CAARS
Pacific Northern Gas Ltd Rates April 23, 1991

1.0 INTRODUCTION

Pacific Northern Gas Ltd. ("PNG", "the Company", "the Applicant"), a subsidiary of Westcoast Energy Inc. ("Westcoast"), transmits and distributes natural gas in west central British Columbia . The 350 mile system begins at Summit Lake near Prince George where it interconnects with Westcoast's pipeline system and terminates at the deep water ports of Kitimat and Prince Rupert. It is primarily an industrial gas transmission system serving large industrial customers of which Ocelot Chemicals Inc. ("Ocelot") is the dominant customer, consuming approximately 67 percent of the annual volume. Currently, residential customers comprise 3 to 4 percent of PNG's load, while commercial, small industrial and natural gas vehicle customers comprise 8 to 9 percent. The Company has a two tier common equity structure. The non-voting Class A stock is publicly traded but primarily held by Westcoast and its major shareholder, Petro-Canada Inc. The Class B voting shares are held in their entirety by Westcoast.

The Applicant's last rate case was in 1985 when a rate of return on common equity of 15 percent was approved. The Company has earned an average normalized return on common equity of 15.46 percent from 1982 to 1990 (Exhibit 4, Tab 2, page 17) and 15.30 percent from 1985 to 1990. Since 1982, the Company's customers have increased from 8,182 to 15,388 (88 percent), rate base from $69 million to $121 million (76 percent), sales from 18 TJ to 34 TJ (87 percent) and common equity from $19 million to $38 million (100 percent). Concurrently, the Company experienced wellhead deregulation leading to transportation service agreements and negotiated contracts. The Company attributes the lack of a need for rate increases since 1985 to increased industrial sales, particularly to Ocelot, reduced debt costs, decreased insurance premiums and lower income tax rates (Exhibit 4, Tab 2, page 26). In the same period, the average price of natural gas declined, albeit demand charges increased, and the Company switched to flow-through income tax accounting. The annual energy costs to residential and commercial customers have been relatively constant since 1985, whereas small and large industrial customers have experienced significant price decreases (Exhibit 4, Tab 2, page 9).

BEFORE:

J.D.V. Newlands, Deputy Chairman
N. Martin, Commissioner
W.M. Swanson, Q.C., Commissioner

This Application, originally estimated to take 8 to 10 days, was heard in Prince Rupert, B.C. from March 18 to 22, 1991 inclusive. The Applicant and all counsel are to be congratulated for their efficient participation which resulted in an expeditious hearing.

2.0 THE APPLICATION

Pursuant to Sections 64 and 104 of the Utilities Commission Act ("the Act"), on November 30, 1990, PNG submitted an Application (Exhibit 1) for an interim refundable rate increase, effective January 1, 1991, to be confirmed after a public hearing.

In the Application, the Company proposed to continue the flow-through method of income tax accounting for 1991, but gave notice that it would seek Commission approval to revert to deferred tax accounting sometime after the 1991 test year. PNG cited the following factors for the Company's estimated $3.16 million revenue deficiency for the 1991 test year: the full impact of the $7.4 million of capital additions constructed in 1990, a 6 percent increase in salary and wages, significant operating and maintenance (O & M) expense increases, and reduced sales to the Skeena Cellulose and Eurocan pulp mills. Further quantification of the above is contained in Exhibit 4, Tab 2, page 24.

Concurrent with the increase, the Company applied to refund to customers approximately $600,000 of the interruptible revenue credits received from Westcoast since January, 1989. At the same time, PNG requested permission to collect from customers approximately $386,000 for the deferral of changes in Westcoast's tolls between November, 1989 and January, 1990.

PNG requested a rate of return on common equity of 15.25 percent for the test year 1991, an increase from the current rate of return on equity of 15 percent approved in the 1985 Decision. The request was supported by the evidence of its rate of return witness (Exhibit 2) which was filed on December 21, 1990 as was the evidence of the Company's other witnesses (Exhibit 3).

The overall rate increase requested was 4.572 percent or 9.18 cents per GJ, before adjustments for Westcoast interruptible credits and toll deferrals. However, PNG applied to implement the interim rate increase on a customer class specific basis in accord with the recommendations the Company had made in the Rate Design Application filed in 1990.

As a result of this Application, by Order No. G-1-91 dated January 8, 1991, the Commission approved an across-the-board interim increase of 4.572 percent in the rates to PNG customers, effective January 1, 1991. Order No. G-2-91 was issued on January 14, 1991 setting down the Application for a public hearing commencing on March 18, 1991 in Prince Rupert.

A summary of PNG's requests in the Application (Exhibit 1) for Commission approval is as follows:

1. Rate increase of $3.16 million based on a rate of return on common equity of 15.25 percent (amended to $2.891 million - Exhibit 49).

