it can work through issues related to rezoning, its witness acknowledged that this may be difficult (T15: 2572).

PGT has not selected a specific site in the Cherry Point industrial site, or done detailed siting studies (T14: 2426-2428) although its project would be compatible with the area's zoning. In addition, the cost and allocation of costs related to the pipeline to Livingston introduces uncertainties with respect to Cherry Point LNG. At the same time, PGT has proposed a larger, regional LNG facility at Cherry Point which could reduce the cost to BC Gas of 3 Bcf of LNG capacity through capacity sharing.

Commission Conclusion

The Commission notes that the SCP estimate includes an explicit contingency allowance of $2.6 million on materials and $8.9 million on installation, plus a further $1.8 million on other categories (Exhibit 1, App. III, pp. 16-17). In addition, a witness for BC Gas stated that the contractor includes a contingency of about 7.5 percent in the estimated cost of installation (T11: 1874). Including the contractor’s allowance of about $13 million gives a total contingency of $26 million or about 9 percent for the project.

The SCP would be built in BC Gas’ existing right-of-way, for the most part. However, concerns remain relative to the still unapproved major river crossings and their potential to delay the project. These concerns are tempered by the currently low inflation rate which tends to ensure that delay-induced costs will not spiral out of control. The greatest price escalation threat is likely to result from a high level of pipeline construction activity. Nevertheless, the Commission accepts the probability that the SCP should be completed at a cost at or below the +10 percent limit stated by BC Gas.

With regard to LNG, the Commission is concerned that siting approvals may extend project schedules and, along with site-specific construction and environmental requirements, may adversely impact the cost of such a facility. In these circumstances, the Commission believes a range of accuracy of plus or minus 15 percent applied to the larger cost estimate for a generic LNG facility is appropriate This leads to the following summary of probable potential over-runs for the resource alternatives.

Table 11-3

Probable Potential Capital Cost Over-Runs

Resource	Capital Cost Million 1997 $	Over-Run Percent	Over-Run Million 1997 $
SCP	348	10	35
NWP(150)	132	10	13
LNG	139	15	21

A 10 percent over-run on the SCP capital costs would increase the NPV cost of service from $506 to $551 million, (over a 30-year period) an increase of $45 million or 9 percent (Exhibit 19, P. 4). Assuming a similar impact on annual cost of service, a 10 percent cost over-run on the SCP would increase core customer rates by about $0.02/GJ in the year 2005.

11.3 Length of Obligation

The approved capital cost of the SCP or a BC Gas-owned LNG facility would be included in the Utility's rate base, and would be depreciated over time. (The Alternate Proposal for the SCP is a different approach, as discussed in section 9.3.) In the September IRP Update, BC Gas depreciated its projects at current BCUC approved depreciation rates of 2.1 percent per year for the SCP and 3.9 percent per year for LNG (Exhibit 1B, p. 5; Exhibit 3I, IR 43).

Northwest requires a 15-year firm service contract [Exhibit 6A, IR 2(b)]. WGSI filed rates for its LNG facility for contract terms from 10 to 25 years (Exhibit 109). PGT proposed a 25-year term to BC Gas, but stated that a 15-year term would also be acceptable (T14: 2510). Williams offered a rate based on a ten-year fixed rate contract (Exhibit 4G, p. 2).

The Commission recognizes that the natural gas market and the regulatory environment have changed considerably over recent years, and will continue to change. It is prudent for utilities to attempt to reduce the length of the commitments that they enter into, in order to preserve flexibility to accommodate changing demand forecasts and market conditions. However, this flexibility can come at a cost, as is evidenced by WGSI LNG fees of $9.36/Mcf for a ten-year contract and $6.33/Mcf for a 25-year contract (Exhibit 109).

The Commission would be especially concerned about a long-term commitment to a new supply resource if there was evidence that consumer demand would not continue to grow as forecast, or that the gas supply accessed by the facility is projected to decline. This is not the case in this proceeding. An LNG facility or large pipeline which is built as part of rate base and is depreciated over 25 or 50 years may seem different from a resource which BC Gas commits to under a 10- or 15-year service contract, but the difference is of questionable significance. The critical consideration is whether the facility will be used and useful. A facility which has been useful for 15 years, and whose cost has been depreciating, likely will continue to have some value for ratepayers throughout its physical life.

11.4 Staged Approach with Northwest

Northwest expansion capacity can be added in blocks of 40 to 100 MMcfd (Exhibit 120). Physical facilities can be built in phases as required to match market growth, and Northwest argues that this prevents expensive and inefficient over-built capacity.

