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

and

IN THE MATTER OF
Applications for Rate Relief
by Pacific Northern Gas Ltd.

DECISION

August 18, 1983

Before:

J.D.V. Newlands, Deputy Chairman
D.B. Kilpatrick, Commissioner
R.J. Ludgate, Commissioner

The Applications of Pacific Northern Gas Ltd. dated December 22, 1982 and March 25, 1983 to amend its filed tariffs were heard in public on June 27, 28, 29 and 30, 1983 in Prince Rupert, British Columbia and in Vancouver, British Columbia on July 6, 1983.

The Commission comprised J.D.V. Newlands, Deputy Chairman; D.B. Kilpatrick, Commissioner; and R.J. Ludgate, Commissioner.

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APPEARANCES

K.C. MACKENZIE	Commission Counsel
R.J. GIBBS C. DONOHUE	for Applicant, Pacific Northern Gas Ltd.
R.J. BAUMAN	for B.C. Timber Ltd. Eurocan Pulp & Paper Co. Ltd. Ocelot Industries Ltd. Aluminum Company of Canada Ltd. Atco Forest Products Ltd.
J.M. PELRINE	for British Columbia Gas Corporation
P. GRIFFIN	for Westcoast Transmission Company Limited

R.J. FLETCHER S.S. WONG D. MACINNIS	Commission Staff
D. LEACH	Hearing Officer
ALLWEST REPORTING LTD.	Court Reporters

I. INTRODUCTION

This Decision deals with Applications by Pacific Northern Gas Ltd. ("PNG" or the "Applicant") dated December 22, 1982 and March 25, 1983, for interim and permanent rate relief.

Commission Order No. G-93-82 dated December 23, 1982 granted an interim increase of 3.38% effective January 1, 1983 with the interim subject to refund with interest at the average prime rate of the principal bank with which PNG conducts its business.

On March 25, 1983 the Applicant applied for a further interim increase of 1.04% and the Commission, pursuant to Order No. G-35-83 dated May 12, 1983, set the matters of both interim and permanent rate relief to be heard in public in Prince Rupert, British Columbia commencing on June 27, 1983.

Copies of both Applications and supporting material were made available for inspection at the offices of PNG and in the office of the Commission, with copies provided to the major industrial clients of the Applicant at the time the Applications were made.

Interventions were received from B.C. Timber Ltd., Eurocan Pulp and Paper Co. Ltd., Ocelot Industries Ltd., Aluminum Company of Canada Ltd., Atco Forest Products Ltd. (all represented by R.J. Bauman), British Columbia Gas Corporation ("B.C.G.C.") (represented by J.M. Pelrine) and Inland Natural Gas Co. Ltd. All appeared at the hearing with the exception of Inland Natural Gas Co. Ltd.

The business of the Company is the transmission and distribution of natural gas in west central British Columbia, with the system commencing at Summit Lake, near Prince George and terminating in the deep water ports of Kitimat and Prince Rupert.

Since the last appearance of PNG before the Commission in 1980, the number of residential customers has increased from approximately 6,900 to 9,800. The rate base has increased from $39 million to $87 million and gas sales revenues have increased from approximately $28 million to $75 million. The latter two increases are primarily the result of the construction of additional facilities and increased sales of gas to the Ocelot methanol plant located at Kitimat.

The Applicant's Class B common shares (voting) are held 100% by Westcoast Transmission Company Limited ("Westcoast") with approximately 45% of the Class A non-voting shares also held by Westcoast. Petro Canada Exploration Inc. holds 19% of the non-voting common shares.

Evidence for the Applicant was given by Mr. R.F. O'Shaughnessy, President; Mr. R.G. Dyce, Vice President, Government and Regulatory Affairs; Mr. T.W. Weaver, Comptroller; and Dr. S.F. Sherwin. The intervenors called no evidence but participated through examination and argument.

II. TEST PERIOD

The Application for interim relief was based upon a forecast test year ending December 31, 1983. This forecast was amended by the Application dated March 25, 1983 and further supplemented by Exhibit 7 filed during the hearing.

There was some discussion with the Applicant during the hearing on the use of a two-year forecast test period. The Applicant was of the opinion that, with the resources available at the present time, a second year could not be forecast with sufficient accuracy to enable its use for rate purposes.

This is a matter which should be given further consideration as significant cost savings may be achieved by adopting a two-year test period provided that sufficient protection is available for both the customer and the investor.

III. THE ISSUES

1. Rate Base

Work in Progress

The majority of construction work in progress in the test period consists of inventory items transferred back as surplus from completed transmission projects.

