Vancouver Island Gas Pipeline Final Report April 6, 1989
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1.0 INTRODUCTION

This report represents the final report of the British Columbia Utilities Commission ("the Commission) with respect to the Applications for Energy Project Certificates made by Pacific Coast Energy Corporation ("PCEC"). The Commission has previously provided an Interim Report to the Lieutenant-Governor in Council with respect to the Commission's findings from Phases I and II of the hearing. This report considers the Commission's findings with respect to Phase III, Markets, Gas Supply and Financial Matters. The consolidated conclusions and recommendations of the Commission with respect to all phases of the hearing are provided in the Executive Summary, produced as a separate report.

The public hearing was the result of the Application of November 1988 by PCEC seeking an Energy Project Certificate and an Energy Operating Certificate from the Government with respect to its proposed natural gas transmission pipeline to be constructed from Coquitlam, B.C. to Vancouver Island. The routing of the pipeline would be via Coquitlam Lake and Indian River to Squamish. The line would continue past Wood Fibre, Port Mellon, Gibsons and Sechelt to a shore approach north of Secret Cove where a crossing of the Malaspina Strait to the southern end of Texada Island would occur. At the north end of Texada Island the pipeline would make underwater crossings to Powell River on the Mainland and to Little River on Vancouver Island. The main transmission line would continue via Comox southward to Nanaimo and Duncan, terminating at Victoria. Laterals to the industrial complexes on the Island would be extended including lines which would service loads at the communities of Port Alberni and Campbell River.

The PCEC Application was the result of an understanding between the Federal and Provincial Governments on funding for the project. The Statement of Principles between the Governments was signed on September 22, 1988. The Binding Agreement between the parties is yet to be finalized at the date of this report.

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The Terms of Reference for the Commission review were issued on December 20, 1988 by the Minister of Energy, Mines and Petroleum Resources and the Minister of Environment. Those Terms of Reference requested that the Commission provide its Report and Recommendations to the Government by March 22, 1989, or as soon thereafter as practical. The Commission responded to this request for an expedited proceeding by issuing its Order No. G-111-88 on December 20, 1988. That Order set January 24, 1989 as the first day of hearings.

As a result of a Pre-hearing Conference held on January 18, 1989, the phases of the hearing were established as follows:

Phase I	Facilities and Capital Costs
Phase II	Environmental and Socio-Economic Considerations
Phase III	Markets, Gas Supply and Financial Matters

The phasing of the hearing recognized that there were significant deficiencies in the PCEC Application. By deferring the review of Markets, Gas Supply and Financial Matters to the third phase of the hearing, it was hoped that PCEC would be able to augment its Application in these areas by reaching Agreements with producers, the industrial customers, the distributor utilities and BC Gas Inc. ("BC Gas"). It was also anticipated that the Binding Agreement between the two Governments would be completed and the financial arrangements resulting from the Agreement would be made known to the hearing. As the hearing progressed the Commission became aware of the sale of British Columbia Hydro and Power Authority's ("B.C. Hydro") Victoria Propane Distribution Grid to Vancouver Island Gas Co. Ltd. ("Vigas") on January 27, 1989, and the award of distribution rights to other areas of Vancouver Island, Powell River and the Sunshine Coast to Vigas on February 20, 1989. <u>Little progress was made during the course of the hearing with respect to any other deficiencies in the PCEC Application</u>.

On February 21, 1989 the Commission heard motions from Intervenors that the level of information available with respect to the third phase of the hearing was so deficient that the final phase could not be started. Following a communication by the Commission with the Ministers of Energy and Environment, the Ministers issued Supplemental Terms of Reference to the Commission on Friday, February 24, 1989. Those Supplemental Terms of Reference requested the Commission provide a Report and Recommendations on the first two phases of the hearing by March 14, 1989. The Commission panel sat for 17 days to hear evidence and argument on the first two phases of the hearing. The Interim Report of the Commission of March 14, 1989 responded to the Supplemental Terms of Reference.

On March 2, 1989, the Commission issued Order No. G-17-89 requiring PCEC to file specific information to fill gaps in the Applicant's Phase III evidence. That material was provided to the Commission on March 6, 1989 and the hearing of Phase III evidence commenced on March 9, 1989. The Commission sat for 13 days during the hearing of Phase III evidence and argument. The Commission made repeated attempts during the hearing to seek sufficient information on several important outstanding items. <u>At the completion of the hearing the following major items remained outstanding</u>:

1. The Inter-Governmental Binding Agreement.
2. Gas Supply Contracts with Producers.
3. Gas Sales Contracts with the Forest companies.
4. Wheeling Agreement between BC Gas and PCEC.
5. Gas Sales Agreements with Local Distributor Utilities ("LDC").
6. Gas Storage Agreement with Unocal Canada Limited ("Unocal").
7. Westcoast Incentive Tolls Agreement (subject to NEB approval).
8. PCEC/Westcoast Operating Agreement.

As a result of the foregoing, this Report and the Commission's conclusions and recommendations have been prepared with a focus on the evaluation of a range of assumptions and alternatives.

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Because of the severe time constraints on all parties to the hearing, dictated by the project in-service date of September 1, 1990 and consequent requirement for a May 4, 1989 construction start, the Commission has been obliged to proceed under less than ideal conditions. Nevertheless, it has heard all the evidence of Intervenors and believes it has clearly identified those issues impacting the public interest.

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2.0 PROJECT DESCRIPTION

2.1 Project Structure

The physical description of the PCEC project and its capital costs have been discussed in detail in the Commission panel's Interim Report dated March 14, 1989. The review of the project in this report focuses on the financial assessment of the project as it has been structured by PCEC.

The project structure proposed by PCEC and the various incentives put in place by all parties related to this project result in an unusually complicated financial support system for the project. Figure 2.1 provides a schematic of the revenues and costs to the project along with the various project incentives that will be put in place at each stage of the project. The project concept is that end-use customers will pay market-sensitive prices at a discount to the cost of oil products currently being consumed in the market area. The Provincial Government will provide conversion grants to assist utility customers and the forest companies in converting their fuel burning equipment to natural gas.

Vigas is the distributor utility awarded the local distribution company ("LDC") rights to serve the markets on Vancouver Island and the Sunshine Coast. BC Gas retains its right to distribute natural gas in the Squamish area through its subsidiary company Squamish Gas Co. Ltd. ("Squamish Gas"). Vigas has entered into Agreements with the Provincial Government whereby the LDC has guaranteed its performance with respect to signing-up customers and maintaining an agreed-upon cost of service (Exhibits 84 and 85). Vigas has also committed to accept a lower return on equity ("ROE") during the initial years of the project.

The revenues available from the LDC and forest companies will flow to PCEC. PCEC has also committed to accept a reduced ROE during the initial three years of operations of the project. The Federal and Provincial Governments have committed to provide grants and

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FIGURE 2.1

PCEC Project Structure

Project Structure		Project Incentives
Forest Companies	Utility Customers	Government Conversion Grants Market Sensitive Pricing
	LDC	LDC Financial & Market Guarantees LDC reduced ROE
	PCEC	Government Grants and Loans Rate Stabilization Facility PCEC reduced ROE
	BC Gas Tolls	BC Gas Opportunity Cost Pricing
	Westcoast Tolls	Westcoast Incentive Tolls
	Producers	Flowback Pricing

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loans to reduce the capital cost of the project that PCEC would have to finance. The Provincial Government has also committed to provide a rate stabilization facility ("RSF") which will provide money to PCEC when there are inadequate revenues to meet the utilities' costs of service. PCEC assumed that the RSF would be refunded when residual revenues exceeded their cost of service.

The cost of transmission across the BC Gas system from Huntingdon to Coquitlam has not been agreed upon by the parties. However, the offer currently made by BC Gas provides for a reduced rate to PCEC compared to the fully-costed rates to other industrial customers.

Westcoast Energy Inc. ("Westcoast") intends to apply to the NEB for reduced tolls on PCEC volumes during the first three years of operations. These are referred to as the Westcoast Incentive Tolls.

The natural gas producers have been approached by PCEC on the basis that natural gas would be purchased at a minimum base price plus a potential for the flowback of extra revenues available from the project after all costs have been met and the RSF has been fully repaid.

It is clear from the foregoing that all participants related to this project are being expected to assist the project financially in its inception. Even the end-use customers can be seen as contributors, in part, to the project since their retail gas prices will be tied directly to the future cost of comparable oil products at a modest discount.

PCEC has stated that the project was designed to impose risks on those participants who will have the potential to be rewarded while largely isolating customers from risks inherent in the project. <u>The greatest risks in the project clearly lie with the Provincial Government in the open-ended RSF</u> and with the natural gas producers in the acceptance of the flowback pricing mechanism. Secondary risks exist for the Federal and Provincial Governments in the

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provision of capital grants and repayable loans. A lesser risk would be absorbed by the various utilities involved in the project through the reduced ROE in the early years and the financial and market guarantees provided by Vigas. Finally, PCEC and its sponsor partners are at risk to the extent of their equity contributions.

2.2 Project Financing

2.2.1 Assumptions in the Application

The total capital cost of the project was estimated at approximately $250 million with an in-service date of September 1, 1990. According to PCEC's proposal and the Statement of Principles, funds to cover the costs of the pipeline to start-up date would be provided by a combination of sponsor companies' equity investment and debt financing in the amount of approximately $75 million, with loans and contributions from the Federal and Provincial Governments for the balance of $175 million. In addition, the LDC's would commit to capital expenditures of approximately $140 million in distribution facilities; the Provincial Government would provide grants of $55 million for the conversion of fuel oil burning equipment to enable burning natural gas; and, the Provincial Government would establish an RSF up to a maximum of $70 million to ensure project viability during the early years. In total, each Government would provide support of $150 million to the project in either grant or loan form (see Exhibit 56, Schedule B of the Statement of Principles.)

The financial contribution of the sponsors was proposed to comprise $50 million external debt financing and an equity investment of $25 million, aiming towards a debt-equity ratio of approximately 65:35. This capital structure would mirror Westcoast's capital structure. While PCEC is expected to be a 50:50 partnership between Alberta Energy Company ("AEC") and Westcoast, evidence presented in the hearing indicated that PCEC is still 100% owned by AEC pending legal transfer of shares to Westcoast (T 3406).

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The sponsors would commit their contributions subject to a list of prerequisite permits and agreements, including an Energy Project Certificate ("EPC") (T 3464). Mr. Willms, policy witness for PCEC, testified that the project debt would be financeable, based on opinions from financial institutions, and that the signing of long-term industrial and utility gas supply contracts would strengthen project financeability.

2.2.2 Update of Financial Arrangements

Operational forecasts of financial performance presented by PCEC during the hearing proposed financial arrangements for the treatment of Government grants, repayment of Government loans and operation of the RSF which differ from the general description of financial arrangements in the Statement of Principles. Witnesses for PCEC testified that their version was thought to reflect the current intent of all parties to the Binding Agreement.

PCEC provided a summary of its assumed arrangements in comparison to those contained in the Statement of Principles (Exhibit 75, Tab 1) showing a different PCEC treatment in the repayment of the RSF. Furthermore, Mr. Willms explained that certain areas of financial arrangements between the Federal Government, the Provincial Government and PCEC, were likely to be modified, e.g. the RSF would be uncapped and, if necessary available for the full 20-year project period. In addition, eligible capital costs would only exclude overhead and interest accrued prior to the approval of an EPC. Mr. Willms maintained that, while there were areas still under discussion, any changes arising from these discussions were unlikely to dramatically affect project economics (T 3393-3397). An example would be allowing more flow-through in order to induce gas producers to sign-up long-term contracts by transferring some proposed RSF repayments to producer netback in earlier years. While the Statement of Principles is a statement of intent of the Binding Agreement, to this date the Binding Agreement has not been signed.