The ability to add smaller increments of capacity to an existing transmission pipeline is a definite advantage, and avoids large expenditures for large, lumpy resource additions which may not be fully needed initially. This attribute is reflected in the way that Northwest capacity is handled in the ROM analysis, and the ROM results appear to include the dollar impact of this feature (Exhibit 3D, IR 9.1). In addition, the foregoing discussion considers in a more qualitative way the effect on capital cost risks.

Over and above considerations related to selection of the optimal next major resource addition, incremental expansions provide BC Gas and others with very useful flexibility to accommodate unexpected variations in demand growth and delays and disruptions in other supplies.

11.5 Schedule Risk

Schedule risk is chiefly the risk that a new resource addition will not be completed in time for the peak demand requirements of BC Gas.

The Application sets out a November, 1999 in-service date for the SCP, assuming a Stage 1 Environmental Assessment Act approval. The Utility expected to obtain a CPCN by January 1, 1998 and EAA approval by July 1, 1998 (Exhibit 1, App. III, pp. 14-15).

The present Northwest open season will close 30 days after the release of this Decision and Northwest anticipates an in-service date of November 1, 2000 (Exhibit 4C, p. 14). This indicates a lead time somewhat in excess of two years for a Columbia Gorge expansion project.

WGSI indicated its LNG facility will be in service in 2000, assuming it received a Project Approval Certificate in March, 1998 as a result of a Stage 1 EAA review (T20: 3626-3627). BC Gas indicated a 2002 in-service date for a utility LNG facility. PGT also stated an in-service date of 2002, while Williams indicated it could be vaporizing LNG for the 2001/02 winter season.

BC Gas argues that a November, 1999 in-service date for the SCP is realistic, as communities along the route support the project. In its Reply, BC Gas maintains that Tilbury is a viable site for LNG expansion, and argues that the BC Gas facility is the preferable LNG proposal.

PGT argues that its schedule to construct the Cherry Point LNG is very reasonable. The company states that the facility would be built in an area that is zoned heavy industrial and that no local opposition is expected. PGT also argues that the likelihood of major opposition to LNG in the Lower Mainland, and "the resultant delays and probable denial of any siting request", argues against attempting to site an LNG facility in BC Gas' Lower Mainland service area.

WGSI argued that it was confident of a 2000 in-service date, assuming a commitment from BC Gas by February 1, 1998 and Stage 1 environmental approval. WGSI argues that PGT has not selected a specific site or done any detailed site design, and that PGT's witness recognized that Cherry Point LNG may not be available until after 2002 (T14: 2467-2468).

Williams argues a zoning change for its LNG site could be obtained within the time provided in its schedule, although its witness acknowledged that the schedule depended on having a letter of intent with BC Gas in the fourth quarter of 1997 (T15: 2599).

Commission Conclusion

The Commission considers that the proposed schedules for the SCP, WGSI LNG, Williams LNG and BC Gas LNG are very tight and that there is a significant risk that the in-service date for any of these projects will be delayed by at least one year. Unexpected problems could cause delays for any of the other alternatives, as well.

As discussed in section 7.5, a one year delay would reduce the ROM benefit of the SCP by $5 million NPV, and having LNG available one year earlier would increase the ROM benefit by $9 million NPV (Exhibit 10). Non-ROM benefits would show a similar trend. There appears to be a greater risk that the SCP will be delayed from the 1999 in-service date that was assumed in the September IRP Update than there is that WGSI or PGT LNG would not be available until after the 2002 date assumed in the Update for LNG. If this comes about, it would reduce the NPV savings of the SCP relative to the LNG alternative.

Of greater concern is whether delays pose a serious risk that gas supply will not be available when it is needed. The Resource Deficit assessment in Chapter 4 indicates this will start to become a concern in the 2002-2003 time period. If LNG is chosen as the next major resource addition, it will be necessary to proceed with it in a timely fashion. The Commission is somewhat concerned by BC Gas' argument that, if LNG is selected, a utility-owned facility is preferable. The utility would need to ensure that efforts to promote the construction of its own facility do not impede or delay the development of an alternative LNG resource.

11.6 LNG Capacity-of-Tank Concerns

There was considerable discussion in the hearing as to whether LNG is less desirable than the SCP and other pipeline alternatives because the capacity of an LNG storage tank is limited. An LNG facility can store only about ten days of supply at maximum send out. [The existing Tilbury facility holds four days of supply at its 150 MMcfd maximum vapourization rate (Exhibit 1, App. II, p. 48)]. In its opening statement, BC Gas states it would be loathe to use LNG (T1: 23). As a result:

> "Because perfect foresight is not available the operators will tend to "hoard" LNG early in the winter due to concerns that the weather will be colder later. The result is that in the real world an LNG facility will usually be operated in less than the theoretically optimal manner." (Exhibit 8C, p. 8)

BC Gas states that it husbands its LNG resource to the best of its ability (T3: 437). However, the witness for BC Gas acknowledges that the Utility used 70 percent of the tank capacity from Tilbury during a cold period in December, 1990 (Exhibit 3G, IR 3.1; T4: 595-597).