2. Credit to customers from Westcoast Interruptible Revenue Credits - $600,000.

3. Recovery of Westcoast Demand tolls from November, 1989 to January, 1990 - $386,000.

4. Amortization of 1990 rate design and 1991 rate hearing costs.

5. Continuation of the treatment for unaccounted for gas as directed in the 1986 Decision.

6. Creation of an interest deferral account to record differences from the estimated rate of 10.6 percent for short-term debt for the 1991 test year (amended to 9.9 percent - Exhibit 49).

7. Creation of a deferral account to record variances from the forecast of large industrial interruptible sales.

8. Recovery of Vancouver Island Natural Gas Pipeline hearing costs (withdrawn by letter of February 15, 1991).

3.0 ISSUES

3.1 Rate Base

The rate base of the Applicant increased 40 percent from $87 million for the 1985 test year to $122 million for the 1991 test year. This reflects an approximate 43 percent increase in gross plant made up primarily of normal plant and extensions, in addition to major line replacement and looping projects for the purpose of reinforcing the security of supply.

3.1.1 Plant Additions

In 1991 PNG made capital budget provisions of $7.4 million including $2.2 million of capitalized overhead (Exhibit 1, Tab 3, page 1). Special projects include $560,000 for a new Kitimat River crossing, $1,034,000 to replace pipe in the Copper River area, $683,000 for corrosion repairs and $560,000 for work at Compressor Station R3 (Exhibit 4, Tab 2, page 54). In an amendment filed at the commencement of the hearing (Exhibit 6), the Company deleted the Copper River replacement and stated that it was pursuing discussions with Ocelot for a major expansion which could result in a 24-mile by-pass route through the Williams Creek area by a new 12-inch line. This line would avoid the Copper River Valley (T. 65).

While the Company wishes to keep open the Copper River Valley option, the Commission has serious concern as to the need for and cost effectiveness of replacing the line in order to obtain small increments of capacity (T. 66). The Commission notes that the Applicant identified certain difficulties with respect to accessibility, federal and provincial fisheries concerns, and that the removal of this section has had little effect on the capacity of the transmission line (Exhibit 4, Tab 2, page 57). Therefore the Commission directs that PNG apply for approval pursuant to Section 51.3 of the Act before budgeting this line replacement again.

3.1.2 Overhead Allocation

The Company has maintained the same overhead policy since its inception some 20 years ago. The Company witness indicated that it had included a review of overhead policy as part of its 5-year plan (T. 274-275). Since overhead allocation is not an exact science, periodic review of policy, particularly overhead policy, is prudent. Sound judgement and consistency must be exercised to ensure proper allocation of overhead to capital projects. The Commission's major concern at this time is with the total costs incurred as compared with prior years.

While the witnesses stated that the Company's overhead was constant and had little volatility over time, Exhibit 18 shows that O & M costs transferred to capital in 1990 and 1991 increased significantly over the preceding three years. In addition, another major component of capitalized overhead, unallocated construction costs, is forecast to increase significantly from $519,000 in 1990 to $801,000 for the 1991 test year (Exhibit 5, Tab 3, page 11).

The Commission knows that overhead is mostly fixed in the short run and must be allocated to capital projects regardless of the level of activities. Although Exhibit 26 was prepared to explain the difference between the two years, the Commission is convinced that PNG's overhead in the 1991 test year is excessive. This is evident in the manpower increases and the activities undertaken by PNG on behalf of Centra Gas British Columbia Inc. ("Centra Gas") since 1990 (T. 108 and 176)[*]. Although the Company's own construction activities and Centra Gas involvements have been reduced in 1991, the same level of overhead still has to be incurred. While the Company has found other projects for the Engineering Department such as preparing a five-year plan, engineering surveys (T. 59) and catching up on drafting (T. 109-110), the Commission considers that these are project oriented activities. As a result, a general reduction of $300,000 in capitalized overhead is adjusted for the 1991 test year. If the Company is incurring costs for preliminary engineering studies such as the Ocelot expansion project, it should apply for Commission approval to include these costs for future capitalization.

* Intercompany charges are further dealt with in Section 3.4.6.

3.1.3 Plant Additions Expensed for Tax Purposes

PNG has been capitalizing certain repair and replacement costs for regulatory purposes but expensing these amounts for income tax purposes (Exhibit 5, Tab 3, page 4). As a result, over the past five years the shareholders have benefitted from tax savings in excess of $750,000 (T. 243). However, this practice reduces the Capital Cost Allowance ("CCA") available for PNG's actual income tax calculations, since under flow-through income tax accounting, the income tax provision will be greater due to a smaller CCA.