The Commission must be satisfied that these inventory items are normal stocks required for construction, not simply over-ordered or scrap materials which may never be issued to another project. Although no disallowance has been assessed, the Commission instructs the Applicant to review its inventory items, and include only items required for safe and efficient operation of the system.

Company Residence

PNG purchased a residence in Terrace in 1983 to provide rental accommodation for a new manager. This is consistent with past practice and one which the Company feels necessary in order to attract qualified personnel to some of its operating positions. It is not widespread practice and the Commission concurs with it in such circumstances.

Transmission Additions

In its amendment to the Application contained in Exhibit 7, the Applicant proposed that certain transmission plant additions and/or reinforcements receive rate base treatment for the full test year. The majority of these facilities had originally been submitted in the Application on a mid-year basis consistent with the balance of the Application.

The Applicant in support of the amendment argued that these additions represented expenditures deferred from previous years, and expenditures from which no additional revenues will be generated because the system capacity has not been increased; and further that a precedent for their inclusion was established in a 1976 decision on an Application by Pacific Northern Gas Ltd.

The Commission has considered these adjustments as well as the precedent referred to by the Applicant. In this connection, the Commission notes that the precedent occurred at a time when the Applicant utilized an historic test year whereas this Application is predicated upon a forecast test year.

The Commission agrees with the Applicant that while these specific facilities may not generate additional revenue that alone is not sufficient justification to allow the facilities to be included for a full year. Neither is the argument that the expenditures are simply deferred from previous years and for existing customers. Some of these deferred expenditures have yet to be made in the test period and in all of the circumstances the Commission concludes that it cannot deviate from the normal practice as requested in Exhibit 7. The adjustment to the Application is therefore not appropriate and the rate base has been reduced by $1,203,850.

Unamortized Deferred Charges

The Applicant's proposals for amortization of certain deferred charges related to deferred interest, line break expenses, customer conversion, system development, foreign exchange losses, hearing costs, and leasehold improvements set out on Exhibit 2, Tab 6. The treatment of these charges is consistent with past practice authorized by the Commission and is accordingly accepted.

2. Revenue and Consumption

Sales Forecast

In the current economic conditions and recognizing the effect of conservation efforts, the Commission accepts as reasonable PNG's residential and commercial use per customer forecast.

With regard to small industrial sales, the Applicant has forecast the higher of the actual 1982 volume or the annual average for the three-year period 1979-1981. For large industrials, the Applicant has predicted consumption at the minimum load factors for B.C. Timber Ltd., B.C. Gas Corporation (Ocelot) the Aluminum Co. of Canada and in excess of the minimum for Eurocan Pulp and Paper Co. Ltd. The estimates were not disputed by the industrial intervenors.

The Commission concludes that with the gradual recovery of the economy the industrial consumption should increase, but for the purposes of this Application has accepted the estimates provided by the Applicant. The Commission emphasizes that this Decision pertains to a 1983 forecast test year based on 1983 sales volume. If the rates applicable to this Decision continue in effect into 1984 and in fact 1984 forecast sales volume significantly exceeds the 1983 forecast on which the approved rates are based, the Commission will consider the appropriate action to ensure that just and reasonable rates prevail in those circumstances. The Commission will therefore require the Applicant's 1984 forecast of sales on or by December 31, 1983.

Take-or-Pay (Banked Gas)

As a result of the economic downturn experienced in 1982, certain of PNG's large industrial customers have been unable to take the minimum gas volumes prescribed by their contracts and hence have paid for gas which has not been taken.

These companies, with the exception of the B.C.G.C., which under a Force Majeure deficiency has a ten-year make-up provision, have five years to draw upon deficiency or make-up volumes after the contracted minimum annual volumes have been taken. If PNG incurs a "take or pay" position with Westcoast, it has a five-year make-up period.

In any year in which an industrial customer fails to take the minimum volume prescribed in the sales contract, the customer is generally required to pay for the deficiency volume at the tariff rate less excise taxes. In this event PNG then calculates an amount equal to the commodity cost of gas for the deficiency volume and this amount is then placed in a deferred revenue account, for future utilization when the deficiency volume is made up.

The test year costs assume full delivery of the forecast sales volume. A revenue deferral which is limited to the commodity cost of gas tends to increase the net income in that year, since certain variable costs such as compressor fuel gas, which are included in the rates, are not actually incurred. When and if the deficiency or make-up gas is taken, the net income in that year is depressed by the same variable costs. The average unit cost of gas purchased from Westcoast is also affected, rising in the year of deficiency and falling in the year the gas is taken.

