IN THE MATTER OF

BC Gas Utility Ltd.

SOUTHERN CROSSING PIPELINE PROJECT

DECEMBER 11, 1998 APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

DECISION

May 21, 1999

Before:

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

TABLE OF CONTENTS

TABLE OF CONTENTS
(Cont'd.)

1.0 BACKGROUND

1.1 The 1997 Application and April 3, 1998 Decision

On May 30, 1997, BC Gas Utility Ltd. ("BC Gas"), a wholly-owned subsidiary of BC Gas Inc., applied to the British Columbia Utilities Commission ("Commission", "BCUC") for a Certificate of Public Convenience and Necessity ("CPCN") under Section 45 of the Utilities Commission Act ("Act") to construct the Southern Crossing Pipeline ("SCP") project. The primary purpose of the SCP is to meet the peak and seasonal needs of its firm system sales customers ("core market") over the next 30 years. The SCP is a 610 mm (24-inch) diameter pipeline, extending across British Columbia from near Yahk to Oliver, B.C.

The Commission conducted a hearing into the CPCN application in the Fall of 1997. In addition to an examination of the SCP, evidence was presented by a number of proponents of alternative proposals to the SCP. The alternatives included other pipeline options proposed by Westcoast Energy Inc. ("Westcoast", "WEI"), Alberta Natural Gas Company Ltd. ("ANG") and Northwest Pipeline Corporation ("Northwest", "NWP") as well as four proposals for the construction of liquefied natural gas facilities ("LNG"). BC Gas proposed constructing an LNG plant in the Lower Mainland, Westcoast Gas Services Inc. ("WGSI") at McNab Creek, B.C., Pacific Gas Transmission Company ("PGT") at Cherry Point, Washington and Williams International Pipeline Company ("Williams") at Sumas, Washington. During that hearing, evidence was also presented on the potential for new gas loads to serve thermal cogeneration projects on Vancouver Island and the Burrard Thermal Generation Plant ("Burrard") in the Lower Mainland, and the possibility of using these projects to provide peaking gas to BC Gas.

After reviewing the evidence in 24 days of oral hearing, Town Hall meetings in Fort St. John, Castlegar and Oliver, and written argument, the Commission issued its Decision on April 3, 1998 denying the application by BC Gas for a CPCN for the SCP ("1998 Decision"). While the Commission acknowledged that there was some urgency in finding a peak shaving resource to serve the Lower Mainland, the Commission also recognized there could be potential synergies between the thermal generation projects and the peaking demands on the BC Gas system which were yet to be fully explored. Consequently, the Commission allowed BC Gas a limited period of time to examine this resource alternative further with British Columbia Hydro and Power Authority ("B.C. Hydro").

1.2 B.C. Hydro Request for Proposals and BC Gas Open Season

In April 1998, B.C. Hydro issued a request for proposals ("RFP") for gas supply and transportation to meet its firm and interruptible gas requirements for Burrard and potential new loads associated with cogeneration projects and other potential developments. B.C. Hydro indicated that it required

188 terajoules per day ("TJ/d") initially and could require 330 TJ/d by 2006. BC Gas responded to the RFP on June 8, 1998 with a proposal which offered firm transportation capacity on the SCP of 115 TJ/d [105 million standard cubic feet per day ("MMcfd")] (Exhibits BCG-1, p. 12; BCG-7, CAPP 20).

On June 3, 1998, BC Gas commenced an Open Season for Firm Tendered Transportation Service on the SCP. The quantity available was a maximum of 105 MMcfd with subscriptions being accepted for any portion of the service offered. A minimum term of ten years was specified, renewable for further terms with two years' notice. Shippers were asked to specify the demand charge they were willing to pay for the service from Yahk to Huntingdon, B.C. above a minimum charge of $68,600 per MMcfd per annum ($7,203,000 per year for 105 MMcfd). Actual throughput volumes would be subject to variable costs, fuel and applicable taxes on the SCP and variable shipping costs, fuel and applicable taxes on the Westcoast Zone 4 pipeline between Kingsvale and Huntingdon. The SCP capacity would be subject to curtailment by BC Gas for a maximum of 15 days during each contract year from November 1 through October 31 the following year. Shippers with signed firm tendered transportation service contracts resulting from this Open Season would have rights to capacity from extension or expansion of the SCP based on an incremental cost structure. The Open Season closed on June 24, 1998 (Exhibit BCG-1, Appendix IV).

The B.C. Hydro RFP and the BC Gas Open Season culminated in contracts for third-party firm transportation capacity on the SCP for 105 MMcfd and arrangements for a similar amount of peak day gas commodity supply to the Lower Mainland.

2.0 THE APPLICATION

2.1 The December 11, 1998 Application

On December 11, 1998, BC Gas again applied to the Commission for a CPCN under Section 45 of the Act to construct and operate the SCP, and included in the scope of the project a compressor station at Hedley, B.C. ("Application"). BC Gas filed with its Application a Term Sheet outlining the principles of proposed agreements among B.C. Hydro, BC Gas and BC Gas Inc. BC Gas also filed a Firm Tendered Transportation Service Agreement ("Transportation Agreement") with PG&E Energy Trading, Canada Corporation ("PG&E Energy Trading") (Exhibit BCG-1). The agreements with third parties are for a firm commitment of 105 MMcfd of SCP capacity between Yahk and Huntingdon. The annual revenue generated from these commitments will be $7.2 million per year for a period of ten years for Firm Tendered Transportation Service. Further, the Application states that BC Gas had entered into a peaking supply agreement with PG&E Energy Trading, and that it would enter into a peaking supply agreement with B.C. Hydro for a combined total of 115 TJ/d (105 MMcfd) of peaking gas supply (Exhibit BCG-1, pp. 13-16).

On December 17, 1998, the Commission, by Order No. G-121-98, established a process involving a workshop, information requests and written submissions to conclude with a reply submission from BC Gas on February 18, 1999 (Exhibit BCUC-1). In the written submissions, parties were asked to address the completeness of the Application, the peaking supply agreements and the Transportation Agreements. Parties were also asked to provide views on any further proceedings required to consider the filings in the context of the 1998 Decision, or as new initiatives.

After reviewing the written submissions, the Commission, in Order No. G-21-99, concluded that a limited oral public hearing was required to review the Application (Exhibit BCUC-5). The Commission limited the scope of the hearing to material changes since the 1998 Decision in the net benefits of the SCP and the alternative proposals. The public hearing commenced on March 29, 1999 and, after eight hearing days, concluded on April 13, 1999. Proponents of other alternatives from the 1997 hearing who participated in this proceeding were Northwest, Westcoast, WGSI and Williams.

2.2 Southern Crossing Pipeline Project

The SCP facilities applied for by BC Gas in the Application are, with the exception of the addition of the Hedley compressor station, essentially the same as those applied for in the previous 1997 application. Specifically, the SCP project is a 312 kilometer (194 mile), 610 mm (24-inch) diameter, 9928 kPa (1440 psig) pipeline which connects the ANG pipeline near Yahk, B.C. with the BC Gas Interior Transmission System ("ITS") near Oliver, B.C. Additional compression of 8,800 hp would be added to the existing BC Gas Kitchener station near Yahk and the existing Kingsvale compressor station would be modified to permit gas to flow west into the Westcoast system (Exhibit BCG-1, p. 6).

A proposed new compressor station with 3140 hp would be constructed on the existing BC Gas 12-inch Kingsvale to Oliver pipeline near Hedley. Through the Oliver to Kingsvale portion of the ITS, the SCP would connect with the Westcoast pipeline at Kingsvale. The SCP would allow BC Gas to receive initially approximately 300 TJ/d (275 MMcfd) of gas on a design day from the ANG pipeline at Yahk, which is an increase from the current capability of 93 TJ/d (85 MMcfd). With the SCP, BC Gas would be able to deliver up to 115 TJ/d (105 MMcfd) of gas per day into the Westcoast pipeline at Kingsvale. Gas flow on the SCP could be from east to west or west to east.

The capital cost of the SCP in the Application is $344.6 million in 1997 dollars, excluding allowance for funds used during construction ("AFUDC") and overhead costs (BCG-1, Appendix I, Table 3). This is an increase of $13.8 million from the $330.8 million in 1997 dollars used in the 1997 application. This additional amount represents the cost of the Hedley compressor station. BC Gas later provided estimates of $364.9 million in 1998 dollars and of $376 million in nominal or "as-spent" dollars, both including AFUDC and overhead (Exhibit BCG-7, BCUC 2.1, 2.2). BC Gas is confident that the cost of the project will come within a variance range of plus or minus 10 percent (T1: 32). All of the cost estimates are based on a proposed in-service date of November 1, 2000.

In addition to the Application for a CPCN, BC Gas requested Commission approval of the Transportation Agreements with B.C. Hydro and with PG&E Energy Trading, the Peaking Gas Purchase Agreements ("Peaking Agreements") with B.C. Hydro and with PG&E Energy Trading, and the Transportation South Capacity Agreement with B.C. Hydro (T7: 906).

3.0 THE AGREEMENTS

On January 8, 1999, BC Gas filed an Umbrella Letter Agreement terminating the Term Sheet with B.C. Hydro and listing five separate agreements among B.C. Hydro, BC Gas and BC Gas Inc. made as of November 27, 1998 and executed January 7, 1999. The Umbrella Letter Agreement also sets out the ability of the parties to terminate the various agreements should they not be approved by the Commission (Exhibit BCG-5). The agreements are discussed in Section 3.1.

3.1 B.C. Hydro Agreements

3.1.1 Firm Tendered Transportation Service Agreement

The Transportation Agreement between BC Gas and B.C. Hydro provides for a contract capacity demand of 52.5 MMcfd from receipt points at Yahk or Kingsvale, B.C. for ten years from the in-service date of the SCP and, thereafter, an annual renewal right with 24 months notice at the option of B.C. Hydro. If BC Gas has plans for expansion of the SCP facilities, under certain notification provisions prior to the seventh year, B.C. Hydro must either extend the term of the agreement for a further ten years beyond the primary term or waive its right to extend the term of the agreement beyond the primary term. During the ten-year primary term, the demand charge is set at $300,000 per month ($3.6 million annually). This monthly demand charge includes the cost of transportation on the Westcoast system from Kingsvale to Huntingdon and does not increase regardless of the Westcoast toll (Exhibit BCG-5).

3.1.2 Peaking Gas Purchase Agreement

Under the Peaking Agreement, BC Gas shall have the right, but not the obligation, to nominate and purchase gas at Huntingdon from B.C. Hydro, up to the daily contract quantity (approximately 52.5 MMcfd), on each of 15 days per year. The price for peaking service is determined by the amount B.C. Hydro would incur to divert gas by using light fuel oil at facilities for which B.C. Hydro has fuel oil capability, whether or not B.C. Hydro provides the peaking service by such use of light fuel oil or otherwise, plus a nomination premium. B.C. Hydro may, at its sole discretion and on 12 months notice, convert the price payable by BC Gas for peaking service to the daily common high price for gas sold at Kingsgate on that day plus a nomination premium (Exhibit BCG-4).

3.1.3 Put Option Agreement

A further agreement involving a "Put" option was entered into among BC Gas, B.C. Hydro and BC Gas Inc. The Put Option Agreement entitles B.C. Hydro, at its sole option, to put to BC Gas Inc. all of B.C. Hydro's financial and all other rights and obligations under the Transportation Agreement and the Peaking Agreement, including any Westcoast Transportation South ("T-South") capacity acquired from BC Gas. B.C. Hydro can exercise this option for up to seven years after the pipeline is in service, with prior notice equal to 13.5 months, given at any time after the commencement of SCP service (Exhibit BCH-1).

3.1.4 Westcoast Transportation South Capacity Agreement

In concert with the above agreements, BC Gas and B.C. Hydro also entered into the Transportation South Capacity Agreement ("T-South Agreement") regarding the assignment of T-South capacity, which recognizes that B.C. Hydro may require T-South capacity in the future. In this agreement, prior to the in-service date of the SCP, and for the first two years of the primary term, BC Gas will provide B.C. Hydro with a right of first refusal for any vintage, long-haul T-South capacity that BC Gas may release and for which other parties do not have rights under existing agreements as of September 30, 1998. Vintage capacity gives a shipper significant flexibility, relative to Westcoast expansion capacity which has a ten-year commitment. If B.C. Hydro exercises the right of first refusal it must assume all related financial obligations to Westcoast and comply with certain other conditions in its dealings with Westcoast as detailed in the agreement (Exhibit BCG-5).

B.C. Hydro states that it understands previous directions of the Commission regarding T-South capacity would have priority over the commitments in the T-South Agreement (Exhibit BCH-6, IR 2.2). BC Gas acknowledges that the agreement places some restriction on its ability to assign T-South capacity to a core market customer who wants to buy gas directly from non-utility suppliers, and agrees that the agreement should be amended to better represent the understanding of the parties (T2: 230-233).

3.1.5 Bypass Transportation and CTS Support Agreements

By letter dated January 13, 1999, BC Gas applied for approval of a Bypass Transportation Agreement, as a Rate Schedule 22 Tariff Supplement, which establishes rates and the terms and conditions of service for B.C. Hydro on the BC Gas Coastal Transmission System ("CTS"). The agreement provides service to Burrard and the Centra Gas British Columbia Inc. ("Centra Gas") interconnect based on a cost equivalent to the cost to B.C. Hydro to construct and operate a bypass pipeline from Huntingdon to Port Moody. The agreement provides for gas delivery of 160 TJ/d from Huntingdon for the period from September 30, 1998 to May 31, 1999, and 200 TJ/d for the period following June 1, 1999. B.C. Hydro may elect to increase the contract quantity to the maximum capacity of the bypass subject to certain notifications to BC Gas to allow for any necessary upgrades to the CTS.

The Bypass Transportation Agreement does not depend upon the issuance of a CPCN for the SCP or approval of the agreements connected with the SCP. On December 17, 1998 the Commission determined that this agreement would be reviewed separately from the process for the review of the SCP Application (Order No. G-121-98, Exhibit BCUC-1).

On January 13 1999, B.C. Hydro filed the CTS Support Agreement with the Commission. This agreement among B.C. Hydro, BC Gas and BC Gas Inc. provides that, in consideration of B.C. Hydro entering into the Bypass Transportation Agreement, the Transportation Agreement and the Peaking Agreement, for a specified time BC Gas Inc. will give some support to B.C. Hydro if the rate for gas transportation under the Bypass Transportation Agreement exceeds a specified amount that is defined as the "Specified Maximum" (Exhibit BCH-1).

3.2 PG&E Energy Trading, Canada Corporation Agreements

The Transportation Agreement between BC Gas and PG&E Energy Trading is similar in its terms to the agreement with B.C. Hydro. It provides for delivery from Yahk or Kingsvale to Huntingdon of up to 1,487 thousand cubic metres per day (52.5 MMcfd) at a demand charge of $201.75 per month per thousand cubic metres for contracted capacity, a charge equivalent to $3.6 million per year. The agreement is effective for a primary term of ten years, with the shipper having the right to extend the term for a further period of one contract year upon 24-months' notice prior to the expiration of the primary term or any extended term. If BC Gas has plans for expansion of the SCP, under certain conditions of notification and within the first seven years, the shipper must either accept the offer of BC Gas and extend the term of the agreement for another ten years after the end of the primary term or waive its right to any extension beyond the primary term (Exhibit BCG-1, Appendix VI).

The Peaking Agreement between BC Gas and PG&E Energy Trading is also similar to the agreement with B.C. Hydro. It gives BC Gas the right to nominate for gas up to the contracted daily demand (approximately 52.5 MMcfd) for up to 15 days during a five-month period between November 1 and April 1 each year. As in the B.C. Hydro agreement, PG&E Energy Trading is under no obligation to source the gas over the SCP. Under the Peaking Agreement, the price that BC Gas pays for peaking service is the daily common high price for gas sold at Kingsgate on that day plus a premium (Exhibit BCG-4).

3.3 Maximum Term of Transportation Agreements

BC Gas states that the maximum term of the Transportation Agreements, with extensions, was to be 20 years (Exhibit BCG-12, BCUC 13.1). The intent of the parties was that the Agreements would be limited to 20 years, with or without expansion of the SCP (T2: 228-230).

As B.C. Hydro and PG&E Energy Trading interpret the Transportation Agreements, Section 8.2 may provide each shipper with the ability to extend its agreement for more than 20 years (Exhibits BCH-6, IR 1.5; PG&EET-4, IR 4.1). PG&E Energy Trading acknowledges that the contract wording probably is not clear, and states that it would not object if approval of the Transportation Agreements included a provision that limits the life of the agreements to 20 years for both shippers (T4: 410 and 411).

3.4 Requests for Disclosure

BC Gas requested that the details of the Peaking Agreements be kept confidential (Exhibit BCG-4). Subsequently, BC Gas provided copies of these agreements with portions relating to the terms on pricing and supply arrangements severed. When B.C. Hydro filed the Put Option Agreement and the CTS Support Agreement, it noted that BC Gas Inc. requested that the agreements be kept confidential (Exhibit BCH-1). B.C. Hydro also requested that the Specified Maximum in the CTS Support Agreement be kept confidential. In separate letters dated January 20, 1999, BC Gas Inc. and BC Gas confirmed that they did not object to the release of these agreements if the Commission considered disclosure was necessary. The Commission concluded that the agreements could assist in the review of the SCP. Consequently, the Put Option Agreement and the CTS Support Agreement, with the Specified Maximum severed, were disclosed (Exhibit BCUC-4).

On February 11, 1999, Westcoast asked the Commission to direct BC Gas to provide full disclosure of the undisclosed premiums in the B.C. Hydro and PG&E Energy Trading Peaking Agreements and the Specified Maximum in the CTS Support Agreement. The Commission established a timetable for written submissions on the disclosure request for the Peaking Agreements (Order No. G-21-99) and for disclosure of the Specified Maximum in the CTS Support Agreement (Order No. G-22-99). Both processes concluded on March 22, 1999 with reply submissions from Westcoast. On March 25, 1999, the Commission issued separate decisions on the disclosure requests. With respect to the disclosure of the premiums in the Peaking Agreements, the Commission determined that the only sections which were relevant to the SCP proceeding were Sections 5.1 and 5.3 of the agreement with B.C. Hydro and Section 5.1 of the agreement with PG&E Energy Trading. The Commission allowed the request for disclosure of Sections 5.1 and 5.3 of the agreement with B.C. Hydro and denied the request for disclosure of Section 5.1 of the agreement with PG&E Energy Trading (Order No. G-34-99, Exhibit BCUC-10).

With respect to the disclosure of the Specified Maximum in the CTS Support Agreement, the Commission denied the request on the basis that knowledge of the Specified Maximum would not materially affect the ability of Westcoast to make the arguments it considered necessary for the SCP proceeding and the fact that the commercial interests of BC Gas Inc. as a non-regulated corporation could be adversely affected (Order No. G-35-99, Appendix 1; Exhibit BCUC-11).

4.0 PACIFIC NORTHWEST REGIONAL RESOURCE BALANCE

In the 1998 Decision, the Commission agreed with BC Gas that it was important to look outside its franchise territory to examine the demand-resource balance of the Pacific Northwest region, insofar as it affected BC Gas' service area. The Commission concluded that a major new supply resource is required in the 2002 to 2003 time period to service the growth in peak and seasonal demand.

In the Application, BC Gas states that there has been almost no material change in regional peak day demand growth since the Decision except that B.C. Hydro has confirmed its supply needs (Exhibit BCG-1, p. 18). The peak day demand that BC Gas forecasts for the region that is south of Station 2, west of Yahk, and north and west of Stanfield, Oregon is shown in the first column in Table 4.1. The regional demand in the winter of 2000/01 is forecast by BC Gas to be 3849 MMcfd, plus 183 MMcfd for B.C. Hydro's Burrard plant. BC Gas estimates the total capacity of transportation and storage to supply the region in 2000/01 at 3,671 MMcfd without the SCP. Without the SCP, this indicates a resource deficiency of 178 MMcfd, plus 183 MMcfd for Burrard. With SCP, the deficiency would be 169 MMcfd if Burrard was taking 183 MMcfd; without Burrard there would be a small surplus.