A witness for WGSI gave evidence that, so long as the design year is sufficiently conservative, there is no need to discriminate against the use of LNG (Exhibit 53, p. 4).

BC Gas argues that the operational usefulness of LNG is critically impacted by the amount that is available in the tank (Argument, pp. 60-61). Because the ROM analysis assumes perfect foresight in its treatment of LNG, BC Gas states that it credits LNG with greater benefits than would be realized in day-to-day operations.

CAC (B.C.) et al. argues that peak shaving gas obtained from existing or planned facilities like thermal generators provides greater flexibility than LNG, which may be restricted to ten days' output per year (Argument, pp. 14, 35). AASEP argues that B.C. Hydro can store energy in its water reservoirs when gas is cheap (Argument, pp. 15-16). BC Gas responds that, while an electric generating facility may provide peaking supply for ten days similar to LNG, there are economic and other limitations on the use of alternate fuels that prevent it from providing seasonal supply.

PGT anticipates that the Utility will remain the supplier of last resort as the gas marketplace changes, and that having storage like an LNG plant in the centre of its primary market area would serve the BC Gas distribution system well (T14: 2537). PGT argues that BC Gas has shown that it will use LNG when it needs it and that liquefaction can "top up" the tank between draw-downs.

WGSI argues that competent forecasting of the requirements of a design year will allow LNG to be used with confidence. Williams argues that BC Gas would not be as reluctant to dispatch LNG if it had an additional 3 Bcf of storage capacity.

Commission Conclusion

The Commission accepts that LNG is a valuable but limited resource, and that BC Gas would need to use it with caution. Perfect weather forecasts are not available, and so ROM results which are based on perfect foresight may overstate the benefits of LNG. At the same time, liquefaction can occur when the tank has been drawn down. It does not appear that the ROM analysis gives credit to this ability to partially cycle LNG storage.

With regard to an equivalent supply of peaking gas from electrical generation facilities, section 6.2.3 identifies several questions that need to be resolved. Nevertheless, such peaking supply may be more flexible than LNG. The factors that constrain the number of days that it would be available appear to be less definite than the fixed size of an LNG tank.

Overall, the Commission recognizes that LNG has certain limitations relative to the SCP and other pipeline proposals which are available each day of the year.

11.7 Regulatory Risk

The three most likely resource additions, namely the SCP, LNG and Northwest expansion, fall within the jurisdiction of the Commission or the U.S. FERC, aside potentially from some relatively small connecting facilities that would be regulated by the NEB. The FERC generally regulates gas companies on a cost of service basis, although it permits companies to negotiate rates and, in a few instances, to charge market-based rates [Exhibit 7B, IR 3(a)].

PGT and Williams described the authority of FERC to modify service contracts to ensure that they are just and reasonable (Exhibit 7D, IR 8.1; Exhibit 5E2, IR 5.2). Initial regulatory approval of an LNG service contract would include approval of initial rates, and would need to be satisfactory to BC Gas for the project to go ahead. BC Gas could participate in the regulatory processes that would lead to any subsequent changes (T16: 2775).

CAC (B.C.) et al. expresses a concern that jurisdiction over energy projects in British Columbia is fragmented between the NEB and the Commission, but none of the participants argue that its regulatory jurisdiction gives some project an advantage.

Commission Conclusion

There were references in the hearing to the North American gas grid, and the Commission is well aware that gas markets and delivery systems are integrated across provincial and international borders. As more market-based structures replace and redefine regulation, this integration is likely to increase. Regulation varies among jurisdictions, and the decisions that regulators may make in the future cannot always be anticipated. To a large extent, it would be up to BC Gas to protect the interests of the Utility and its customers through the wording of the service contracts that it enters into, and which will require Commission approval. Regulatory risk is an issue, but the Commission does not consider that, on the evidence presented, any of the alternatives have an advantage as a result.

12.0 COMMISSION CONCLUSIONS

This hearing provided the Commission with a unique opportunity to review the BC Gas Application for the Southern Crossing Pipeline coincidentally with a number of other proposals involving pipeline or liquefied natural gas projects. The active participation of all project proponents, some of whom come under other regulatory authorities, was most useful to the Commission in reaching a decision.