* *Intercompany charges are further dealt with in Section 3.4.6.*

This results in a risk or liability to both customers and future shareholders, who may have to repay a tax benefit enjoyed by current shareholders (T. 114-138).

PNG raised a concern that pursuant to the Income Tax rules a tax reassessment of the repair write-offs for the previous four years could be made. Therefore, the utility has proposed a deferral account to absorb any tax reassessment retroactive to 1986. The Company believes that the tax savings resulting from the repair cost write-offs have been effectively passed back to customers due to the writing-off of certain deferral accounts during the period (T. 241-244).

Since the forecast made by the Company in the tax calculation for regulatory purposes has been substantially below the actual amounts claimed (T. 292), the Commission has no objection to the utility continuing to claim the maximum allowable tax savings as long as it is for the benefit of the customers. Therefore a deferral account is approved to account for the actual tax savings and any reassessment risk starting in the 1991 test year. Although the tax savings arising from prior year write-offs may have been passed back to the customers to some extent, the tax treatment was entirely at PNG's discretion. Since the shareholders benefitted from the higher average earnings they should assume the tax reassessment risk from write-offs prior to 1991.

A similar problem exists for capitalized overhead forecast to be expensed for tax purposes (T. 140). The Commission believes that a deferral account should be set up to accumulate the difference between forecast and actual overhead expensed for tax purposes.

3.1.4 Insurance Proceeds from Line-Break Loss

The Company proposed (T. 144) that insurance proceeds pertaining to the 1987 line-break should be credited to the 1991 beginning balance and amortized over ten years. It appears that there are six years remaining for the original line-break amortization to be complete. Therefore the Commission considers it appropriate to write-off the insurance credit with the remaining amortization.

3.1.5 Water Heater and NGV Grants

In 1986 the Commission approved applications by the Company to provide grants to customers for hot water heaters and natural gas vehicle ("NGV") conversions. The method of accounting is the net marginal method with the income tax credit recorded as an offset to rate base (Exhibit 22, Order No. G-15-86). The intent was to reduce the rate base impact when PNG was on deferred income tax accounting. Subsequently, at its own request, PNG adopted flow-through income tax accounting in order to assist Ocelot (Exhibits 11 and 12). The Company found it appropriate to continue the deferral tax calculation for the above grants, otherwise the credit would also be directed to reduce income tax (T. 200). The Commission agrees that the calculations, as demonstrated in Exhibits 25A and 25B, would not increase the customer costs related to the conversion grants (T. 201). However, tax savings can be realized if the grants are treated on a gross basis as suggested by counsel for the industrial customers (T. 745).

Since the Company is currently on flow-through income tax accounting and intends to make an application on this issue sometime after the 1991 test year, the Commission will allow the existing method to continue until a decision has been issued on the above application. Meanwhile, the Company is to reflect the deferred tax as no-cost capital in the capital structure. It is expected that in future the utility will inform the Commission of any inconsistency between a particular Order and a general policy change, so that some timely technical clarifications can be made (T. 22).

3.1.6 Hearing Costs

PNG applied to amortize the rate design hearing costs over three years (T. 145). The Commission considers that a five-year period more appropriately reflects the extent of the rate design benefits and has adjusted the amortization accordingly.

With regard to the recovery of the costs of the Applicant and of the Commission in revenue requirement proceedings, the Commission will consider the allocation of those costs between the customers and shareholders. One such method, which has been adopted by the Commission in some proceedings, is to permit the Applicant to recover the percentage of its costs in relation to what was sought and what was granted in the revenue deficiency. The Commission will seek suggestion from all interested parties in the next proceeding.

In this proceeding, even though there is a significant difference between what was sought and what is granted, the Commission will direct the Applicant to write off its cost incurred inclusive of Commission costs over two years commencing in 1991. The Commission notes that due to the expeditious hearing the costs declined by approximately 54 percent to approximately $116,000 from those initially forecast ($250,000).

3.1.7 Depreciation Rate for Computer Equipment

In recognition of the useful life of computer equipment (Exhibit 5, Tab 3, page 5), the Commission approves the increase in the depreciation rate from 5 percent to 20 percent as proposed by the Company.

3.2 Sales and Revenue

3.2.1 Sales

The Company estimates that 70 percent of gas consumption by residential and commercial customers is temperature sensitive. The Company has developed an estimate of usage per customer by averaging the results of degree day patterns for a 5-year and 25-year period to recognize current conservation efforts and warmer weather trends, as opposed to the previous methodology which used 25-year degree days. This adjustment to the normalization process can have ongoing impacts and will be reviewed again in the next revenue requirement hearing. In addition, the Company updated its forecast in Exhibit 6 to reflect certain errors on unbilled revenues.