Westcoast disputes these figures for a variety of reasons set out below. In its Supplemental Evidence, Westcoast states that the regional demand in 2000/01 should more accurately be forecast as 3,569 MMcfd, excluding Burrard, and that the ability for transportation and storage to supply the region totals 3,867 MMcfd. This indicates a resource surplus of 298 MMcfd, without Burrard. These numbers are shown in the second column in Table 4.1.

4.1 Pacific Northwest Demand

4.1.1 British Columbia Gas Demand

BC Gas continues to use its 1997 Integrated Resource Plan ("IRP") peak day demand forecast [Exhibit BCG-12, WEI 70(a)]. The current economic slowdown in B.C. will reduce demand slightly in the short-term, and peak day demand is forecasted to be slightly below the 1998 Decision estimates until 2007. (The difference is about 12 TJ/d (11 MMcfd) in 2002.) BC Gas expects its firm sales and peak day demand to grow by about 1.7 percent per year after 2006, compared to the growth of about 1.2 percent per year presented in the 1997 proceeding [Exhibit BCG-7, WEI 68(g)]. BC Gas projects its on-system industrial firm demand at 51 MMcfd, not including the 24 MMcfd of curtailment supply available [Exhibit BCG-12, WEI 70(b)].

Westcoast and BC Gas use the same peak day demand information for BC Gas, Pacific Northern Gas Ltd. ("PNG") and Centra Gas. Westcoast reduces the demand for firm industrials in B.C. from 135 to 51 MMcfd. Westcoast states that the BC Gas industrial demand includes 24 MMcfd of available curtailment supply from the industrials. Westcoast also believes that BC Gas firm demands for PNG and Centra Gas include firm industrial requirements of 40 MMcfd and 20 MMcfd, respectively (Exhibit 27, p. 6). BC Gas acknowledges that it may have included some industrial demand in the peak day demand numbers for the Local Distribution Companies ("LDCs") and so may have overstated the industrial demand by 64 to 84 MMcfd [Exhibit BCG-12, WEI 70(c); T1: 90-92].

4.1.2 U.S. Pacific Northwest LDC Demand

The peak day demands that BC Gas used for Cascade Natural Gas ("Cascade"), Northwest Natural Gas, Puget Sound Energy and Washington Water Power, were obtained from IRP excerpts filed in the 1997 proceeding. Information filed by WGSI in the Environmental Assessment Office review of its LNG project indicates that Northwest Natural Gas and Cascade currently expect their peak day demand to be higher (Exhibit BCG-7, BCUC 5.1). Northwest Pipeline Corporation states that it now expects demand in its market area to grow by 2.6 percent annually, compared to growth of 1.87 percent that was expected in 1997 (T5: 657 and 658).

Table 4.1

Proponents' Peak Day Demand and Supply Forecasts for 2000/01

Volumes in MMcfd

	BC Gas	Westcoast
Demand		
BC Gas Demand	1187	1187
Firm Industrials	135	51
Cascade	351	221
Centra Gas	97	97
Northwest Natural Gas	762	762
Puget Sound Energy	868	868
Washington Water Power	86	45
Sumas Bypass	55	30
Northwest Pipeline Industrials	172	172
Pacific Northern Gas Ltd	110	110
Vancouver Island Cogeneration	26	26
Demand (without Burrard)	3849	3569
Burrard Thermal – B.C. Hydro	183	0
Total Demand	4032	3569
Supply		
Westcoast T-South	1875	1930
East Kootenay Link	85	85
Northwest Pipeline Gorge	486	486
Jackson Prairie Storage	736	850
Mist Storage	180	180
Tilbury LNG	160	160
Northwest Natural Gas LNG	150	150
Vancouver Island Cogeneration	0	26
Total Supply (without the SCP)	3671	3867
Surplus (Deficiency)	**(361)**	**298**
SCP	192	0

Source: BC Gas Forecast: Exhibit BCG-7, BCUC 5.2, Tables 5.2(i), 5.2(ii)
Westcoast Forecast: Exhibit 27, Tables 3.2A, 3.2B

The Pacific Northwest region is considered to lie north and west of Stanfield, as the capacity of Northwest through the Columbia Gorge is a constraint on gas shipments into the region. Two laterals leave the Northwest system at Plymouth, near Stanfield, and it is at this point that the Northwest Pipeline Corporation system becomes constrained to westward shipments. In its forecast of Cascade demand, Westcoast uses only the core market peak day demand for the Cascade divisions that lie west of Plymouth (Exhibits 27 and 39). Westcoast reduces the BC Gas forecast of Cascade peak day demand by about 125 MMcfd based on Cascade's 1996 IRP. For a similar reason, Westcoast makes a 40 MMcfd reduction to the Washington Water Power demand, based on IRP information, and discussions regarding the baseload Northwest component of the LDCs' demand (T6: 883-888).

4.1.3 U.S. Pacific Northwest Industrial Demand

BC Gas estimates the firm demand at Sumas which bypasses the Northwest system as 55 MMcfd, based on conversations with users of the bypass pipelines [Exhibit BCG-12, WEI 70(c)]. Westcoast estimated a demand of 30 MMcfd, based on its peak day deliveries to these pipelines over the past several winters (Exhibit 27, p. 7). BC Gas used the 30 MMcfd number in the regional demand and supply tables that it discussed in Argument.

BC Gas used Northwest's 1998 shippers list to estimate the firm Northwest industrial demand [Exhibit BCG-12, WEI 70(c)]. Westcoast used the same numbers, but indicated that some component of this demand may be curtailable.

In Argument, to deal with disagreements about the firm demand for U.S. LDCs and the portion of industrial load that may be curtailable, BC Gas suggested the use of the current firm Northwest contract demand north of the Columbia Gorge of 1811 MMcfd and adding supply from Northwest Natural Gas LNG, Mist Storage and Northwest fuel requirements to estimate a regional demand for the Northwest system (T7: 910-913). Westcoast argued that this use of available supply to estimate demand overstates the regional demand, and cannot be relied on (T7: 1103).

4.1.4 Thermal Generation Demand

BC Gas based its estimate of B.C. Hydro gas demand on the quantities shown in the April 1998 B.C. Hydro RFP. B.C. Hydro expects firm gas supply and transportation of 26 MMcfd for Vancouver Island cogeneration will be needed commencing in 2000. This is expected to increase to 90 TJ/d (82 MMcfd) within two years. The refurbished units at Burrard will require "up to" 200 TJ/d (183 MMcfd) (Exhibit BCH-3, Schedule A).

Westcoast included the demand for the Island Cogeneration Project ("ICP"). However, Westcoast stated that Burrard demand should be excluded until there is conclusive evidence that Burrard will be operated with firm baseload supply.

If Burrard has firm gas supply, Westcoast considers that a similar amount of peaking supply would be available (Exhibit WEI-3, p. 18; T6: 786 and 787). Nevertheless, Westcoast recognized that B.C. Hydro would need to determine if it needed the electrical power, before it decided to curtail Burrard and provide its supply as peaking gas (T6: 869-875). B.C. Hydro cautions that, although electricity may be available in the U.S., one cannot assume that it can be delivered to market areas in B.C. during all peak electricity periods, due to possible electric inter-tie capacity limitations (Exhibit BCH-6, IR 3.4).

PG&E Energy Trading identified proposed thermal electric generation projects in the U.S. Pacific Northwest that would consume 510 MMcfd or more of gas (Exhibit PG&EET-4, IR 1.1). Generation capability in the Northwest Power Pool Area, which includes British Columbia and Alberta, is expected to increase by approximately 2800 megawatts ("MW") from 1998 to 2007 (Exhibit 35). Using the ICP fuel rate of 42.6 TJ/d for 240 MW, and assuming all the additional generation in the Power Pool is gas fired, this would represent about 450 MMcfd of gas load (Exhibit BCH-6, IR 3.1).

4.2 Regional Supply

The BC Gas forecast of available transportation and storage resources to supply the Pacific Northwest region is shown in Table 4.1. The forecast includes the transmission capacity into the region on the Westcoast, Northwest and East Kootenay Link ("EKL") pipelines, and the SCP; plus underground storage at Jackson Prairie Storage ("JPS") and Mist Storage, and Tilbury LNG and Northwest Natural Gas LNG. The numbers include the expansion at JPS and 45 MMcfd from Phase I of Northwest Columbia Gorge expansion. BC Gas estimates total peak day capacity serving the region in 2000/01 at 3671 MMcfd, excluding 192 MMcfd from the SCP. The corresponding Westcoast estimate is 3867 MMcfd.

4.2.1 JPS Expansion Capacity

Northwest gave evidence that the expanded capacity of JPS will be 850 MMcfd (Exhibit NWP-1, p. 10). BC Gas shows 736 MMcfd for JPS, which does not include the 100 MMcfd of JPS expansion capacity that will be retained by Northwest for balancing, as this capacity may not be available for use by others. BC Gas also made a 14 MMcfd reduction for compression fuel (Exhibit BCG-12, BCUC 1.2.2).

Northwest believes that all of the JPS capacity will be available to the region on a peak day, since Northwest generally allows a shipper to take more gas out of the Northwest pipeline system than the shipper is able to put in. A shipper's access to this supply is restricted in the event of a declared entitlement, where delivering the additional supply to the shipper would affect other parties transporting gas (T5: 669-671). Also, Northwest states that deliverability from JPS after the expansion will start to decline after nine days of peak withdrawals (T5: 650). Westcoast used the Northwest forecast of 850 MMcfd from JPS in its Supplemental Evidence.

4.2.2 Industrial Curtailment

BC Gas states that it included the industrial curtailment of firm on-system industrial customers to reduce peak day demand (Exhibit BCG-12, BCUC 1.1 and 1.2.5). Based on the evidence discussed under Section 4.1, this indicates that the LDC demand numbers are total system sales peak day demand, part of which may be supplied by industrial curtailments. The PNG and Centra Gas peak day numbers also appear to include firm industrial demand. In its assessment of regional peak day supply, BC Gas has not included any further “potential” curtailment of industrial customers or thermal generation, other than the ICP on Vancouver Island.

Westcoast states that Northwest industrial demand used by BC Gas may include customers that have the potential for curtailment on a peak day. If this is the case, a portion of this demand should be recognized in peak day supply. However, Westcoast did not propose an adjustment to BC Gas’ supply or demand numbers on this basis (Exhibit 27, pp. 7 and 8, T5: 703-709).

In Argument, COFI, Methanex and Cominco state that they favour the SCP over increased industrial curtailments despite suggestions that curtailments are a market efficiency that should be explored (T7: 989-990).

4.2.3 Other Supply Issues

Westcoast believes that BC Gas understated Westcoast T-South capacity by 55 MMcfd, and included 1930 MMcfd in its evidence. Westcoast now contracts 30 MMcfd of firm winter-only capacity resulting from the higher horsepower available on cold days. Westcoast arranges recallable JPS to backstop the service on warmer winter days (Exhibit WEI-7, IR 3.2).

The year-round contractible capacity of the Westcoast system is 1900 MMcfd, but BC Gas considers that a further 25 MMcfd adjustment is needed to compensate for the loss in heating value due to the increase in liquids extraction in 1998 (Exhibit BCG-12, BCUC 1.2.1). Westcoast filed evidence showing that the actual heat content at Huntingdon in December 1998, was higher than that assumed in the May 1997 IRP Update and the actual heat content in December 1996, indicating that the heat content of gas moving on its system has not been significantly affected over that period (Exhibit WEI-6, IR 18.5; T1: 83 and 84).

Westcoast also excludes the SCP supply, but includes 26 MMcfd from the ICP in 2000/01. This is consistent with B.C. Hydro's evidence that all of the ICP demand is curtailable (Exhibit BCH-6, IR 3.1). The ICP firm demand and available curtailment supply increase to 41 MMcfd starting in 2001/02.

In Argument, BC Gas used the Westcoast supply numbers, but adjusted the total for the 114 MMcfd of JPS capacity that is reserved for balancing and fuel. BC Gas repeated its concern about the effect of declining heat content on effective Westcoast capacity (T7: 913 and 914).

4.3 Thermal Generation Need for Baseload (Pipeline) Gas Supply

BC Gas states that: "Only pipeline solutions can be considered for meeting the needs of B.C. Hydro and other thermal generation operators together with the peaking and seasonal needs of the core market customers of BC Gas." (Exhibit BCG-11, p. 3). To illustrate the point, BC Gas compares its ability to provide 200 TJ/d of thermal generation supply by new pipeline capacity such as the SCP or with an LNG facility. With new pipeline capacity, 15 days of curtailment would be required in a normal year while up to 50 days of full or partial curtailment would be needed with LNG (Exhibit BCG-12, BCUC 3.1).

BC Gas was unable, in the time available, to provide regional information in support of its position. This would have required an analysis of the load duration profile of each LDC in the region. As other LDCs in the region experience similar weather, BC Gas expects that only new pipeline capacity will enable gas-fired generation to operate relatively uninterrupted year-round (Exhibit 7, Undertaking No. 9). Westcoast has also only looked at the regional resource balance on a peak day basis (T6: 875).

4.4 Regional Resource Balance

Demand forecasts are inherently uncertain. BC Gas largely uses numbers from the 1997 SCP proceeding. The current forecast of BC Gas' peak day demand is slightly lower through 2006, but this is more than offset by the current higher load growth expectations for Centra Gas, Northwest Natural Gas and Cascade. There is uncertainty about the industrial and thermal generation load, and the portion of that load which is curtailable. There is also uncertainty about the portion of the firm load of U.S. LDCs that should be included in the regional resource balance.

4.4.1 <u>Position of Participants</u>

In Argument, BC Gas states that the need for the SCP is evident from the regional supply/demand information (T7: 915). PG&E Energy Trading argues that there are parties in the region seeking approximately 700 MMcfd of long-term incremental gas supply, and the SCP will provide the firm transportation capacity PG&E Energy Trading needs to meet its peaking arrangement with BC Gas and the other market demands it perceives (T7: 978).

The Consumers' Association of Canada (B.C. Branch) et al. ["CAC (B.C.) et al."] favours BC Gas' projections over those of Westcoast, and concludes that the determination in the 1998 Decision that a new supply would be needed by 2003 is still reasonable. CAC (B.C.) et al. recommends the in-service date for the SCP be delayed to 2001 to allow time to resolve the Westcoast toll from Kingsvale, to reduce the potential for schedule-induced cost over-runs on the project and to delay the date when customer rates will include the cost of the SCP (T7: 1006-1010).

Westcoast argues that the region will not require another significant peak day resource addition until the 2003/04 time period (T7: 1097). WGSI acknowledged that, in its filing to the Environmental Assessment Office, it concurred with the 1998 Decision that a new resource will be required in the next five years, but noted that further information had been presented in this hearing. WGSI also argues that the market will decide when a new supply resource will be required. (T8: 1116-1120).

4.4.2 Commission Discussion

The evidence supports several adjustments to the BC Gas regional demand forecast. The curtailable portion of the B.C. firm Industrial load should be removed and the Sumas Bypass number reduced to 30 MMcfd. Likewise, the Cascade and Washington Water Power demands should be reduced to the firm core loads that lie west of the constraint point on the Northwest system near Stanfield. Leaving aside the B.C. Hydro Burrard demand, this results in the regional peak day demand used by Westcoast.

The evidence regarding supply supports adjustments to BC Gas' forecast to increase Westcoast T-South by 55 MMcfd and to include supply from the ICP, before considering the SCP. It is not clear how much new supply from the current JPS expansion should be included in the regional supply. Based on Northwest's evidence that there may be circumstances when the supply would not be available to shippers, and considering that JPS deliverability starts to decline before the end of the cycle, the prudent approach is to accept the BC Gas forecast of an additional 196 MMcfd of JPS supply.

The demand for thermal generation, particularly Burrard, and the corresponding peaking supply that may be available, is more problematic. Although B.C. Hydro expects to baseload Burrard, it has not committed to large amounts of firm gas supply. It does not seem reasonable that B.C. Hydro's firm electricity load will increase its firm gas needs from zero in 1997/98 to 183 MMcfd in 1999/00. Also, it would not be prudent to assess the regional resource balance without making some allowance for uncertainty. Westcoast indicated a planning tolerance in the order of 100 MMcfd would be appropriate (T6: 883). In this context, it appears reasonable to accept the BC Gas estimate of 183 MMcfd for Burrard demand, while recognizing that the timing is likely to be delayed until at least 2000/01.

At the same time, on the assumption that B.C. Hydro requires firm gas for Burrard to meet its firm electrical load, and in the absence of dual fuel capability, no firm peaking from Burrard should be included in the resource balance.

There appears to be considerable potential for additional thermal generation in the Pacific Northwest. However, at this time neither the potential gas demand nor the peaking supply that may be available should be included in the regional resource balance, due to uncertainties over commitments and timing.

4.4.3 Commission Determination of Regional Resource Balance

The foregoing adjustments result in the following regional resource balance shown in Table 4.2. This is similar to the evidence presented in a BC Gas witness aid (Exhibit 36). As the hearing progressed, BC Gas appeared to move toward the forecast put forward by Westcoast, except for the amount of supply from JPS and the demand for firm gas at Burrard.

Table 4.2

Regional Peak Day Supply and Demand
Volumes in MMcfd

	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06
Regional Supply	3446	3687	3753	3768	3808	3808	3848	3848
Regional Demand (without Burrard)	3390	3472	3569	3681	3744	3828	3898	3961
Surplus (Deficiency) (without Burrard)	56	215	184	87	64	(20)	(50)	(113)
Burrard - B.C. Hydro	0	0	183	183	183	183	183	183
Regional Demand (with Burrard)	3390	3472	3752	3864	3927	4011	4081	4144
Surplus (Deficiency) (with Burrard)	56	215	1	(96)	(119)	(203)	(233)	(296)

This regional resource balance indicates the need for the addition of a new peaking resource as early as the winter of 2001/02.

Table 4.2 highlights how the firm gas and transportation requirements of new thermal electrical generation loads can very significantly affect the regional resource balance. If B.C. Hydro determines that it will not baseload Burrard with firm gas, and if no similar thermal generators come on stream in the forecast period, then the peaking resource could be delayed until 2003/04.

On the other hand, if B.C. Hydro or a similar thermal generator contracts for a substantial firm gas supply at an earlier date, some expansion of the transportation infrastructure into Huntingdon will be required. The Commission believes it is prudent to plan for this demand.

5.0 OTHER CHANGES SINCE THE 1998 DECISION

The hearing updated the 1998 Decision for material changes. Chapter 4 confirmed the Commission's view that a new peaking resource is required. This Chapter identifies other material changes which have been considered by the Commission in ruling on the Application.

5.1 Regional Price Isolation

BC Gas expressed concern about the price of gas at Huntingdon becoming isolated from other regional trading centres, such as Kingsgate, B.C. and Stanfield, Oregon, during periods of high demand. In its Application, BC Gas stated: "Without the creation of the SCP option to provide access to supply alternatives, all gas consumers in B.C. will increasingly be subject to the detrimental effects of regional price isolation." (Exhibit BCG-1, p. 8).

BC Gas had made use of numerous studies, publications, and conference presentations to conclude that major changes in Western Canadian Sedimentary Basin ("WCSB") infrastructure, including the Alliance Pipeline ("Alliance"), will alter pricing relationships to the detriment of B.C. consumers (Exhibit BCG-7, BCUC 6.1). By way of illustration BC Gas indicated that higher regional demands beginning in mid-December, 1998 during a cold spell, caused a tightening of the supply/demand balance in the Pacific Northwest and B.C. Separation of the Sumas price from the Rockies price (Utah/Wyoming) continued to affect prices throughout December and affected the setting of the January monthly index price [Exhibit BCG-7, BCUC 6.2(a)]. BC Gas' comparison of the prices is reproduced below.

($US/MMBtu)	Sumas	Rockies	Difference
Average December Daily Prices	3.29	1.73	1.58
January Monthly Index	2.88	1.82	1.06
February Monthly Index	1.77	1.63	0.14

BC Gas filed a table showing the spread between the Sumas Common High and the Kingsgate Common High prices, in $Cdn/GJ, during the winter high demand periods from 1996 to 1999 (Exhibit 7, IR 12). This table showed that on November 22, 1996 the Sumas Common High was $2.90 Cdn/GJ higher than Kingsgate. On four other winter days the spread was in excess of $1.00/GJ. In 1997/98 the spread never exceeded $0.47/GJ. In one unusual two-day period in December 1998 the spread reached $21.39/GJ, dropping to $1.03/GJ two days later. BC Gas explained the reasons for the unusual spike in its response to information requests from Centra Gas and Northwest (Exhibit BCG-7, CENTRA 3.0). BC Gas attached to its response a copy of Inside FERC's Gas Market Report for December 25, 1998 describing this most unusual event and commenting on the low liquidity at the Sumas trading centre.