PNG argued that interest earned on the deferred gas account as well as the entire value of the account if the deficiency or make-up gas is not taken within the prescribed time period, should be the property of the shareholders. Counsel for PNG agreed that if a take-or-pay position with Westcoast was incurred by PNG, the carrying cost as well as any loss of gas due to non-recovery would be a shareholder's responsibility.

In the present circumstances, it might develop that the interest earned by the Applicant as well as the deferred variable cost of gas would be offset by interest expense incurred as a result of take or pay with Westcoast, and the deferred revenue thereby offset by costs incurred from Westcoast. The Commission concludes that this is unlikely however, since some customers may be in take-or-pay while others may increase their consumption, thereby eliminating any take-or-pay development in PNG. The current forecast test year may well demonstrate the validity of the foregoing, since even though several of the Applicant's large industrial customers are currently in a take-or-pay position, PNG may not ultimately be in that position with Westcoast. In any event, the Commission concludes, on the evidence heard, that it is unlikely that the Applicant will be in a take-or-pay position with Westcoast to the extent that the Applicant's customers are in that position with PNG.

Mr. Bauman, on behalf of the industrial intervenors, excluding B.C.G.C., argued that any benefits should be spread amongst all the customers.

Mr. Pelrine, on behalf of B.C.G.C. argued that any benefit should be given to the customers incurring the deficiency and that this matter could be set aside for further consideration.

The Commission accepts the position put forward by the industrial intervenors represented by Mr. Bauman, and finds these potential funds to be the property of all of the customers. If in the future a significant dollar value is involved (i.e. when the five-year or ten-year periods for recovery have expired) the Commission will make the appropriate order for the distribution of these funds in a just and reasonable manner.

The Commission also concludes that future rates should reflect interest earned on funds received for which gas is not delivered. Accordingly, the Commission directs that the Applicant accrue interest on funds in the deferred revenue account at a rate equal to that paid for 30-day money by the Applicant's principal bank. Disposition of the interest earned by the deferred revenue account will be the subject of a further Order by the Commission.

Investment Income

In addition to the interest income on deferred revenue, the Applicant forecast short-term interest income of $49,200 (Exhibit 5, Tab 15). The Applicant argues that such income is non-utility in nature.

The Applicant has been granted relief for the costs of capital by applying the weighted cost of capital to rate base, which includes an allowance for working capital. The Commission therefore concludes that any interest earned during the normal course of business must be treated as utility income.

3. Expenses

Operating and Maintenance Expenses

The Commission acknowledges the value of the update to cost of service provided by the Applicant in Exhibit 7, which significantly simplified and shortened the hearing process despite certain adjustments to rate base. The Applicant's adjustments reflected reductions in the 1% "in lieu of" municipal taxes and actual property taxes and payroll costs. The major change was a net downward adjustment in revenue requirement of approximately $170,000 to properly reflect the calculation of the 1% tax and the working capital effect.

The Applicant put forward forecast operating, maintenance and administrative costs of $5,337,766 (Schedule II) which the Commission accepts for the purposes of this Decision. Operating and maintenance statistics for the period of 1978 - 1983 are recorded in Appendix A attached. Costs applicable to 1983 will be utilized by the Commission as a base in the determination of a fair and reasonable level of these expenditures for future fiscal periods.

Inter-Company Charges

There have been significant increases in the charges to PNG by Westcoast Transmission for certain administrative and operating expenses. In response to questions from the Commission, the Applicant provided evidence from Westcoast personnel (A.H. Willms, Senior Vice-President and Mr. Podmore, Controller) to explain and justify the current charges, which had risen by 34% on May 1, 1982 and by a further 16% on April 1, 1983.

The evidence indicates that the largest portion of the increase aside from that attributed to increased services was in the overhead charge implemented by Westcoast after its annual review of inter-corporate charges. While the Commission recognizes that the sharing of administrative expenses benefits both companies, that the Applicant benefits from Westcoast's resources in expertise, and that the bulk of the increase is attributable to the provision of increased services, the Commission nevertheless expects PNG to provide its own services where comparable or lower costs may result. Moreover, in future the Commission will require advance notice of any proposed increase in those charges not directly related to increased services.