Need for Additional Resources

Chapter 4 of this Decision examines the demand-supply balance for natural gas for the BC Gas service area as well as for the Pacific Northwest region. On the basis of the analysis in that Chapter, the Commission is satisfied that the demand forecast indicates that a major new supply resource addition is required within the next five years to serve the growth in peak and seasonal demand, particularly in the Lower Mainland of British Columbia.

Results of ROM Analysis

Chapters 5, 6, 7, 8 and 9 focus on the ROM used by BC Gas. The model analyses a variety of input assumptions and resource portfolios to determine the optimal resource portfolio for meeting the needs of the core customers of BC Gas. As discussed in section 3.3, the results of the ROM analysis form the basis for the September, 1997 IRP Update and BC Gas' assertion that the SCP is the preferred next major infrastructure addition.

While acknowledging that there are limitations to the operation of the model, the Commission accepts the directional guidance the model provides in the selection of a resource portfolio. In Chapters 6, 7 and 8 the Commission reviews each of the model assumptions in turn. Generally, the Commission finds the majority of the assumptions to be reasonable for purposes of the modeling. However, the Commission does not accept two of the assumptions: namely, the discount rate used by BC Gas and the estimate of third-party transportation revenue. The Commission revised the nominal discount rate from 6.18 percent to 10 percent to reflect the long time horizon used in the BC Gas analysis and the associated uncertainty of the assumptions. The Commission also reduced the third-party revenue generated by the SCP from $64 million to $44 million in 1997 NPV dollars, at the 10 percent discount rate.

On the basis of these adjustments, as presented in Chapter 9, three groups of resource options emerge as superior: the LNG option, the NWP expansion option and the SCP with WEI/NWP expansion option. All the LNG alternatives show very similar results and, based on the information provided by the hearing participants, no individual LNG proposal emerges as the preferred LNG option at this time. Therefore, the Commission considered LNG as a single class for further evaluation. The SCP plus LNG case is excluded from consideration in the LNG group because it ranks $40 to $60 million lower in NPV savings than LNG projects alone. BC Gas did not include the KPP proposal of ANG in its ROM analysis, and the evidence indicates that it is unlikely to have greater benefits for BC Gas customers than the SCP, without substantial support from other shippers. Also, the Commission finds that the Alternative Approach for financing the SCP would have fewer benefits than normal rate base treatment of the capital expenditure.

Non-ROM Benefits

The three leading groups of resource options are then evaluated in Chapter 10 on the basis of other, non-ROM benefits. Again, the Commission makes several adjustments with respect to the benefits that BC Gas proposed. The addition of the non-ROM benefits brings the alternatives closer together but continues to show LNG as the preferred resource option. The adjusted ROM analysis and the adjusted non-ROM benefits plus ROM analysis both fail to show the SCP as ranking highest in NPV savings.

Other Concerns about the SCP

Even if the above results are not accepted as conclusive in themselves, they are directionally reinforced by other concerns of the Commission regarding the SCP project.

First, the Commission is concerned about making a large capital investment for core market customers to serve a peaking and seasonal load when there are less costly and lower risk alternatives to meet the need. BC Gas claims that there would be third-party revenues from transportation customers to increase the utilization of the pipeline and offset a portion of the costs of the project. However, BC Gas did not support these claims with any firm commitments or a market test.

Second, the 30-year demand forecast used to justify the SCP extends beyond the 15 to 20 year forecast planning horizon contemplated by the Commission in its IRP guidelines. Beyond 2016 the data has been trended out to 2026. The Commission questions the reliability of that data as well as the risks and uncertainties associated with a 30-year commitment. The gas industry in general, with the role of the LDCs in that industry in particular, is continuing to face change into the future which adds to the uncertainty of a long-term commitment. In the circumstances, core customers may be better served by an approach which is not so heavily dependent on forecast savings to be realized many years in the future. A more incremental approach to resource additions viewed over a shorter time horizon would reduce risk.

Third, with only 170 MMcfd of additional and alternate supply to the Lower Mainland, much of the benefit of this pipeline is limited to the Interior. There are implications for the Westcoast system such as the potential stranding of some Westcoast pipeline capacity on T-South above Kingsvale and uncertainties over toll rates that may be charged for transmission service between Kingsvale and Huntingdon.

Fourth, although BC Gas adopted an integrated approach to meeting gas supply requirements in the Lower Mainland and the Interior, transmission requirements are unique to the individual service area and, as discussed in section 7.2, there are solutions available to serve the needs in these regions separately and incrementally.