B.C. Hydro commented on its concern over price isolation at Sumas. In its view, historical data fails to capture the substantial effect of B.C. Hydro's future purchases and the continued growth in other markets served through Sumas. It argued that without increased gas infrastructure, the Sumas/Huntingdon price will spike more often and higher than in the past. B.C. Hydro noted that the price spike at Sumas/Huntingdon which occurred in December 1998 did not occur at other market hubs such as Kingsgate, and referred to prices in January 1999 when the Huntingdon monthly index was approximately $3.00/MMBtu ($U.S.) while the Kingsgate price was $2.00/MMBtu ($U.S.). If B.C. Hydro had been purchasing 57.5 TJ/day during the month of January, it would have saved $2.6 million ($Cdn) in gas costs for the month by purchasing at the Kingsgate price. B.C. Hydro is prepared to incur some fixed costs on the SCP and have access to Alberta gas supplies to avoid being exposed to high commodity prices at Huntingdon. B.C. Hydro stated that the Kingsgate prices on average would have to be about $0.41/GJ lower in the winter months (151 days November through March) in order to cover the full annual demand charges of the SCP of $3.6 million (Exhibit BCH-6, IR 1.1).

Westcoast and the Canadian Association of Petroleum Producers ("CAPP") took the position that, although there may be some differential between Sumas/Huntingdon and Kingsgate prices, it would seldom be sufficient to justify paying the full cost of transportation from Yahk to Huntingdon. They held that the $0.188/Mcf toll offered to B.C. Hydro and PG&E Energy Trading, for transportation from Yahk or Kingsvale to Huntingdon, was being subsidized by the core market, in that those parties contracted for

100 percent of the capacity of the SCP at a price that contributed only 15 percent of the full cost of service. CAPP noted that a BC Gas witness indicated that a thermal power generation facility requesting transportation service from Yahk to any point on the Interior Transmission System would pay a toll of \$0.53/GJ under the current BC Gas Schedule 22 (T1: 26 and T7: 1032). BC Gas disputed the charge of subsidization for B.C. Hydro and PG&E Energy Trading on the basis that the price for the contract demand was interlocked with a valuable winter peaking agreement.

PG&E Energy Trading was asked in cross-examination by CAPP to consider a hypothetical situation where the rate for transportation from Yahk to Huntingdon was in the \$0.40 to \$0.70/Mcf range and how that would affect its interest in attracting markets in the Pacific Northwest. PG&E Energy Trading replied that today's market would probably not support those kinds of rates for transportation (T4: 375).

5.2 The Alliance and Other New Pipelines

The Alliance Pipeline, due to commence operations in November 2000, will place a new and very large demand on the Alberta and B.C. supply basin. BC Gas expressed concern that Alliance, with an initial capacity of over 1.5 billion standard cubic feet per day ("Bcf/d"), has the potential to divert volumes that would otherwise flow on Westcoast's transmission lines. This could result in under-utilization of Westcoast's facilities and higher unit tolls for its customers. Alliance indicates that it expects eventually to draw 25 to 40 percent of its total throughput from B.C. sources. As BC Gas is dependent on Westcoast for delivery of most of its gas supplies, commencement of Alliance operations could put BC Gas and its customers at risk. BC Gas noted that B.C. producers will be able to choose which way their gas will flow, either south on Westcoast or east on Alliance, depending on which path offers them the highest marginal price. In contrast, gas consumers in B.C. do not have meaningful access to supply alternatives outside of northeastern B.C. BC Gas contends that in the same manner that producers have been provided with market alternatives via Alliance, gas consumers in B.C. require new competitive supply options.

BC Gas was asked to provide any study or work done by it that analyzes the effect of WCSB infrastructure changes on regional pricing relationships. In reply, BC Gas listed a number of information sources and the conclusions drawn. These sources observed that the connection of the WCSB with the rest of the North American market, through expansions of TransCanada Pipeline and the Northern Border pipeline, are already increasing netbacks to Western Canadian producers. This has caused prices to Western Canadian gas consumers to rise. With Alliance in operation and insufficient gas supply within B.C. to fill all pipeline capacity, in periods of high demand, B.C. consumers will be expected to match Chicago prices less the variable pipeline cost of transportation to mid-west markets, plus the cost of transportation on Westcoast to Sumas.

BC Gas suggested that a particularly good summary of the changes could be found in the Energy ERA January, 1999 study entitled, "*Anticipated Continental Natural Gas Infrastructure Developments*", which BC Gas appended to its reply. The report noted that production levels had risen in the WCSB in the last ten years from 4 trillion standard cubic feet ("Tcf") annually to over 5.5 Tcf. As a result, production levels have been high enough to supply almost all of the export pipeline capacity available. The shortage of export pipeline capacity in the last few years has caused Western Canadian gas prices to become disconnected and fall below other continental gas prices. With the recent opening of considerable pipeline capacity to eastern markets, prices in Alberta have approached Gulf Coast prices. The majority of this increased pipeline capacity is directed at the U.S. Midwest market which is already served by excess pipeline capacity, and new Canadian capacity will have to compete in an already overpiped market. Increased WCSB supplies are unlikely to substantially affect Chicago prices, as Chicago prices are already set at Gulf Coast prices plus variable transportation costs, but other continental prices may be affected. Increased Canadian flows to the Midwest will back out both Gulf Coast and Southwest supplies and may lead to less Western Canada supply heading to California. If in short supply, Western Canadian gas will be choosing between shipping to Chicago or California. Western Canadian prices will be pulled up to as high as California or Chicago prices, less variable transportation costs. Overall, it appears increasingly likely that a shortfall in Western Canadian production levels compared to pipeline export levels is developing and is likely to remain in place for many years. The implication is that Western Canadian prices will be much more closely linked to Gulf Coast prices and western and eastern markets will compete increasingly for scarce Western Canadian supplies (Exhibit BCG-7, BCUC 6.1).

PG&E Energy Trading stated that Alliance could compete with natural gas supply currently accessing Huntingdon, thereby affecting the availability of natural gas and the volatility of prices at Sumas/Huntingdon. In PG&E Energy Trading's opinion, by linking Huntingdon with Kingsgate, the SCP project would enhance the security of gas supply and the efficiency of pricing at Huntingdon. The result of this integration would create a more liquid natural gas market at Huntingdon with prices more in line with those elsewhere in North America (Exhibit PG&EET-3). PG&E Energy Trading suggested that a shortage of gas supply in northeast B.C. could impair the ability to fully use existing transportation capacity from northeast B.C. to Huntingdon. The shortage of gas supply in northeast B.C. became apparent during the winter of 1998/99 when Station 2 gas traded at a premium of $0.10 to $0.15/GJ ($Cdn) over the Alberta market. This resulted in the movement of gas supply from Alberta to B.C. via Gordondale (Exhibit PG&EET-4, BCUC IR 2.1). PG&E Energy Trading testified that it would have been unwilling to enter into a peaking gas agreement with BC Gas without access to a new source of supply (Exhibit PG&EET-3, p. 3).

5.3 Currency Exchange Rate

BC Gas commented on the downward move in short-term U.S./Cdn exchange rates from the $0.74 rate used in the 1997 application to an early 1999 rate in the $0.66 range. The Application includes updated cost information from suppliers and takes into account changes associated with the reduced value of the Canadian dollar. BC Gas noted that a lower Canadian dollar will cause U.S.-based options, and projects such as LNG which use more U.S.-sourced materials, to be more costly relative to the SCP than the use of a $0.74 exchange rate would indicate (Exhibit BCG-11, p. 5).

Williams stated that, unless otherwise indicated, all net present value ("NPV") savings and proposal numbers for its LNG project at Sumas, Washington are denominated in Canadian dollars at an exchange rate of $0.67. More specifically, the numbers were based on the original 1997 dollars used in the 1997 submission and converted to Canadian dollars at a rate of $0.67 (T4: 458).

In its filed evidence Northwest converted the cost estimates from U.S. dollars to Canadian dollars at an exchange rate $0.74. The NPV savings calculated by BC Gas in the 1997 application were at that same exchange rate and, in the interests of comparability, Northwest continued to use the same approach for its 1999 submissions. During the course of the current proceedings, on occasions where Northwest filed updated costs, an exchange rate of $0.66 was used (T5: 537).

5.4 Cost of Capital

BC Gas filed a table showing total cost of service for each of the first ten years of SCP service. The assumed costs of debt and equity were the same as used in the 1997 application (Exhibit BCG-7, BCUC 2.4). In evidence filed by BC Gas March 5, 1999, it noted that a more current outlook of the cost of capital, and consistent with the capital structure approved for BC Gas revenue requirements, would increase the NPV benefit of the SCP by approximately $39 million at a 10 percent discount rate. The more current outlook would recognize the retirement of preferred share equity and its replacement with long-term debt, would reduce short- and long-term debt rates by 0.5 percent and 1.5 percent respectively, and would reduce return on common equity from 10.5 percent to 9.25 percent. The effect of these changes in the BC Gas cost of capital would reduce the annual cost of service of the SCP by approximately $7 million (Exhibit BCG-11, p. 5).

Westcoast argued that the change in NPV claimed by BC Gas for the reduced cost of capital is not a factor which the Commission should have regard to in considering the changes to the net benefits of the various proposals, reasoning that all of the proposals now have lower costs of capital (T7: 1082). Without rerunning the 1997 Resource Optimization Model ("ROM") analysis for all portfolios to reflect the lower cost of capital, it is not possible to determine the overall change in the net benefits of the alternatives.

5.5 Higher Westcoast Pressure and Interior Transmission System Reinforcement

In the 1998 Decision, the Commission encouraged BC Gas to investigate the possibility of deferring ITS system reinforcements by obtaining higher delivery pressures from Westcoast at Savona and Kingsvale. In the Application, BC Gas reported that it had held discussions with Westcoast and is now confident that pressure higher than the 500 psig contract minimum pressure is available at these delivery points. BC Gas has now assumed for ITS design purposes that 600 psig pressures will be available from Westcoast on a design day without the need to contract for a compression service charge (Exhibit BCG-1, p. 17). BC Gas testified that the higher delivery pressure from Westcoast with the SCP in place would reduce somewhat the NPV of the SCP related to ITS reinforcement savings but would make no material change in the difference in the annual cost of service savings. If the SCP is not available the higher pressure would delay the need for a third compressor at Savona by one year to 2001/02 (Exhibit BCG-7, BCUC 11.2; T1: 139).

Westcoast described certain modifications, completed in 1998, which will allow WEI to provide compression service from the discharge side, rather than the suction side, of its stations at both Savona and Kingsvale. WEI completed installing the necessary compression horsepower at Savona and Kingsvale to provide BC Gas with higher pressures up to 850 psig at those delivery points. If the maximum pressure desired is less than 850 psig then pressure reducing valves will be required at each location. The cost of such installations is estimated at approximately $400,000 at each site (Exhibit 39, Response to WEI Undertaking at T6: 842 and 843).

It appears to Westcoast that higher pressures could allow BC Gas to avoid up to a further $30.8 million in future compression costs at Savona and Kingsvale on the BC Gas system (Exhibit WEI-3, p. 12). Since November 1, 1998 Westcoast has had approximately 12 MMcfd of existing T-South capacity between Station 2 and the Inland Delivery Area available for the Interior market. This capacity can meet BC Gas' incremental requirements in the Interior for at least three years at a 1999 toll of $0.1345/Mcf (Exhibit WEI-3, p. 10).

5.6 Westcoast Tolls and the National Energy Board Decision

5.6.1 Westcoast Tolls

The Westcoast system from Station 2 south has a number of delivery points. BC Gas pays two toll rates, one to the Inland Delivery Area and a through toll from Station 2 to the Huntingdon Delivery Area. Westcoast filed a series of tables describing the toll changes and showing the cost of service changes that have occurred since the 1997 proceeding. The updated tolls from 2001 onward are less than the tolls used by BC Gas in the 1997 ROM analysis. In the ROM analysis used by BC Gas the Kingsvale to Huntingdon toll was assumed to be 45 percent of the total T-South toll for each year (Exhibit WEI-6, BCG 8).

5.6.2 National Energy Board Decision on Westcoast Tolls

On July 14, 1998, BC Gas applied to the National Energy Board ("NEB", "Board") for orders requiring Westcoast to establish a new receipt point at the interconnection of the Westcoast system and the BC Gas Interior Transportation System at Kingsvale, and to prescribe the terms and conditions, including tolls, for the transportation of natural gas by Westcoast to Huntingdon. BC Gas suggested that tolls for the requested service reflect the volume distance-based toll methodology approved by the Board in an earlier Decision for tolls in Zone 4. The Board announced its Decision, RH-2-98, on March 26, 1999. In its Decision, the Board directed Westcoast to establish a new receipt point at Kingsvale and to receive, transport and deliver any gas delivered at Kingsvale to the Huntingdon delivery area. The Board also said that the appropriate toll for firm service from Kingsvale to Huntingdon will be the Zone 4 toll from Station 2 to Huntingdon, approximately $0.242/Mcf. The toll assumed by BC Gas for its ROM NPV analysis was $0.106/Mcf.

In its opening statement, BC Gas commented on the NEB Decision, noting that the NEB had approved BC Gas' application for access to the Westcoast system with Kingsvale as a receipt point, but the Board had determined that, without the expansion of T-South transmission facilities, firm receipts at Kingsvale would block transmission capacity that normally would flow from Station 2 to Huntingdon and determined that the appropriate toll for firm service from Kingsvale to Huntingdon shall be the full Zone 4 toll. The NEB Decision stated: "Upon the next or some future expansion, there may well arise a situation where a fundamental reexamination of the Westcoast tolling system is required."

BC Gas believes that expansion of T-South capacity to accommodate volumes from the SCP project would eliminate the concern of blocked capacity from Station 2. This should result in a significant reduction in the Kingsvale to Huntingdon toll, and hence BC Gas argues that the toll estimate used in the Application remains reasonable.

6.0 CHANGES TO NET PRESENT VALUE BENEFITS OF ALTERNATIVES

The 1998 Decision acknowledged that there were limitations to the operation of the ROM but accepted the directional guidance the model provides in the selection of a resource portfolio. In the assessment of total ROM and non-ROM NPV savings, the 1998 Decision found that, with the large amount of uncertainty in the factors underpinning the analysis, each of the SCP, Northwest and LNG options remained competitive within the margin of error of the analysis. This Chapter updates the NPV analysis only for significant changes to alternative projects which have occurred since April 1998. The remaining non-quantified benefits are equally important and are discussed in Chapter 7.

6.1 Southern Crossing Pipeline Project

6.1.1 Firm Transportation Revenue

Under the Transportation Agreements with B.C. Hydro and PG&E Energy Trading, BC Gas has commitments for 105 MMcfd of firm capacity on the SCP. The annual revenues being generated by these contracts is $7.2 million. BC Gas estimates that the annual revenues represent an NPV benefit of $50 million, assuming a 30-year analysis with a 27-year revenue stream starting in 2000/01 and discounted at a rate of 10 percent to yield 1997 values (Exhibit BCG-7, BCUC 7.1).

Westcoast argued that this NPV benefit should be reduced by 40 percent based on the potential cancellation of the Transportation Agreements after ten years due to a higher Kingsvale to Huntingdon toll (T7: 1066 and 1067). In reply, BC Gas argued that the value of the SCP would remain with or without the contracts after ten years (T8: 1229).

BC Gas stated that the intent of the parties was to limit the Agreements to 20 years, with or without expansion of the SCP (T2: 228-230). The toll for the second ten-year term is subject to adjustment according to a formula giving consideration to then-current Westcoast tolls.

With the Westcoast toll of $0.106/Mcf used by BC Gas in its analysis, a ten-year annual revenue of $7.2 million discounted at 10 percent indicates a NPV of $30 million. The same revenue stream over 20 years shows a NPV of $42 million. There are no contracts for service beyond 20 years and revenues in this period should be treated with caution. On balance, the Commission concludes that an additional NPV benefit to the SCP in the range of $42 million to $50 million appears reasonable, subject to the adjustment for Westcoast tolls made in the following section.

6.1.2 Effect of National Energy Board Decision

On March 26, 1999, the NEB directed Westcoast to establish a new receipt point at Kingsvale and to receive, transport and deliver any gas delivered at Kingsvale to Huntingdon. The Board also determined that the appropriate toll for firm transportation on Zone 4 from Kingsvale to Huntingdon would be the Zone 4 toll from Station 2 to Huntingdon.

The Zone 4 toll from Station 2 to Huntingdon (and consequently from Kingsvale to Huntingdon) is currently $0.242/Mcf (Exhibit WEI-6, IR 8). The Kingsvale to Huntingdon toll assumed in the 1998 Decision and in BC Gas' December 1998 Application was $0.106/Mcf. As the Transportation Agreements include delivery by BC Gas over the combined SCP-Westcoast systems from Kingsgate to Huntingdon for a fixed demand charge, the economic viability of the SCP is influenced by the amount of the Westcoast Kingsvale to Huntingdon toll.

Several parties put forward evidence during the hearing to show that the NEB Decision made the SCP and the related agreements uneconomic. BC Gas provided calculations which showed that the impact on NPV of the full Zone 4 toll was $45.5 million negative if based on the full Westcoast T-South toll used in the 1997 IRP (Exhibit 26). The NPV impact was $29.9 million negative if based on the Base Case tolls provided by Westcoast in the current proceeding (Exhibit WEI-6, Table 8A-1).

BC Gas stated that the Board's Decision offered various possibilities for mitigating the impact of the Board's toll. First, BC Gas noted that the NEB's Decision leaves open the possibility of a re-examination of the Westcoast tolling system upon the next or some future expansion. In BC Gas' view the suggestion that Westcoast tolls may require a fundamental examination by the NEB leaves open the possibility that the Westcoast toll for the next 30 years will be something less than the full Zone 4 toll (T1: 25).

Second, BC Gas indicated that given that the full Zone 4 toll was to be charged it would contract for capacity all the way from Station 2 rather than Kingsvale to Huntingdon. This would allow BC Gas to optimize and mitigate its use of the pipeline and reduce the net cost of the Kingsvale to Huntingdon segment of the Westcoast T-South system (T1: 26). BC Gas further indicated that it could release Inland Delivery Area capacity and use Station 2 to Huntingdon capacity to move gas from Kingsvale to Huntingdon and from Station 2 to the Inland Delivery Area. This would result in Westcoast costs which are not materially different from those in the 1998 Decision (Exhibit 6, IR 1). Under such a scenario, BC Gas would hold about 5 MMcfd of surplus Westcoast capacity until about 2005 (Exhibit 7, IR 8).

The NEB Decision sets the Westcoast toll from Kingsvale to Huntingdon at the full Zone 4 postage-stamp level for the immediate future. As noted previously the NEB may re-examine the Westcoast tolling methodology at the next or some future expansion. Westcoast testified that this may occur within the next five to eight years (T6: 746). To the extent that the NEB Decision anticipates a future re-examination of the Westcoast tolling system, and in view of the trend in North American away from similar postage-stamp tolling arrangements, the Commission believes it highly improbable that the present tolling regime will persist through the full 30 years forecast period. The Commission accepts that the higher toll may continue until 2006 and calculates the negative NPV at $8 million as the difference in costs over six years discounted at 10 percent and assuming a November 2001 SCP startup.

BC Gas' ability to mitigate virtually all the negative impact of the toll by contracting for capacity from Station 2 south to Huntingdon at the same $0.242/Mcf rate, and transporting gas in two segments (Station 2 to Savona and Kingsvale to Huntingdon) requires NEB confirmation and, therefore, is not guaranteed.

6.1.3 Other Third-Party Revenue

In the 1998 Decision, the Commission determined that a reasonable amount to credit the SCP for potential third-party revenues within the ROM analysis was $4 million per year, excluding deliveries to on-system non-core customers.