For small industrial sales, the Company provided its actual results as compared with projections made by these customers (Exhibit 4, Tab 2, page 67). Although customer projections for several years have been lower on average than actual results by approximately 3 percent, PNG's 1991 forecast is approximately 6 percent lower than customer projections. The Commission accepts the utility's explanation that this reflects the difficulty of forecasting and makes no adjustment to sales volumes (T. 315).

PNG declined to provide the specific sales projections made by large industrial customers as this was considered by those customers to be confidential information. However, a comparison of PNG's own individual customer forecasts with actual sales since 1985, as provided under Exhibit 4, Tab 2, page 65, shows that the utility has been 1.85 percent too low in forecasting Ocelot sales and approximately 2 percent too low for industrial sales in total. PNG made further adjustment to Ocelot sales, as shown on Exhibit 6, to reflect the reduced operating level anticipated during the 1991 test year from 62 MMcf per day to

59 MMcf per day. The Company further indicated that Ocelot would move ahead its three week planned shutdown to the fall of 1991 and hence would lower its forecast gas sales by 1.3 PJ (T. 510). Since the large industrial customers were active participants in the hearing and did not question the PNG forecasts, the Commission accepts the Company's forecast. However, since small variations in sales can lead to magnified impacts on equity returns, the Commission will expect PNG to provide more detailed forecasts in future hearings.

3.2.2 Westcoast Interruptible Credits and Tolls

PNG had previously received Commission approval to defer the refund and recovery relating to Westcoast interruptible credits and tolls (Exhibit 1, Application, page 5). The net credit of approximately $214,000 is proposed to be refunded to the customers based on class load factors. While this request was not approved along with the interim increase on Order No. G-1-91, the refunds will be made as a one-time credit to the customer classes.

3.2.3 Large Industrial Interruptible Sales Deferral Account

PNG has requested Commission approval to establish a deferral account for 1991 into which will be accrued variations between actual and forecast levels of industrial interruptible sales revenue (Exhibit 3, Tab 1, page 9). The utility stated that its business risk had increased due to higher income exposure on sales. As evidence, the Company noted that the 1991 forecast load factor of 123 percent for industrial sales is significantly higher than the 93 percent forecast for the 1985 test year. The granting of a deferral account for industrial interruptible sales will reduce PNG's sales exposure on common equity from 8.1 percent to 5.5 percent (T. 329 and see Section 3.6.2).

The Applicant agreed that the probability of firm sales loss is remote (T. 297). Also, an analysis of the sales over the last three years indicates that actual industrial sales have on average come very close (within 5 percent) to forecast levels (Exhibit 4, Tab 2, page 65). The Commission is concerned about the potential disincentive caused by the guarantee implicit in a deferral account (T. 329) and the removal of a key element of management responsibility, i.e. forecasting. Despite having considered the industrial intervenors' submission that they "support the use of deferral accounts wherever a significant forecasting risk exists." (T. 743), the Commission is still reluctant to set up a deferral account for items over which a utility has some element of control. However, the

Commission is cognizant that for 1991 there is increased interruptible sales uncertainty due to the planned shutdown of Ocelot, which has been moved ahead to 1991 without a concomitant reduction in PNG's sales forecast, and the recent order by the Commission that the Applicant negotiate large industrial interruptible rates based on value of service. On the other hand, it should be recognized that in a situation in which cold weather leads to higher firm heating consumption, interruptible gas sales could decrease due to curtailment without adversely affecting the finances of the utility. In fact, utility profit could rise, assuming no additional costs were incurred, although the drop in interruptible sales would still allow the utility to receive deferral account relief. The Commission determines that a deferral account is not required at least until July 1, 1991 when PNG files the new rate structures. At that time, the Commission will receive submissions and, if required, will determine the operative conditions of a deferral account.

3.2.4 Other Income

The Application presented Other Income on a net basis by removing it from the income statement, and the related financing from the capital structure. In Exhibit 49, the Company re-established this income on a gross basis by reporting Other Income as other utility revenue, including the related principal amount in rate base and in the capital structure. The Commission concurs with the gross method for ease of reconciliation (T. 498).

3.3 Gas Purchases

The Commission is satisfied that the evidence indicates that PNG has used its best efforts in the contract demand nomination with Westcoast (T. 220-223). The Commission is further satisfied that the Company will endeavour to purchase as much low cost gas as it can. Starting in November, 1991, the Company has the opportunity to purchase 25 percent of its gas requirement from sources other than CanWest Gas Supply Inc. (the successor of B.C. Petroleum Corporation) if this would be advantageous. PNG's contract gas supply with CanWest expires in 2002 (T. 180).