4. Engineering Matters

Westcoast Pressure and Delivery Pressure Agreement

The purchase contract under which PNG purchases gas from Westcoast provides for a minimum delivery pressure of 500 psig (3,400 kpa). This pressure is measured at the Westcoast inlet to the PNG system at Summit Lake. Historically, the pressures at this point on the Westcoast system have been at 700 psig or greater because of the need to ensure delivery of contract volumes to the U.S. market at Sumas. In fact, as recently as 1980, PNG selected new compressors for its system which were designed to utilize this pressure and meet the requirements of its market. As a result of being able to take advantage of the higher than minimum contract pressure of 500 psig, PNG has been able to defer capital and operating costs to the advantage of the consumers.

In recent months, Westcoast has reduced line pressure in its system because of the very much lower sales to the U.S. market, with the result that PNG is no longer able to depend on receiving gas at the 700 psig necessary to ensure that all its customers are served at peak periods.

PNG has undertaken a two-part program to meet the pressure deficiency. The first involves upgrading existing facilities at a cost of $1,450,700. The second involves purchasing additional compression from Westcoast when circumstances require. To this end, PNG has negotiated an agreement with Westcoast under which PNG may request, on notice, a 700 psig delivery pressure. Daily charges for this service include 50% of the fixed costs and 100% of the variable costs of the compressor operation as well as an incremental fuel charge. The annual cost of this service is estimated to be approximately $124,000 for an estimated 20 days use.

While it is unfortunate that the circumstances have changed so that PNG has been required to undertake these additional steps, the Commission concludes that the Applicant's proposed expenditures and pressure agreement with Westcoast will provide a prudent solution to its pressure problem.

Company Fuel Use and Losses

Prior to 1982, PNG was using reciprocating compressors driven by natural gas to provide transmission pressure. During 1981-82, four gas turbine centrifugal compressors were added, one each at compressor stations R1, R2, R3 and R4. Because gas turbines are particularly inefficient under partial load conditions, PNG has modified the compressor units at R3 so that low system demand can be met with fewer units. These units should then be operating closer to design flow conditions, yielding better fuel efficiency.

As the following table shows, in addition to increased compression required for deliveries to Ocelot over the past three years, PNG has consumed increasing volumes of compressor fuel gas because of additional compression requirements to meet overall load growth on its system.

Year	Fuel Gas Use (Mcf) (Vol. 1, Tab 9, Page 3)	
1978	53,000	
1979	61,000	
1980	74,000	
1981	82,000	
1982	288,000	
1983	632,000	(Vol. 1, Tab 9, Page 1)

With the addition of centrifugal compressors the fuel consumption increased significantly from, 82,000 Mcf in 1981 to 632,000 Mcf in forecast 1983. The Company's forecast of fuel gas use is based on historical recent experience of 2.75% of gas purchased. The Commission recognizes that the fuel consumption/system flow relationship is not linear but rather exponential, and the compression necessary to deliver gas increases exponentially with the system flow. The Commission therefore accepts the Applicant's 1983 fuel gas forecast but will require that future forecasts be refined by the Applicant as the system becomes more stable.

Line Breaks

PNG incurred a major line break in February 1981, which was not detected until April of that year. The break was caused by a rockslide downstream of a tunnel near MP-327, with rock penetrating the berm and puncturing the pipe. PNG estimates a loss of 130,000 Mcf of gas with a value of $176,900. The recent history of the Applicant's gas losses from line breaks is as follows:

Year	Line Break Loss (Mcf)
1978	24,900
1979	13,300
1980	nil
1981	132,500
1982	nil
1983	nil

The 1981 loss was large, amounting to over one percent of total gas purchases for that year. As a result, total unaccounted for gas in 1981 was 382,892 Mcf, or 3.3% of purchases, whereas the average is closer to 2%.

Following this incident the Applicant was directed to examine its leak detection program, and report the findings to the Commission. In a letter dated June 8, 1982, PNG demonstrated that it would be more cost-effective to increase the surveillance of the line to four investigations per year, than to add city gate station metering for monitoring gas balances.

The Commission concludes that the Applicant should establish its surveillance program at the four times per year level. If this does not prove cost-effective and additional metering appears to be required the Applicant should so advise the Commission.

Ocelot Pigging Facilities

PNG plans to install pigging facilities in the 10-inch lateral serving the Ocelot Methanol plant in Kitimat, at a cost of $231,000. The line, 35 miles long, was initially constructed without such facilities in order to minimize capital costs. However, since its completion this lateral has been found to have a higher pressure drop than predicted, and unacceptable levels of contaminants have been found in the filters at the Ocelot meter station.

The Commission concurs with the Applicant's plans that the expenditure should be made at this time.