In the current proceeding, Westcoast submitted that $4 million per year was based on revenues of $0.12/GJ for interruptible transportation movements of 90 TJ/d. At a 10 percent discount rate, annual revenues of $4 million would have an NPV of $28 million over the study period. In Westcoast's view, the Transportation Agreements with B.C. Hydro and PG&E Energy Trading generate less than $0.082/GJ, net of a Westcoast toll of $0.106/GJ. Consequently, Westcoast suggested that the NPV benefits should be reduced by up to $28 million (Exhibit WEI-3, pp. 27-31). Westcoast argued that PG&E Energy Trading and B.C. Hydro control 100 percent of the SCP capacity to Huntingdon, and cited BC Gas evidence from the 1997 hearing which indicated that initially the greatest demand would be for east-to-west interruptible movements [Exhibit 2A, ANG 7.1(vii)]. Consequently, in Westcoast's view, the $28 million NPV benefit should be reduced by about two-thirds or $19 million (T7: 1069 and 1070). CAPP and Northwest also suggested some double counting of third-party revenues.

BC Gas disagreed that there was any double counting of revenues (T8: 1230). BC Gas evidence suggested that the third-party revenues should not be reduced by the amount of the Westcoast Kingsvale to Huntingdon toll since "regardless of any third-party movements, the Westcoast charges would be paid by the core market". Revenues provided by third-party commitments are for capacity not required by the core market (Exhibit BCG-7, BCUC 7.2). Moreover, BC Gas indicated that although the Transportation Agreements with PG&E Energy Trading and B.C. Hydro use 100 percent of the east-to-west capacity of the SCP, the potential remains for third-party revenues from east to west using capacity not fully utilized on a daily basis or from additional capacity generated by displacement from volumes contracted to move from west-to-east. Additionally, BC Gas suggested that it could serve B.C. Hydro and PG&E Energy Trading using its surplus Westcoast capacity and use the SCP to take advantage of mitigation revenue (Exhibit BCG-12, BCUC 7.1). Consequently, BC Gas argued that the contracting of firm east-to-west capacity would not have any material effect on the estimates of third-party revenues indicated in Sections 7.3 and 9.5 of the 1998 Decision (Exhibit BCG-7, BCUC 8.3; T8: 1230). BC Gas further argued that, as day prices at Kingsgate exceeded those at Sumas on 213 days in 1997/98 by an average of $0.16/MMBtu ($U.S.), the opportunity existed to generate $3.9 million of annual revenue based on physical backhaul assuming 75 percent of the price differential could be captured (T8: 1232 and 1233; Exhibit BCG-12, BCUC 7.2 as corrected at T1: 19).

BC Gas acknowledged, however, that a portion of the non-ROM third-party revenues accepted in Sections 10.3 and 10.10 of the 1998 Decision, would be affected by the contracting of firm east-to-west capacity. To the extent that a thermal generation project in the Interior goes forward or revenues from other service offerings materialize, BC Gas expects a portion of the non-ROM third-party revenue to be preserved (BCG-7, BCUC 8.3).

The Commission believes that the $3.9 million component of third-party annual revenue is based on reasonable assumptions. While it is likely that additional revenue from new Rate 22 transportation customers may be realized at some future date during the 30-year outlook, the full $2 million per year additional revenue over the 30-year term, suggested by BC Gas, is highly speculative. On balance, the Commission believes that the assumption of $4 million per year of third-party revenue, as assumed in the original ROM analysis, remains reasonable. In addition, the Commission concludes that there should be no change to the amount of zero to $3 million per year of incremental (non-ROM) third-party revenues allowed in Section 10.3 of the 1998 Decision.

6.1.4 Hedley Compressor

The NPV saving benefit attributed to the Hedley compressor by BC Gas is made up of two components. The first is a saving related to the avoided cost of providing a similar 20 MMcfd increment of capacity on the Northwest system. The second is claimed as the benefit from additional third-party revenue made possible by the added capacity which the compressor provides to the SCP.

BC Gas submitted that the addition of the Hedley compressor station to the SCP project would increase the east-to-west capacity of the Kingsvale-Oliver section of the ITS from 93 TJ/d to 115 TJ/d (or 85 MMcfd to 105 MMcfd). BC Gas has estimated an NPV benefit for the Hedley compressor of $8 million, based on the cost of service difference between the additional compression and the Northwest cost for an equivalent amount of capacity and $0.9 million per year of additional revenue from spot movements (Exhibit BCG-7, BCUC 8.2). Northwest argued that if it implemented levelized tolls the Hedley compressor benefits would be reduced.

Westcoast claimed that there is no NPV benefit arising from the Hedley compressor station. First, Westcoast argued that BC Gas has excluded from its NPV calculation any additional commodity costs to the core market resulting from the Peaking Agreements with B.C. Hydro and PG&E Energy Trading. In Westcoast's view, the price of peaking gas under the agreements would be significantly higher than the northeast B.C. baseload supply cost incorporated into the original ROM analysis. Second, the NPV benefits claimed depend on the ability of BC Gas to generate additional third-party revenues on the additional 22 TJ/d (20 MMcfd) of capacity. Westcoast believes that the SCP would be required to operate at a very high load factor to generate such revenues and, if there is demand for such capacity, the revenues will be captured by B.C. Hydro and PG&E Energy Trading. Third, Westcoast argued that the sale of the additional capacity from the Hedley compressor generates gross revenues of approximately $650,000 per year net of the Westcoast toll of $0.106/Mcf, leading to a shortfall of net revenues over the annual cost of service. Westcoast further argued that this shortfall is increased now that the comparable toll approved by the NEB for Kingsvale to Huntingdon service is $0.242/Mcf (T7: 1070-1073).

BC Gas replied that the premise of Westcoast's argument was incorrect. BC Gas characterized the NPV benefits of the Hedley compressor as resulting from the increase in capacity that enables BC Gas to receive more peaking gas from B.C. Hydro and PG&E Energy Trading. This in turn allows BC Gas to reduce supply from other sources such as Northwest. BC Gas argued that it had not included commodity costs in its comparison of Northwest and the peaking gas arrangements with B.C Hydro and PG&E Energy Trading, and consequently it was a fair comparison, since the commodity cost was not included in either side of the equation (T8: 1233 and 1234).

The Commission accepts that the Hedley compressor capacity will create an opportunity for increased third-party revenue and displacement of other capacity. The Commission believes that an $8 million NPV benefit is a reasonable estimate.

6.1.5 Westcoast Expansion Deferral Savings

BC Gas claimed an additional $5 million in NPV benefits resulting from deferral of Westcoast expansion costs (T7: 936). BC Gas suggested that combining the SCP and peaking gas acquisition with B.C. Hydro's firm gas supply would allow BC Gas to better optimize its pipeline capacity portfolio in the future. BC Gas based its $5 million NPV estimate on a two-year deferral of the first 100 MMcfd increment of Westcoast expansion (Exhibit BCG-1, p. 21).

Westcoast argued that these claimed savings should be ignored for two reasons (T7: 1073 and 1074). First, since Westcoast's incremental toll for its first 100 MMcfd expansion would be virtually the same as the existing rolled-in toll there would be no impact on BC Gas' cost to hold Westcoast capacity and consequently no savings. Second, the ROM analysis in the 1997 SCP Application had already incorporated this benefit.

The Commission accepts that under a rolled-in allocation scenario, tolls charged existing shippers on T-South will not be increased as a result of construction of the 100 MMcfd expansion (Exhibit WEI-7, BCUC 1.1). Therefore, in the view of the Commission, BC Gas' claim to an NPV benefit is not adequately supported.

6.1.6 Avoided Fixed Charge for Peaking

BC Gas, in its Application, included an NPV benefit of $10 million for the SCP based on an estimated $1.255 million annual saving by avoiding fixed costs for peaking gas supply ("peaking") on days or years in which peaking was not required (Exhibit BCG-7, BCUC 10.1). BC Gas later modified this saving to be a range of $6 to $10 million NPV to account for the potential of a higher cost of peaking from B.C. Hydro. This potentially higher peaking cost would result from a higher distillate price than had been assumed for the distillate-based formula in the Peaking Agreement between B.C. Hydro and BC Gas. However, BC Gas also indicated that it believed that B.C. Hydro's forecast of the distillate cost was too high and that it would be able to achieve a lower cost of distillate fuel (T7: 936 and 937).

Westcoast argued that the additional NPV benefit attributed to the avoided fixed charges for peaking should be reduced by $10 million rather than increased by $10 million as claimed by BC Gas. Westcoast put forward three reasons for its position (T7: 1074-1077).

First, Westcoast claimed that the peaking arrangements embodied in the agreements with B.C. Hydro and PG&E Energy Trading were essentially the same as the spot gas arrangements claimed by BC Gas in the 1997 proceeding and rejected by the Commission in the 1998 Decision.

Second, Westcoast argued that a more reasonable assumption about the cost of future distillate prices would reduce the peaking gas purchase benefit from $10 million to $3.7 million (Exhibit 26).

And third, Westcoast claimed that BC Gas changed the assumption about the number of days of peaking required from eight days assumed in the 1997 proceeding to 5.5 days in the current proceeding. Westcoast argued that assuming eight full days of peaking would be required in an average year would change the annual saving of $1.65 million to an annual cost of $1.48 million, and result in an NPV cost of approximately $10 million rather than a benefit.

BC Gas replied that the 5.5 days of peaking referred to 5.5 days of full SCP capacity to the Lower Mainland in a normal year, and the 8 days cited by Westcoast was referring to spot purchases at Yahk for both the Lower Mainland and the Interior. Consequently, BC Gas argued that the 5.5 days was consistent with earlier data used in the 1997 analysis (T8: 1236 and 1237). BC Gas evidence states that the estimated peak day use was based on the normal year requirement [Exhibit BCG-7, BCUC 10.1 and Figure 1.5(a)], and that the best indication of average use over a number of years would be the use in a normal year. However, BC Gas also acknowledged that if the peaking gas arrangements were used for nine full days the higher variable costs would offset the savings in fixed costs of the Southern California Gas Company storage and if used for more than nine days the savings would be more than offset [Exhibit BCG-12, WEI 86(f) and 86(g)].

Over the last five years, the annual peaking volumes called on by BC Gas ranged from 0 to 683 TJ. The annual volumes represent 0 to 8.6 full days per year of peaking purchases, based on the amount of peaking supply that BC Gas had contracted for each year. The average over the five-year period is 2.8 full days per year [Exhibit BCG-12, WEI 87(a)]. BC Gas also pointed out that in a series of years with no requirement for peaking the NPV benefit would be $25.4 million [Exhibit BCG-12, WEI 86(g)].

The Commission concludes that BC Gas' assumptions related to the probable use of peaking gas in the Lower Mainland in a normal year, which form the basis for its calculation of annual savings from the avoidance of fixed charges, are reasonable. On balance, the Commission believes that a range of $4 to $10 million of incremental NPV saving reflects the long-term probabilities.

6.1.7 Cost of Capital

BC Gas stated in evidence that its after-tax, weighted cost of capital was currently lower than that assumed in the 1998 Decision, having been reduced from 6.18 percent to 5.17 percent. This lower cost of capital reduced the annual cost of service of the SCP by about $7 million and resulted in NPV savings of $39 million [Exhibits BCG-11, p. 5; BCG-12, WEI 106(c)]. BC Gas argued that the use of the lower cost of capital was appropriate because that is the cost of capital that would be used if BC Gas was applying now for the first time to build the SCP. BC Gas also pointed out that both Westcoast and Northwest had used revised cost of capital estimates in their evidence (T7: 937).

Westcoast argued that the lower cost of capital and the resulting NPV saving should be ignored for several reasons. First, all of the alternatives have lower costs of capital. Second, using lower costs of capital would have resulted in changes to the ROM selection of resources within each portfolio. Moreover, Westcoast argued that the lower cost of service assumptions are unlikely to remain valid over 30 years. Finally, Westcoast argued that the cost of service assumptions did not make any provision for SCP capital cost overruns (T7: 1082).

The Commission finds persuasive the argument that the cost of capital used in the original ROM analysis may well have impacted the selection of gas resource portfolios within the ROM and to change it unilaterally is, therefore, not appropriate. The Commission concludes that the fairest course of action is to retain the original cost of capital for all projects without assigning any specific NPV benefit to the current SCP proposal. At the same time the Commission notes that, qualitatively, the effect of the current lower cost of capital is to favour front-loaded capital projects such as LNG and the SCP.

6.1.8 Additional Westcoast Capacity for Summer

Under its tariff, Westcoast is only committed to deliver 91 percent of a shipper's contract demand during the months of April to October. In other months, Westcoast is committed to deliver 100 percent of contract demand (T6: 767). Therefore, in Westcoast's view, BC Gas would need to contract for about 115 MMcfd in order to meet its contractual commitments to the SCP shippers to deliver 105 MMcfd 365 days per year from Kingsvale to Huntingdon. The financial impact of providing such additional capacity would be an annual cost of about $900,000 and an NPV impact of about $6 million, assuming the contracts were not renewed after a ten-year term (T7: 1085 and 1086).

BC Gas argued that the Westcoast claim was wrong for two reasons. First, the Transportation Agreements do not require BC Gas to hold any specific amount of Westcoast capacity. Second, BC Gas has sufficient spare capacity in the April to October period to deliver the gas (T8: 1240).

The Commission is satisfied that there is no need for BC Gas to contract for additional capacity on Westcoast to meet its obligation to the SCP shippers under the Transportation Agreements.

6.1.9 ITS Reinforcement Savings

In the 1998 Decision, the Commission accepted a credit in the ROM analysis of $19 million NPV, at a 10 percent discount rate, for reduced ITS reinforcement costs if the SCP was constructed (Exhibit BCG-7, BCUC 11.1). In its Application, BC Gas stated that, based on a historical review of pressures at Savona and Kingsvale and statements contained in correspondence with Westcoast, BC Gas is now confident of its ability to receive 600 psig design-day pressures without having to contract for a compression service charge. BC Gas indicated that it is now assuming 600 psig for ITS design purposes (Exhibit BCG-1, p. 17).

During the hearing Westcoast stated that it could provide pressures up to 850 psig at Savona and Kingsvale, although pressure control devices could be required (T6: 842 and 843). Westcoast believes that the higher delivery pressures would allow BC Gas to significantly reduce future ITS reinforcement costs, which should result in a corresponding reduction in the ITS reinforcement benefit for the SCP. Westcoast argued that the value of this benefit should be reduced to about $7 million NPV (T7: 1086-1088).

BC Gas indicated that the optimization of flows between the SCP and the EKL also provided significant reinforcement benefits. With the SCP and EKL flows optimized, coupled with 600 psig at Savona from Westcoast, the SCP could deliver gas to the Southern Okanagan Natural Gas pipeline at 750 psig, the maximum operating pressure of the 10-inch Oliver-Penticton pipeline. Thus 115 MMcfd of gas could be delivered north from Penticton through the existing 12-inch pipeline. (Exhibit 7, IR 11).

The Commission is satisfied with BC Gas' explanation of how it proposes to optimize the combined SCP and EKL flows in conjunction with the 600 psig design-day pressure which it believes to be available from Westcoast at Savona. As it appears the Westcoast fee for a higher delivery pressure would offset much of BC Gas' reinforcement savings, the Commission concludes that the ITS reinforcement credit in the 1998 Decision continues to be reasonable.

6.1.10 Improved Balancing Benefit

Westcoast stated in its evidence that since the 1997 hearing it changed its nominating procedures by introducing intra-day re-nomination rights, and that it plans to introduce a second opportunity to re-nominate during the gas day in the near future. Westcoast submitted that the changes to its nominating procedures would provide BC Gas with considerable flexibility and "…should enable it to virtually eliminate imbalances" (Exhibit WEI-3, pp. 12 and 13). Westcoast argued that BC Gas calculated the NPV value of balancing by reference to its ability to avoid the cost associated with imbalances and, therefore, the changes to its new nomination procedures would significantly reduce the balancing benefit attributable to the SCP. Westcoast noted that, although adjustments were subjective, it would be reasonable to reduce the balancing benefit of the SCP by two-thirds or approximately $14 million NPV (T7: 1088 and 1089).

BC Gas submitted that the re-nomination service was a necessary but not sufficient condition of achieving a balancing benefit. In the view of BC Gas, re-nomination service will allow a party with access to large balancing resources, such as useable linepack or underground storage, to effectively utilize them but, without those resources, there is no significant net benefit to be expected from a re-nomination service alone. BC Gas also stated that the SCP would add significantly to its imbalance management capability in terms of useable resources (Exhibit BCG-12, BCUC 6.1).

The Commission believes that the introduction of intra-day renomination rights on the Westcoast pipeline does little to solve BC Gas' balancing problems. Only when considered in conjunction with the linepack provided by the SCP does improved intra-day nomination have significant value to BC Gas. In view of the fact that the Commission anticipated improved renomination procedures when it determined the value of improved balancing in its 1998 Decision, the Commission sees no reason to reduce the benefit previously assigned.

6.1.11 Seasonal Supply to Lower Mainland

Westcoast argued that the Transportation Agreements with B.C. Hydro and PG&E Energy Trading, which limit the availability of the SCP to 15 days of peaking service to the Lower Mainland, prevent the SCP from providing any seasonal gas to the Lower Mainland. Further, Westcoast referred to the 1997 proceeding and suggested that BC Gas' ROM analysis was based on use of the SCP for approximately 38 days in a design year and approximately 21 days in a normal year. The limitation of the SCP for core market use to 15 days of peaking per year, in Westcoast's view, resulted in a significant overstatement of the ROM NPV benefits of the SCP (T7: 1091-1093).

Westcoast also noted that the ability of the SCP, under the Transportation Agreements, to move optional seasonal gas to the Lower Mainland was reduced to 0 Bcf from 2.3 Bcf in a design year and from 1.5 Bcf in a normal year. The ability of the SCP to move optional seasonal gas to the Interior is undiminished. Optional seasonal gas was defined by BC Gas as volumes of seasonal gas which could be used if the price of gas supplied from the ANG system at Yahk were lower than gas prices for supplies from the Westcoast system at Savona (Exhibit 6, IR 2).

BC Gas argued that the evidence from the 1997 hearing was consistent with its current Application (T8: 1250 and 1251). BC Gas referred to graphs from the 1997 and 1999 proceedings depicting normal weather core market use of the SCP to show that they were the same. Additionally, BC Gas referred to testimony indicating that the ROM and financial analysis underpinning the 1998 Decision was based only on the peaking supply to the Lower Mainland (T4: 422). On that basis, BC Gas argued that an NPV benefit for seasonal gas was not included in the analysis initially (T8: 1251).

The Commission is satisfied that the ROM analysis, used as the basis for the 1998 Decision, incorporated no benefit for the SCP's ability to move optional seasonal gas into the Lower Mainland. Hence, the SCP's inability (with the Transportation Agreements in place) to deliver seasonal gas to the Lower Mainland, cannot justify a decrease in NPV. The reduced ability of the SCP to move seasonal gas into the Lower Mainland is recognized by the Commission as a qualitative factor to be considered in its evaluation of the project.

6.2 Columbia Gorge Expansion of Northwest Pipeline Corporation

Northwest submitted that the NPV benefits ascribed to its Columbia Gorge Expansion project should be increased by $328.1 million ($Cdn) due to phasing of the project, third-party revenue opportunities, increased balancing capability, project developments and changes to the Gas Research Institute ("GRI") surcharges and fuel (Exhibit 29, p. 1). Other issues raised during the hearing were changes to the cost of capital and the currency exchange rate.

6.2.1 Levelized Rate Design

Northwest proposed a levelized rate design as opposed to the traditional rate design put forward in the 1997 proceeding (Exhibit NWP-1, p. 7). Northwest indicated that the NPV savings resulting from this change to levelized rates totaled $9.9 million based on a comparison of a 200,000 decatherm/d (211 TJ/d) Columbia Gorge expansion with the SCP (Exhibit 13, p. 2; T5: 523; T8: 1132). Northwest acknowledged that it could have put forward a levelized toll in the 1997 hearing but chose not to (T5: 590).

The Commission is unable to identify substantive support for the $9.9 million NPV saving claimed and believes this amount may be overstated in view of the fact that the new methodology could result in higher rates in later years. The Commission sees insufficient justification to make an adjustment to the NPV of the Northwest scenario to account for a newly proposed levelized rate structure.