3.4 Operating Costs

An analysis of the Application (Exhibit 1, Tab 11, page 1) indicates that for the 1991 test year the Company forecasts a significant increase of 22 percent in O & M costs. This is accounted for by a 17.5 percent wage and benefits increase and a 29 percent increase in other O & M costs. PNG cited the reasons for the increases as being a 6 percent wage award, a 5 percent general price escalation, lower overhead transferred to capital, more meter removals and repairs, additional personnel, and significant pipeline maintenance costs due to corrosion problems.

3.4.1 Unit Measurement

The Commission recognizes that the cost of doing business is becoming more expensive due to price level increases, but at the same time expects some economies of scale in view of the continuing growth of the utility (T. 153-154). As demonstrated under the two fundamental measurements of O & M efficiency (Exhibit 4, Tab 2, page 16), O & M cost per GJ sold shows an increase from $0.1508 for 1985 to $0.2114 for 1991; and O & M cost per customer shows an increase from $380 for 1985 to $473 for 1991. The percentage changes for the above measurements from 1990 to 1991 are 26.2 percent and 17.6 percent respectively.

As inflation has not been taken into account for the changes from 1985 to 1991, it is difficult to determine what economies of scale should have been achieved without the benefit of some comparison to other utilities of similar size and customer mix. However, the forecast changes of 1991 over 1990 appear excessive. Some of the factors affecting the increases are discussed below.

3.4.2 Corrosion Repair Costs

The Applicant itemized the additional budgeted 1991 corrosion repair and investigation costs at approximately $647,000, which its witness stated were extraordinary even though they may be recurring in future (T. 54). Since PNG has indicated in its five-year plan that it would apply for a rate increase in each of the next five years (T. 283), the Commission directs the utility to treat the $647,000 as abnormal costs for amortization over ten years, similar to the treatment of line-break costs. In the next rate case, the utility will have an opportunity to re-examine whether these types of costs are recurring.

3.4.3 Compressor Overhaul Costs

PNG included $200,000 to overhaul a compressor at Station R3 (T. 55-56). The Commission agrees with the Applicant that such costs recur at three to four year intervals for the life of a compressor. Since the Company has six units in total, it is reasonable to expect some maintenance provision each year despite the fact that no turbine overhauls were carried out in 1990. Accordingly, an allowance of $200,000 is approved.

3.4.4 Meter Removals and Repairs

The Company testified that 1989 and 1990 were abnormal years with only a small number of meters removed and repaired. To offset the low rate of meter removals in the previous two years, the Company has apparently made provision for a worst-case scenario in 1991 (T. 44-50). Instead of forecasting a normal 30 percent repair rate for meters tested, PNG forecasts that 50 percent will be repaired. The Commission therefore directs that $50,000 should be removed from the Company's cost of service. However, if the actual meter removal and repair costs in total are above $150,000, the Company may apply for approval to recover such extra costs.

3.4.5 Manpower

A general discussion of the PNG manpower requirement (T. 155-166) together with the statistics contained on Exhibit 4, Tab 2, page 11 shows that the number of employees has increased significantly from 85 in 1989 to 94 in 1990 and 97 in 1991. In addition, the average remuneration, particularly in the administration departments, has increased at greater than the inflation rate. The Commission notes that 1990 was a busy year for the utility. PNG undertook a high level of capital activity in addition to its participation in the distribution planning and design associated with the Vancouver Island Natural Gas Pipeline system through its affiliate, Centra Gas. The Commission is concerned that such manpower build-up may not be entirely used to serve the needs of the PNG customers. This will be reviewed again in the next proceeding.

3.4.6 Inter-Company Services

As shown on Exhibit 4, Tab 2, page 42, PNG has been paying its parent, Westcoast, a fee of approximately $29,000 per month for services provided over the last five years. Meanwhile, the Company has been setting up its own services such as payroll and billing in an apparent attempt to move away from a reliance on Westcoast. The Commission is satisfied that the 1991-1992 costs at $27,723 per month have been reviewed and adjusted properly by PNG (T. 214-215), and expects the utility to continue the review, particularly in light of the dramatic manpower increase. As a result, PNG may not require the same level of Westcoast services in future.

PNG also has a service agreement with Centra Gas (Exhibit 4, Tab 2, page 43). This agreement covers the provision of PNG's manpower and services to Centra Gas at cost. During 1990, PNG was reimbursed $310,000 by Centra Gas, and expects to recover a further $250,000 in the 1991 test year. The Company witness stated that a normal mark-up on such services would be 10 to 15 percent (T. 38).