Thornhill Subdivision

The Thornhill subdivision of Terrace was bypassed with a twelve inch main, the intention being to downgrade the pressure of the existing ten inch line through Terrace to provide local distribution only, and taking the Kitimat flow from the twelve inch bypass. That bypass has only been partially completed, so that the complete Prince Rupert flow was obliged to pass through a section of six inch pipe. This has caused the line pressures at both Prince Rupert and Kitimat to drop substantially below design pressure. At a budgetted cost of $131,000, the Applicant plans to put the existing ten inch line through Terrace back into transmission service so that it can be operated at 960 psi. This will restore the line pressures in Kitimat and in Prince Rupert to design levels. When the twelve inch bypass is completed some time in the future, the line through Terrace can be derated again to distribution pressures. The Commission concludes that the proposed expenditure offers a prudent solution to the problem.

Mile 305 Relocation

A portion of the transmission line near MP-305 located at the junction of the Skeena and the Gitnadoix River is threatened with a washout. Evidence given at the hearing indicated that the river bank is receding more quickly than previously anticipated and PNG now proposes to relocate the line without further delay. The project cost is now estimated to be approximately $402,000. The Commission concurs with the Applicant and the appropriate adjustment has been made in the rate base.

5. Rate of Return on Common Equity

Dr. S. Sherwin provided rate of return testimony on behalf of PNG and recommended a rate of return on common equity of 16.5%. The industrial intervenors exclusive of the British Columbia Gas Corporation suggested a rate of return in the range of 13% to 15%. The British Columbia Gas Corporation submitted that there was no evidence to support an increase above the 15.5% approved in 1980.

The expert testimony of Dr. Sherwin centered on three tests to determine a fair return to utility investors. While these tests, described as the comparable earnings test, the discounted cash flow technique, and the risk premium approach in the Commission's view can be useful where appropriately applied, they of necessity must be subject to the exercise of judgement in the context of the actual circumstances in which the utility operates.

It is well recognized that business and financial risks are a major consideration in assessing risk and rewards. In this instance particularly significant factors are the Applicant's business and financial risks relating to heavy dependence on industrial sales. Normally, a utility with a large proportion of industrial load in relation to residential and commercial load carries a substantial element of business risk, because of exposure to downturns in business cycles.

PNG would be particularly exposed to this risk except for the protection provided by take-or-pay commitments in its major industrial contracts. The contract with B.C.G.C. under which gas is provided to the Ocelot methanol plant, is an important example of this protection. Dr. Sherwin credited that contract with providing PNG with the stability of a significant residential load and concluded that the business risk was reduced by the take-or-pay provisions of that contract. On the other hand he concluded that the financial risk was increased because, in his opinion, governments may interfere with contracts which impose unforseen financial burdens on the taxpayers.

The Commission concludes that the business risk of PNG is substantially reduced by the existence of the B.C.G.C. contract and that the financial exposure attributable to risk of interference by the government is de minimis.

Another factor bearing on the appropriate reward to the equity investor is related to the capital structure. From the investor's viewpoint, a thinner equity component carries with it correspondingly greater risk, because of volatility of earnings.

In the Applicant's circumstances the Commission concludes that the capital structure is a significant consideration and must influence the level of return granted. The Commission has also considered the rates of return recently allowed other utilities regulated under the Act and the significant decline in the cost of capital over the past year. The Commission concludes that a particularly significant factor in assessing risk to the equity holders in PNG relates to the business and financial risks inherent in the nature of the Applicant's operations. For this reason the Commission concludes that, although the take-or-pay provisions in its industrial contracts (and notably in the Ocelot supply contract with B.C.G.C.) significantly reduce the business and financial risks of PNG, these risks remain of a higher order than found in Inland Natural Gas Co. Ltd. In the final analysis, the allowed rate of return must be reasonable in comparison to rates of return prevailing in companies of comparable risk.

Reflecting its judgement in all of these factors, the Commission concludes that, based on the Applicant's present capital structure, the rate of return on equity required to protect the investor, maintain the facilities, and provide reasonable rates to consumers is in the range of 15.5% to 16.25%. While lower than that sought by the Applicant and recommended by Dr. Sherwin, it is the conclusion of the Commission that 15.87% is fair and reasonable for the purpose of setting rates for service. The Commission notes that the significant declines in interest rates and inflation which have occurred since the last PNG Decision have been reflected in substantially reduced rate of return decisions in 1983 in other jurisdictions. The Commission concludes that the modest increase in the rate of return on common equity from the 15.5% awarded in the 1980 Decision to the 15.87% now approved is consistent with the improving economic conditions and the risk and capital structure of the Applicant.