6.2.2 Cost of Capital and Exchange Rate

Northwest submitted that its updated cost of debt resulted in an NPV saving of $6.2 million (Exhibit 13, p. 2; T5: 523). Northwest noted that BC Gas updated its cost of debt and other financing costs and that Northwest undertook to do likewise. Northwest indicated that it had lowered its cost of debt from 9.34 percent, which is its weighted average cost of debt, to 7.5 percent which represents current financing rates for an incremental expansion. Northwest also indicated that it had used 9.34 percent in its 1997 analysis and that it is the rate used in most of Northwest's rate studies as well (T5: 551).

With respect to the level of a $Cdn/U.S. exchange rate, Northwest submitted some information at an exchange rate of $0.66 U.S./Cdn, because BC Gas had raised the issue (T5: 537). However, Northwest argued that although exchange rates cannot be accurately forecast, a large negative adjustment for a lower current exchange rate is unreasonable based on logic alone. In Northwest's view, the inter-dependency of the Canadian and U.S. economies made a further adverse spread unlikely (T8: 1139).

BC Gas on the other hand argued that the Northwest project exposes the core market customers to a significant currency risk because their tolls will be expressed in U.S. dollars (T7: 953).

As indicated in Section 6.1.7, the Commission recognizes that the cost of capital for all proponents has declined since the 1998 Decision. The Commission, however, does not intend to make a change to the cost of capital or exchange rate for any of the projects.

6.2.3 Phased Approach

Northwest stated that it had adopted a phased approach in its Columbia Gorge Expansion Project, which would allow new increments of capacity to be placed in service in time to meet market growth "…without an expensive overbuilding of initial capacity". Northwest submitted that this phased approach resulted in an NPV saving of $194.2 million ($Cdn) based on a comparison of a 300,000 decatherm/d (317 TJ/d) expansion occurring in 2000 to a series of phased expansions. The comparison discounted the cash flows resulting from the two scenarios at 10 percent over a 30-year period (Exhibits 13, p. 2; 29, p. 2). Northwest argued that the results of the ROM have been misunderstood and that the assumptions used in the 1997

ROM analysis by BC Gas regarding the amount and timing of Northwest capacity required were illogical. These assumptions in the ROM analysis, in Northwest's view, disadvantaged the Columbia Gorge Expansion (T8: 1135 and 1136).

BC Gas argued that Northwest's analysis of its phased approach was significantly flawed insofar as Northwest delayed the in-service dates of the various phases of the project from those in BC Gas' IRP and ROM analysis. The consequence of this delay, BC Gas submitted, was that the cost savings arose from the fact that BC Gas would be short of gas supply (T7: 941 and 942, Exhibit 32).

The Commission does not accept that the revised phasing of the Columbia Gorge expansion proposed in this hearing is a solution to BC Gas' peaking gas supply problem. The Commission is satisfied that the impact of adequately phased expansion of the NWP system was properly accounted for in the ROM output which formed the basis for the 1998 Decision.

6.2.4 Third-Party Mitigation Revenue & Elimination of GRI Surcharges

Northwest argued that, at the time of the 1998 Decision, the toll mitigation benefits from third-party revenues had not been explored at the same level of detail as in this proceeding. Northwest estimated the potential NPV savings resulting from rate mitigation revenues at $70.3 million NPV (T8: 1129-30). Northwest also submitted that there was a minimum level of mitigation available based on the enhanced fixed variable rate design that reduced the reservation rate component with a corresponding increase in the commodity rate. If the capacity is unutilized, shippers would not pay the commodity portion, generating a floor level of rate mitigation of $12 million ($Cdn) NPV based on a 250 MMBtu/d expansion (Exhibit 29, p. 6). This appears to consist of two parts: a minimum, no flow, mitigation of $4.9 million due to avoidance of the GRI charge and $7.1 million mitigation due to the shifting of $0.03/MMBtu ($U.S.) from the demand portion of the toll to the commodity portion (T8: 1132).

BC Gas argued that, based on a review of the data provided in Schedules 5.4 and 5.5, very little revenue had been earned over the last three years on short-term capacity releases on the Stanfield-Sumas corridor (Exhibit NWP-4, IR 5; T7: 943). Northwest was unable to point to data that reflected valuable northward capacity from Stanfield for release in the summer months (T5: 625).

In the 1998 Decision, the Commission stated that:

> "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." (p. 87)

The Commission is satisfied that NPV savings from avoidance of the GRI surcharge, from the tolling shift of a portion of the charge from capacity to commodity and from mitigation revenue, are likely to be well within the $0 to $33 million NPV allowed for the Northwest case in the 1998 Decision.

6.2.5 Fuel Rate Decline

Northwest submitted that a decrease in the expected fuel factor utilized on its system, from the 1.9 percent used at the time of its 1997 Application to 1.0 percent, would support NPV savings for the Columbia Gorge Expansion Project of $4 million ($Cdn) (Exhibit 29, p. 7). Northwest confirmed that the fuel factor is adjusted annually based on actual experience (Exhibit NWP-4, IR 12.1). Fuel use factors from 1990 to 1999 (pending) had varied from a low of 1.0 percent in 1999 to a high of 1.9 percent, for an average of 1.4 percent (Exhibit NWP-4, IR 12.2; T5: 593).

The Commission accepts that Northwest has experienced a declining trend in its fuel rate over the past decade. However, the Commission is of the view that it may be overly optimistic to assume that the lowest rate experienced over the past decade can be maintained over a future 30-year period. On balance, the Commission considers a $2.0 million additional NPV saving to reasonably reflect the improved fuel factor.

6.2.6 Enhanced Balancing

Northwest submitted that the 3.2 Bcf expansion of JPS, of which Northwest would retain one-third, would result in an additional 1.1 Bcf available for system balancing as well as an additional 100 MMcfd of firm deliverability. Based on this, Northwest submitted that its balancing capabilities were nearly ten times greater than the 120 to 160 MMcf of useable linepack available from the SCP for balancing (Exhibit 29, pp. 4 and 5). Northwest argued that its block of storage resources is dedicated to the operational and balancing requirements of Northwest shippers. With four daily transportation nomination opportunities and the ability to net and/or trade imbalances, Northwest further argued that shippers had the flexibility to manage transportation imbalances before and after they occurred (T8: 1131). Consequently, Northwest claimed that the NPV savings attributed to the Columbia Gorge Expansion Project should be equal to, or greater than, the approximately $21 million ($Cdn) (at a 10 percent discount rate) attributed to the SCP for balancing. A $21 million NPV benefit ascribed to the Columbia Gorge Expansion would represent an increase of approximately $11 million over the $10 million benefit attributed to it in the 1998 Decision (Exhibit 29, pp. 4 and 5; T8: 1132).

BC Gas argued that there were no increased benefits for balancing resulting from the JPS expansion or the Columbia Gorge Expansion Project. BC Gas further argued that the balancing provisions in the Northwest tariff had not changed and that there was a major difference between use of linepack on one's own pipeline and reliance on others to provide balancing (T7: 945). In BC Gas' view, there was no reason for the Commission to change its determination with respect to the balancing benefits from the Columbia Gorge Expansion Project (T8: 1177).

The Commission is satisfied that the expansion of JPS, of which Northwest retains its one-third share, will significantly improve Northwest's ability to balance flows on it own pipeline. The extent to which this improvement will be available to BC Gas is less clear. While the increased availability of JPS will undoubtedly provide a balancing benefit to all Northwest shippers, the amount of the benefit available to BC Gas at times of peak demand when it is most needed is likely to be modest and less flexible than having linepack available on its own system.

The Commission is prepared to recognize an increased NPV savings for the Northwest case on this account equal to two-thirds the benefit allocated to the SCP. This represents a $4 million increase in NPV savings from $10 million to $14 million, at a 10 percent discount rate.

6.2.7 Risk of Cost Overruns

Northwest submitted that the project cost estimate of the SCP is overly optimistic (Exhibit 29, pp. 10 and 11). Northwest further argued that the capital cost and cost of service of the Columbia Gorge Expansion project were significantly lower than the SCP (T8: 1139). However, Northwest acknowledged that its capital cost estimate for Phase 1 of the Columbia Gorge Expansion project has risen by 14 percent since it last appeared before the U.S. Federal Energy Regulatory Commission. A guarantee of 5 percent above the revised cost estimate was offered to Duke Energy, based on Northwest's confidence level in the revised cost estimate (T5: 542). Northwest further acknowledged that the cost estimate for Phase II of its project has risen by approximately 18.5 percent since the 1997 proceedings due to design changes (Exhibit NWP-4, IR 1; T5: 534). Northwest also stated that its confidence level in its cost estimates was the same for all of the phases of its expansion proposal when it appeared in the 1997 SCP proceeding (T5: 543).

The Commission notes the evidence from the Columbia Gorge Expansion costing and is concerned that initial estimates for pipeline construction through difficult terrain are likely to be low and may well be exceeded in practice by a substantial margin. The Commission sees no reason to make an adjustment to the NPV calculations for Northwest based on capital cost risk of the SCP, but this matter is addressed further in Chapter 7.

6.3 Liquefied Natural Gas Facilities

Two Intervenors, WGSI and Williams, propose to construct LNG facilities to serve the core market peak demand of BC Gas and, potentially, other customers.

WGSI proposes to construct a 3 Bcf LNG facility at McNab Creek northeast of Port Mellon, B.C. By using both potential displacement and backhaul volumes, WGSI claimed that the total volume available to BC Gas for peaking would be at least 301 MMcfd and could be as high as 397 MMcfd. Since the 1997 hearing, WGSI has continued development of its project particularly with respect to environmental certification, zoning, First Nations consultations and construction preparation (WGSI-2, pp. 1-3). In April 1999, WGSI received a Project Approval Certificate under the B.C. Environmental Assessment Act (Exhibit 40).

Williams proposes to construct a 3 Bcf LNG facility in Whatcom County in Washington State, near Northwest's Sumas Compressor Station and at the confluence of the Northwest, Westcoast and BC Gas/Sumas International Pipelines Inc. pipelines (Exhibit WIP-1, pp. 12 and 13).

6.3.1 Release of Additional Westcoast Capacity

During the hearing there was considerable debate concerning the amount of Westcoast capacity that could be released by BC Gas if an LNG facility was constructed to meet its Lower Mainland core market peak demand. WGSI stated that, in the RH-2-98 hearing before the NEB, BC Gas indicated that it could de-contract approximately 200 MMcfd of T-North and T-South capacity on Westcoast following introduction of a 3 Bcf LNG facility. WGSI contrasted this estimate to information provided previously to the Commission by BC Gas that suggested that it would de-contract some 100 MMcfd in such circumstances. WGSI estimated that, over 30 years, an additional 100 MMcfd of de-contracting of Westcoast capacity could result in BC Gas toll payment savings of about $50 million NPV, which could be added to the NPV benefits ascribed to the WGSI LNG project in the 1998 Decision (Exhibit WGSI-2, p. 7; T8: 1115 and 1116).

Westcoast stated that the availability of 200 MMcfd of Westcoast capacity coupled with 100 MMcfd of inexpensive Westcoast expansion capacity would make 300 MMcfd of capacity available to serve the regional market and thermal generation plants. Westcoast also indicated that the availability of this 300 MMcfd of capacity plus a similar 300 MMcfd from an LNG facility would have a significant dampening effect on potential price shocks (Exhibit WEI-3, pp. 8-10).

BC Gas agreed that the NEB evidence suggested that if an LNG facility were constructed in the Lower Mainland it could possibly release as much as 200 MMcfd, but stated that its analysis indicated this is unlikely to happen (T2: 271). BC Gas indicated that it stood by the results of its 1997 ROM analysis and that the amount of Westcoast capacity that might be released given either LNG or the SCP was no different than the scenario examined in the 1997 proceeding (Exhibit BCG-12, BCUC 2.2; T2: 271-273).

WGSI also claimed that additional released capacity on Westcoast would have benefits outside of the ROM calculation. WGSI suggested that additional available Westcoast capacity resulting from de-contracting an additional 100 MMcfd would increase the $6 million NPV benefit ascribed to LNG in the 1998 Decision for price shock protection by a substantial but unquantified amount. In WGSI’s view the 200 MMcfd of total de-contracted capacity would be more effective than the 85 MMcfd delivered to the Lower Mainland by the SCP, which was credited with NPV benefits of $24 million (Exhibit WGSI-2, p. 7).

BC Gas responded that it would be reluctant to dispatch LNG, making LNG less effective as a tool for mitigating price shocks. Moreover, BC Gas, as noted above, disagreed with the assumption that 100 MMcfd of additional Westcoast capacity would be released (T2: 274 and 275).

The Commission concludes that, in the event of construction of a 3 Bcf LNG facility in the Lower Mainland, BC Gas would most likely be able to release approximately 100 MMcfd of upstream Westcoast capacity. Depending upon circumstances at the time, this figure could be either higher or lower. This release of Westcoast capacity, in the LNG cases, was taken into account in the ROM model output supporting the 1998 Decision and no Intervenor provided independent analysis of the issue. Therefore, no adjustment to LNG NPV values appears necessary. Moreover, to the extent that the recent NEB Decision might be interpreted to imply that any competitive facility that results in the release of Westcoast capacity may have to pay for the impact of the released capacity until it becomes re-contracted, one might argue that adjustments should be made to the costs associated with alternatives to the SCP. However, no negative adjustment is made to LNG NPV benefits.

6.3.2 Third-Party Revenue

In the 1998 Decision, the Commission determined that "… zero additional third-party non-ROM benefit is appropriate for LNG." In the 1999 proceeding, Williams claimed that an NPV benefit of $84.6 million exists based on the potential for third-party revenues. Williams' analysis assumed that BC Gas would require only 200 MMcfd from a 3 Bcf, 300 MMcfd LNG facility leaving 100 MMcfd for service to other customers. The assumptions and calculation of the NPV amount were as follows:

Annual Levelized Cost of Service ("LCOS") - 3 Bcf Facility	$ 27.0 million
Annual LCOS for 200 MMcfd Peaking	18.1 million
Annual LCOS for 100 MMcfd Peaking	8.9 million
NPV Savings of LCOS for 100 MMcfd Peaking (30 years at 10%)	84.6 million

(Exhibit WIP-3, p. 5).

Witnesses for Williams testified that it could provide some, albeit less, third-party mitigation revenues by building a 4 Bcf LNG tank or two, 2 Bcf tanks, contracting 1 Bcf to third parties and providing 3 Bcf to BC Gas. Williams submitted that this would reduce the unit cost of LNG to U.S. $5.39/Mcf from U.S. $6.02/Mcf (T4: 465). Williams argued that such revenue mitigation would provide $21.3 million of NPV benefits over 30 years (T8: 1145).

The Commission notes that Williams' first proposal for the generation of third-party revenue ignores the fact that BC Gas' requirement is for 3 Bcf of LNG storage and that this was the basis of the Commission's 1998 evaluation. There is little evidence of market support for Williams' second proposal, which would involve the construction of a 4 Bcf facility and generate third-party revenue from the capacity in excess of BC Gas' requirement. The Commission, therefore, sees no reason to adjust the NPV savings to the Williams LNG proposal on this account.

6.3.3 Guaranteed Project Cost

WGSI stated that the cost, size, location and operation of its proposed LNG facility remain essentially unchanged since the previous proceeding (Exhibit WGSI-3, IR 1). As in the 1997 hearing, WGSI is not presenting its project on the basis of project cost, but rather on the basis of a fixed price offer to BC Gas. WGSI indicated that its current offer to BC Gas remains the same as that presented to the Commission in the previous proceeding. WGSI offered a range of contract terms from 10 to 25 years (Exhibit WGSI-2, p. 6). WGSI confirmed that it has not entered into any agreements with Centra Gas, nor has Centra Gas received Commission approval for tolls for services it would provide to enable BC Gas to fill or draw from

WGSI's proposed LNG facility (Exhibits WGSI-3, IR 9; WGSI-4, IR 3.3.1). Consequently, the cost to BC Gas for use of the WGSI facility is neither known nor fixed.

Williams indicated that for its base 3 Bcf LNG facility there was no change in capital cost, location or operation since the 1997 proceedings (Exhibit WIP-4, IR 1). Williams' proposed LNG facility has an estimated cost of $133.9 million (1997 dollars Cdn) (Exhibit WIP-3, p. 11). Williams indicated that it would guarantee its cost based upon an agreed engineering cost estimate between BC Gas and Williams (Exhibit WIP-3, p. 7). However, Williams also acknowledged that it had not yet agreed with BC Gas upon a firm cost estimate and that, once the two parties have an agreement, then Williams would be at risk for cost increases from that point forward (Exhibit WIP–4, IR 4.1).

Williams indicated that in the case of the SCP, in the absence of a cost guarantee by BC Gas, there is a substantial risk of a cost overrun that would be borne by BC Gas ratepayers. Williams estimated for the SCP an NPV cost, based on a 30-year cost of service analysis assuming a 15 percent cost overrun. The high end of Williams' estimate is $58.3 million NPV which Williams maintains should be considered an NPV benefit to its fixed contract price offering. Williams notes that BC Gas could reduce this NPV benefit to zero by offering an overrun guarantee (Exhibit WIP-3, p. 7).

The Commission is not prepared to assign a specific NPV saving to LNG projects on the basis of a speculative cost overrun on the SCP. However, when it evaluates the qualitative merits of the competing projects, it will recognize the potential value of a fixed price LNG contract relative to the risks of pipeline construction cost overruns.

6.3.4 Cost of Capital and Exchange Rate

The Commission will make no adjustment to NPV savings since it does not propose to make any change to the ROM output related to cost of capital or foreign exchange rate differences. These issues are consistently dealt with in Sections 6.1.7 and 6.2.2. Instead, it will qualitatively consider these factors in assessing the projects. In this respect, the Commission notes that there is a difference in the level of exchange rate risk between the WGSI proposal and the Williams proposal.

6.3.5 CTS Reinforcement Benefit

In the ROM analysis reviewed in the 1998 Decision, BC Gas included an avoided cost of $2.6 million NPV 1997 dollars Cdn (at 10 percent discount rate) for system reinforcement benefits to the Coastal Transmission System provided by the WGSI LNG project.

BC Gas submitted a revised estimate of NPV benefits based on a comparison of the magnitude and timing of system reinforcements with and without the WGSI LNG facility and assuming demand from Burrard of 200 TJ/d (Exhibit BCG-12, BCUC 11.1). BC Gas calculated that the benefits of the WGSI LNG facility related to deferral of system reinforcements on the CTS were $8.8 million NPV at 10 percent, which is $6.2 million NPV higher than recognized in the 1998 Decision (Exhibit BCG-8, p. 27).

The Commission concludes that, in the light of B.C. Hydro's new baseload requirements for thermal generation, an additional NPV savings credit of $6 million should be allocated to the WGSI LNG proposal to account for deferral of CTS reinforcement costs.

6.4 Revisions to Net Present Value Benefits from Decision

In the 1998 Decision the Commission compiled a table showing the non-ROM benefits that it believed should be added to the ROM output for the three leading resource options. The NPV benefits were expressed as savings relative to a baseline default portfolio, and Table 10-2 in that Decision was a summary of the total NPV saving value of each of the resource alternatives. Where a range of probable NPV values had been assigned, both the minimum and maximum values were included.

Table 6.1 below summarizes the changes to the ROM and non-ROM quantifiable benefits that the Commission concludes are warranted by the evidence adduced in the current hearing. The SCP NPV benefits are increased by between $46 million and $60 million based on firm transportation revenues, Hedley compressor benefits and avoided fixed charges for peaking. These increases are partly offset by a decreased benefit due to the higher than previously assumed Westcoast firm toll for service from Kingsvale to Huntingdon. The NPV benefits attributable to Northwest's Columbia Gorge Expansion Project increase by $6 million due to a decline in the fuel rate and enhanced balancing benefits. The WGSI McNab Creek LNG Project's NPV benefits are increased by $6 million due to enhanced Coastal Transmission System reinforcement benefits. No change is made to the previous NPV benefits associated with Williams' Sumas LNG Project.

Table 6.1

Summary of Revised NPV Benefits

Project	NPV Benefits per 1998 Decision		NPV Adjustments per Current Hearing		Revised NPV Benefits	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Southern Crossing	532	552	46	60	578	612
Northwest Expansion	541	562	6	6	547	568
WGSI McNab Creek LNG	602	602	6	6	608	608
Williams Sumas LNG	602	602	0	0	602	602

As is evident from Table 6.1, the quantified values of the benefits accruing to the SCP, Northwest and LNG resource options are similar, given the limits of accuracy of the ROM and the recent updates. A determination of the best resource addition will rely on the assessment of non-quantifiable and other benefits in Chapter 7.