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3.0 MAJOR COMPONENTS OF PROJECT STRUCTURE

3.1 Markets

Two LDC's, Vigas and BC Gas will be providing natural gas service to marketing areas on Vancouver Island and several communities along the coastal mainland. BC Gas will serve the Squamish area and Vigas will serve the 28 communities listed in Table 3.1.

TABLE 3.1

Communities to be Served by Vigas

Campbell River	Gibsons	Powell River
Central Saanich	Ladysmith	Qualicum Beach
Chemainus	Langford	Royston
Colwood	Laslo/Little River	Saanich
Comox	Metchosin	Sechelt
Courtenay	Nanaimo	Sidney
Crofton	North Saanich	Victoria
Cumberland	Oak Bay	View Royal
Duncan/Cowichan	Parksville	
Esquimalt	Port Alberni	

Source: Exhibit 82, p. 8

Currently, the residential and commercial customers in the above communities operate principally on propane, LFO, electricity or wood. The LDC's have selected propane and LFO users as the target market.

There are two key elements in the marketing strategy; a competitive burner tip price and conversion grants. Assured price discounts in favour of natural gas are expected to provide a significant incentive for customers to convert and permit the distribution utilities a high degree of confidence in their marketing forecasts outlined in the following sections.

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3.1.1 Vigas

3.1.1.1 Burner Tip Price

Forecast burner tip prices have been based on the residential and commercial light heating fuel rate (in constant 1988 $) published on December 12, 1988 by the Ministry of Energy, Mines and Petroleum Resources ("MEMPR"). A 4% inflation factor was assumed to predict natural gas prices over the 20-year time frame based on discounts established in Schedule 14 of the Vigas Rate Stabilization and Disposition Agreement (Exhibit 85). This schedule shows a 15% discount in year 1, declining uniformly to a 10% discount in year 7 and remaining at 10% thereafter.

The customer population was broken down into two customer classifications:

Small General Service

Residential Market

- includes detached homes, trailers, multiple dwellings excluding apartment blocks

Small Commercial if less than 24,163 ft^2

Large General Service

Commercial

- includes office buildings, nursing homes, hotels, motels, apartments, warehouses, retail stores (T 3833).

An exception to this pricing mechanism is the rate to be set for large apartments currently purchasing fuel through oil-buying cooperatives. Initially the rate will be determined by negotiation with these associations and later may be made to converge with the current commercial formula.

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The final bill a customer pays is dependent not only on the burner tip price, but on the efficiency of heat transfer in his appliance. An efficiency adjusted price comparison of gas with competing energy forms was illustrated in Exhibit 117. It is obvious from this analysis that natural gas will have a strong presence in the space heating market. In both Small and Large General Service, the price advantage of gas over LFO in the early years is about 36% dropping to about 28% in the 20th year[1].

3.1.1.2 Vigas Market Study

The marketing study was prepared for service to the communities shown in Table 3.1, with the objective of establishing high, low and medium forecasts of consumption and demand over a 10-year time frame. It was assumed that most of the growth will occur over that period with the 20-year forecast being achieved by an extrapolation of the 10-year curve.

Two primary assumptions of the market analysis were that consumers currently burning wood or consuming electricity for heating would not be potential conversion customers and that the B.C. Hydro "Electric Plus" Program would be terminated in each community.

Initial market surveys were conducted in all communities to be served to identify concentrations of population, current building stock and heating consumption rates. This information provided a data base for existing conditions. New construction predictions were based on population growth forecasts developed from Statistics Canada data and on discussions with local community planning groups.

The capture rate for new customers was estimated to be the same in all service areas. Small General Service account capture was calculated at 50% in the first year and at 75% of the remaining
potential customers in all

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1 Furnace efficiency - natural gas = 75%, LFO = 65%

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subsequent years. Natural gas was assumed to be the energy of choice for all Large General Service accounts and a 100% capture rate was expected for this classification.

A conversion rate profile was developed separately for each community. This ranged from 2 to 5%/year in Qualicum Beach, to 10 to 15%/year in Powell River.

The final phase of the study applied heat conversion estimates to these accounts resulting in a consumption and demand forecast for the service area by year. A range of three forecasts was formulated and the results are displayed in Table 3.2. The "Low" forecast, although based on the 10% price differential, assumes that the marketplace will be reluctant to accept the attractiveness of gas as a primary heating fuel (T 3726).

TABLE 3.2

Vigas Forecast Sales Volumes (TJ)

Year	Low[1]	Medium[1]	High[2]	% Med to High
1	2802.9	2934.9	3058.1	4.2
2	4732.6	5119.2	5355.2	4.6
3	6750.6	7366.0	7894.0	7.2
4	8293.4	9110.1	10021.2	10.0
5	9140.6	10094.8	11244.3	11.4
6	9634.1	10653.8	11905.5	11.7
7	9988.6	11046.6	12416.1	12.4
8	10334.,0	11421.7	12825.4	12.3
9	10680.8	11796.6	13231.8	12.2
10	11023.2	12165.6	13638.3	12.1

1. Based on 10% gas price discount to LFO.
2. Based on 15% gas price discount to LFO in early years.

Source: Exhibit 82A and Exhibit 116

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3.1.1.3 Vigas Marketing Program

Vigas will embark on a marketing campaign which has four features: an appliance financing plan, furnace rebate program, rental arrangements, and conversion subsidies.

Financing will be offerred up to 85% of the cost of purchasing and installing appliances. The interest rate will be set at 1% over current rates for mortgages of equal term between one and three years.

Customers will have the option of entering into a long-term rental agreement for furnaces and hot water tanks.

Vigas intends to sell medium efficiency furnaces (estimated at 75%) with promotional discounts from manufacturers in the range of 15-25% off the retail price. Even with this discount the expected shortfall in conversion cost will be about $450, with a five year payback period (see Table 3.3).

TABLE 3.3

Conversion Grant Calculation
Vigas Service Area

		Light Fuel Oil ("LFO")	Natural Gas ("NG")
Efficiency Adjusted Rate		$13.37/GJ (60% Eff.)	$9.63/GJ (75% Eff.)
Consumption		60 GJ	60 GJ
TOTAL BILL		$802.20	$577.80
Savings			$224.40
Savings Over 5 Years			$1,122.00
Furnace Cost			$2,100.00
Grant Required	- no furnace discount		$978.00
	- 25% furnace discount		$453.00

Source: Commission Staff

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Maximum conversion subsidies of $700 for residential customers and $1,000 for commercial customers will be made available for the first five years.

3.1.2 BC Gas

3.1.2.1 Burner Tip Price

BC Gas has based its Squamish market forecast on a crude oil price of $18 (U.S.)/bbl and gas at a 10% price discount to LFO, with both assumed to escalate at 4%. In the residential sector the price advantage of gas over LFO ranges from 30-40% while in the commercial sector the price advantage ranges from 15-20%.

3.1.2.2 BC Gas Market Study

The Market Study was conducted in three phases to develop the total 20-year market projection. The first phase was made up of an initial customer count and a forecast of potential customers not currently served by the existing propane grid system. This was based on a forecast of future population growth prepared from "Municipal Statistics" 1986 census data supplemented by information from the Central Statistics Bureau of the Ministry of Environment. These two sources provided a data base for present and future customer expansion in areas where distribution mains were expected to be placed.

Inland Natural Gas Co. Ltd.'s ("Inland's") historical capture rates were applied to forecast information on new construction. Similarly, Inland's conversion rates were applied to existing dwellings using alternative energy. "Use per customer" consumption levels were applied in the final phase to achieve the consumption forecast shown in Table 3.4.

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TABLE 3.4

BC Gas Forecast Sales Volumes (TJ)

	Residential	Commercial	Total
1990	64	156	221
1991	74	159	233
1992	83	161	245
1993	92	163	255
1994	100	164	265
1995	109	166	275
1996	118	168	286
1997	127	170	297
1998	136	172	308
1999	145	175	320
2000	153	177	330
2001	162	179	341
2002	169	180	349
2003	177	182	359
2004	184	183	367
2005	190	184	375
2006	196	186	382
2007	202	187	389
2008	208	188	396
2009	213	189	402

Note: Residential Average Use = 90 GJ/yr.
Commercial Propane Conversion = 889 GJ/yr.
Commercial New Customer = 400 GJ/yr.

Source: Exhibits 101 and 102
(Exhibit 101 adjusted for error in Commercial account addition.)

Overall, the market projections in Table 3.4 are very close to those contained in the independently produced Canadian Resourcecon Report (Exhibit 25). Although the first year difference between the two predictions is 52 TJ the cumulative total separation in year 20 is only 14 TJ or 3.5% from the BC Gas forecast.

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3.1.2.3 BC Gas Marketing Program

Residential conversions are expected to be to mid-efficiency natural gas forced-air furnaces with an efficiency rating of about 80% (Exhibit 102, p. 2). To assist in this conversion, BC Gas is prepared to offer financing to residential conversion customers at a rate of prime plus 4%. It is assumed that unless the payback for conversion is less than five years, residential customers would not take up the option and a grant in excess of $900 per customer will be required to make up the difference (Exhibit 102, p. 4). A current propane customer, on the other hand, would require a much smaller grant of about $100 (Exhibit 102, p. 4).

3.1.3 Industrial Market

Seven pulp mills currently make up this market sector. Their locations, and the loads they are expected to generate, are shown in Table 3.5. The displacement of HFO by natural gas will require about 10,934 TJ of energy per year. The load forecast maintains this consumption level over 20 years of the project life although, as a proportion of the total load, it declines as residential and commercial load builds. The industrial load declines from approximately 75% in year one to about 35% in year 20.

These loads are principally affected by the newsprint side of the industrial operation. Although currently this section is running at 100% of plant name plate capacity, a downturn in production is not expected to result in a drop in load, rather, it is expected to be replaced by additional new capacity. Effectively, there is not expected to be any change in consumption (T 3888). As energy costs rise, energy conservation will reduce demand but this again is expected to be replaced by capacity additions, thus maintaining the projected load at about current levels (T 3889-3890).

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The industrial load factor is expected to be about 87.5% if the mills nominate firm gas volumes at twice the fuel requirement of their kilns (T 3872).

Vigas stated that it believed it had the right to develop and serve new industrial loads within its franchise area in order to diversify its customer base and provide for the possibility of peak shaving through industrial curtailment (Exhibit 116, p. 14). There is a possibility that future industrial loads may come on-stream on Texada Island in the Vigas service area and at Britannia Beach in the BC Gas - Squamish service area.

TABLE 3.5

Industrial Load Forecast

Company	Location	1992 Annual Fuel Use (bbl's)	Estimated Natural Gas Consumption (TJ)	% Load
Fletcher Challenge	Crofton	272,667	1,865	17.0
Fletcher Challenge	Elk Falls	70,000	479	4.4
Howe Sound Pulp & Paper	Port Mellon	153,000	1,046	9.5
MacMillan Bloedel Ltd.	Harmac	226,400	1,548	14.1
MacMillan Bloedel Ltd.	Port Alberni	219,500	1,501	13.7
Western Pulp Limited Partnership	Squamish	226,407	1,548	14.1
MacMillan Bloedel Ltd.	Powell River	435,250	2,976	27.2
		1,603,224	10,934*	100.0

Source: Exhibit 118, individual mill estimates, from COFI to PCEC.
* Conversion @6.838 GJ/bbl adjusted for 365 days (T 3883).