Fifth, the Commission is also aware from evidence presented in the hearing that there is the potential for new gas loads to develop to serve cogeneration plants on Vancouver Island and the Burrard Thermal Plant in the Lower Mainland. The Commission recognizes that firm commitments for bringing these projects to fruition have yet to materialize. However, these projects would have some important ramifications for gas demand and for proposals for serving that demand. These projects would increase the demand for baseload gas which could make a pipeline proposal such as the SCP more attractive. In addition, they could offer peak shaving arrangements where natural gas is replaced by an alternate fuel to generate electricity or where the use of gas is otherwise curtailed to provide gas to meet peak demands on the gas system. B.C. Hydro could meet electricity demands by making spot electricity purchases or by using hydroelectric generation. The Commission is of the view that the synergies between these proposed thermal generation projects and the peaking demands on the BC Gas system should be explored further to determine if they could together provide a lower cost option for gas and electric utility customers.

CPCN Application for the SCP

On the basis of the evidence presented and the foregoing concerns of the Commission with respect to the SCP, the Commission concludes that the SCP is not the preferred resource option at this time. From a review of all of the evidence, the Commission is satisfied that BC Gas requires a peak shaving resource to serve the Lower Mainland. The Commission concludes that the LNG option is preferable to the short-listed pipeline options and, under normal circumstances, would expect BC Gas to proceed directly to the LNG solution. However, the Commission also recognizes the potential benefits that cogeneration plants on Vancouver Island and the Burrard Thermal Plant may provide as a low cost peaking option for the customers of BC Gas. At this time, investigation of this option is incomplete. The Commission believes that it is in the public interest to allow BC Gas to examine this option with B.C. Hydro in more detail.

Therefore, on the basis of all the evidence presented to the Commission, the May 30, 1997 Application by BC Gas for a CPCN for the Southern Crossing Pipeline is denied.

Future Action on Supply Resources

The Commission is very much aware that there is some urgency required in finding a resource alternative to meet the seasonal and peaking demand for natural gas, particularly in the Lower Mainland. In the absence of sufficient firm commitments by third parties to make the SCP viable, the Commission is also of the view that BC Gas should develop separate strategies for meeting its transmission capacity needs in the Lower Mainland and Interior regions.

To ensure that the process continues to move forward, the Commission, therefore, expects BC Gas to explore with B.C. Hydro ways in which the two utilities can better serve their customers through a peak shaving arrangement. Recognizing the need for resource additions in the Lower Mainland within five years and the length of time needed to obtain the necessary approvals and to construct an LNG plant, should one be required, a strict timetable is necessary.

The Commission expects BC Gas to expedite negotiations with B.C. Hydro to explore the benefits of peak shaving with the objective of presenting a firm proposal to the Commission no later than October 2, 1998. At the least, such a proposal should contain firm in-service target dates for thermal generation or other plant facilities that will provide the peak shaving, a commitment with respect to a firm supply of gas at Huntingdon, a signed agreement as to terms and prices for the purchase of peak shaving gas and an outline of any new gas pipeline infrastructure required to service cogeneration facilities or other new peak loads. In this regard, the Commission notes that if there is a requirement for new pipeline infrastructure upstream of Huntingdon to serve these loads, BC Gas may wish to re-examine the SCP and attempt to obtain commitments from B.C. Hydro for capacity on the SCP which would make it a viable alternative.

At the same time that BC Gas is pursuing this peak shaving option, it is expected to proceed in parallel to finalize plans for an LNG storage plant to serve the Lower Mainland as a contingency plan in case the peak shaving option with B.C. Hydro does not materialize or the financial terms available to BC Gas are not in the best interests of its customers. The evidence presented in this proceeding demonstrates that there are a number of potential LNG options available for serving BC Gas customers in the Lower Mainland.

In the event that efforts to reach a satisfactory peak shaving arrangement with B.C. Hydro are not successful by October 2, 1998, the Commission expects BC Gas to present a firm proposal to the Commission for a 3 Bcf LNG facility to serve its customers by January 29, 1999. In view of the interest shown in this proceeding in providing LNG service and the close ranking of the LNG options in all the analyses presented, the Commission concludes that BC Gas should issue a request for proposals ("RFP") for LNG service.

As a minimum the RFP should require the proponent to demonstrate that zoning or site approval for its plant is in place or confirm it has a definite and realistic process and timetable for obtaining approval of its site. Proponents should also be required to provide a plant performance specification covering liquefaction and regasification and redelivery, a construction timetable and in-service date, and a firm price offer (subject only to regulatory approval) for contractual terms of 10, 15 or 20 years.

BC Gas is not excluded from making its own response to the RFP but is expected to meet all of the RFP requirements, and to justify its own proposal on the same basis as the proposals of any other party.