7.0 OTHER CONSIDERATIONS

Developments since the 1998 Decision have several important implications for BC Gas' efforts to source natural gas for its system sales customers. In addition to the changes to NPV benefits considered in Chapter 6, the Commission must consider other factors that are not easily monetized. This Chapter looks at these more qualitative aspects, and addresses topics which received attention in the procedures established by Order No. G-121-98 and in the hearing, but which are not covered explicitly elsewhere in this Decision.

7.1 Supply Portfolio Diversification

The 1998 Decision stated that diversity of supply, or the ability to access alternative sources, provides flexibility to obtain gas in the event of a physical interruption in supply from one source. It also permits the use of lower cost gas in the event there are significant cost differentials between sources. The Commission identified non-ROM NPV benefits for the SCP, LNG and Northwest expansion cases for increased security of supply, and went on to state:

> "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." (p. 76).

The 1998 Decision considered further the Price Shock Protection benefits of diversity of supply, as diversity should provide supply choices and improve the liquidity and competitiveness of the gas market at Sumas. The Commission also identified non-ROM NPV benefits for Price Shock Protection.

7.1.1 Security and Reliability of Supply

BC Gas' evidence in this proceeding refers to the explosion at the Solex Gas Liquids Extraction Facility in Taylor, B.C. in January 1999. The explosion caused the Westcoast McMahon Gas Plant to be shut down for two days, and would have caused supply concerns if temperatures had not been higher than normal at the time. BC Gas also identifies subsidence problems on the Northwest system in 1997 and 1999 as an indication of the vulnerability of supply into the area (Exhibit BCG-11, pp. 3 and 4). BC Gas considers that a third significant pipeline source is better than two, since the SCP could move volumes from Yahk if there was a disruption in the northern part of the Westcoast system (T2: 167 and 259).

BC Gas also expresses concern about the dependability of peaking supplies that may be based on "market solutions" instead of real capacity such as the SCP would provide (Exhibit BCG-11, p. 7). On a peak day, a peaking gas supplier who resorts to day market spot purchases may cause price spikes or could find that spot gas is not available (Exhibit BCG-12, PIAC 2).

COFI, Cominco and Methanex, B.C. Hydro, PG&E Energy Trading and the Office and Professional Employees' International Union, Local 378 also argue that the SCP will enhance reliability and security of supply. PG&E Energy Trading states that projected growth in regional demand, limited access to alternate transportation capacity and uncertainty of supply in northeastern B.C. have led to increased price volatility and risk exposure (T7: 979).

Westcoast considers that the increase in security of supply with the SCP will be small, due to the low probability of disruptions on the Westcoast system and the relatively small amount of capacity that the SCP can provide (T5: 731 and 732).

Northwest argues that its Columbia Gorge expansion project provides increased access to the Alberta, Rocky Mountain and San Juan basins, while the SCP would be constrained by available Westcoast T-South capacity. Northwest also has access to JPS, Clay Basin storage and Plymouth LNG, and believes it can provide significant security of supply and pricing benefits (T8: 1126).

Williams states that an LNG facility, which is contained at a single site, gives as good security of supply as additional pipeline capacity, which would be susceptible to events such as landslides (T4: 496 and 497). Williams argues that its LNG facility would be market area storage, and would provide security in the event of problems on another system (T8: 1152).

The Commission recognizes that the SCP and Northwest do provide added security of supply and emergency protection to the BC Gas ratepayers in the event of a supply problem upstream of Kingsvale on the Westcoast system. The SCP, if constructed, will add significantly to security of supply to the Interior system, a benefit not available from other alternatives. The additional security offered to the Lower Mainland is more modest since the capacity of the SCP represents a very small proportion of the total capacity requirement. Under emergency conditions the modest support it would provide could be sustained over a longer period of time than that available from LNG storage.

7.1.2 Benefits of Gas Supply Diversity

Section 5.1 discusses the evidence of increasing price isolation at Huntingdon. No participant proposes specific changes to the NPV Price Shock Benefits that the Commission determined in the 1998 Decision, but several refer to the opportunity that supply diversity provides to buy gas from the lowest cost source on any particular day. BC Gas expects that if prices in northeastern B.C. increase relative to Alberta, it will source seasonal gas for the Interior at Yahk rather than off the Westcoast system (T2: 245). BC Gas noted that the proposed flows into Alliance represent 20 percent of B.C. production and only 6 percent of Alberta production. To the extent that the additional capacity causes prices to equalize or otherwise differ from the price forecast in the 1998 Decision, BC Gas could use the SCP to provide flexibility and diversity to mitigate the price impacts (Exhibit BCG-12, Williams 2). In the view of BC Gas, these benefits were larger than, or additional to, the increased security or price shock benefits credited to the SCP in the 1998 Decision (T2: 245-247, 260).

PG&E Energy Trading considers that supply at Station 2 on the Westcoast system has greater price risk than in Alberta, because it is at one end of the current North American pipeline grid, and parties trying to source gas there have limited market power. In terms of arranging gas to meet its peaking gas requirements, PG&E Energy Trading found much more flexibility in the Alberta market than at Station 2, and felt that it required that flexibility to satisfy the needs of its customers. Alberta has a larger supply basin and more storage, and has several pipeline connections to the North American grid. If prices rise in Alberta, PG&E Energy Trading has flexibility in its portfolio to hold gas back in Alberta and buy gas in other areas to meet the needs of its customers (T4: 406-410).

B.C. Hydro described how the SCP transportation capacity would provide arbitrage opportunities. Annual average prices in northeastern B.C. and Alberta tend to be similar, but there can be significant monthly or daily variances (Exhibit BCH-6, 1.1 to 1.4).

B.C. Hydro expects to buy significant quantities of BC Gas as part of its competitive gas supply portfolio. However, it is fundamental to its portfolio approach that not all supply be from one source, or one set of market conditions and over one transportation path. B.C. Hydro expressed the view that, without securing access to diverse sources of gas and their associated transportation paths, there cannot be diversity in supply sources or market prices. A lack of diversity or flexibility to mitigate constrained market conditions, such as are likely at Huntingdon without increased gas infrastructure, is not in the best interest of gas customers, including B.C. Hydro ratepayers (T7: 967 and 968). In B.C. Hydro's view, an LNG facility would not add to basin diversity (Exhibit BCH-6, 1.3).

COFI, Cominco and Methanex argue that the SCP's benefits of greater customer choice and increased access to competitively priced gas, will continue for the long term (T7: 986 and 987).

The Commission believes that the events of the past year underscore the price risk mitigation potential of the SCP. There are also indirect benefits to all other BC Gas customers if the supply diversification available to BC Gas, B.C. Hydro and PG&E Energy Trading provides a governor on wellhead prices in northeastern B.C. Northwest also provides similar, but smaller, benefits.

7.1.3 <u>Flexibility to Adapt to Changing Circumstances</u>

BC Gas proposes the SCP as a project that will bring a wide range of benefits to core market customers and others in the current and expected gas market. BC Gas maintains that the value of the SCP to core market customers will continue regardless of whether BC Gas or direct sellers provide gas to the core market (Exhibit BCG-11, p. 14).

As a pipeline solution, the SCP will provide the ability to serve potential thermal generation loads, and to capture potential new gas loads in the Interior. B.C. Hydro states that the flexibility that accompanies additional transportation resources will be needed to accommodate emerging changes in the Western Canadian gas sector, such as the construction of the Alliance Pipeline which could have unpredictable results (T7: 964).

Westcoast presents a different view, stating that market participants should be permitted to bring forward flexible, market-responsive solutions to the regional need for peaking supply. In Westcoast's view, this is preferable to relying on the conventional practices of the past, like building the SCP, where risks fall on consumers and solutions lack flexibility to meet the challenges of the future. Energy use patterns can be expected to change in the future, but how they will change is uncertain. Westcoast recommends that actions taken today should focus on the next five to ten years (T5: 696 and 697).

The Commission concurs that the impact the Alliance Pipeline may have on Alberta and B.C. gas markets remains uncertain. However, the presence of the SCP will enhance the options for pipeline expansion alternatives should Alberta-sourced gas become increasingly competitive.

7.2 Pipeline-on-Pipeline Competition

BC Gas presents the SCP as a new pipeline connection with the North American pipeline grid which will provide competition for pipeline expansion and for gas supplies, and which will put a governor on the extent of future cost increases (Exhibit BCG-11, p. 3). An LNG facility or expansion of the Westcoast or Northwest system would provide similar peak day supply, but would not provide similar incremental pipeline-on-pipeline competition.

BC Gas argues that it expects that a competing pipeline will place a competitive constraint on future Westcoast tolls (T7: 950). As an example, BC Gas identifies that the SCP would provide motivation for Westcoast to keep its Kingsvale to Huntingdon tolls down. Higher tolls would create an incentive to extend the SCP from Oliver to Huntingdon (T7: 940).

COFI, Cominco and Methanex expect that the SCP will promote competition for future pipeline expansion. From their perspective as gas users, the SCP provides superior diversity of supply and transportation, compared to storage or other pipeline projects (T7: 987-989). B.C. Hydro states that access to additional transportation paths is necessary to achieve diversity in supply sources and market prices. CAC (B.C.) et al. also argues that, assuming continued long-term growth, all B.C. consumers would benefit from being an integral part of the diversified gas transportation infrastructure in North America (T7: 1000).

Westcoast acknowledges that the SCP would provide diversity, as it would add another connection and more capacity to the supply basin that now supplies B.C. However, Westcoast felt the price risk of the SCP was too great (T5: 728). Williams argues that a third pipeline connection is only one aspect of the broad competition issue. Also, Northwest already accesses the same supply base as the SCP (T8: 1157).

The Commission accepts that the SCP and Northwest expansions would provide a measure of transportation diversity which may temper expansions and costs on the Westcoast system. The SCP provides enhanced benefits to Interior customers. The SCP, alone among the projects under consideration, introduces a new, though limited, link between the ANG/PGT system and the Westcoast/Northwest system.

7.3 Potential for Capital Cost Overruns

The 1998 Decision discussed the capital costs of the preferred alternatives considered in the 1997 proceeding, and the potential for cost overruns. The Commission accepted that the SCP probably could be completed within 110 percent of BC Gas' cost estimate.

In this hearing, BC Gas states that it continues to be very confident in its current cost estimate of $376 million in as-spent dollars (including AFUDC and overhead), within a variance range of plus or minus 10 percent (T1: 32). BC Gas has not performed a formal risk analysis on the project cost variance. The 10 percent variance level represents BC Gas' confidence level in the estimate, based on utilization of existing rights-of-way and its understanding of environmental impacts. Additional field work, Right-of-Way agreements with the Osoyoos Indian Band and Canadian Pacific Railway, detailed public consultation, low levels of inflation, reduced steel prices and availability of contractors in the year 2000 have all added to its confidence in the estimate (Exhibit BCG-12, WEI 80). One remaining concern is that if BC Gas' efforts to directionally drill the Columbia River are not successful, BC Gas plans to use an articulated concrete mat cover for the crossing. A cost estimate for this contingency has not been prepared (T2: 278).

BC Gas includes $18 million of contingencies in its estimate (T2: 191). In addition, a contractor bidding on pipe installation assumes risk for unscheduled downtime, and normally includes an additional contingency allowance of 7.5 percent for downtime in its bid (T4: 438). The estimated installation cost for the SCP is $214.4 million in "as spent" dollars (Exhibit BCG-7, BCUC 2.2). This would indicate that the contractor contingency is approximately $15 million for a total contingency of $33 million (about 9 percent).

BC Gas states that it does not consider that the decision on the SCP Application should turn on who assumes the risk of cost overruns. However, once a decision has been made on the Application, BC Gas is prepared to discuss an incentive mechanism related to capital cost, providing the mechanism has some symmetry (T1: 52 and 53).

In this proceeding, Westcoast updated its estimate of the cost of expanding its T-South facilities. Westcoast did not materially change its estimate from 1997 to 1999 (T6: 755-757). Pipe prices are slightly lower currently than they were in 1997 (Exhibit WEI-6, IR 20 and 21). Westcoast states that pipeline construction activity in 2000 is now expected to be higher than in 1999. Westcoast also argues that the SCP construction schedule is aggressive and that this increases the risk of cost overruns. BC Gas responded that Alliance is the only significant pipeline construction project in Canada at that time and it is scheduled to be in service in November 2000.

Northwest argues that the construction of the SCP through challenging terrain under an aggressive schedule invites overruns, which will force core customers to pay higher tolls (T8: 1123). Williams expressed concerns about the impact on costs from the amount of rock encountered, population encroachments and river crossings.

WGSI is prepared to offer fixed price contracts to BC Gas. Williams is willing to guarantee a rate to BC Gas for its LNG facility once an engineering cost estimate is agreed upon with the customer (Exhibit WIP-5, IR 3.2). Williams further argues that BC Gas should guarantee its SCP cost numbers to protect the core customer (T8: 1154). BC Gas considers Williams' Sumas LNG tolls as illustrative and are not guaranteed until construction costs were better estimated and negotiations had occurred (T8: 1190).

Northwest does not guarantee its cost estimates, although it did offer a guaranteed cost to Duke Energy for Phase 1 of the Gorge Expansion (T5: 535). A witness for Williams described how, on large projects, Northwest works with the contractor and the ultimate customer to reach an agreed cost estimate. Northwest will then guarantee the rate based on that estimate (T4: 478). The estimate also provides a basis for sharing cost increases or decreases with the contractor (T4: 508 and 509).

Westcoast states that the agreement with its shippers on the Maritimes and Northeast Pipeline has a rate cap, which implies a capital cost cap or some other cap. The Alliance Pipeline has a similar provision. The Foothills Pipeline agreement some years ago had a capital cost maximum, with an incentive if costs came in under a certain amount and a penalty if they were over the amount (T6: 849).

CAC (B.C.) et al. states that its support for the SCP is based on assumptions with respect to costs to core market customers and argues that the risk of cost overruns will be mitigated by the test of prudency with respect to the expenditures (T1: 31; T7: 999). Williams argued that the risk of cost overruns cannot be mitigated by prudency reviews because significant cost overruns can occur even though all costs are prudently incurred (T8: 1157).

In spite of BC Gas' confidence that the SCP can be built within 10 percent of the estimated cost and the willingness of BC Gas to negotiate an incentive mechanism to control costs, the Commission concludes that the SCP could expose ratepayers to an unacceptable risk of cost overruns, unless BC Gas commits to a cap on costs to be included in rate base. The potential for fixed rate contracts with LNG providers is a significant benefit of the proposed LNG alternatives, in that it protects ratepayers from capital cost overruns.

7.4 Customer Views

The CAC (B.C.) et al. supports the SCP (Exhibit CAC-3). The change in the CAC (B.C.) et al.'s position since the 1997 hearing is attributable to a number of factors. It is the view of CAC (B.C.) et al. that the potential benefits of ensuring core customers will not have to pay more for gas due to a lack of flexibility in supply arrangements outweigh the risks to core customers of higher than forecast costs or lower than forecast gas demand. The CAC (B.C.) et al. wants BC Gas to resolve the tariff issues arising from NEB's RH-2-98 Decision, and to reduce the likelihood of cost overruns, by delaying the SCP in-service date by one year to the winter of 2001/02 (T7: 1008-1011).

COFI, Cominco and Methanex supported the Application and urged the Commission to move quickly to make a final decision to ensure that a year would not be lost due to needless delay (Exhibit COFI-1). Diversity and security of supply, increased competition, and improved reliability constitute their reasons for continuing to support the SCP. COFI, Cominco and Methanex prefer to avoid further industrial curtailments as a peaking option for BC Gas.

Numerous commercial and industrial customers of BC Gas provided Letters of Comment supporting the SCP, often citing increased reliability and competitive supply. The Columbia Power Corporation is discussing the development of gas powered generation facilities in the Columbia-Kootenay region with TransAlta Energy Corporation and new pipeline capacity, as provided by the SCP, would be a prerequisite (Exhibit 34). B.C. Hydro, which will become BC Gas' largest transportation customer, participated in the hearing to support the SCP and associated agreements.

The Lower Mainland Large Volume Gas Users Association ("LMLGUA") opposed the SCP in its February submission but did not provide further evidence or make final argument in the hearing (Exhibit LMLGUA-1). The Commission notes that the LMLGUA opposes the SCP because of a concern that some costs of the pipeline will be allocated to LMLGUA members. This rate design matter will be dealt with in a future proceeding but the Commission anticipates that all ratepayers who benefit from the SCP, directly or indirectly, will contribute to its costs in proportion to the benefit it provides to each rate category.

The Commission recognizes that there is substantial customer support for the SCP. The objective of utility regulation is to provide safe, reliable, low cost and convenient service to customers while allowing the utility an opportunity to earn a fair return on its invested capital. Even though the Commission may recognize the desires of ratepayers, it remains to the Commission to determine which resource best meets the requirements of all customers.

7.5 Customer Rate Impacts

The 1998 Decision accepted that the delivered cost of gas to BC Gas customers would not be significantly different under the SCP or other alternatives. The SCP was estimated to be $0.14/GJ more expensive than LNG or Northwest at startup and decline over time so that the SCP became less costly than the other options after 2014. The Commission viewed these estimates as being conservative, since they did not incorporate the non-ROM benefits of the SCP.

When compared to the 1997 SCP proposal, BC Gas estimates that the new SCP burnertip rate has declined by $0.05-$0.07/GJ over most of the next decade. This makes the SCP burnertip rate about $0.02 to $0.03/GJ more expensive than LNG until 2010, after which the SCP burnertip rate becomes lower than the LNG burnertip rate (Exhibit BCG-7, BCUC 12.1).

This new SCP rate impact includes the effect of the annual third-party revenues and other increased benefits as described in the Application. BC Gas uses an assumption about the Westcoast toll from Kingsvale to Huntingdon that was made prior to the NEB Decision and, therefore, the BC Gas filing understates the rate impact of the present SCP project. Offsetting this, however, is the fact that the market and operational benefits (e.g., improved balancing, increased security, price shock protection benefits) as quantified in the 1998 Decision are not accounted for in the BC Gas filing. Also, as noted in Chapter 6, there is a possibility that interest rates at the time of debt issuance may be less than forecast in the 1998 Decision. On the other hand, a cost overrun on the SCP would increase core customer rates.

The Commission concludes that the customer rate impacts as a result of the SCP or other alternatives remain similar. The SCP has modestly reduced its rate impact on customers as a result of the third-party revenue and peaking arrangements with B.C. Hydro and PG&E Energy Trading.

7.6 Regulatory Risk

In the context of the SCP and other resource proposals, there are two main types of "regulatory risk". A regulatory agency could effectively override approval decisions by other agencies and prohibit construction by refusing an approval; secondly, a regulatory agency could require changes to project specifications, timing, tariffs, or contracts to such an extent that they differ significantly from those used by another regulatory agency to reach its decision. The SCP requires a Project Approval Certificate ("PAC") from the Province and a CPCN from the BCUC. BC Gas expects to receive a PAC at the end of its Stage 1 review (Exhibit BCG-12, NWP 8.2).

WGSI received a PAC from the Province on April 9, 1999, after a Stage 2 review (Exhibit 40). An application to rezone the McNab Creek site is expected to be heard at a Sunshine Coast Regional District public hearing in June 1999. The Squamish Nation, in whose traditional territory the plant would be located, opposes WGSI's proposal (Exhibit SN-1). WGSI indicates the Squamish Nation's concerns are expected to be resolved by a commercial agreement (T8: 1110). As a public utility, WGSI's LNG plant would need either a CPCN from the BCUC or an exemption from regulation by the BCUC and the Lieutenant Governor in Council.

The Sumas LNG and Northwest proposals fall within the jurisdiction of both the U.S. Federal Energy Regulatory Commission and local or state siting agencies. Williams does not anticipate siting delays as the entire 60-acre site is owned or optioned by Williams.

From a regulatory perspective, BC Gas argued that a project built in B.C. is preferable to a U.S. project because future tolling decisions will consider the interests of BC Gas' customers. The CAC (B.C.) et al. also indicates it is more comfortable with a B.C. project regulated in B.C. COFI, Cominco and Methanex also argue that, as a point of comparison in favour of the SCP, consumers of BC Gas would not have the same influence on the terms and conditions of service or rates charged on the other pipelines as they would for the SCP (T7: 989).