6. Rates and Tariffs

The Commission confirms the existing interim rates and will accept for filing revised tariff rate schedules which will permit the Applicant to generate the revenue requirement as set out in the schedules of this Decision. The new rates will become effective, upon timely filing, with consumption on and after September 1, 1983.

DATED at the City of Vancouver, in the Province of British Columbia, this 18th day of August, 1983.

J.D.V. Newlands, Deputy Chairman

D.B. Kilpatrick

D.B. Kilpatrick, Commissioner

R.J. Ludgate, Commissioner

PROVINCE OF BRITISH COLUMBIA

BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-63-83

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

and

IN THE MATTER OF Applications for Rate Relief by Pacific Northern Gas Ltd.

BEFORE:	J.D.V. Newlands, Deputy Chairman; D.B. Kilpatrick, Commissioner; and R.J. Ludgate, Commissioner	)	August 18, 1983

O R D E R

WHEREAS a public hearing pertaining to Pacific Northern Gas Ltd. ("P.N.G.") commenced before this Commission at Prince Rupert, B.C. on Tuesday, June 27, 1983 to hear, inter alia, the following matters:

(a) An Application dated December 23, 1982 for a 3.38% interim rate increase effective January 1, 1983 to its filed Tariff Rate Schedules.

(b) An Application dated March 25, 1983 seeking a further 1.04% interim rate increase and permanent rate relief; and

WHEREAS the Commission has considered the Applications and the evidence adduced thereon, all as set forth in a Decision issued concurrently with this Order.

NOW THEREFORE the Commission hereby orders Pacific Northern Gas Ltd. as follows:

1. The interim rates currently in effect as authorized by Commission Order No. G-93-82 are hereby confirmed as permanent increases.

2. The Rate Base for the Test Year ending December 31, 1983 is approximately $88,900,000.

.../2

3. The Total Revenue Requirement for the Test Year ending December 31, 1983 is approximately $75,850,000.

4. The Commission will accept for filing, subject to timely presentation, revised Tariff Rate Schedules conforming to the above-noted Revenue Requirement, effective with consumption on and after September 1, 1983. The amended Tariff Rate Schedules will allow P.N.G. an opportunity to earn a rate of return on common share equity of 15.87%.

DATED at the City of Vancouver, in the Province of British Columbia, this 18th day of August, 1983.

BY ORDER

Deputy Chairman

SCHEDULE I

PACIFIC NORTHERN GAS LTD.

Utility Rate Base - Mid Year 1983

Description	Per Application (Exh 2 Tab 2 Sch 1)	Amendment per Exhibit 7	Amended Application	Commission Adjustments	Adjusted Balance
Gas Plant in Service	$100,055,120	$1,404,000[a]	$101,459,120	$(1,203,850)[b]	$100,255,270
Less Accumulated Depreciation	11,182,435	-	11,182,435	-	11,182,435
Net Plant in Service	88,872,685	1,404,000	90,276,685	(1,203,850)	89,072,835
Construction Work in Progress	538,081	-	538,081	-	538,081
Net Utility Plant	89,410,766	1,404,000	90,814,766	(1,203,850)	89,610,916
Unamortized Deferred Charges	1,129,621	5,184 (58,842)	1,075,963	(3,750)[c]	1,072,213
Cash Working Capital	(3,755,762)	1,437,164 4,900 (3,268)	(2,316,966)	-	(2,316,966)
Other Working Capital	507,474	-	507,474	-	507,474
Investment in Rate Base	$ 87,292,099	$2,789,138	$ 90,081,237	$ (1,207,600)	$ 88,873,637

PACIFIC NORTHERN GAS LTD.

Notes to Schedule I

(a) Summary of Applicant's Amendment to Gas Plant in Service (Exhibit 7):

Exhibit 7	Item 5	$1,107,050
	Item 7	51,026
	Item 8	(6,230)
	Item 10	193,600
	Item 11	58,554
TOTAL		$1,404,000

(b) Disallowance of Plant in Service for full year (Exhibit 7):

Exhibit 7	Item 5	$1,107,050
	Item 10 ($193,600 X 1/2)	96,800
		$1,203,850

(c) Hearing Cost (Exhibit 2, Tab 6)

	Per Application	Actual	Adjustment
Beginning	–	–	–
Addition	$100,000	$85,000	–
Amortization	50,000	42,500	$7,500
Ending	50,000	42,500	–
Mid-Year	25,000	21,250	3,750

SCHEDULE II

PACIFIC NORTHERN GAS LTD.