In brief, the Commission requires BC Gas to submit a progress report to the Commission on the status of the thermal generation peak shaving options by July 3, 1998. A final report, if possible including a signed contract for Commission approval, should be submitted to the Commission no later than October 2, 1998. By this time BC Gas should be able to demonstrate whether or not this option is in the best interests of its customers. If this option is not the best alternative for the customers of BC Gas, the Commission expects BC Gas to proceed immediately with an RFP for an LNG facility, and to submit an application for a CPCN or a contract for approval with the Commission for the proposal selected by BC Gas, no later than January 29, 1999.

The Commission is aware that land use concerns may delay or ultimately prevent the construction of an LNG facility to serve the Lower Mainland. In the event an LNG facility is not feasible, BC Gas should file a report by January 29, 1999 setting out the alternative course of action that it intends to pursue.

ITS Reinforcement

The examination of alternatives for reinforcement for the Interior Transmission System, independent of requirements for the Lower Mainland, requires further analysis. When the 406 mm (16-inch) loop was installed from Oliver to Penticton in 1994, BC Gas appeared to be placing some emphasis on using Oliver as the primary point of supply for the lower and central Okanagan. This, coupled with the forecast need for at least some rehabilitation of the 273 mm (10-inch) pipeline between Oliver and Trail, indicates a need for greater emphasis on studying alternatives to meet the growing demand on the ITS through additional capacity to Oliver.

When BC Gas is reconsidering the reinforcement options for the ITS, the Commission expects that any future CPCN application for reinforcement of the ITS will explore a number of scenarios among which the following elements could be included:

- increased supply pressure from Westcoast at Savona and Kingsvale (as discussed in section 7.2.1);
- opportunities for DSM and industrial curtailments within the ITS service area;
- more emphasis on supplying the central Okanagan from the Oliver hub;
- continuation of the 406 mm (16-inch) pipeline loop north from Penticton toward Kelowna, with pipe of the optimum diameter;
- extension of looping east of Oliver, both to increase capacity and to reinforce the pipeline between Oliver and Trail as necessary;
- increased capacity on the Kingsvale to Oliver section of the ITS through added compression at either Kingsvale or Princeton;
- increased access to gas supplies from ANG through added compression on the EKL at Kitchener or other locations;
- consideration of the use of satellite LNG for peak shaving at one or more locations on the ITS, since the ratio of peak day demand to the annual average demand is approximately three-to-one; and
- consideration of phasing in reinforcements in economic increments to match the rate of increase in demand on the ITS.

<u>WGSI Exemption Request</u>

In its August 15, 1997 submission, WGSI applied to the Commission pursuant to Section 88(3) of the Utilities Commission Act for an exemption from regulation for its proposed LNG facility. As the Commission has previously noted, no individual LNG project emerges as a preferred option at this time. Furthermore, in the absence of firm contracts that would allow the Commission to assess the monopoly power of the facility, and without an examination of other utility considerations, the Commission is not prepared to exempt the proposed WGSI facilities at this time.

The WGSI application is therefore denied. Should BC Gas bring forward a contract for LNG from the WGSI facility for approval by the Commission in the future, WGSI can make its application for an exemption at that time.

Dated at the City of Vancouver, in the Province of British Columbia, this 3rd day of April, 1998.

Original Signed by:
Lorna R. Barr
Deputy Chair

Original Signed by:
Kenneth L. Hall, P. Eng
Commissioner

Original Signed by:
Frank C. Leighton, P. Eng.
Commissioner

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ORDER
NUMBER G-31-98

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

and

An Application by BC Gas Utility Ltd.
for a Certificate of Public Convenience and Necessity
regarding its Southern Crossing Pipeline Project

BEFORE: L.R Barr, Deputy Chair)
K.L. Hall, Commissioner) April 3, 1998
F.C. Leighton, Commissioner)

O R D E R

WHEREAS:

A. On May 30, 1997 BC Gas Utility Ltd. ("BC Gas") applied to the Commission, pursuant to Section 45 of the Utilities Commission Act ("the Act"), for a Certificate of Public Convenience and Necessity ("CPCN") to expand its existing Interior Transmission System pipeline a distance of approximately 310 km (193 miles), with a 610 mm, (24-inch) pipeline, from Yahk to Oliver, B.C. The CPCN will allow the Utility to construct and operate certain loop and compression facilities which comprise the Southern Crossing Pipeline ("SCP") Project. The SCP Project was previously referred to in the SCP Project Engineering Report and the BC Gas 1997 Integrated Resource Plan update that were filed with the Commission on February 7, and May 5, 1997. These filings were incorporated as appendices to the CPCN application; and