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3.1.4 Commission Conclusions

Because of the proposed 15% starting price discount, the Commission believes the Vigas "High" forecast is within reasonable expectations and the Commission has adopted this forecast in preparing its base case financial projections in Section 4.0.

Considering the closeness of the independent Canadian Resourcecon and BC Gas forecasts the Commission believes that the Squamish Gas forecast loads are suitable for use in the financial projections. This load represents only about 7% of the total LDC market in the first year.

The Electric Plus Program, future expectation of low electric prices,* and the heating oil supplier's initial defensive reaction to natural gas in its traditional markets may all have a negative impact on the Vigas market projections. The Electric Plus program is expected to be phased out by the end of 1989 (T 3731). Competitive reaction by LFO suppliers is unlikely to be sustainable in other than the short-term. There remains some concern that, in the event of high oil price escalation, electricity may become the competitor fuel for natural gas.

The Commission has adopted the loads forecast in Exhibit 109 adjusted for the difference between purchase gas and sales gas in its financial projections in Section 4.0. This exhibit is based on the Vigas high forecast, the BC Gas forecast shown in Table 3.4 and the Industrial forecast shown in Table 3.5.

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* Future expectation of continued low electric rates is likely diminished by recent Provincial Government announcements following the March 30, 1989 budget.

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3.2 Peak Shaving Requirements

3.2.1 PCEC Position

The PCEC pipeline was not designed to deliver the total system gas requirements on the coldest days of the year. As with other pipeline systems, PCEC expects to curtail industrial customers and have the LDC minimize its demands on the transmission utility on those coldest days.

If the LDC is to provide peak shaving,* the pipeline can be designed to a smaller size to reflect the reduced demand conditions. On the other end of the line, an improved system load factor** would allow PCEC to attain better prices from producers.

PCEC originally proposed to meet a 50% load factor (Exhibit 7, Tab 2) but this was later revised to a 45% level (T 2801).

PCEC based this decision on two analyses:

- The Pacific Northern Gas ("PNG") load curve was examined, after removing company-use gas and small industrial consumption. This resulted in a load factor determination of about 45% for the PNG system (T 2801-2802).

- B.C. Hydro presented an exhibit in the 1982-1983 hearings (Exhibit 93) which showed interruptible, firm, send-out and contribution of peak shaving facilities to the overall gas load profile. Since this information resulted in a load factor of 39.5%, it was concluded that a 45% load factor was appropriate for Vancouver Island service (T 2801-2803).

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* Peak Shaving is the use of a supplemental supply of energy to augment normal pipeline supplies during peak demand periods of relatively short duration.

** Load factor is the average daily requirement divided by the maximum daily requirement stated as a percentage.

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In the case of the industrial customers, PCEC assumed that the various mills would require firm natural gas service without any curtailment to the lime kilns. PCEC estimated the non-curtailable load to be 18 TJ/day and included this in their design criteria.

The PCEC methodology was attacked by various participants at the hearing as being simplistic and generally a step back from the demand/commodity pricing concepts that have developed in recent years. It is generally conceded that the demand/commodity method of pricing provides appropriate economic signals to all parties so that peak shaving will occur at various points of the pipeline system to the extent that it is economically viable to do so. However, PCEC argued that their methodology would induce the LDC's to improve their load factor under the gate station pricing scheme and that the 45% load factor stipulation was a proxy for the economic allocation of peak shaving requirements on the system.

3.2.2 BC Gas Position

BC Gas considered -15^{O}C as an appropriate design day temperature for Vancouver Island and the Sunshine Coast so that a 30% load factor was recommended for the project (Exhibit 101). A level fixed at 45%, as with any fixed level, fails to provide the correct economic pricing signals from producers and transporters of the gas to the distribution utility and the consumer.

BC Gas had four recommendations (Exhibit 101, p. 5-6):

- The PCEC pipeline should be sized initially to deliver full residential and commercial peak demands as future capacity may be very expensive to acquire.
- Industrial customers should be converted to dual fuel systems so that full interruption is feasible.

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- PCEC could improve its load factor on the Westcoast system in later years of the project by obtaining gas across the Inland system, using possible Fraser Delta underground storage or expansion of Liquified Natural Gas ("LNG") facilities.

- BC Gas proposed that peak shaving for Squamish could be accomplished through peak shaving in the Lower Mainland area.

In summary, BC Gas stated that it was possible to achieve a 45% load factor in the Squamish service area by converting the existing propane plant to a propane-air peak shaving facility. The addition of air compression and blending equipment would cost $260,000 and existing propane facilities would be retained in the Squamish Gas cost of service (Exhibit 101, p. 3). However, the utility proposed that if the pipeline design permitted, peak shaving should be accomplished in the Lower Mainland area (Exhibit 101, p. 6).

3.2.3 Vigas Position

Vigas expected its load factor would fall in the range of 22% to 36.5% in normal year weather and be between 19% and 31.5% in extreme cold conditions. A 45% load factor would limit the maximum daily take from the pipeline to about 80% of the peak required in a normal year and 70% in a cold year (Exhibit 117, p. 7).

Vigas considered the 45% load factor to be an arbitrary number which did not reflect the extreme temperatures on the Island (T 3700-3701). In fact, when the Agreement for their service area was negotiated with the Provincial Government, Vigas assumed the industrials would be 100% interruptible and no provision for peak shaving was included in the Agreement (T 3783-3787). As capital costs were not included in rate base until a desired ratio of capital expenditures to volumes was reached, the cost of service was effectively capped. The contract would have to be reopened to address capital costs for peak shaving equipment, otherwise, Vigas would have a strong motive to pass these costs onto the RSF (T 3789-3790).

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Vigas emphasized that it had little opportunity to improve its load factor without the advantage of large industrial load customers. In a few isolated circumstances it would be possible to interrupt large commercial customers, but this would be expensive as customers will want to be compensated for their costs of dual fuel capability by lower energy costs (Exhibit 116, p.9). This discount was estimated to be about $1.50/GJ (in Exhibit 140) with accompanying lost revenue when the interrupted customer goes on alternative fuel.

Vigas contended that since PCEC intends to pressurize the transmission pipe to 2,000 psi, it would be impossible to put propane in the transmission line. In order to maintain propane in vapour form, it would have to be superheated. The pressure to the mills however, is proposed to be 250 psi which is a more suitable level for propane injection and propane peak shaving facilities could be provided at these locations (T 3696-3697). The LDC would supply the load serving the lime kilns with propane in the winter months, based on the assumption that the kilns can be operated on propane. If the logistics of transportation, placement of the peak shaving facility and arrangements with the mill can be worked out, this would be a viable alternative. However, the displaced load only meets the system demands between a normal and extreme cold day (T 3844).

In Exhibit 140 Vigas confirms that the displacement of lime kiln volumes and interruption of large institutional and commercial customers (hospitals and Department of National Defense at Comox) would not be sufficient to provide peak shaving requirements to meet the 45% threshold during extreme temperature conditions. Additional propane-air facilities costing between $26 million and $32.6 million would have to be built and would entail peak shaving installations at some 26 sites throughout the service area (Exhibit 140, p. 8).

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3.2.4 Commission Conclusions

Insufficient evidence was advanced during the hearing to permit the Commission to form any conclusions on peak shaving. In its normal regulatory role under Part 3 of the Utilities Commission Act, the Commission will have to work with both the LDC's and PCEC in the coming months to finalize the most economic method of peak shaving so as to minimize the overall cost of the system and the draws made on the RSF. In the current absence of sufficient facts to determine this issue, the Commission offers the following general views to assist the Government in analyzing the economics of the project.

Natural Gas Peak Shaving

The ideal method of peak shaving is to have LNG storage or underground storage of natural gas near or downstream of the market to be served. This option is not currently available to Vigas and is discussed further in Section 3.8.

Conversion of Lime Kiln Load

From Exhibit 116 it is clear that conversion of the lime kiln load to propane or propane vapour would increase the extreme peak day load factor to about 36.7% in year 10. The financial runs undertaken in Section 4.0 have included Commission estimates of the costs for providing propane-air facilities to supply the lime kiln loads at all mills.

Interruptible Rates

Interruptible rates could be offered to industrial and institutional customers to induce them to maintain their existing oil burners and oil storage that would be used during a curtailment period.

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Propane-Air Plants

Propane-air plants can be constructed by the LDC's to inject propane into the natural gas stream on the coldest days so as to meet all the residential and commercial loads while not increasing the LDC's requirement for natural gas. The cost of the propane-air plants must be compared with the additional cost that would be incurred to increase the pipeline service itself. These costs include: the increased nomination on the Westcoast system, increased gas supply costs (including storage), the costs of advancing compressor additions on the PCEC system, increased operating costs to PCEC, and finally the potential increase in costs for wheeling gas across the BC Gas system. Insufficient information exists to determine this matter definitively now. The Commission would anticipate working with PCEC and the LDC's to resolve this matter outside of the hearing process. This matter is dealt with further in the Commission's recommendations in Section 6.0.

In assessing the financial impacts of peak-load requirements on the Commission's determinations in Section 4.0 of this report, the Commission has assumed in its base case that the LDC's would be able to maintain a load factor of 40%. The pessimistic case assumes the LDC's would be able to maintain a load factor of 35% by peak shaving the lime kiln loads. In the optimistic financial assessment the Commission has adopted the PCEC proposal that a mandated 45% load factor be maintained.

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Therefore, with respect to the additional costs of peak shaving, the Commission's financial cases have included the peaking costs required to meet the assumed load factors. To meet the pessimistic case load factor of 35%, the Commission has included $6 million of capital cost into the Vigas cost of service projection to allow for peak shaving the lime kiln load. The Commission's base case allows for an initial capital expenditure of $15 million plus about $200,000 annually to approximate the LDC cost of service for peak shaving to a 40% load factor. In the Commission's optimistic case, the addition to the Vigas estimates is $30 million to allow for peak shaving to a 45% load factor.

The Commission has also considered the timing of propane-air plant addition. The load profile of the project and the incentive rates from Westcoast are such that these plants can be added to the system in year 3.

3.3 Cost of Service

3.3.1 BC Gas

This utility operates a propane distribution grid serving approximately 900 customers in the Squamish area. The Company was purchased by Inland from Superior Propane Ltd. in 1987. In Exhibit 102, the Company provided its initial 20-year forecast on load growth, rate base and cost of service. The latter were developed based on current experience plus a general 4% cost escalation. Capital cost reflected an abandonment of the existing propane plant and the assumption that PCEC would provide all required gas based on Squamish Gas forecast load factor.

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A revised submission (Exhibit 101, Appendix A) was provided reflecting the retention and upgrading of the propane plant for peaking purposes in response to PCEC's assumed load factor of 45% for LDC gas supply. Cost of service therefore would increase slightly resulting in lower gate prices. These gate prices would be further lowered if the discount were adjusted to 15% relative to fuel oil prices in the initial years, declining to 10% in later years parallel to the assumptions of Vigas and PCEC.

The Commission believes that Squamish Gas has reasonably forecast its cost of service associated with the market resulting from natural gas supply in the Squamish area and will incorporate such information in the financial and market analyses.

3.3.2 Vigas

Vigas is a subsidiary of Inter-City Gas Corporation which distributes natural gas across Canada and in the United States. In February 1989, Vigas purchased the Victoria propane-air distribution system from B.C. Hydro and was awarded distribution rights for communities on Vancouver Island and the Sunshine Coast. It currently operates a propane distribution system in Nanaimo with approximately 1,200 customers.