Given trade agreements and delivery by displacement, Williams disagrees that a United States project built to meet peaking requirements in B.C. has less supply security than a project sited in B.C. (T8: 1152). Aside from their locations and regulatory regimes, BC Gas noted that the SCP and the Northwest Gorge expansions were conceptually similar, namely they both connect the Westcoast/Northwest system and the ANG/PGT system (T8: 1174).

Regulatory risk does not appear to be a major issue and the Commission simply notes that projects regulated by the BCUC link the regulator directly with the ratepayers to be served by such projects and the shareholders of the projects.

7.7 Currency Exchange Risk

The value of the Canadian dollar, expressed in U.S. dollars, has fluctuated widely over the past two years. The 1998 Decision was based on a $0.74 conversion rate. Evidence in the hearing used a $0.66 conversion rate, which was roughly the rate at that time. At the time of writing this Decision, the Canadian dollar is trading at approximately $0.68 to the U.S. dollar.

Capital expenditures on projects will be impacted by the conversion rate at the time of expenditure for U.S. goods and services. The Commission notes that those projects with tolls expressed in U.S. dollars are exposed to higher exchange rate risk.

7.8 Benefits to B.C. Hydro

B.C. Hydro expects to become a major buyer of natural gas in the Province and BC Gas' largest transportation customer. While B.C. Hydro expects its gas needs to grow to 250 TJ/day, Westcoast disputes this total, noting that firm loads to Burrard have been forecast for years but have yet to materialize (T7: 963, 1060 and 1061).

Diversity in B.C. Hydro's supply and transportation portfolio should allow it to mitigate costs and reduce price volatility at Huntingdon/Sumas, while promoting competition between gas supply basins. In B.C. Hydro's view, price spikes at Huntingdon/Sumas will become more frequent and more severe without the SCP. B.C. Hydro also stated that historical data failed to capture the substantial effect of its future purchases and the continued growth of other markets served through Huntingdon.

B.C. Hydro does not need to install new facilities at Burrard or the ICP to free-up peaking gas. Due to the flexibility of the gas system relative to electricity, it expects to provide daily peaking gas during low load hours at night and still operate its generating facilities during heavy electrical load hours. B.C. Hydro estimates substantial potential savings can be realized on high gas consumption days in the Lower Mainland by purchasing electricity at the Mid-Columbia Index, purchasing gas at Sumas or Kingsgate, or burning distillate at the ICP (Exhibit BCH-6, IR 3.5).

B.C. Hydro argues that the Transportation Agreement and the Peaking Agreement are directly linked and cannot be considered in isolation, that it is only by providing the peaking service that it could obtain firm transportation service on the SCP (T7: 971). Additionally, the T-South Agreement would give B.C. Hydro potential access to vintage T-South capacity no longer required by BC Gas. This would allow B.C. Hydro to manage its gas transportation portfolio more effectively given the shorter term commitment required for Westcoast vintage capacity compared to the ten-year commitment required for expansion capacity (Exhibit

BCH-5, p. 3). B.C. Hydro accepted that previous directives of the BCUC respecting vintage T-South capacity would have priority over the commitments in the T-South Agreement (Exhibit BCH-6, IR 2.2).

The CAC (B.C.) et al. notes that most of its client group are also customers of B.C. Hydro, and sees these agreements as additional benefits of the SCP which the other alternatives do not provide (T7: 1002).

Westcoast, however, holds the view that any benefits derived by B.C. Hydro are a result of contractual arrangements with BC Gas and come at the expense of BC Gas' core market customers (T7: 1062 and 1063). Westcoast argued that the potential benefits identified by B.C. Hydro are limited to, first, the use of the SCP to arbitrage price differentials between Sumas and Kingsgate, and, second, the ability to arbitrage price differences between gas and electricity. The first type of benefit, Westcoast argued, is not a new benefit, but simply a transfer of a benefit which existed previously and had simply been a transfer from the core market customers of BC Gas to B.C. Hydro (with half of the transferred benefit going to PG&E Energy Trading). The second type of benefit in Westcoast's view was not unique to the SCP, but would be created by any pipeline that delivered baseload supply to a thermal generation facility. In any event, Westcoast argued, the Commission should not sanction any transfer of benefits from BC Gas core market customers to B.C. Hydro (T7: 1062-1064).

In the 1998 Decision, the Commission instructed BC Gas to explore peak shaving synergies with B.C. Hydro in an effort to secure contracts which would benefit the ratepayers of both utilities. The eventual agreements are highly beneficial to B.C. Hydro customers. In arriving at its Decision, however, the Commission has concluded that its jurisdiction is limited to an analysis of the potential benefit to BC Gas ratepayers only. The Commission has, therefore, not included the potential benefit to B.C. Hydro into its conclusions on the disposition of the Application. It merely notes them here because they were the focus of considerable discussion by participants in the hearing.

7.9 Regional Economic Impacts

While of limited debate in the hearing, the effect that the SCP may have on regional economies in B.C. was the topic of most of the approximately 100 Letters of Comment. Letters from local governments and businesses in the southern Okanagan and Kootenay regions tend to welcome the SCP for its economic benefits in a region of significant unemployment and a stagnant resource-based economy.

The Office and Professional Employees' International Union, Local 378 ("OPEIU") states that the SCP will increase job security for its 3,400 members employed by B.C. Hydro and BC Gas by augmenting the employers' economic health. While the OPEIU "... appreciate the desire of the BCUC to find the lowest cost solutions …" it is concerned that the engineering and financial techniques that dominate the analyses downplay the SCP's social and economic impacts, which the OPEIU view as positive (Exhibit LC-50; T7: 1013).

In contrast, Letters of Comment from local governments and other representatives from Northeastern B.C. express concerns about the impacts of the SCP on gas exploration and production in the Peace River and Fort Nelson regions.

BC Gas also states that the significant capital expenditures associated with the SCP would create employment and tax revenues for all levels of government, that the WGSI LNG project's regional benefits are reduced because it contains a higher proportion of U.S.-sourced materials, and Westcoast's proposed "marketplace" solutions provide no economic benefits. CAC (B.C.) et al. supported the economic benefits of a B.C. project. Others suggested that the most costly projects provide the highest benefits, and regional tax benefits would be costly to core customers (T8: 1123), or would be offset by reductions in taxes associated with reduced production from northeast B.C. (T8: 1151).

The Commission has concluded that the Act does not give it the mandate to consider broad social, environmental and economic development impacts on non-BC Gas customers. The Commission has, therefore, not included regional economic impacts into its determination of the Application.

7.10 Commission Determination

Based on the foregoing sections, the Commission finds that the SCP offers more qualitative benefits than the LNG or Northwest options. At the same time, the Commission is very concerned that the issuance of a CPCN to the SCP without measures to control the risk of capital cost overruns, could lead to an installed project cost which could cause the SCP to become more costly than LNG or a Northwest expansion. Therefore, the Commission finds that any CPCN must be conditional upon BC Gas standing behind its evidence, so that cost overruns over 10 percent will not be borne by ratepayers.

8.0 COMMISSION CONCLUSIONS

The Commission concluded in Chapter 4 that there is an impending need for a peaking resource addition. Whichever new resource is selected, the cost of the addition can be expected to increase customers' rates, a fact recognized and accepted by the CAC (B.C.) et al. in its support of the SCP. The Commission is concerned that BC Gas and its customers are at a watershed period where costly peak resource additions are unavoidable, at the same time as natural gas commodity prices are likely to rise. Consumers may be expected to react negatively to the combined rate impacts. BC Gas and the Commission will have to manage this circumstance to moderate customer impacts as much as possible.

In reviewing the Application of BC Gas for a CPCN to construct the SCP, the Commission acknowledges the inherent difficulty in valuing the many near-term and long-term costs and benefits of the resource alternatives for meeting peak demand, given the considerable uncertainty about future gas commodity pricing and differentials. Each of the three leading resource options of LNG, SCP and Northwest, offers substantial benefits compared to other alternatives.

Based on the valuation of those costs and benefits that can be monetized, Chapter 6 concludes that each of the resource options has similar value. It, therefore, falls to the Commission's best judgement of the other benefits and risks inherent in each resource option to determine whether to grant the requested CPCN. The substantial benefits of the SCP in providing a flexible peaking resource, risk mitigation against gas pricing differentials, reinforcement of the Interior Transmission System, balancing and linepack benefits have been discussed in the foregoing chapters. The Commission concludes that the SCP offers the highest potential benefit to ratepayers over the long-run, but at higher customer rates in the near term. The Transportation Agreements with B.C. Hydro and PG&E Energy Trading provide firm third-party revenue from SCP capacity. However, while the agreements are significant in assisting the cost of service and are directly linked to peaking gas supplies provided by the shippers, they do not contribute as much revenue in the contract period as the Commission would have preferred. In the longer run, it is expected that this capacity will command a much higher value.

As one element of mitigating potential customer rate impacts, the Commission will ensure that the risk to core market customers of capital cost overruns is limited. BC Gas has expressed confidence that it can contain capital costs to within 10 percent of the estimate contained in the Application. The Commission will require, as a condition of the CPCN, that costs beyond 110 percent of the capital cost in the Application be absorbed by the shareholder and not BC Gas ratepayers. To maximize the incentive, savings below 90 percent will also accrue to the shareholder. BC Gas estimates the capital cost target of the SCP as $376 million in nominal or "as spent" dollars, including overhead and AFUDC, assuming a November 1, 2000 in-service date. The maximum rate base addition will be capped at $414 million and the minimum rate base addition will be $338 million. BC Gas must file by June 15, 1999 a statement regarding its willingness to accept a CPCN for the SCP that includes, as a condition, this mechanism to limit ratepayer exposure to capital cost overruns.

While a major resource addition is required, a delay until the 2001/2002 winter peak demand period could be tolerated without undue risk of shortages to BC Gas customers. Further, a delay until November 2001 could allow BC Gas additional flexibility in construction of the SCP in order to minimize its capital cost. The Commission is prepared to allow such a delay conditional upon BC Gas confirming that a November 2001 in-service date can be accommodated in its agreements with B.C. Hydro and PG&E Energy Trading. If BC Gas adopts a November 2001 in-service date, the estimated capital cost target in "as spent" dollars would be increased by the actual change in the Canadian Consumer Price Index ("CPI") from 2000 to 2001. For example, if the CPI increases by 1 percent, the estimate of the capital cost target to be included in rate base would be presumed to increase to $380 million. By June 15, 1999, BC Gas must advise the Commission of its intended date of completion of the SCP project, and confirm that all related agreements will accommodate that date.

In conjunction with its Application for a CPCN for the SCP, BC Gas also requested that the Commission approve the Firm Tendered Transportation Service Agreements with B.C. Hydro and PG&E Energy Trading, the Peaking Gas Purchase Agreements with B.C. Hydro and PG&E Energy Trading, and the Transportation South Capacity Agreement with B.C. Hydro. The Commission is prepared to approve the Transportation and Peaking Agreements provided that the Transportation Agreements are amended to limit the total term to a maximum of 20 years, as discussed in Section 3.3. The Commission is also prepared to approve the Transportation South Capacity Agreement provided that it is amended as discussed in Section 3.1.4 to clarify that, in accordance with earlier Commission directives, assignments to core market customers wishing to purchase gas directly from non-utility suppliers would take precedence over assignments under the T-South Agreement. The Commission understands that the parties are prepared to make these changes to the agreements. The amendments to the agreements are to be filed with the Commission by June 15, 1999.

Dated at the City of Vancouver, in the Province of British Columbia, this 21st day of May, 1999.

Original signed by:
Peter Ostergaard
Chair

Original signed by:
Lorna R. Barr
Deputy Chair

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

Original signed by:
Frank C. Leighton
Commissioner

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-51-99

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

and

The December 1998 Application by BC Gas Utility Ltd.
for a Certificate of Public Convenience and Necessity
regarding its Southern Crossing Pipeline Project

BEFORE:	P. Ostergaard, Chair) L.R. Barr, Deputy Chair) K.L. Hall, Commissioner) F.C. Leighton, Commissioner)	May 21, 1999

O R D E R

WHEREAS:

A. On May 30, 1997, BC Gas Utility Ltd. ("BC Gas", "the Utility") applied to the Commission ("the 1997 Application"), pursuant to Section 45 of the Utilities Commission Act ("the Act"), for a Certificate of Public Convenience and Necessity ("CPCN") to construct and operate certain pipeline and compression facilities referred to as the Southern Crossing Pipeline ("SCP") Project; and

B. The Commission held a public hearing on the 1997 Application and issued a Decision dated April 3, 1998 ("the 1998 Decision"), which concluded that the SCP Project was not the preferred option at that time, and denied the 1997 Application for a CPCN for the SCP Project; and

C. In the 1998 Decision, the Commission recognized that planned cogeneration plants on Vancouver Island and the Burrard Thermal Plant might provide a low cost peaking option for the customers of BC Gas and that the demand for baseload gas for these plants could make a pipeline proposal such as the SCP more attractive. The Commission, therefore, expected BC Gas to expedite negotiations with British Columbia Hydro and Power Authority ("B.C. Hydro") to explore ways in which the two utilities could better serve customers through a peak shaving arrangement; and

D. On December 11, 1998, BC Gas applied for a CPCN for the SCP Project ("the Application"), and added to the scope of the Project a compressor station located at Hedley, B.C. on its existing Kingsvale to Oliver pipeline. BC Gas estimated the cost of the SCP at $376 million "as spent" dollars, including overhead and allowance for funds used during construction; and

E. In the Application, BC Gas proposed that the review of the Application be conducted in the context of the 1998 Decision and that only new issues be addressed; and

F. Commission Order No. G-121-98, dated December 21, 1998, established a timetable for a Workshop, Information Requests, and written submissions on the completeness of the Application and related peaking supply agreements and transportation service agreements, along with participant views on any further proceedings which may be necessary to consider these filings in the context of either the 1998 Decision or as new initiatives; and

G. The Application included a Firm Tendered Transportation Service Agreement ("Transportation Agreement") with PG&E Energy Trading, Canada Corporation ("PG&E Energy Trading") for transportation capacity on SCP. By a letter dated January 8, 1999, BC Gas filed a Transportation Agreement and a Transportation South Capacity Agreement, both dated November 27, 1998, and an Umbrella Letter Agreement dated January 7, 1999, all made with B.C. Hydro; and

H. By a second letter dated January 8, 1999, BC Gas filed copies of Peaking Gas Purchase Agreements ("Peaking Agreements") with B.C. Hydro and PG&E Energy Trading dated November 27 and 30, 1998, respectively, and requested that specific terms on pricing and supply arrangements be kept confidential on the basis that disclosure could adversely affect the price or supply of gas to BC Gas and its customers in the future; and

I. By a letter dated January 13, 1999, B.C. Hydro filed a Put Option Agreement and a CTS Support Agreement, both made November 27, 1998 among B.C. Hydro, BC Gas and BC Gas Inc., and requested that the "Specified Maximum" as defined in the CTS Support Agreement be kept confidential on the basis that disclosure could adversely affect its position and that of its customers; and

J. In its February 11, 1999 submission, Westcoast Energy Inc. ("Westcoast") requested that the Commission direct BC Gas to fully disclose the premiums in the Peaking Agreements and the "Specified Maximum" in the CTS Support Agreement; and

K. In its February 17, 1999 submission, BC Gas requested that the Commission approve the Transportation Agreements and the Peaking Agreements with B.C. Hydro and PG&E Energy Trading; and

L. Order No. G-21-99, dated February 22, 1999, established the timetable for an oral public hearing commencing Monday, March 29, 1999, to review the Application, with the scope of the hearing to be limited to material changes since the 1998 Decision to the net benefits of the SCP and alternative proposals; and

M. Order No. G-34-99, dated March 25, 1999, approved the request by Westcoast that the Commission direct BC Gas to fully disclose the undisclosed premiums in the Peaking Agreements only with respect to the previously undisclosed information in Sections 5.1 and 5.3 of the B.C. Hydro Peaking Agreement, and otherwise denied the request; and

N. Order No. G-35-99, dated March 25, 1999, denied the request by Westcoast for disclosure of the Specified Maximum in the CTS Support Agreement; and

O. The public hearing commenced on March 29, 1999 and oral argument was completed on April 13, 1999; and

P. In the public hearing, BC Gas requested approval of the Transportation South Capacity Agreement with B.C. Hydro; and

Q. The Commission has considered the Application, the written evidence filed prior to the hearing, and the evidence and argument presented at the public hearing, and has determined that a CPCN should be issued for the SCP provided the conditions in this Order are met.

NOW THEREFORE pursuant to sections 45, 46, 64 and 71 of the Act, the Commission finds that the issuance of a CPCN for the SCP project and approval of the related agreements will be in the public interest providing that the following conditions precedent are met:

1. BC Gas files, by June 15, 1999, a statement regarding its willingness to accept a CPCN for the SCP that includes, as a condition, the mechanism to limit ratepayer exposure to capital cost overruns that is described in the Decision that accompanies this Order.

2. BC Gas files, by June 15, 1999, executed amendments to the Transportation Agreements with B.C. Hydro and PG&E Energy Trading, which limit the total term of each of these agreements to a maximum of 20 years.

3. BC Gas files, by June 15, 1999, an executed amendment to the Transportation South Capacity Agreement with B.C. Hydro, which clarifies that, in accordance with earlier Commission directives, assignments of Westcoast Transportation South capacity to core market customers wishing to purchase gas directly from non-utility suppliers, take precedence over B.C. Hydro's right of first refusal.

4. BC Gas advises the Commission, by June 15, 1999, of its intended date of completion of the SCP project, and confirms that all related agreements will accommodate that date.

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of May, 1999.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

APPEARANCES

G.A. FULTON K. DUKE	British Columbia Utilities Commission, Counsel
C.B. JOHNSON R.M. LONERGAN	BC Gas Utility Ltd.
C.K. YATES B. GRANT D.A. HOLGATE	PG&E Energy Trading, Canada Corporation
R. GATHERCOLE 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]
R.W. LUSK, Q.C.	British Columbia Hydro and Power Authority
J. CHAMPION R.B. WALLACE	Council of Forest Industries and Cominco Ltd. and Methanex Corporation
N.J. SCHULTZ	Canadian Association of Petroleum Producers
C.B. WOODS	Mobil Oil Canada
T.W. JENNINGS	Centra Gas British Columbia Inc.
J. LUTES R. SIRETT	Westcoast Energy Inc.
C. JONES	Westcoast Gas Services Inc.
C. WEAFER	Lower Mainland Large Volume Gas Users Association
C. REARDON	Squamish Nation
P.E. SCHMID	Northwest Pipeline Corporation
A. GOLDBERG	Williams International Pipeline Co.
H. LEDDERHOF	Ecology Circle
S. BOUCHER-CHEN	Northwest Pacific Energy Marketing Inc.
B. FARMER	Office and Professional Employees International Union Local 378,
R. ZEILSTRA	Columbia Power Corporation

J.B. WILLISTON J.W. FRASER	Commission Staff
ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

INDEX OF WITNESSES

BC Gas Utility Ltd. - Panel	RICHARD T. BALLANTYNE RANDY L. JESPERSEN WILLIAM R. MANERY
Westcoast Gas Services Inc. - Panel	DOUGLAS S. THORNEYCROFT JEFFREY M. MYERS
PG&E Energy Trading, Canada Corporation - Panel	KEITH J. BOHN DARRELL C. DANYLUK
The Williams International Pipeline - Panel	MATT J. GILLIS PETER C. THOMAS STEVEN D. KOFOED DANIEL N. POTTS
Northwest Pipeline Corporation - Panel	JOHN B. DAVIS KIRK T. MORGAN BRUCE E. WARNER
Westcoast Energy Inc. – Panel	ARTHUR H. WILLMS RONALD B. MAAS DENNIS E. ELIAS

LIST OF EXHIBITS

	Exhibit No.
BC Gas Utility Ltd. - Southern Crossing Pipeline Project Application for a Certificate of Public Convenience and Necessity, dated December 11, 1998	BCG-1
BC Gas Utility Ltd. - Southern Crossing Pipeline Project Application for a Certificate of Public Convenience and Necessity, Preliminary Engineering Report, dated February 7, 1997	BCG-2
BC Gas Utility Ltd. - Southern Crossing Pipeline Project Application for a Certificate of Public Convenience and Necessity, Engineering Report Update, dated September 2, 1997	BCG-3
BC Gas Utility Ltd. Letter enclosing Peaking Gas Purchase Agreements dated January 8, 1999	BCG-4
BC Gas Utility Ltd. Letter enclosing the B.C. Hydro and Power Authority Firm Tendered Transportation Service Agreement, Transportation South Capacity Agreement and Umbrella Letter Agreement, dated January 8, 1999	BCG-5
BC Gas Utility Ltd. and BC Gas Inc. Letters regarding the Put Option Agreement and CTS Support Agreement, dated January 20, 1999	BCG-6
BC Gas Utility Ltd. Response to Information Request No. 1, dated February 4 and February 8, 1999	BCG-7
BC Gas Utility Ltd. Written Submission, dated February 17, 1999	BCG-8
BC Gas Utility Ltd. Letter requesting Deferment of date for filing Written Evidence, dated February 24, 1999	BCG-9
BC Gas Utility Ltd. and BC Gas Inc. Letters (three letters) regarding Westcoast Energy Inc. Request for Disclosure, dated March 3, 1999	BCG-10
BC Gas Utility Ltd. Written Evidence, dated March 5, 1999	BCG-11
BC Gas Utility Ltd. response to Information Request No. 2, dated March 22, 1999	BCG-12
B.C. Utilities Commission Letter and Order No. G-121-98, dated December 21, 1998	BCUC-1
B.C. Utilities Commission Letter No. L-4-99, dated January 19, 1999	BCUC-2
B.C. Utilities Commission Letter No. L-5-99, dated January 20, 1999	BCUC-3
B.C. Utilities Commission Letter (without enclosures), dated January 28, 1999	BCUC-4
B.C. Utilities Commission Letter and Order No. G-21-99, dated February 22, 1999	BCUC-5
B.C. Utilities Commission Letter to B.C. Hydro and Power Authority, dated February 24, 1999	BCUC-6

LIST OF EXHIBITS
(Cont'd.)