The Company has loaned Centra Gas some of its employees, in particular, its President, Mr. R.F. O'Shaughnessy and Vice President, Operations, Mr. J. Kreut. Mr. Kreut has since begun to work for Centra Gas permanently, as have some other employees. Mr. O'Shaughnessy spends 50 percent of his time on Centra Gas related tasks. Although the Company's policy witness, Mr. Dyce, stated that there was no loss of efficiency (T. 42), PNG's involvement in Centra Gas appears to relate directly to PNG's manpower increases since 1990. Furthermore, new and less experienced employees can cause added hiring, relocation, and training costs in addition to a loss of value until such employees reach full effectiveness. Therefore, for revenue requirement purposes, the Commission finds it reasonable that PNG, by virtue of its non-arms-length relationship, is deemed to have charged Centra Gas a further $58,000, being $38,000 (approximately 15 percent of the $250,000 currently expected to be recovered), and $20,000 for all of its recruiting and relocation costs.

3.5 Other Issues

3.5.1 Large Corporation Tax and Credit

Although the financial impact could be insignificant the Commission agrees with counsel for the industrial customers, that PNG should make provision for its allocated exemption in the calculating of the Large Corporation Tax and income tax investment allowance under Section 181.2(4) of the Income Tax Act (T. 13-14).

3.5.2 Availability of Information

Counsel for the large industrial customers suggested that there should be a mechanism allowing the public to inspect correspondence between the utilities and the Commission (T. 284-289). The Commission library has always been a source for information on utilities in its jurisdiction and contains the gas utility Annual Reports to the Commission which are public documents. The Commission believes that any interested party requiring information should obtain it through specific requests to the utility or the Commission rather than through a regular information distribution on all matters. Since this issue raises a general Commission policy matter, the large industrial customers should make a direct submission to the Commission if they have specific views on this matter.

3.5.3 Test Year

Discussion was held regarding the possibility of a two-year test period (T. 325-328). In view of PNG's five-year plan (Exhibit 4, Tab 2, page 36) which indicates that it will apply for rate increases in each of the next five years, the Commission is concerned about the amount of effort and hearings costs to be incurred. PNG should examine alternatives to handle its revenue requirement more efficiently and report the results to the Commission.

3.5.4 Demand-Side Management ("DSM")

The evidence in the hearing (T. 371-378) indicates that PNG is not a leader in the program but intends to keep abreast with and get involved with programs carried on by other utilities. Although the Company does not have to be a leader in this field, it should as a minimum, inject the DSM concept into its planning process by emphasizing the need to examine DSM alternatives before new facilities are added.

3.6 Rate of Return on Equity

3.6.1 Introduction

As a result of the 1986 Revenue Requirements Decision, PNG was allowed the opportunity to earn a rate of return of approximately 15.0 percent within a range of 14.75 percent to 15.25 percent on a common equity component of approximately 27 percent of the capital structure. Over the past five years, PNG's normalized rates of return on equity have been as appears in the following table:

Normalized Rate of Return on Common Equity

1986	14.26%
1987	15.38%
1988	16.08%
1989	15.44%
1990	15.56%

(Exhibit 38A)

In the current Application, PNG has requested a rate of return of 15.25 percent on a common equity component of 31.18 percent of the capital structure. This Application is supported by Ms. Kathleen McShane, an expert witness. Her recommendation was based on an assessment of the business and financial risks faced by the utility.

The Application was opposed by the large industrial customers whose own rate of return witness, Dr. William Waters, provided evidence indicating that the appropriate return on equity was in the range of 13.25 percent to 13.75 percent on the same common equity component.

Both of these experts are eminently qualified to give opinion evidence and both were of much assistance to the Commission in evaluating the complex topic of rate of return on equity.

3.6.2 Riskiness of PNG

Position of PNG

The recommendations put forth by the utility and by the large industrial customers were consistent with their respective views concerning the riskiness of PNG.

The Company's witness, Ms. McShane, testified that PNG faces four key business risks. These are:

(i) Cost Forecasting risks;
(ii) Market Demand risks;
(iii) Physical and Gas Supply Risks; and
(iv) Regulatory Risks.

Cost forecasting risks arise from unanticipated changes in costs. Ms. McShane testified that PNG's major risk with respect to costs arises from its plans to fund $21.3 million through short-term debt at an estimated cost of 9.9 percent, with deviations from the forecast level of short-term debt accrued into a deferral account. PNG is currently unable to issue long-term debt as it has not met the 2.0 times interest coverage required by its debt covenants. Ms. McShane stated that PNG's inability to meet the times interest coverage provisions of its debt covenants is a result of the suspension of deferred income tax collection.

Ms. McShane testified that PNG's primary market risk arises from the high concentration of sales (92 percent) to a small number of industrial customers who operate chiefly in cyclical industries. The situation is exacerbated by the fact that one customer, Ocelot, is expected to take 67 percent of total system volumes in 1991 through a combination of firm sales volumes, firm service volumes and interruptible sales. As discussed in Section 3.2.3, PNG proposes to mitigate the risks associated with interruptible sales through the use of a deferral account into which variations from the projected levels of industrial interruptible volumes would be placed.