In Exhibits 82 and 82A, Vigas provided market and cost of service forecasts with high, medium and low market penetration scenarios. In developing the medium scenario, the utility adopted a gas price based on a 10% discount in relation to the price of LFO. The Provincial Government has now set the discount at 15% for the first two years, declining to 10% in later years. As a result, Vigas believes that it can achieve the volumes illustrated in the high scenario, and that this should be viewed as the most likely case.

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Vigas' forecast did not use deferral accounts to mitigate the impact of the relatively high cost of service on the RSF in earlier years of the project. The forecast was prepared on a stand-alone basis. Debt cost, equity component and rate of return are in accordance with the LDC agreements with the Provincial Government. Other cost of service components were developed based on Vigas' experience on Vancouver Island. Vigas forecasts a capital investment of $191 million over the first 10-year period. Sales volumes and revenues were based on Vigas' own forecast load factor with no provision for peaking services.

The forecast gate prices available to PCEC in the first two years were below the $2.00/GJ minimum assumed by PCEC in its original Application. This minimum requirement was withdrawn by PCEC in later analyses as shown in Exhibit 87.

In response to a Commission staff request, Vigas provided Exhibit 140 outlining its peak shaving alternatives in the event it would be required to meet the 45% load factor requirement imposed by PCEC. The cumulative gate revenue available to PCEC as a result of the higher cost of service required to meet the higher load factor would be reduced by $233 million or 15%, from Vigas' original forecast (Exhibit 82, Schedule 10-4) over the 20-year projection period. However, the impact on gate prices will be much greater in earlier years, ranging from a 60% lower price in year 2 to 11% reduction in year 20.

The Commission believes that Vigas' cost of service projections, contained in the medium scenario referred to in the LDC agreement with the Provincial Government, should be used in the pessimistic case scenario for the analysis of PCEC's financial performance. The high Vigas scenario should be viewed as the base case in analysing the economic viability of the Vancouver Island gas pipeline.

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3.3.3 PCEC

The Commission's Terms of Reference require it to "review and assess pro forma financial statements, rate base, and cost of service estimates for the period 1990 through 2010 and the assumptions used in their preparation." PCEC in its Application (Exhibit 8) detailed its initial assumptions with respect to project costs, sales volumes and revenues, Government grants and loans, debt and equity financing, cost of gas and associated transmission and storage costs, and other cost of service components.

The following are revised treatments of the above assumptions proposed by the Applicant during the hearing. Many have the effect of lowering the cost of service in the earlier years of the project and more closely reflect the current status of discussions on outstanding agreements.

Depreciation

PCEC proposed in its initial submission to write-off the cost of land rights as depreciation expenses. Since the standard depreciation schedule approved by the Commission does not make allowance for land rights depreciation, PCEC revised the above provision to reflect normal Commission practice. The result is reduced depreciation expenses.

PCEC excluded the value of assets represented by the repayable Government loans of $75 million from depreciable assets resulting in reduced depreciation expenses in the period prior to repayment. This is a desirable treatment of the repayable grant.

PCEC proposed to depreciate half of the plant additions made during the year, but the Commission System of Accounts allows depreciation based only on each year's beginning balances. PCEC revised the above provisions to conform to Commission practice resulting in reduced depreciation expenses in the same period.

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Interest and Return on Equity

PCEC provided its forecast interest expenses, capital structure and return on equity in Exhibit 8, Tab 1, p. 4. PCEC in Exhibit 74 revised its original forecast interest rate from 10.5% to 11.5%. In order to improve early year project performance PCEC also proposed lower returns on its common equity in earlier years of the project: 10.5% in the first year rising to 14% in the third year. From year 4 forward, normal treatment would ensue. PCEC estimated the ROE for years 4 to 20 to be 14.5%.

Corporate Taxes

In response to a Commission Information Request, PCEC amended its tax rate of 42.59% to 42.84% [Exhibit 20, Tab 3, c. 2.1(v)]. As in the calculation of depreciation in the initial Application, PCEC deducted the $75 million repayable Government loan from Undepreciable Capital Cost in determining Capital Cost Allowance for Income Tax calculation. Section 13(7.1) of the Income Tax Act specifies that only forgivable loans and grants need to be deducted for such purpose. PCEC revised its Capital Cost Allowance calculations in its later versions of the financial model resulting in lower Income Tax expenses in earlier years of the project.

O & M Costs

PCEC provided details by cost elements [Exhibit 20, Tab 3, 2.1 (vii)]. These costs were escalated by 4% to reflect price level changes during the 20-year period and based on operating experience of Westcoast in pipeline operations. The details are to be contained in an operating agreement that has yet to be finalized between Westcoast and PCEC. The costs forecast by PCEC appear to be reasonable for normal pipeline operations, and the Commission accepts these costs for financial analysis purposes subject to the above agreement being scrutinized by the Commission in its future reviews.

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Property Taxes

PCEC assumed that no property taxes would be levied on the pipeline in the first three years. Intervenors disputed the validity of such assumption, with the result that the impact of property tax payment was tested in some of the sensitivity analyses of the financial model.

3.3.4 Cost of Service Optimization

As required by the Terms of Reference, the Commission and the hearing participants examined alternative ways to enhance project economics and feasibility. Exchange of information between PCEC and Commission staff prior to the hearing revised certain financial assumptions as described in Section 3.3.3.

In addition, PCEC assumed that the RSF would be repaid first, before Government loans were repaid; this however would be contrary to the financial arrangements described in the Statement of Principles. PCEC also assumed loan repayments would be made in the following year rather than in the current year, as the cumulative surplus reached specified amounts. The impact of the above assumptions was to delay the buy-back of assets resultant from refinancing Government loans, thereby maintaining rate base at lower levels and reducing cost of service in the earlier years.

Financial witnesses for COFI suggested that depreciation is the rate making mechanism for recovery of capital, and proposed that the sponsors should defer depreciation expense until the RSF had been fully repaid (Exhibit 123). This method would improve early-year flow-through to producers and at the same time would reduce the draw on the RSF.

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The COFI witnesses suggested that the project could be financed on the basis of 75% debt and 25% equity, since project risk would be significantly reduced by existence of the RSF. A higher debt ratio would also reduce cost of service and improve overall project profitability.

The response of PCEC as shown in Exhibit 73, item 1, indicates that lowering costs in earlier years will eventually increase total project costs over its life. The Commission, after exploring conceivable methods to enhance project economics such as deferral of depreciation, higher debt to equity ratio, lower allowed returns, etc., accepts PCEC's position and is satisfied that a reasonable balance between short-term gain and long-term cost has been achieved in the proposal submitted by PCEC and amended as described in this section.

3.4 Gate Station Revenue

The gate station revenue to PCEC is to be the result of subtracting the cost of service of each LDC from the total revenue of each distribution utility. The PCEC revenue will vary with both the size of the market and the components of the LDC cost of service. Including peak shaving facilities in the LDC cost of service, for example, will decrease the gate station revenue available to PCEC. As Exhibit 22 shows, the ultimate impact of all project shortfalls will be on the RSF and on the gas supplier (see Figure 4.1, p. 50).

Vigas stated that according to the "Vigas Rate Stabilization and Disposition Agreement" it is possible for the gate station price to the LDC to become negative. In that event, the RSF would compensate the LDC's cost of service. The utility would continue to earn its rate of return subject to the restrictions on costs and volumes provided for in the Agreement (T 3851-3852).

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3.5 Industrial Revenue

Agreements between PCEC and the seven mills remain unresolved at this time. The proposed contract pricing formula develops a value for gas based on the price of heavy fuel oil of the same quality and specifications which the industrial customers are currently able to use. The effect of recently announced government regulations on sulphur content must also be factored into the equations. As the proposed contract allows the distributor of the gas the right of curtailment to maintain a high system load factor, the industrial client is also required to maintain dual fuel burning capability. These items, which affect the PCEC revenues also remain to be settled in negotiations.

3.5.1 Price

The proposed pricing formula depends on six factors that determine natural gas prices equivalent to low or high sulphur heavy fuel oil purchased in Los Angeles and transported to the coast of British Columbia. Currently, negotiations between PCEC and COFI have not settled the appropriate freight charges, conversion factor (to equate the price of high sulphur residual fuel oil in Los Angeles to the West Texas Intermediate crude price) or the conversion factor that equates barrels of oil to gigajoules of gas.

The sulphur content of displaced fuel oil also remains an outstanding issue between the Provincial Government and the four plant owners. It has been the industry's position with MEMPR that natural gas would be considered provided that there was no net cost increases (T 3954) and that an equivalent price did not factor in a low sulphur content. The sulphur content of the oil that the mills had been using averaged 1.35% in 1988 (T 4118). However, on Monday, March 20, 1989, the Ministry of the Environment stated that the sulphur content of heavy fuel oil was to be limited to 1.1%. This amounts to a premium of $2.00/bbl at least and this amount has been included in the Commission's financial analyses.

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3.5.2 Agreement

Curtailment

Natural gas has a lower calorific content than HFO which poses a particular problem to lime kilns if required to change fuels. Therefore the mills propose to exclude the kiln load of 13.75 TJ/d from curtailment and to limit other curtailment to five days per year. This seems appropriate in their opinion given other mills in the interior have similar curtailment restrictions (T 3873-3876).

According to Exhibit 109, PCEC proposes to provide the industrials with a curtailed load down to 18 TJ/d, over the 20-year forecast period, or 4.25 TJ/d over their requirement for kiln supply. The total annual curtailment actually drops from 275 TJ in 1991 to 168 TJ in 2010. This occurs as a result of the industrial load decreasing in proportion to that of the LDC. As the poorer LDC load factor comes to dominate the total supply, PCEC is required to increase its nomination level, thus reducing the industrial curtailment level (T 3902-3903). The Commission concludes that the curtailment of all of the mill load, except kiln requirements, is reasonable.

Dual Fuel Capability

To maintain dual fuel capability at each plant the industrial customers will be required to store more fuel than is currently necessary. On the average, incremental storage will cost about $136,000/mill. The mills want some recognition of this requirement in rates (T 3876). This matter has not been concluded and the Commission has made no allowance for it in its financial analyses.

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Term of Contract

The mills are prepared to enter into purchase contracts that match the term and security of natural gas supply probably in the range of 10 years (T 3955). PCEC, however, wants the term defined as the greater of either ten years or the retirement of the RSF and Federal and Provincial loans (T 3955). Under some scenarios that could conceivably extend up to 20 years. The Commission concludes that the agreement should be for the length of 10 years or until the RSF and government loans are repaid.

"Most Favoured" Nation Clause

COFI wishes to ensure that future industrial customers are treated no better than the mills. The Commission believes this is only reasonable except in cases where alternate fuel availability reduces the competitive position of natural gas.

3.6 BC Gas Inc. Wheeling Agreement

PCEC made two Applications to the Government for EPC's. The principal Application assumed that PCEC would negotiate a wheeling agreement with BC Gas to transport natural gas across the BC Gas system from Huntingdon to Coquitlam. An alternative Application was supplied which would have PCEC initiating its transmission system directly from the Westcoast gate station at Kilgard. PCEC asked that the alternative Application not be considered by the Commission and has pursued the negotiation of a wheeling agreement with BC Gas.

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Throughout the hearing PCEC maintained that they were very close to completing a wheeling agreement with BC Gas. Representatives from both parties stated that negotiations were progressing and agreement had been attained on all matters except for price. However, the two parties are widely apart in their price assumptions. PCEC has offered to pay a rate of approximately $2 million in year one of the project, rising to nearly $3 million in year 20. The BC Gas proposal, based on PCEC's avoided cost, assumes rates of approximately $4 million in year one rising to $4.3 million in year 7, and remaining constant thereafter.