	Exhibit No.
B.C. Utilities Commission Letter and Order No. G-23-99, dated February 25, 1999	BCUC-7
B.C. Utilities Commission Letter and Order No. G-29-99, dated March 16, 1999	BCUC-8
B.C. Utilities Commission Letter and Order No. G-22-99, dated February 24, 1999; and Letter and Order No. G-30-99, dated March 16, 1999	BCUC-9
B.C. Utilities Commission Order No. G-34-99, dated March 25, 1999	BCUC-10
B.C. Utilities Commission Order No. G-35-99, dated March 25, 1999	BCUC-11
B.C. Hydro and Power Authority Letter enclosing the Put Option Agreement and the CTS Support Agreement, dated January 13, 1999	BCH-1
B.C. Hydro and Power Authority Letter (without attachments), dated February 5, 1999	BCH-2
B.C. Hydro and Power Authority Submission, dated February 11, 1999 (including as Schedule A, a letter from B.C. Hydro and Power Authority, dated February 10, 1999, with attachment)	BCH-3
B.C. Hydro and Power Authority Letters (two letters) regarding Westcoast Energy Inc. Request for Disclosure, dated March 3, 1999	BCH-4
B.C. Hydro and Power Authority Evidence filed in Response to B.C. Utilities Commission Order No. G-21-99, Direction No. 4, dated March 8, 1999	BCH-5
B.C. Hydro and Power Authority Response to B.C. Utilities Commission Information Request No. 1, dated March 22, 1999	BCH-6
B.C. Hydro and Power Authority Response to Westcoast Energy Inc. Information Request No. 1, dated March 22, 1999	BCH-7
Canadian Association of Petroleum Producers Submission, dated February 11, 1999	CAPP-1
Centra Gas British Columbia Inc. Submission, dated February 11, 1999	CENTRA-1
Consumers' Association of Canada (B.C. Branch) et al. Letter, dated January 12, 1999	CAC-1
Consumers' Association of Canada (B.C. Branch) et al. Letter, dated January 15, 1999	CAC-2
Consumers' Association of Canada (B.C. Branch) et al. Submission, dated February 11, 1999	CAC-3
Council of Forest Industries, Cominco Ltd. and Methanex Corporation Submission, dated February 11, 1999	COFI-1
Fort Nelson–Liard Regional District Submission, dated February 11, 1999	FNLRD-1
Lower Mainland Large Gas Users Association Submission, dated February 11, 1999	LMLGUA-1

LIST OF EXHIBITS
(Cont'd.)

	Exhibit No.
Northwest Pipeline Corporation Submission, dated February 11, 1999	NWP-1
Northwest Pipeline Corporation Letter, dated February 24, 1999	NWP-2
Northwest Pipeline Corporation Written Evidence, dated March 5, 1999	NWP-3
Northwest Pipeline Corporation Response to BC Gas Utility Ltd. Information Request No. 1, dated March 22, 1999	NWP-4
Northwest Pipeline Corporation Response to B.C. Utilities Commission Information Request No. 1, dated March 22, 1999	NWP-5
Northwest Pipeline Corporation Response to Consumers' Association of Canada (B.C. Branch) et al. Information Request No. 1, dated March 22, 1999	NWP-6
Northwest Pipeline Corporation Response to Northwest Pacific Energy Marketing Inc. Information Request No. 1, dated March 22, 1999	NWP-7
Peace River Regional District Submission, dated February 11, 1999	PRRD-1
PG&E Energy Trading, Canada Corporation Submission, dated February 11, 1999	PG&EET-1
PG&E Energy Trading, Canada Corporation Letter, dated March 3, 1999	PG&EET-2
PG&E Energy Trading, Canada Corporation Written Evidence, dated March 5, 1999	PG&EET-3
PG&E Energy Trading, Canada Corporation Response to B.C. Utilities Commission Information Request No. 1, dated March 22, 1999	PG&EET-4
PG&E Energy Trading, Canada Corporation Response to Northwest Pacific Energy Marketing Inc. Information Request No. 1, dated March 22, 1999	PG&EET-5
PG&E Energy Trading, Canada Corporation Response to Westcoast Energy Inc. Information Request No. 1, dated March 22, 1999	PG&EET-6
PG&E Energy Trading, Canada Corporation Response to Williams International Pipeline Company Information Request No. 1, dated March 22, 1999	PG&EET-7
Squamish Nation Written Evidence, received March 5, 1999 (document dated March 5, 1998)	SN-1
Squamish Nation response to B.C. Utilities Commission Information Request No. 1, received March 23, 1999	SN-2
Westcoast Energy Inc. Submission, dated February 11, 1999	WEI-1
Westcoast Energy Inc. Letter, dated February 23, 1999	WEI-2
Westcoast Energy Inc. Written Evidence, dated March 5, 1999	WEI-3

LIST OF EXHIBITS
(Cont'd.)

	Exhibit No.
Westcoast Energy Inc. Letters (two letters) regarding Westcoast Energy Inc. Request for Disclosure, dated March 12, 1999	WEI-4
Westcoast Energy Inc. Letters (two letters) regarding Westcoast Energy Inc. Request for Disclosure, dated March 22, 1999	WEI-5
Westcoast Energy Inc. Response to BC Gas Utility Ltd. Information Request No. 1, dated March 22, 1999	WEI-6
Westcoast Energy Inc. Response to B.C. Utilities Commission Information Request No. 1, dated March 22, 1999	WEI-7
Westcoast Energy Inc. Response to Consumers' Association of Canada (B.C. Branch) et al. Information Request No. 1, dated March 22, 1999	WEI-8
Westcoast Gas Services Inc. Submission, dated February 11, 1999	WGSI-1
Westcoast Gas Services Inc. Written Evidence, dated March 5, 1999	WGSI-2
Westcoast Gas Services Inc. Response to BC Gas Utility Ltd. Information Request No. 1, dated March 22, 1999	WGSI-3
Westcoast Gas Services Inc. Response to B.C. Utilities Commission Information Request No. 1, dated March 22, 1999	WGSI-4
Williams International Pipeline Company Submission, dated February 11, 1999	WIP-1
Williams International Pipeline Company Letter, dated February 24, 1999	WIP-2
Williams International Pipeline Company Written Evidence, dated March 5, 1999	WIP-3
Williams International Pipeline Company Response to BC Gas Utility Ltd., Information Request No. 1, dated March 22, 1999	WIP-4
Williams International Pipeline Company Response to B.C. Utilities Commission Information Request No. 1, dated March 22, 1999	WIP-5
Williams International Pipeline Company Response to Consumers' Association of Canada (B.C. Branch) et al. Information Request No. 1, dated March 22, 1999	WIP-6
Williams International Pipeline Company Letter, dated March 23, 1999	WIP-7
Letter from Arvay Finlay on behalf of Westcoast Gas Services Inc., dated December 2, 1998	LC-1
Letter from Arvay Finlay on behalf of Westcoast Gas Services Inc., dated October 7, 1998	LC-2
Letter from The Association of Kootenay & Boundary Municipalities, dated June 2, 1998	LC-3
Letter from Blue Horizon Hotel, dated February 10, 1999	LC-4

LIST OF EXHIBITS
(Cont'd.)

	Exhibit No.
Letter from Mr. Leonard Booth, Slocan, dated February 3, 1999	LC-5
Letter from The British Columbia Public Interest Advocacy Centre, dated October 23, 1998	LC-6
Letter from The British Columbia Public Interest Advocacy Centre, dated July 9, 1998	LC-7
Letter from The British Columbia Public Interest Advocacy Centre, dated July 6, 1998	LC-8
Letter from British Columbia Restaurant and Foodservices Association, dated February 5, 1999	LC-9
Letter from Mr. Dennis Brown, Hacienda Inn, Creston, dated December 9, 1997	LC-10
Letter from Canadian Association of Petroleum Producers, dated October 30, 1998	LC-11
Letter from Canadian Inovatech Inc., dated February 5, 1999	LC-12
Letter from Cartech Collision, dated February 9, 1999	LC-13
Letter from Castle Glass & Windshield Ltd., dated February 10, 1999	LC-14
Letter from Century Pacific Foundry Ltd., dated February 5, 1999	LC-15
Letter from the City of Castlegar, Office of the Mayor, dated May 26, 1998	LC-16
Letter from the City of Cranbrook, Office of the Mayor, dated May 12, 1998	LC-17
Letter from the City of Fernie, dated May 13, 1998	LC-18
Letter from the City of Fort St. John, Office of the Mayor, dated February 5, 1999	LC-19
Letter from the City of Fort St. John, Office of the Mayor, dated November 9, 1998	LC-20
Letter from the City of Grand Forks, dated May 21, 1998	LC-21
Letter from the City of Rossland, Office of the Mayor, dated January 12, 1999	LC-22
Letter from the City of Rossland, Office of the Clerk, dated May 15, 1998	LC-23
Letter from the City of Trail, dated February 1, 1999	LC-24
Letter from the City of Trail, dated May 15, 1998	LC-25
Letter from Comfort Welding Ltd., dated December 4, 1997	LC-26
Letter from Cominco Ltd., dated February 9, 1999	LC-27
Letter from Cranbrook and District Chamber of Commerce, dated May 11, 1998	LC-28

LIST OF EXHIBITS
(Cont'd.)

	Exhibit No.
Letter from Creston Fire Protection & Safety, dated February 10, 1999	LC-29
Letter from the District of Sparwood, dated May 7, 1998	LC-30
Letter from the District of Taylor, Office of the Mayor, dated December 16, 1998	LC-31
Letter from Duke Energy Marketing, dated September 18, 1998	LC-32
Letter from Fort St. John & District Chamber of Commerce, dated December 17, 1998	LC-33
Letter from Greater Vancouver Apartment Owners' Association, dated February 11, 1999	LC-34
Letter from H&M Excavating Ltd., dated February 17, 1999	LC-35
Letter from The Harrison Hot Springs Resort, dated February 9, 1999	LC-36
Letter from Hedley Community Recreation Commission Association, dated October 5, 1998	LC-37
Letter from Highland Foundry Ltd., dated February 9, 1999	LC-38
Letter from International Union of Operating Engineers, Local Union No. 115-115A-115B-115C, dated May 11, 1998	LC-39
Letter from Kastco Rentals (1995) Ltd., Facsimile date January 11, 1999	LC-40
Letter from Keljan Services, dated February 11, 1999	LC-41
Letter from Kootenay Project Services, dated February 9, 1999	LC-42
Letter from Liberty Investments Limited, dated February 9, 1999	LC-43
Letter from Luther Law Corp, Dunbar Developments Inc., dated February 4, 1999	LC-44
Letter from McIntyre, Woods Geotechnical Engineers, dated February 9, 1999	LC-45
Letter from Montecito Towers, dated February 8, 1999	LC-46
Letter from Nelson and District Chamber of Commerce, dated February 10, 1999	LC-47
Letter from Northwest Pipeline Corporation, dated November 10, 1998	LC-48
Letter from Nu Creek Developments, dated February 8, 1999	LC-49
Letter from Office and Professional Employees, International Union Local 378, dated February 11, 1999	LC-50
Letter from Peace River Regional District, dated January 25, 1999	LC-51
Letter from Peace River Regional District, dated January 20, 1999	LC-52

LIST OF EXHIBITS
(Cont'd.)

	Exhibit No.
Letter from Peace River Regional District, dated January 4, 1999	LC-53
Letter from Pelton Reforestation Ltd., dated February 5, 1999	LC-54
Letter from Pizzey Consulting Ltd., dated February 5, 1999	LC-55
Letter from Province of British Columbia, Legislative Assembly, Official Opposition Caucus, Bill Barisoff, MLA, Okanagan-Boundary, dated May 22, 1998	LC-56
Letter from Province of British Columbia, Legislative Assembly, Government Caucus, Ed Conroy, MLA, Rossland-Trail, dated February 9, 1999	LC-57
Letter from Province of British Columbia, Legislative Assembly, Official Opposition Caucus, Richard Neufeld MLA, Peace River North, dated January 14, 1999	LC-58
Letter from Regional District of Central Kootenay, dated June 3, 1998	LC-59
Letter from Regional District of Okanagan-Similkameen, dated February 10, 1999	LC-60
Letter from Regional District of Okanagan-Similkameen, dated December 8, 1997	LC-61
Letter from Charles B. Roberts, Robson, dated February 8, 1999	LC-62
Letter from Scaf-Tech Services, dated February 8, 1999	LC-63
Letter from School District No. 5 (Southeast Kootenay), dated February 10, 1999	LC-64
Letter from School District No. 43 (Coquitlam), dated February 5, 1999	LC-65
Letter from School District No. 51 (Boundary), dated February 10, 1999	LC-66
Letter from Sonax Furniture Manufacturing Ltd., dated June 1, 1998	LC-67
Letter from Southview Property Management Inc., dated February 4, 1999	LC-68
Letter from Timberland Consultants Ltd., dated February 4, 1999	LC-69
Letter from Town of Creston, dated May 25, 1998	LC-70
Letter from Town of Oliver, dated May 27, 1998	LC-71
Letter from Town of Princeton, dated October 8, 1998	LC-72
Letter from Vale Appraisals, dated February 4, 1999	LC-73
Letter from the Village of Midway, dated February 5, 1999	LC-74
Letter from the Village of Pouce Coupe, dated February 11, 1999	LC-75
Letter from the Village of Silverton, dated May 13, 1998	LC-76

LIST OF EXHIBITS
(Cont'd.)

LIST OF EXHIBITS
(Cont'd.)

	Exhibit No.
Interventions	INT
Interested Party Status	IP
BC Gas Utility Ltd. Information Request revised response to B.C. Utilities Commission Information Request No. 2, Request No. 12.2, dated March 22, 1999	1
BC Gas Utility Ltd. and B.C. Hydro and Power Authority, Peaking Gas Purchase Agreement, pages 8 and 9	2
Westcoast Energy Inc. Aid for Cross-Examination, Peak Day Forecast Comparison, dated March 24, 1999	3
Westcoast Energy Inc. Aid for Cross-Examination, BC Gas' Peak Day Demand Forecast Reconciliation	4
Westcoast Energy Inc. Aid for Cross-Examination, Southern Crossing Pipeline Usage	5
BC Gas Utility Ltd. Responses to Undertakings No. 1 through 5, dated March 29, 1999	6
BC Gas Utility Ltd. Responses to Undertakings No. 7 through 12, dated April 1, 1999	7
BC Gas Utility Ltd. Response to Westcoast Energy Inc. Information Request No. 3, Requests No. 115 and 116, dated April 1, 1999	8
BC Gas Utility Ltd. Letter to National Energy Board regarding Points for Clarification, dated March 31, 1999	9
Westcoast Gas Services Inc. Letter to B.C. Utilities Commission regarding Statements of Qualification for Doug Thorneycroft and Jeff Myers, dated March 17, 1999	10
Westcoast Gas Services Inc. Application for a Project Approval Certificate documents	11
B.C. Hydro and Power Authority Response to Westcoast Gas Services Inc. Information Request No. 1, dated March 30, 1999	12
Northwest Pipeline Corporation Response to B.C. Utilities Commission Information Request No. 2, dated April 1, 1999	13
Northwest Pipeline Corporation revised Response to BC Gas Utility Ltd. Information Request No. 1, Request No. 2.2, dated April 6, 1999	14
Northwest Pipeline Corporation revised Response to BC Utilities Commission Information Request No. 1, Request No. 1.1, dated April 6, 1999	15
Northwest Pipeline Corporation Supplemental Response to B.C. Utilities Commission Information Request No. 1, Request No. 2.3, dated March 15, 1999	16

LIST OF EXHIBITS
(Cont'd.)

LIST OF EXHIBITS
(Cont'd.)

ABBREVIATIONS

A. Organizations

AECO	Alberta Energy Company
Alliance	Alliance Pipeline
ANG	Alberta Natural Gas Company Ltd
BCUC, Commission	British Columbia Utilities Commission
BC Gas, the Utility	BC Gas Utility Ltd.
B.C. Hydro	British Columbia Hydro and Power Authority
CAPP	Canadian Association of Petroleum Producers
Cascade	Cascade Natural Gas
Centra Gas	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.
FERC	Federal Energy Regulatory Commission (U.S.)
GRI	Gas Research Institute (U.S.)
Jackson Prairie, JPS	Jackson Prairie Natural Gas Storage Project in Lewis County, Washington, U.S.
LMLGUA	Lower Mainland Large Volume Gas Users Association
Methanex	Methanex Corporation
NEB, Board	National Energy Board
Northwest, NWP	Northwest Pipeline Corporation
OPEIU	The Office and Professional Employees' International Union, Local 378
PG&E Energy Trading	PG&E Energy Trading, Canada Corporation
PGT	Pacific Gas Transmission Company
PNG	Pacific Northern Gas Ltd.
SIPI	Sumas International Pipeline Inc.
Act	Utilities Commission Act
Westcoast, WEI	Westcoast Energy Inc.
WGSI	Westcoast Gas Services Inc.
Williams, WIP	Williams International Pipeline Company

ABBREVIATIONS
(cont'd.)

B. Terms

AFUDC	Allowance for Funds Used During Construction
Bcf	Billion standard cubic feet
Burrard	Burrard Thermal Generation Plant
CTS	Coastal Transmission System
CPI	Canadian Consumer Price Index
CPCN	Certificate of Public Convenience and Necessity
EKL	East Kootenay Link
GJ	gigajoule
Transportation Agreement	Firm Tendered Transportation Service Agreement
ICP	Island Cogeneration Project
IRP	Integrated Resource Plan
ITS	Interior Transmission System
LNG	Liquefied Natural Gas
LDCs	local distribution companies
Mcf	Thousand standard cubic feet
MMcfd	Million standard cubic feet per day
NPV	net present value
PNW	Pacific Northwest
PAC	Project Approval Certificate
Peaking Agreement	Peaking Gas Purchase Agreement
RFP	request for proposals
ROM	Resource Optimization Model
SCP	Southern Crossing Pipeline
1998 Decision	April 3, 1998 Commission Decision
T-South	Westcoast Transportation South
T-South Agreement	Transportation South Capacity Agreement
T-North	Westcoast Transportation-North
Tcf	Trillion standard cubic feet
TJ	terajoule
WCSB	Western Canadian Sedimentary Basin