Utility Income and Earned Return for the Test Year 1983

	Per Application	Amendment per Exhibit 7	Amended Application	Commission Adjustments	Adjusted Balance
Gas Sales (Mcf)					
(Exh 2 Tab 9)	22,129,567	-	22,129,567	-	22,129,567
Gas Sales Revenue					
(Exh 2 Tab 19)					
*Existing rates including interim	$75,622,003	-	$75,622,003	-	$75,622,003
Deficiency	784,950	$(6,906)	778,044	$(572,327)[e]	205,717
Total Sales Revenue	76,406,953	(6,906)	76,400,047	(572,327)	75,827,720
Operating Expenses					
(Exh 2 Tab 18)					
Purchase of gas	49,420,754	-	49,420,754	-	49,420,754
Oper., Mtce., Admin. & Gen	5,374,974	(37,208)[a]	5,337,766	-	5,337,766
Depreciation	2,152,456	1,401	2,153,857	-	2,153,857
Amortization	228,179	(11,768)	216,411	(7,500)[d]	208,911
Franchise taxes	521,595	-	521,595	(3,900)[c]	517,695
Property and sundry taxes	2,640,353	(433,461)	2,172,484	-	2,172,484
		(34,408)			
Foreign exchange loss	189,225	-	189,225	-	189,225
Misc. Revenue and Expenses	(125,496)	-	(125,496)	(49,200)[b]	(174,696)
	60,402,040	(515,444)	59,886,596	(60,600)	59,825,996
Income before Income taxes	16,004,913	508,538	16,513,451	(511,727)	16,001,724
Income taxes (Exh 2 Tab 16)	4,342,689	135,909	4,478,598	(217,081)	4,261,517
EARNED RETURN	$11,662,224	$ 372,629	$12,034,853	$ (294,646)	$11,740,207
Return on Rate Base					
Utility Rate Base	$87,292,099	$ 2,789,138	$90,081,237	$(1,207,600)	$88,873,637
Rate of Return on Rate Base	13.36%		13.36%		13.21%

* Existing Rates include the January 1, 1983 interim and the February 1, 1983 Federal Excise Tax decrease.

PACIFIC NORTHERN GAS LTD.

Notes to Schedule II

(a) Summary of Applicant's Amendment to Operation and Maintenance Expenses:

Exhibit 7	Item 2	$ 9,900
	Item 6	(1,142)
	Item 7	(51,026)
	Item 8	(6,640)
	Item 9	11,700
		$(37,208)

(b) Short-term Investment Income included as utility income (Exhibit 5, Tab 15):

$(49,200)

(c) Reduced Franchise Fees as a result of Commission Adjustments (Exhibit 2, Tab 13, Schedule 3):

$$\frac{\$17{,}386{,}539}{\$76{,}406{,}953} \times \$572{,}327 \times 3\% = \$(3{,}900)$$

(d) Hearing Cost Adjustment

Per Schedule I Note (c) $(7,500)

(e) Revenue Deficiency Adjustments:

Deficiency per Application	$ 778,044
Commission adjustment	(572,327)
Deficiency per this Decision	$ 205,717

PACIFIC NORTHERN GAS LTD.

Income Tax Expense
for the Year Ending December 31, 1983

Total Rate Base			$88,873,637
Return on Rate Base @ 13.21%			$11,740,207
Less:	Return on Debt Portion = $88,873,637 x 9.03%		8,025,289
After Tax Return on Equity			3,714,918
Plus:	Loss on Foreign Exchange	$189,225	
Less:	Amortization of Capital Issue Cost	(3,030)	
	Inventory Allowance	(22,175)	
	Land Right Allowance	(15,000)	
	Subtotal		149,020
Net Income After Tax for Determination of Income Tax Expense			3,863,938
Income Tax	- Deferred @ 52%		2,129,026
	- Payable @ 52.9%		2,132,491
Total Income Tax Expense			$ 4,261,517

SCHEDULE IV

PACIFIC NORTHERN GAS LTD.

Average Common Equity
During the Calendar Year 1983

Particulars		Amount
Common Share Capital, December 31, 1982		$ 8,002,000
Retained Earnings, December 31, 1982		12,152,305
Total Common Equity, December 31, 1982		20,154,305
Projected 1983 Net Income after Tax	$3,673,726	
Less: Dividends on Preferred Shares	337,500	
Dividends on Common Shares	1,600,400	
1983 Retained Earnings		1,735,826
Total Common Equity, December 31, 1983		21,890,131
Average Common Equity During 1983		$21,022,218

SCHEDULE V

PACIFIC NORTHERN GAS LTD.