Unfortunately this agreement remains uncompleted. The Commission understands that the PCEC proposal is based on their assessment of the incremental costs that BC Gas would incur to wheel the gas, while BC Gas methodology reflects the philosophy of the bypass legislation adopted by the Provincial Government. It also reflects the positions taken by the Commission that utilities such as BC Gas may discount their rates from full cost rates to those industrial customers who have an alternate fuel or other option. Any discounted rates must cover at least the variable costs of the utility and must be approved by the Commission.

The Commission recognizes that any eventual agreement between the parties must be accepted by the Government in the case of BC Gas, and by the Commission in the case of PCEC. Therefore, if the parties continue to be unable to resolve their differences, the Commission will need to become involved at some point. For the purposes of the Commission's financial runs in Section 4.4 of this report, it has used the BC Gas offer contained in Exhibit 75 for the purposes of its pessimistic and base case runs. The Commission has adopted the PCEC estimates in its optimistic scenario.

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3.7 Westcoast Transportation Tolls

Westcoast proposes to assist the Vancouver Island natural gas pipeline by offering incentive tolls in the first three years of operations. Westcoast intends to apply to the NEB for approval of the incentive tolls as part of its rate filing to be made in the spring of this year. The proposal is that PCEC be offered a discount of $0.25/GJ in the first year of operations, $0.20/GJ in the second year and $0.15/GJ in the third year.

Mr. Maas of Westcoast testified that the reduced tolls would be beneficial to all existing customers on the Westcoast system since the load would be incremental to existing loads and could be accommodated in the first three years without requiring new capacity additions to the Westcoast pipeline. He argued that because the incentive tolls would recover substantially more than the variable cost incurred by Westcoast, the incremental sale would therefore benefit everyone. This view was supported by BC Gas representatives who noted that Inland had received assistance from Westcoast in the initial years of its distribution service.

Other participants at the hearing, notably the Independent Petroleum Association of Canada ("IPAC"), were concerned that a discount from the fully-costed tolls of Westcoast could be interpreted as a subsidy from existing shippers on Westcoast to the PCEC project.

In argument PCEC encouraged the Commission to enlist the intervention of the Provincial Government before the National Energy Board ("NEB") in support of the incentive tolls.

The Commission has considered the positions taken by each party on this matter and generally supports the notion that if the PCEC load increment in the early years of operation can be accommodated within the existing system capacity of Westcoast, then a potential exists to discount the tolls to PCEC without harming any existing shippers

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on the Westcoast system. So long as the incentive toll covers the variable costs of Westcoast, plus the cost of service for any modifications to accommodate the incremental load, PCEC will at least contribute a rate which will not cause the tolls of other shippers to rise. Over the longer run the development of the Vancouver Island load will benefit all parties.

While holding the above views, the Commission concurs with IPAC to the extent that existing shippers on the Westcoast system should not be expected to contribute direct subsidies to the development of the PCEC system. The Commission views a direct subsidy as being an increase in tolls to existing shippers above that which they would have paid had PCEC not been on the system during the initial three-year period. In this regard, the Commission notes the evidence of Mr. Willms of Westcoast that Westcoast shareholders would not be inclined to support the incentive tolls through a reduced return on equity. If Westcoast is not prepared to provide a direct subsidy to PCEC, it should not expect its existing shippers to provide that subsidy either.

The matter of the incentive tolls must be decided by the NEB. For the purposes of its financial runs the Commission has included the three-year incentive tolls in both base and optimistic cases. In the Commission's pessimistic financial assessment it has assumed that fully-costed tolls of Westcoast would be applied.

With respect to future tolls from Westcoast after the incentive period, PCEC assumed that rates would remain constant at current levels. PCEC witnesses noted that rates since 1981 had actually fallen 7.5% per annum in real terms. This testimony was discounted by other evidence pointing to the large drop in export sales in 1980/81. In final argument PCEC set the upper boundary of price increases at 2% per year. Vigas speculated that Westcoast tolls would rise about 3% per year.

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The Commission does not foresee Westcoast tolls rising until new facility additions are required. This is unlikely to occur during the three year incentive toll period. In the future when an ethane extraction plant or new sales to the United States require facility additions, tolls will rise.

In the Commission's base case it is assumed that fully-costed Westcoast tolls stay constant until 1994, and then escalate at 3% per year. The pessimistic case has rates rising with inflation from year one. The optimistic case assumes that rates stay constant into the future.

It is noteworthy that the financial impact of the Commission's base case assumption is small compared to the PCEC estimate that rates could go up by 0-2% per year from the initial year. If the Commission's base case assumption is conservative the positive impact on the RSF would be about $2 million.

3.8 Natural Gas Storage

In order to purchase its gas supplies at an attractive, high load factor PCEC intends to contract with Unocal for storage in Unocal's Aitken Creek storage field. PCEC estimated they would be able to contract for that storage at a cost of $0.55/Mcf for the first 10 years of the project. Negotiations have not been concluded with Unocal.

The Commission demanded further information on this matter in its Order No. G-17-89. The response provided by PCEC to the hearing (Exhibit 75) included letters from Unocal dated April 14, 1988 and March 3, 1989. The most recent letter stated that "Unocal is prepared to provide storage space at an initial demand charge of $0.55 to $0.60/Mcf based on a flat delivery profile extending over a 150 day delivery period. The actual cost at the time this project commences and the cost in subsequent years will be determined using this base cost adjusted by an escalator which is yet to be negotiated".

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In response to an Information Request by Vigas (T 3101), PCEC filed Exhibit 124. That exhibit responded that Unocal's most recent position was that the $0.50 to $0.60/Mcf price was a mixture of fixed costs based on peak day demand and operating costs based on actual amount of gas withdrawn. PCEC noted that they would again meet with Unocal on April 5, 1989.

At this point, PCEC does not have an agreement with Unocal with respect to the price for storage, the amount of storage to be used, or the method of withdrawal. Unocal had proposed that withdrawals occur on a flat delivery profile, but PCEC has assumed fluctuations in deliveries to match its demand profile. In the absence of any commitments with respect to this natural gas storage, the Commission has assumed that, for the purpose of its base case financial run, the cost of storage would be $0.55/Mcf in year one of the project, escalating thereafter at the general inflation rate. The Commission assumes that PCEC may withdraw natural gas to smooth its load profile as required, rather than on a flat delivery profile. The Commission's pessimistic case assumes the initial storage cost to be $0.60/Mcf escalating at inflation. The optimistic case adopts the PCEC proposal that storage be at $0.55/Mcf during the first 10 years of the project, escalating thereafter at inflation.

<u>The availability of storage is integral to the gas contracting plans of PCEC. Any conditions attached to an EPC related to gas supply must also apply to natural gas storage.</u>

While storage at Aitken Creek would assist PCEC in increasing its load factor of natural gas purchases, it is unfortunate that this storage is located at the upper end of the Westcoast system rather than in closer proximity to the PCEC markets. The Commission heard testimony that wells drilled on Vancouver Island in recent years had been unsuccessful and Mr. de Grasse of Vigas testified that it was unlikely that underground storage would be found on Vancouver Island. Other natural gas storage

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facilities located downstream of the Westcoast system include the LNG plant owned by BC Gas and storage fields located in Washington State. Those facilities are currently dedicated to BC Gas customers, but Vigas noted that the existing storage contracted by BC Gas in Washington State could come up for renegotiation in the next few years. BC Gas provided other evidence that there could be a potential for the development of underground natural gas storage in the Lower Mainland if a suitable structure could be found.

In summary, there is no available natural gas storage downstream of the Westcoast system currently available to PCEC. The Commission has, therefore, not assumed any storage becoming available downstream of Westcoast in its financial runs. The future availability of natural gas storage on Vancouver Island or in the Lower Mainland would be highly beneficial to the project.

3.9 Natural Gas Supply

PCEC proposes to contract directly with producers for all the natural gas supplies needed to satisfy the markets of the distributor utilities and the industrial customers. The natural gas purchases are to be made at a high load factor so as to minimize the price. It has become common in British Columbia that Producers are willing to offer significant discounts to large volume/high load factor customers. For example, the British Columbia Petroleum Corporation ("BCPC") field price available to industrial customers with a high load factor is $1.03/GJ.

To improve the load factor of the markets served by PCEC, the transmission company intends to maintain relatively high volume purchases from producers in summer months and to inject the natural gas not immediately needed into Unocal's Aitken Creek storage. The gas would be taken from storage during the peak winter period and delivered to market. PCEC would thereby purchase gas at a high load factor under a "take or release contract" specifying a minimum load factor of 75%.

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PCEC has made preliminary inquiries with Producers attempting to purchase gas at a minimum price of $1.06/GJ, plus flowback of excess revenues from the project if oil prices rise in future. The flowback occurs after all repayable grants and the RSF are repaid and retail prices generate surplus funds after paying utility costs and the minimum field price. The minimum price offered to the Producer was based on PCEC's understanding of the competitive price when it first discussed matters with Producers in the spring of 1988 (Exhibit 73). PCEC has also stated that it would be willing to purchase gas at the wellhead or after processing. Natural gas from Alberta delivered to the project would be purchased at the inlet to the Westcoast system in Alberta.

Under the proposed flowback pricing scheme, producers require two events to occur to do well from sales to PCEC. First, crude oil prices would have to rise so that the retail price in the market place, which is tied to retail oil products prices, would also rise. Higher oil prices in themselves would be insufficient to provide a superior return to producers: for producers to do well under the flowback pricing scheme it is necesssary that the spread between natural gas prices and oil prices widen in future years. These two events would be consistent with a market where natural gas was in continuing over-supply, which would lead to depressed gas prices and wide spreads between natural gas and crude oil prices. This requirement was confirmed by Mr. Rutherford of PCEC when examined by Commission Counsel (T 3302-3303).

The spread between natural gas prices and oil prices is currently at an historic high. Recent projections, including the NEB forecast of December, 1988, expect the spread between natural gas and crude oil prices to narrow in the 1990's. This speculation is largely premised on the anticipated depletion of natural gas deliverability in the United States and a substantial increase in exports from Canada. This would tend to tighten the natural gas supply/ demand balance and improve prices for natural gas producers.

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PCEC stated they were optimistic that they could sign up volumes sufficient to meet the third year deliverability requirements of PCEC's own market forecast. In the absence of any reasonable information on gas supply from PCEC in its Application, the Commission ordered the production of all information by Order No. G-17-89. The response, filed on March 2, 1989, was included in Exhibit 75. The information was again updated in Exhibit 104 and 104A. PCEC has had correspondence with Westcoast Petroleum Ltd., Chieftain Development Co. Ltd., Texaco Canada Resources, BP Canada, Remington Energy Ltd. and two other producers who wish to remain anonymous. The volumes of natural gas assumed by PCEC to be available from these producers are as follows:

1.	Chieftain Development Co. Ltd.	-	9 MMcf/d
2.	Westcoast Petroleum Ltd.	-	2 MMcf/d
3.	Texaco Canada Resources	-	3-5 MMcf/d
4.	Remington Energy Ltd.	-	15-17 MMcf/d
5.	BP Canada	-	5-10 MMcf/d
6.	Others	-	5 MMcf/d
	TOTAL		39-48 MMcf/d

The Commission notes from the correspondence that the above volumes from the identified producers could not be categorized as commitments to the project. At best, they may be interpreted as preliminary expressions of interest. BP Canada withdrew its support for the project by letter dated March 23, 1989 noting, amongst other matters, that BP Canada does not support the PCEC rationale that requires them to purchase gas on behalf of end-users and LDC's.