B. On June 26, 1997 the Commission held a pre-hearing conference on the BC Gas SCP Application that was set down by Order No. G-63-97. The pre-hearing conference outlined a draft regulatory agenda and timetable to hear the SCP Application. The parties in attendance at the pre-hearing conference reached consensus on a final Regulatory Agenda; and

C. On June 27, 1997, by Order No. G-75-97, the Commission set down the BC Gas SCP CPCN Application for review by way of a public hearing, and established a Regulatory Agenda Timetable for the public hearing; and

D. Commission Order No. G-75-97 also stated that, on the basis of commitments of parties at the pre-hearing conference, the Commission expected proponents of competing proposals to file detailed evidence and provide witness panels to testify at the public hearing; and

E. On August 15, 1997, the proponents of three other pipeline projects and of four Liquefied Natural Gas ("LNG") facilities, filed evidence regarding their respective proposals; and

F. Westcoast Gas Service Inc. ("WGSI"), in submitting its August 15, 1997 proposal for an LNG facility, included with it an application to the Commission under Section 88(3) for an exemption from the provisions of the Act ; and

.../2

G. British Columbia Hydro and Power Authority ("B.C. Hydro") appeared at the hearing and filed evidence regarding the potential for additional thermal gas-fired generation in British Columbia and the potential for peak shaving arrangements with BC Gas from such generation facilities; and

H. The public hearing commenced on October 14, 1997 and the evidentiary portion of the hearing was completed on November 25, 1997 and written argument was completed on December 19, 1997; and

I During the hearing, in early November, 1997, Town Hall meetings took place in Fort St. John, Castlegar and Oliver, B.C.; and

J. On January 29, 1998, the Commission issued Reasons for Decision allowing WGSI to file rebuttal argument in response to certain arguments of the Consumers' Association of Canada (B.C. Branch) et al.; and

K. The Commission has considered the Application, the written evidence filed prior to the hearing, the evidence presented at the hearing, and the written arguments that were filed after the hearing.

NOW THEREFORE the Commission orders as follows:

1. The May 30, 1997 Application by BC Gas for a CPCN for the Southern Crossing Pipeline Project is denied.

2. The application by WGSI for an exemption under the Act for its proposed LNG project is denied.

3. BC Gas is to file a progress report by July 3, 1998 and a final report by October 2, 1998, on the feasibility of obtaining peak shaving from B.C. Hydro and its electricity suppliers.

DATED at the City of Vancouver, in the Province of British Columbia, this 3rd day of April, 1998.

BY ORDER

Original Signed by:

Lorna R. Barr
Deputy Chair and
Chair of the Division

APPEARANCES

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MS. T. SCHMID	Northwest Pipeline Corporation
A. HOLLINGWORTH D.M. WOOD V. SALVI	Pacific Gas Transmission Company HNG Storage Company
J. LUTES R. SIRETT	Westcoast Energy Inc.
J. ARVAY, Q.C. C. JONES	Westcoast Gas Services Inc.
A. GOLDBERG	Williams International Pipeline Co.
MS. C. REARDON	Association for Advancement of Sustainable Energy Policy
J. QUAIL MS. P. MacDONALD	Consumers' Association of Canada (B.C. Branch) et al. [British Columbia Old Age Pensioners' Organization, Council of Senior Citizens' Organizations of B.C., Federated Anti-Poverty Groups of B.C., Senior Citizens' Association of B.C., West End Seniors' Network, B.C. Coalition for Information Access, End Legislated Poverty and the Tenants' Rights Coalition]
N. SCHULTZ	Canadian Association of Petroleum Producers
D. BURSEY	Council of Forest Industries and Cominco Ltd.
F. WEISBERG	Export Users Group
C. WEAFER	Lower Mainland Large Volume Gas Users Association
S. CARPENTER	Northwest Pacific Energy Marketing Inc.
B. WOODS	Duke Energy
F. BASHAM	Talisman Energy
S.R. MILLER	Petro-Canada Oil and Gas
R.W. LUSK, Q.C. MS. Z. LAZIC	British Columbia Hydro and Power Authority

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The Williams International Pipeline - Panel	KRIS HOHENSHELT DANIEL POTTS RAY SMITH MATT GILLIS DON COERS
Canadian Association of Petroleum Producers - Panel	MICHEL E. SCOTT CHARLES RUIGROK REAL CUSSON FRANK BASHAM
Northwest Pipeline Corporation - Panel	JOHN R. SMITH JOHN B. DAVIS BARRIE B. McCULLOUGH