Utility Capitalization and Cost of Capital
Mid-Year 1983

Particulars	Per Application Mid-Year 1983 Balance	% of Capital Structure	Adjusted Balances	% of Capital Structure	Cost %	Cost Component %
Total Long Term Debt	$46,857,769	53.13	$46,857,769	53.17	16.98	9.03
Preferred Stock	4,947,969	5.61	4,947,969	5.62	7.01	0.39
Deferred Income Taxes	12,171,274	13.80	12,171,274	13.81	-	-
Contributions in Aid of Construction	2,358,283	2.68	2,358,283	2.68	-	-
Construction Advances	768,423	0.87	768,423	0.87	-	-
Common Equity	21,088,104	23.91	21,022,218	23.85	15.87	3.79
Total	$88,191,822	100.00	$88,125,936	100.00%		13.21

Pacific Northern Gas Ltd.

OPERATING, MAINTENANCE & ADMINISTRATIVE STATISTICS

Costs Attributable to BCGC 1983		1983	1982	1981	1980	1979	1978
2.046.594	Operating & Maintenance Cost	$ 4,194,389	$ 2,947,303	$ 1,537,606	$ 1,296,355	$ 1,068,950	$ 834,667
	Number of Customers at Year End	9,776	8,546	7,817	6,857	6,158	5,393
11,630.000	Volume Sold (Mcf)	22,129,567	16,577,992	11,232,709	11,355,129	10,677,983	9,067,387
	(a) Operating & Maintenance Cost per Customer	$ 429	$ 345	$ 197	$ 189	$ 174	$ 155
¢ 0.175	(b) Operating & Maintenance Cost per Mcf Sold	$ 0.1895	$ 0.1778	$ 0.1369	$ 0.1142	$ 0.1000	$ 0.0921
¢ 0.038	O & M Cost per Mcf Sold - Not Including Gas used in Operations	$ 0.096	$ 0.109	$ 0.097	$ 0.087	$ 0.072	$ 0.064
¢ 228.900	Administrative & General Cost	$ 1,180,585	$ 1,007,806	$ 789,238	$ 724,266	$ 473,942	$ 449,713
	(c) Administrative & General Cost per Customer	$ 121	$ 118	$ 101	$ 106	$ 77	$ 83
¢ 0.0195	(d) Administrative & General Cost per Mcf Sold	$ 0.0533	$ 0.0608	$ 0.0703	$ 0.0638	$ 0.0444	$ 0.0496
	Number of Regular Employees	72	70	65	58	52	48
	(e) Number of Customers per Employee	136	122	120	118	118	112

TAB 10
SCH. 1

APPENDIX A

Exhibit 26

LIST OF EXHIBITS

	Exhibit No.
Pacific Northern Gas Ltd. Tariff B.C.U.C. No. 2 December 22, 1982 Interim Application	1
Pacific Northern Gas Ltd. March 25, 1983 Application to Amend its Schedule of Rates - Volume 1	2
Pacific Northern Gas Ltd. March 25, 1983 Application to Amend its Schedule of Rates - Volume 2, Rate of Return Testimony of Stephen F. Sherwin	3
Pacific Northern Gas Ltd. June 8, 1983 Application to Amend its Schedule of Rates - Volume 3, Testimonies of Pacific Northern Witnesses	4
Pacific Northern Gas Ltd. June 8, 1983 Application to Amend its Schedule of Rates - Volume 4, Response to Request for Additional Information dated May 27, 1983	5
Pacific Northern Gas Ltd. June 20, 1983 Application to Amend its Schedule of Rates - Volume 5, Responses to June 9 and 14, 1983 Information Requests	6
June 24, 1983 Letter Pacific Northern Gas Ltd. to B.C.U.C. and Amendments to the Filed Application	7
Affidavit of Service of Marina Ireland, June 27, 1983	8
Contract August 1, 1981 between Pacific Northern Gas Ltd. and British Columbia Petroleum Corporation - Gas Sales Contract	9
Pacific Northern Gas Ltd. Accounting for Deferred Revenue on the Occurrence of Force Majeure Deficiency Volumes - B.C. Gas Contract	10
Pacific Northern Gas Ltd. Accounting for Deferred Revenue on the Occurrence of Regular Deficiency Volumes - B.C. Gas Contract	10A
Pacific Northern Gas Ltd. Cumulative Balances of Deferred Revenue January - May 1983	11
Exhibit Prepared for Industrial Intervenors - Schedules Comparing 1981, 1982 and 1983 Operating, Maintenance and Administrative Expenses	12

LIST OF EXHIBITS
(cont'd)