The greatest stumbling blocks to signed gas supply contracts appear to be the minimum price offered by PCEC and the uncertainty regarding flowback. Representatives from IPAC indicated that, in their view, the price would be insufficient to attract sufficient volumes from producers. This view was echoed by Vigas. Indeed, even the representative of AEC, a sponsor of the pipeline project and owner of Chieftain, indicated that the proposed pricing would be insufficient for the latter company (T 3465-3466).

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PCEC has stated that they must have sufficient long-term contracts of natural gas to meet not only the requirement to finance the project, but also to meet the Provincial Core Market Policy tests, as administered by the Commission. PCEC counsel noted in argument that PCEC believed that the Commission should specify a condition to any approval of an EPC that the Core Market gas supply tests be met.

The Commission views the lack of progress on attaining a natural gas supply for this project as being the most serious impediment to its financing and completion. It is quite clear that any increase in producer prices negotiated in future would flow directly to the account of the Provincial Government, to be financed under the RSF. Consequently, the full risk of negotiating higher prices of natural gas will be borne by the Government, not PCEC. This risk to the Government cannot be overstated.

In the Commission's base case financial runs it is assumed that the initial base price of $1.06/GJ will have to be escalated, at least at inflation, during the 20 years of the project. In addition, the producers would enjoy the flowback of excess revenues from the project when they were attained. Based on the anticipated price of crude oil at $20.25 (U.S.)/bbl in 1991 escalating at inflation, the producers would begin to see flowback in 1997. At that time the RSF would be paid off.

However, under the pessimistic financial case, the natural gas price assumptions are the same as in the base case, but the value of crude oil is set at $15.40 (U.S.)/bbl escalating thereafter at inflation. In that case Producers never see any flowback of excess revenue, the Government grants are never repaid, and the RSF grows to a maximum value of $270 million in the year 2007.

The optimistic financial case presumes that PCEC would negotiate contracts at the $1.06/GJ plus flowback. In this case, the Commission assumed crude oil prices to be the average of the high and low forecasts issued by the NEB

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in December, 1988. In this case, producers obtained flowback in the first year of the project and there is never any draw made upon the RSF.

The uncertainty of gas prices at this time and the risk of future fluctuations in oil prices creates a significant financial exposure to the Provincial Government which cannot be over-emphasized. In final argument, PCEC speculated that if the minimum price of natural gas had an escalator attached to it, the company might be able to negotiate a cap on prices in later years. Such a cap on future prices was first put forward by Vigas and would be extremely valuable if oil prices rose rapidly, because other energy, particularly electricity, could become the competitor of natural gas in the retail markets if oil product prices rose to very high levels.

The Commission is dissatisfied with the performance of PCEC with respect to gas supply and has made this view known to PCEC's witnesses and its counsel several times during the course of the hearing. At this juncture, the Commission believes that any activity by PCEC to negotiate natural gas prices after the issuance of a conditional EPC should require participation on behalf of the Provincial Government so that prices and terms can be negotiated with assurance of timely approval. These negotiations must be completed before May 4, 1989 so that the final award of an EPC can be confirmed before PCEC must order pipe and award construction contracts to meet the in-service target date of September 1, 1990.

3.10 Reassessment of Facilities and Capital Costs

3.10.1 Pipe Size

In Section 2.4.1 of its "Interim Report - Phases I and II, March 14, 1989", the Commission noted that "In the event that Phase III evidence on market projections results in a 20-year sales forecast substantially in excess of the projections utilized by PCEC, consideration should be given to possibly upsizing a portion of the pipeline system to 323.9 mm O.D."

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There was considerable evidence advanced in Phase III to argue both for and against the installation of larger pipe for a portion of the route. The LDC's suggested that larger pipe was required to provide for the possibility of future peak shaving with underground storage in the B.C. Lower Mainland or Washington State (T 3530, 4510). The LDC's also argued (T 3704-3706 and Exhibit 116) that their load forecast for year 20 exceeded the pipeline capacity of 150 MMcf/d. They also suggested that a future loss of pipeline capacity was to be expected due to construction of an ethane stripping plant in the Taylor area (T 3851). These arguments were countered by PCEC in the testimony of Mr. Kavanaugh (T 4270-4283 and Exhibit 135). PCEC's position essentially relied on the fact that, while the most economical "ultimate capacity" of the 273.1 mm O.D. pipeline was 150 MMcf/d, this could be increased to about 200 MMcf/d for a very slight increase in operating cost by the use of additional compression. A capacity of 200 MMcf/d would enable PCEC to supply pipeline gas for the LDC's design day (i.e., extreme) forecast as well as the extreme Industrial load as forecast by COFI. The situation is summarized in Table 3.6 below.

TABLE 3.6

Pipeline Capacity Requirements, Year 20

	TJ/d	MMcf/d
Vigas extreme (Exhibit 116)	157.8	143.5
BC Gas extreme (Exhibit 103)	3.7	3.4
Industrial extreme (T 3902)	48.0	43.6
Total	209.5	190.5

From Table 3.6 it can be seen that since all present load forecasts are accommodated with the 273.1 mm O.D. pipeline, the decision on pipe size really amounts to how best to deal with future unknown industrial loads. While the Commission recognizes that various participants mentioned rumours of such loads at Britannia Beach, Texada Island and Powell River, (T 4552), there was no evidence of definite plans in any of these locations.

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It is the Commission's view, therefore, that the only reason for installing pipe larger than 273.1 mm O.D. is to preclude future looping of the pipeline through areas of extreme construction difficulty or environmental sensitivity. With this in mind, based on the evidence in Phase I of this hearing, the one area which qualifies as a candidate for larger pipe is the Coquitlam Watershed. The Commission believes that the risks in traversing the watershed are manageable now, particularly since the Greater Vancouver Water District ("GVWD") has the option of taking this watershed out of service for part of the year, if necessary. In future, this option may not be available and in any case, future looping of the pipeline through the watershed would entail otherwise avoidable risks.

PCEC stated in Exhibit 135 that 323.9 mm O.D. pipe could be installed through the watershed for an additional cost of about $2 million and that this would preclude future looping in the watershed (T 4426). The Commission concludes that this cost is justified in order to eliminate future intrusions into the watershed for pipeline construction. With this exception, the Commission does not believe that any further system capacity increases can be economically justified now, since the proposed system can handle even the most optimistic load forecasts over the 20-year project life.

3.10.2 Campbell River Lateral

The loads forecast by COFI for the Elk Falls Mill at Campbell River fell far short of those forecast for the other mills due to technical difficulties in the conversion of kilns (Exhibit 118). As a result, the Commission became concerned that the Campbell River Lateral, consisting of some 48.8 km of 114.3 mm O.D. pipeline, might not be economically justifiable. PCEC was requested to evaluate this and report back to the Commission (T 3503) and as a result filed Exhibit 144.

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Exhibit 144 shows that the RSF rises to a higher amount without the Campbell River loads than it does with them. The exhibit also shows that once the RSF is paid off, producer unit revenues are lower without the Campbell River case. The Commission concludes that the Campbell River Lateral would make a positive financial contribution to the project and should continue to be considered part of the project for that reason.

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4.0 FINANCIAL MODELS

4.1 Introduction

Section 5 of the Terms of Reference directs the Commission to review and assess the cost of service of the proposed project including pro forma financial statements and the assumptions used for the 20-year projected period. A number of financial cases were examined to achieve this objective.

The Statement of Principles dated September 22, 1988 lays out a framework of project financing and on-going assurance of competitive rates to gas users, pending the completion of a Binding Agreement. PCEC developed a financial model incorporating its project cost and financing assumptions to demonstrate financial feasibility of the proposed pipeline. As noted in Section 2.2.2, many of the assumptions differ from those of the Statement of Principles, but PCEC advised the hearing that the adjustments more closely represent the current thinking of the parties to the proposed Binding Agreement.

4.2 The Model

The mechanics of the financial model, developed in support of PCEC's project, use the regulatory process as a starting point. Rate base comprises capital costs and working capital less grants; cost of service is developed with sales volumes projected by PCEC for industrial customers and by LDC's for core market customers; sales prices are calculated in relation to the price of light fuel oil and competitive industrial fuels. The gate price to each LDC is calculated by taking their total sales revenue less their cost of service. A surplus or deficit results after deducting from the total PCEC gate revenue the cost of storage, Westcoast tolls, BC Gas wheeling, gas purchases and PCEC's own cost of service. A deficit would trigger the withdrawal of funds from the RSF; a surplus first repays any outstanding balances from the RSF and then flows-through to producers as netback revenue. Exhibit 22 provided a graphical demonstration of the proposed overall concept of the project and is reprinted here as Figure 4.1.

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FIGURE 4.1

PCEC Project Financial Flows

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A basic PCEC assumption was that revenues in excess of cost of service would be used to either reduce the RSF balance or to flowback as improved gas purchase payments to the producers. Government loans were to be repaid from funds generated from depreciation recovery, shareholders equity or additional financing by PCEC.

The results of the cost of service model were applied to the pro forma financial statements, which were presented on a corporate basis in the various runs prepared by PCEC. These statements basically reflected the results of the cost of service model and its assumptions related to PCEC's assets, liabilities and equity for the 20-year projection period. The Statement of Changes in Financial Positions reflected PCEC's projected cashflow to meet its financial obligations and to maintain a reasonable capital structure such that funds could be raised for timely capital expenditures. Interest coverage tests were shown in Exhibit 20, Tab 3, c. 2.3, which indicated that the normal interest coverage requirement of two times could be met.

4.3 PCEC Base Case

In addition to the financial model presented in the Application, PCEC established a Base Case model (Exhibit 87 and revised as Exhibit 87A) for the purpose of future financial comparisons as the hearing progressed. The results indicated that the cumulative RSF could reach $13 million in year 3, and be fully repaid in year 4; the Producers would start receiving netback revenue in year 5. PCEC believed that their Base Case was conservative and represented a reasonable balance of probabilities. BC Gas agreed in part with the conclusion of PCEC but noted that a wide range of outcomes could occur depending on the assumptions made.

Counsel for Vigas, in argument, contended that the PCEC Base Case was too optimistic. COFI suggested that the financial runs performed by PCEC did not reflect the principles set forth in the Statement of Principles.

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4.4 Range of Scenarios

Many financial cases were run during the course of the hearing with outputs ranging from a required draw on the RSF of $550 million in the worst case to zero draw on the RSF in the best case.

PCEC provided a schedule, in final argument, showing the impact on the RSF of changes in each major variable and concluded that the dominant variables were Westcoast tolls, capital cost overrun and peak shaving related to LDC load factors. BC Gas concluded that none of the financial model runs had demonstrated the correct scenario. Vigas suggested that Exhibit 114 which had been prepared according to COFI assumptions was too pessimistic. COFI pointed out that changes in the oil price assumption would have the greatest impact on the RSF.

In view of the differing opinions of participants and considering the wide range of assumptions and unsigned agreements, the Commission staff requested PCEC to prepare Exhibit 143, setting the upper and lower limits of each variable within a reasonable range, yet excluding the extreme circumstances. The intent was to provide a degree of confidence as to the pessimistic, likely and optimistic occurrence of all variables. For the purpose of running the financial models, PCEC's interpretation of financial arrangements contemplated in the Binding Agreement was accepted. Any significant variance in the signed Binding Agreement could vary the results.