Ms. McShane stated that PNG's market and demand risks were further exacerbated by the suspension of deferred income tax collection, which has increased the risk that the large industrial customers, and in particular Ocelot, may not pay a fair share of PNG's total future tax liability.

With respect to physical and gas supply risks, the witness testified that PNG faces higher risk than other gas distributors due to the difficult nature of the terrain covered by the line. In addition, she stated that the movement towards unbundling natural gas service rates and direct natural gas sales has further increased the utility's risk.

Ms. McShane testified that the regulatory risk faced by PNG is minimal.

In addition to the business risks discussed above, the witness also examined PNG's financial risk. Based on an examination of PNG's capital structure and times interest coverage, Ms. McShane testified that PNG faces greater financial risk than other Canadian utilities. PNG's capital structure, net of deferred taxes, is comprised 60 percent of debt compared with an average utility structure of 52.6 percent debt. PNG's interest coverage is calculated at 1.92 times for 1990 and estimated at 2.11 times for 1991, (assuming a return on equity of 15.25 percent) compared with an average utility times interest coverage of 2.7 (Exhibit 2, Tab 1, pages 26 and 27). She testified that a 13.5 percent return on equity would be sufficient to generate a 2.0 times interest coverage (Exhibit 4, Tab 1, page 40).

Based on the above, Ms. McShane concludes that PNG's cost of equity capital is higher than that of the average high-grade Canadian utility. Using a discounted cash flow approach to estimate the implicit cost of capital for high-grade utilities and utilities similar in risk to PNG, she determines that a one percentage point differential in return on equity between PNG and high-grade Canadian utilities is appropriate and conservative.

Position of Large Industrial Customers

In his prepared testimony, Dr. Waters stated that the basic risk faced by PNG's investors was that operating income would not be sufficient to meet all of PNG's obligations, including the provision of a fair rate of return on equity. This would occur if rates were set at a level insufficient to cover all costs including a fair return to capital; if actual costs exceeded or revenues were less than those assumed in setting rates; or if PNG became unable to achieve rates that covered costs, suggesting a longer term problem (Exhibit 33, page 12).

Dr. Waters stated that PNG's exposure to regulatory risk was minimal since,

> "the BCUC's regulatory practices have evolved in ways which have kept the regulatory environment responsive to changes in economic conditions."
>
> (Exhibit 33, page 12)

In addition, Dr. Waters testified that PNG's cost forecasting and market demand risks were subject to significant offsets which reduced the risks borne by PNG's investors. These included the requested deferral accounts for interruptible sales and for short-term interest costs which effectively insulate PNG from the effects of variations in these items, and business interruption insurance which insulated PNG from the effects of a prolonged physical interruption in deliveries.

Further, Dr. Waters testified that PNG's past history with respect to achieving its allowed rate of return indicated that PNG was able to satisfactorily forecast its costs and revenues. In addition, if significant unanticipated costs were to occur, past history indicates that the Commission would be sympathetic to PNG and allow the creation of deferral accounts.

Dr. Waters stated that the only material source of risk to PNG's investors, was a permanent impairment of PNG's earning power resulting from the loss of the Ocelot load. However, the witness testified that in his view this risk was remote since,

> "Ocelot has long been aware that there are, for all practical purposes, no alternative uses for methanol and ammonia plants located in Kitimat, B.C. Accordingly, for decisions involving whether or not to operate the plants, the relevant costs are essentially the variable production costs. .... On the assumption that Ocelot can acquire natural gas feedstock at competitive prices and that gas transportation costs will not escalate substantially,Ocelot can reasonably expect to continue production for as long as the plants are operational."
>
> (Exhibit 33, page 17)

Further, the witness testified, that the risk associated with serving Ocelot was additionally reduced by the government guarantees associated with the first 80 percent of Ocelot's firm contract demand.

Nonetheless, Dr. Waters does agree that PNG is riskier than the average high-grade utility. Based on evidence contained in his risk premium test, (to be discussed below), the witness concludes that PNG's cost of equity capital is 60 to 80 basis points greater than that of the average high-grade utility.

3.6.3 Return on Equity ("ROE")

Company Evidence

The Company's estimate of the required ROE was made using three standard tests to determine the appropriate cost of equity capital. These were:

(i) the Comparable Earnings test;
(ii) the Discounted Cash Flow ("DCF") test; and
(iii) the Risk Premium test.

The first two methods calculate the ROE by reference to a selected group of non-regulated companies. The third method does not rely on reference groups.