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Consumers' Association of Canada (B.C. Branch) et al. - Panel	JOHN D. TODD
British Columbia Hydro and Power Authority - Panel	KELLY S. LAIL GRAEME L. SIMPSON
Village of Lions Bay - Panel	BRENDA BROUGHTON
Sunshine Coast Regional District - Panel	PATRICIA M.S. BALDWIN

TOWN HALL MEETING PRESENTATIONS

Fort St. John Town Hall Meeting November 3, 1997

MR. JESPERSEN for BC Gas Utility Company
MR. SEEDALL for Pacific Gas Transmission Company and HNG Storage Company
MR. DENIS ELIAS for Westcoast Energy
MAYOR THORLAKSON for the City of Fort St. John
MR. DON EDWARDS for Fort Nelson-Liard Regional District
MR. FRED JARVIS for Peace River Regional District
MR. BRIAN CHURCHILL - Fort St. John
MR. HUGH MOREY - Director, Fort Nelson

Castlegar Town Hall Meeting November 5, 1997

MR. JESPERSEN for BC Gas Utility Ltd.
MR. SEEDALL for Pacific Gas Transmission Company
MR. ELIAS for Westcoast Energy Incorporated
MR. PORTER for Alberta Natural Gas Pipeline
MR. PETER WESTLAKE - Chamber of Commerce, Christina Lake
MR. RALF SPICER, Goldfell
MR. HAROLD TODD, Trail
MR. JOHN LEBOUROFF, Castlegar
MS. JACKIE HAMILTON, City of Castlegar
MR. HANS LOW, Fruitvale

Oliver Town Hall Meeting November 6, 1997

MR. CLIFF for BC Gas Utility Ltd.
MR. SEEDALL for Pacific Gas Transmission Company
MR. ELIAS for Westcoast Energy Incorporated
MR. PORTER for ANG Company Limited
MR. PHILLIPS or Osoyoos Indian Band
MR. ANDY TOTH
MR. JOE PASTOR, Gallagher Lake

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ABBREVIATIONS

A. Organizations

AECO	Alberta Energy Company
ANG	Alberta Natural Gas Company Ltd
ARC	ARC Financial Corporation
BCUC, the Commission,	British Columbia Utilities Commission
BC Gas, the Utility, BC Gas Utility	BC Gas Utility Ltd.
CanWest	CanWest Gas Supply Inc.
CAPP	Canadian Association of Petroleum Producers
Centra	Centra Gas British Columbia Inc.
Cominco	Cominco Ltd.
COFI	Council of Forest Industries
CAC (B.C.) et al.	Consumers' Association of Canada (B.C. Branch) et al.
Duke	Duke Energy Trading and Marketing, L.L.C.
FERC	Federal Energy Regulatory Commission (U.S.)
GLJ	Gilbert Laustenson Jung
Jackson Prairie, JPS	Jackson Prairie Natural Gas Storage Project in Lewis County, Washington, U.S.
LMLVGUA	Lower Mainland Large Volume Gas Users Association
NEB	National Energy Board
NORPAC	Northwest Pacific Energy Marketing Inc.
Northwest, NWP	Northwest Pipeline Corporation
NOVA	NOVA Gas Transmission Limited
PGT	Pacific Gas Transmission Company
PNG	Pacific Northern Gas Ltd.
SCP Co.	Non-regulated subsidary of BC Gas Inc. (Alternate Financing Approach for SCP)
SIPI	Sumas International Pipeline Inc.
SoCal	Southern California Gas Company
Unocal	Unocal Canada Limited
Westcoast, WEI	Westcoast Energy Inc.
WGSI	Westcoast Gas Services Inc.
Williams, WIPL	Williams International Pipeline Company
VIGJV	Vancouver Island Gas Joint Venture

ABBREVIATIONS
(cont'd)

B. Terms

AFUDC	Allowance for Funds Used During Construction
Bcf	Billion standard cubic feet
CPCN	Certificate of Public Convenience and Necessity
DSM	Demand-Side Management
EAA	Environmental Assessment Act
EKL	East Kootenay Link
GSOM	Gas Supply Optimization Model
IRP	Integrated Resource Plan
ITS	Interior Transmission System
KPP	Kootenay Pacific Pipeline
LP	linear program, linear programming
LNG	Liquefied Natural Gas
LDCs	local distribution companies
MATA	multi-attribute trade-off analysis
MMcfd	Million standard cubic feet per day
NPV	net present value
PNW	Pacific Northwest
PAC	Project Approval Certificate
RFP	request for proposals
RIM	Ratepayer Impact Measure
ROM	Resource Optimization Model
SCP	Southern Crossing Pipeline
T-South	Westcoast Transportation-South
T-North	Westcoast Transportation-North