Exhibit 143 was prepared based on PCEC's calculation of change in LDC revenues and cost of service, which reflected the different assumptions of load factors and peak shaving conditions. More recent Vigas cost of service estimates, including peak shaving alternatives, were provided in Exhibit 140.

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The Commission has considered all of the evidence and the many financial runs undertaken by participants at the hearing. The wide range in the estimates and the implications for financial support from the RSF are the result of the many outstanding agreements which have previously been discussed in Section 1.0 of this report. PCEC has no agreements with its downstream customers or its upstream transporters and gas suppliers. Estimates must be made of the market size, load factor, sales, PCEC cost of service, BC Gas wheeling cost, Westcoast transmission cost, gas storage costs and producer prices. On top of these estimates there exists a very large business risk related to the future of oil prices.

As required by the Terms of Reference, and in view of the wide range of estimates made by PCEC and the various intervenors, the Commission has created three financial scenarios for presentation in this report. Table 4.1 tabulates the assumptions of the Commission for each of the three scenarios. The pessimistic scenario should not be interpreted as being a worst-case scenario. In the pessimistic case the Commission has included reasonably probable, but negative, findings for the project compared to the Commission's Base Case. Equally the optimistic case could be exceeded if oil prices rose rapidly and/or other fortuitous events occurred.

The largest impacts on the project finances, as reflected in the RSF, result from changes in oil prices, the spread between crude oil and natural gas field prices, peak shaving requirements, and changes in capital costs. By far, the most volatile factor is the forecast of oil prices. For example, the value of West Texas Intermediate crude oil hit a low of $13 (U.S.)/bbl in mid 1988 and has risen recently to a high exceeding $20 (U.S.)/bbl. Forecasts of future prices vary considerably.

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Figure 4.2 illustrates the three crude oil forecasts used in the Commission runs. The pessimistic case assumes a low crude oil price with oil and natural gas prices escalating at equal rates. The base case assumes a higher oil price but retains the percentage spread between oil and gas prices into the future. The optimistic case assumes a high crude oil price and a rapidly widening spread between the crude oil and natural gas prices into the future.

FIGURE 4.2

Comparison of Crude Oil Price Forecasts

Source:	Case A	-	$15.14 (U.S.)/bbl escalated at 4%
	Case B	-	$20.25 (U.S.)/bbl escalated at 4%
	Case C	-	Average of high and low NEB forecast of December, 1988

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Tables 4.2 through 4.4 illustrate the financial highlights of the Commission's cases. The detailed assumptions have been explained in Section 3 and are consolidated on Table 4.1.

The Commission's base case, (Table 4.3) assumes an oil price of $20.25 (U.S.)/bbl in 1991 with the Producer natural gas price being $1.06/GJ. This spread between natural gas and oil prices is higher than in the pessimistic case and the Commission's base case assumes that the first year relationship between natural gas and oil prices continues until the flowback to the producer occurs in year 1997. The base case is predicated on a load factor of 40% for the LDC's and a PCEC capital cost of $256 million.

The Commission views the base case as having the highest probability of occurrence. The greatest variant to the base case is likely to come about as a result of future oil prices. These prices tend to be very volatile and historically oil price forecasts have proved to be poor when compared with the actual price movements that did occur. In the base case the RSF rises to $13 million in 1994 and is paid out by 1997. The loans are fully repaid in 2002.

The Commission's pessimistic case, (Table 4.2) is a combination of low oil prices with natural gas prices maintaining their current spread with oil prices. This case assumes an LDC load factor of 35% and a capital cost overrun of some $20 million over the Commission's base case. The output from this model run indicates that the RSF would continue to rise to the year 2007 when it would reach a maximum level of $270 million. At the end of the 20-year assessment period, the RSF would continue to have a deficit of $260 million. In addition there would be no repayment of either the Federal or Provincial loans in this scenario.

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The financial implications of the Commission's pessimistic case are most serious. The assumptions which lead to this result have some probability of occurrence. It is for this reason that the Commission strongly encourages the Government to assert its position with respect to the negotiation of gas prices for this project and the scrutiny of the construction bids made to PCEC.

The Commission's optimistic case, (Table 4.4) assumes that oil prices rise more rapidly than natural gas prices so that there is a widening spread between these commodities throughout the forecast. This forecast also assumes that the LDC's are capable of meeting a 45% load factor and the capital costs of the project come in $17 million less than the base case. In the optimistic case, the RSF is never used to support the cost of service of PCEC. The natural gas producers receive a flowback of surplus revenues from the project in the first year of the project. The repayable loans to the Governments are repaid starting in 1994 with the final payment being made in 1997.

It should be noted that the desirable results of the optimistic case also have a reasonable prospect of occurring. For example, the Commission is aware that the pipe prices tendered to PCEC are less than those budgetted. Further, if PCEC is able to take advantage of the current lull in pipeline construction activity, it may be able to attain the capital cost identified in the optimistic case. With respect to oil prices, the Commission has not used the NEB's high oil price, but has averaged the Board's low and high forecasted prices for the 20-year period.

In summary, the financial runs indicate that the project is viable depending on future oil and natural gas prices. The negative effects of the potentially low oil prices impact directly on the RSF and the Provincial Government. The Provincial Government must protect itself from this possibility.

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TABLE 4.1

BCUC - Financial Assumptions

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TABLE 4.2

Financial Highlights -
Commission Case A (Pessimistic)

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TABLE 4.2

(continued)

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TABLE 4.3

Financial Highlights -
Commission Case B (Base)

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TABLE 4.3

(continued)

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TABLE 4.4

Financial Highlights -
Commission Case C (Optimistic)

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TABLE 4.4

(continued)

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5.0 TRANSPORTATION SERVICE ALTERNATIVE

The Energy Project Applications by PCEC were structured on the concept that all customers would purchase natural gas through PCEC. PCEC would do all contracting with producers and attempt to package the purchases and deliveries in the best method to improve the load factors and prices for all customers (see Section 3.9). This type of arrangement is commonly called "sales service".

It was clear from the outset of the hearing that the industrial customers and LDC's wished to purchase their natural gas directly from producers. This type of arrangement has become common in British Columbia and Canada since 1985. "Transportation Service" is consistent with the initiatives of the Federal and Provincial Governments to deregulate the purchasing practices for the natural gas industry as expressed in the Agreement on Natural Gas Markets and Prices, October 31, 1985.

Following the award of natural gas rights in Victoria, Vancouver Island and the Sunshine Coast to Vigas, the distributor utility stated it also would prefer to make use of transportation service. BC Gas also supported transportation service.

Vigas dealt further with the matter of direct sales and transportation service in the written direct evidence of Mr. de Grasse which was filed as Exhibit 116 of the hearing. Vigas was uncertain whether direct sales would reduce gas purchase costs, but they did see two possible benefits. First, that the direct negotiations would bring producers and market participants closer together, thereby improving each party's understanding of the other. Second, Vigas felt that gas purchase arrangements might be perceived more positively if negotiated by parties not affiliated with companies having producing interests in British Columbia. Vigas further stated it would be willing to work with industrial customers to co-ordinate their gas purchases.

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The industrial customers also stated through their direct evidence that they were prepared to enter into contracts with the Producers if it would assist bringing the project to fruition. The industrial customers were willing to consider arrangements with LDC's to ensure that the gathering, processing and transportation tariffs were effectively co-ordinated to minimize costs. The benefit that the industrial customers saw in direct sales was that, after the RSF was paid down, the industrial customers could purchase natural gas and pay transportation service without having the retail price tied to the price of heavy fuel oil.

The PCEC response to the desire for transportation service changed as the hearing proceeded. In Exhibit 56, PCEC took the position that it must enter into long-term contracts for the purchase of natural gas to cover the market requirements in the early years of the project. It was noted that the negotiation of the Government loans and RSF were fashioned with the overall sales service concept in mind. Notwithstanding that, PCEC stated that it might be able to allow the large industries the option of converting a progressively increasing portion of their requirements to transportation service after five years.

Later, in response to an Information Request from Commission staff dated March 21, 1989, PCEC provided additional information with respect to transportation service (Exhibit 136). The financial assessment undertaken by PCEC was intended to show that it would be very difficult to duplicate the efficiencies that PCEC had built into its project application if one were to undertake transportation service. PCEC maintained that any proposal for structuring the project on a transportation basis could only be considered in the context of the Binding Agreement. Apart from being advised from time to time that negotiations were continuing, the Commission received no information on the evolution of the Binding Agreement during the course of the hearing. All financial cases in this report are based on the Commission's understanding of the Statement of Principles entered into by the Federal and Provincial Governments in September, 1988 and PCEC's understanding of negotiations towards a Binding Agreement.

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PCEC made it clear that if transportation service were to be offered in the early years of the project it must be decided immediately. If the industrial customers or LDC's made an initial choice for sales gas, PCEC felt it would not be possible to convert to transportation service for some period of years because of the commitments which PCEC would have undertaken to secure a supply of gas for its customers on a long-term basis. In final argument, Counsel for PCEC further hardened PCEC's position by encouraging the Commission to consider any transportation option as being outside the perview of the Commission.

In assessing the arguments on this matter, the Commission recognizes that a change in project structure to allow for transportation service would be very difficult to accomplish at this late date while still attempting to complete the project to provide gas service in September, 1990. However, there are many difficulties with the proposed method of natural gas contracting put forward by PCEC. The sales service concept not only appears to be a backward step in conflict with the Government's initiatives to decontrol wellhead activities of the Producers, but the flowback structure advocated by PCEC could lead to regional development problems in future years. Since the flowback scheme distributes all surplus revenues in future years to the Producers, the Producers selling gas to this project will do well if crude oil prices rise quickly and natural gas prices in the other competitive markets remain low compared to crude oil prices. In such an event, industries would be induced to locate at areas other than those served by PCEC so that they could take advantage of the lower natural gas prices that would exist elsewhere.

The Commission is also aware that the proposed purchase practices of PCEC are premised upon producers offering a lower than market price in early years of the project in anticipation of receiving substantial flowbacks later. Any change to transportation service based upon existing contracting methodologies would have a substantial impact

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upon the RSF in the early years of the project. Mr. Rutherford of PCEC acknowledged this in his direct evidence (Exhibit 56) when he stated that it would be necessary for the direct purchaser of natural gas on a non-netback basis to offer the Producers more in the early years of the project to compensate for the absence of the potentially higher prices if oil prices rose significantly.

While the Commission acknowledges all of the problems that the provision of transportation service could cause to the timely completion of this project, the Commission does not accept the assertions by PCEC that transportation service would necessarily cause higher overall prices for the project. Clearly a different contract approach with the Producers would cause differences in the amounts and timing of flows from and to the RSF. However, so long as the contracting methodology (sales or transportation service) was undertaken in a co-ordinated manner, the benefits of deregulation could flow to the market served by the PCEC project without a higher overall cost to the RSF.

As the Government is aware, the initiatives it has undertaken to decontrol the natural gas purchasing activities have led to substantial benefits to the consumers of natural gas. In implementing these policies, the Commission and the utilities have worked industriously over the past three years to ensure that transportation arrangements were put in place which married the benefits of direct natural gas purchases with transportation arrangements so that the benefits of load-factor resulting from common nominations, curtailment and interruptible service could be shared by all users. Structures can be put in place for the PCEC system which will mirror the benefits available elsewhere in the province. For example industrial customers in the interior of the province not only blend their purchases between interruptible and firm gas purchases, but the industries allow themselves to be curtailed by the distributor so that their pipeline space and natural gas can be used to serve the peak requirements of residential and commercial customers on the coldest days of the winter. In return, the industrial customers are awarded a lower cost of service from the distributors and can nominate reduced capacity on the Westcoast system.

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The resolution of this matter is beyond the ability of the Commission to deal with since it is dependent upon the structure of the Binding Agreement. If the Governments were to agree on a funding mechanism which would accommodate transportation service the Commission would encourage that it be offered. However the Commission believes it would be virtually impossible to put all the necessary arrangements in place in time to permit a May 4, 1989 construction start even if an appropriate Binding Agreement were to be concluded immediately.

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6.0 CONCLUSIONS AND RECOMMENDATIONS ON PHASE III

This section contains the Commission's recommendations with respect to Phase III of the hearing, Markets, Gas Supply and Financial Matters. As stated in Section 1.0, the Commission has previously provided an Interim Report to the Lieutenant Governor in Council with respect to the Commission's findings from Phases I and II of the hearing. The principal conclusions and recommendations of the Commission with respect to all phases of the hearing are included in an Executive summary, produced as a separate report.

The Interim Report and the previous sections of this report encompass a full review of all matters related to the Application as directed in the Terms of Reference for the hearing.

In reaching its conclusions and recommendations the Commission has been mindful of the project schedule to deliver natural gas to Vancouver Island markets by September 1, 1990. To preserve this delivery schedule, the critical path requires that PCEC commit to marine surveys by April 18, 1989 and issue contracts for pipe and construction by May 4, 1989. PCEC will require a conditional EPC by April 18, 1989 and would have to meet those conditions before May 4, 1989. A Binding Agreement would also be required by May 4, 1989.

The Commission has used PCEC's amended interpretation of the Statement of Principles on the assumption that it more closely represents the likely outcome of the Binding Agreement. In negotiating the Binding Agreement, the Governments should consider the financial impacts of any changes from this interpretation, as they will affect the project economics.

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6.1 Markets

As indicated in Section 3.1, the Commission concludes that the LDC market forecasts are appropriate for the financial analysis of the project. Its concern regarding competition from electric energy has been reduced by recent Government statements on future electric pricing trends. However, the market sensitive pricing concept should make provision for the potential of electricity becoming the prime competitor of natural gas under a high oil price scenario.

6.2 Gas Supply and Storage

The Commission concludes that gas supply contracts and the availability of storage are inextricably linked and are central to the project economics. The Commission is concerned with the lack of progress by PCEC in resolving these key issues. Since time is of the essence, THE COMMISSION RECOMMENDS THAT AN EPC SHOULD REQUIRE THE FOLLOWING CONTRACTS TO BE COMPLETED BY PCEC AND APPROVED BY THE PROVINCIAL GOVERNMENT BY MAY 4, 1989:

> LONG-TERM GAS SUPPLY AND STORAGE CONTRACTS SUFFICIENT TO MEET THE THIRD YEAR LOAD OF THE LDC PLUS THE INDUSTRIAL LOAD.
>
> LONG-TERM GAS SALES AGREEMENTS WITH THE INDUSTRIAL CUSTOMERS.

IN ADDITION, THE COMMISSION RECOMMENDS THAT A REPRESENTATIVE OF THE PROVINCIAL GOVERNMENT PARTICIPATE IN THE PROCESS SO THAT PRICES AND TERMS CAN BE NEGOTIATED WITH THE ASSURANCE OF TIMELY APPROVAL.

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The impact of future crude oil and natural gas prices on the RSF is extreme. The Province should not allow the project to proceed without assuring itself that these risks are managed through final long-term gas supply contracts. The Commission's pessimistic case scenario shows a maximum draw on the RSF of $270 million which would not be repaid in the 20-year project analysis period.

6.3 Peak Shaving

PCEC's proposal to require the LDC's to meet a 45% load factor creates problems for the LDC's. Vigas did not include any allowance in its service proposal to the Provincial Government for the capital cost of peak shaving equipment. Squamish Gas did not include peak shaving in its market and financial assessment.

Peak shaving is a brad and complex issue involving all participants in the project.

The Commission concludes that insufficient evidence was advanced to permit a rational and timely resolution of the appropriate allocation of peak shaving responsibilities among the participants. THE COMMISSION RECOMMENDS THAT THIS COMPLEX PROBLEM BE RESOLVED BY THE INTERVENTION OF THE COMMISSION WITH THE LDC'S, INDUSTRIALS AND PCEC UNDER PART 3 OF THE UTILITIES COMMISSION ACT. SINCE THE COMMISSION'S FINANCIAL MODELS INCORPORATE A RANGE OF PEAK SHAVING POSSIBILITIES, THE COMMISSION BELIEVES THAT THE OPTIMUM SOLUTION CAN BE ACHIEVED AFTER THE ISSUANCE OF A CONDITIONAL EPC.

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6.4 LDC Cost of Service

The Commission accepts the cost of service forecast by BC Gas and Vigas, subject to resolution of peak shaving requirements as recommended in Section 6.3 above. These forecasts are incorporated in the Commission's financial analysis of the project and the Commission has allocated funds for peak shaving to the cost of service of the LDC's to meet the minimum load factors assumed in the three Commission runs.

6.5 PCEC Cost of Service

The Commission concludes that PCEC's cost of service assumptions, as modified during the hearing, produce a reasonable balance between short-term gain and long-term cost to the project.

The Commission considered deferred depreciation and a higher debt/equity ratio as methods of reducing cost of service in the early years, but did not include them in its financial analysis because of their long-term implications on project economics.

6.6 PCEC/Industrial Contracts

The Commission concludes that the minimum term of contract between PCEC and its industrial customers should be the grater of 10 years or the time required for repayment of the RSF. The participation of the mills in this project is vital to its economics, and, therefore, THE COMMISSION RECOMMENDS THAT THE PROJECT NOT PROCEED WITHOUT LONG-TERM AGREEMENTS AND THAT THE PRICE OF NATURAL GAS TO THE INDUSTRIAL CUSTOMERS BE BASED ON THE PRICE OF ALTERNATIVE LOW SULPHUR FUEL OIL DELIVERED TO THE MILLS. The Commission accepts PCEC's evidence that the mills individually will not be curtailed below their lime kiln load.

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6.7 PCEC/LDC Contracts

The Commission concludes that PCEC will require long-term contracts with the LDC's to finance the project. In turn, the LDC's will require long-term gas supply contracts if they are to sign up for sales service. The Commission believes that gas supply to the core market should be contracted on a long-term basis with an initial volume equal to the third year volumes of the LDC's.

6.8 BC Gas Wheeling

The Commission concludes that a PCEC agreement with BC Gas covering wheeling costs between Huntingdon and Coquitlam is essential to the project in order to preclude a review of the Applicant's alternative (Kilgard) Application.

The Commission's financial analysis utilized the positions of both the parties in its sensitivity tests. The Commission reiterates its willingness to assist the parties to reach an agreement.

6.9 Westcoast Tolls

The Commission believes that, if the PCEC load increment during the first three years of operation can be accommodated within the existing Westcoast system capacity, then "incentive tolls" would not harm existing shippers on Westcoast's system. The incentive tolls would be highly beneficial to the project economics in the first three years. This toll will require the approval of the NEB.

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6.10 Pipe Size

THE COMMISSION RECOMMENDS PIPE SIZE BE INCREASED FROM 273.1 MM O.D. TO 323.9 MM O.D. THROUGH THE GVWD COQUITLAM WATERSHED TO ELIMINATE FURTHER INTRUSIONS FOR CONSTRUCTION PURPOSES SHOULD LOOPING OF THE PIPELINE BE REQUIRED IN FUTURE YEARS.

6.11 Campbell River Lateral

THE COMMISSION RECOMMENDS THE CAMPBELL RIVER LATERAL BE RETAINED DESPITE LOWER THAN ANTICIPATED INDUSTRIAL LOADS.

6.12 Transportation Service

The Commission has considered the evidence from intervenors at the hearing with respect to transportation service, which involves direct contracting of gas between producers, LDC's and industrials. While the Commission recognizes that the transportation service approach is more in tune with current trends in gas marketing, it concludes that this option, although highly desirable, should not be considered a viable alternative at this time for two reasons:

- the possible impact of such a change on the final Binding Agreement; and
- the potential jeopardy to the September 1, 1991 in-service date.

If the project's in-service date is delayed substantially the Commission would recommend that transportation service be incorporated into the project structure.

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6.13 Commission Costs

Pursuant to Section 133 of the Utilities Commission Act, the Commission determines that its costs incurred incidental to all phases of this hearing are to be paid by PCEC.

IN THE MATTER OF
the Utilities Commission Act,
S.B.C. 1980, c. 60, as amended

and

IN THE MATTER OF
an Application and an Alternative Application
by Pacific Coast Energy Corporation for
an Energy Project Certificate to Construct
and Operate Natural Gas Pipeline
Transmission Facilities to and on Vancouver Island

FINAL REPORT
PHASE III

April 6, 1989

Before:

J.G. McIntyre, Chairman
N. Martin, Commissioner
F.C. Leighton, Commissioner

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PARTICIPANTS

VANCOUVER

G.A. FULTON		Commission Counsel
C.W. SANDERSON M. MONTGOMERY M. SINCLAIR	F. ROBERGE R. RUTHERFORD	Pacific Coast Energy Corporation
A.H. WILLMS J.A. KAVANAUGH	R. MAAS J.H. PODMORE	Westcoast Energy Inc.
F. PROTO		Alberta Energy Corporation
C.B. JOHNSON D. FAIRBAIRN	M.F. SHOEMAKER J. THRASHER	BC Gas Inc.
R.B. WALLACE L.G. GUENTHER	H. JAMES J. de GRASSE	Vancouver Island Gas Company Ltd.
J.J. CAMP, Q.C. J. SANDERSON L. GRAY K. MacMILLAN W. WATERS	J. FIORANTE W. MacDONALD W. MANION R. DOUGANS M. JACKSON	Council of Forest Industries
D.R. SEXSMITH R.C. DeWOLF	R.B. HILLARY	Independent Petroleum Association of Canada
J. ANDERSON		Canadian Petroleum Association
P. McGEE		Self
G. BELL		Self

W.J. GRANT S.S. WONG	P.H. GRONERT R.B. BROWNELL	Commission Staff
ALLWEST REPORTING LTD.		Court Reporters and Hearing Officer

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ABBREVIATIONS

AEC	Alberta Energy Corporation
bbl	Barrel
BC Gas	BC Gas Inc.
B.C. Hydro	British Columbia Hydro and Power Authority
BCPC	British Columbia Petroleum Corporation
COFI	Council of Forest Industries
the Commission	British Columbia Utilities Commission
EPC	Energy Project Certificate
GVWD	Greater Vancouver Water District
HFO	Heavy Fuel Oil
ICG	ICG Utilities (British Columbia) Ltd.
Inland	Inland Natural Gas Co. Ltd.
IPAC	Independent Petroleum Association of Canada
LDC	Local Distribution Company
LFO	Light Fuel Oil
LNG	Liquified Natural Gas
MEMPR	Ministry of Energy, Mines and Petroleum Resources
NEB	National Energy Board
NG	Natural Gas
PCEC the Applicant	Pacific Coast Energy Corporation
Producers	Natural Gas Producers
ROE	Return on Equity
RSF	Rate Stabilization Facility
Squamish Gas	Squamish Gas Co. Ltd.
Unocal	Unocal Canada Limited
Vigas	Vancouver Island Gas Company Ltd.
Westcoast	Westcoast Energy Inc.