The Company's sample consisted of 33 low risk industrial companies which were selected based on coefficients of variation for book and market returns, betas, and equity ratios. Together the beta and coefficient values measure the variability of returns and of stock prices which are suggestive of business risk while the equity ratios are indicators of financial risk. However, an assessment of the coefficients of variation for book and market returns and betas for both the sample and for high-grade utilities led Ms. McShane to conclude that the sample was riskier than average high-grade utilities. Using price/earnings ratios, dividend payout ratios and expected growth rates, the witness determined that the implicit cost of capital for high-grade utilities was approximately 50 basis points less than for the sample. Thus, the sample results of the Comparable Earnings and DCF tests were adjusted downward to reflect this result. However, since as indicated in Section 8.2.1, Ms. McShane found PNG's required cost of capital to be 100 basis points greater than that of average high-grade utilities, an upward adjustment of one percentage point was also made to the sample results. The net effect is to increase the sample results of the Comparable Earnings and DCF tests by 50 basis points.

The Comparable Earnings test measures the return on book equity achieved by low risk industrials over the selected time period. The DCF test estimates the prospective rate of return on market valued common equity for low risk industrials using a dividend yield plus growth model . The risk premium test estimates the necessary premium over and above the risk free interest rate, as measured by long-term government bonds, which must be paid by the utility to attract investors.

Since both the DCF and Risk Premium test measure return on a market rather than book basis, the initial results are considered a "bare-bones" cost of capital. This "bare-bones" cost of capital is then adjusted to provide financing flexibility for the utility which is assumed to occur when the utility has a market to book ratio of 115 percent. This results in an 130 basis points addition to the cost of equity.

Based on the three tests, the ROE for PNG was estimated by Ms. McShane as follows:

Comparable Earnings	14.8 percent
DCF	15.6
Risk Premium	15.6

Based on a 50 percent weighting for the Comparable Earnings test, a 20 percent weighting for the DCF test and a 30 percent weighting for the Risk Premium test, Ms. McShane concluded that the appropriate ROE for PNG is 15.25 percent.

Position of Large Industrial Customers

Unlike Ms. McShane, Dr. Waters did not utilize the Comparable Earnings test but relied solely on the DCF and Risk Premium tests to determine the appropriate rate of return on equity for the utility. In his prepared testimony, Dr. Waters stated that his concerns with respect to the Comparable Earnings test were that:

> "(i) the concept of comparable earnings does not necessarily have any relationship with the concept of a fair return:
>
> (ii) the measurement of comparable earnings (based on accounting data) provides results which are difficult to compare meaningfully across companies and across time."

(Exhibit 33, page 42)

With respect to accounting data, Dr. Waters stated,

> "I've had to deal in my own corporate context with a very prestigious firm of auditors who manage to get sued, like all the others, from time to time. But there is a particular desire on their part to make sure that whatever you

> want to present can be presented, if generally accepted accounting principles permit. And they seem to permit one heck of a lot."

(T. 580)

Dr. Waters' application of the DCF test resulted in a "bare bones" cost of capital of 12.0 percent, some 180 basis points less than Ms. McShane's estimate. He attributes this difference to differences in the sample selected (Ms. McShane's sample is riskier than his sample) and to differences in the estimates of growth. Since Dr. Waters finds that the risk of PNG is comparable to the risk of the sample he has selected, no adjustments to reflect the particular circumstances of PNG were undertaken.

With respect to the risk premium test, Dr. Waters estimated a "bare bones" cost of capital of 12.4 percent to 13.2 percent compared with Ms. McShane's "bare bones" cost of 14.3 percent. Since both witnesses used the same risk free government bond rate and had somewhat similar views as to the size of the equity market risk premium in total, the difference in results reflects primarily the difference in views with respect to the risk associated with PNG. This was confirmed by Dr. Waters (T. 678).

Based on these two tests, Dr. Waters concluded that the "bare bones" cost of capital for PNG is in the range of 12.75 percent to 13.25 percent. However in order to ensure that should the "bare bones" cost of capital change over the year, the allowed ROE would not become unfair to the Company, Dr. Waters adds a 50 basis points margin of safety. Amongst other items this margin is intended to allow the Company to raise new capital without diluting existing shareholder equity if the need should arise.

As a result, Dr. Waters final recommendation is that the appropriate ROE for PNG is 13.25 percent to 13.75 percent.

3.6.4 Capital Structure

As indicated in Section 3.6.2, PNG has not met the interest coverage ratio provisions of its long-term debt indentures. This means that PNG has relied on short-term debt financing for approximately $21 million or 17.26 percent of its capital structure. The Company estimates the cost of short-term debt at 9.9 percent and has asked the Commission to allow deviations from the estimated interest costs to be accrued in a deferral account. This would have the impact of insulating the Company from the risks associated with short-term interest rates.

Dr. Waters supported the use of a deferral account for fluctuations in short-term interest costs since it would allow PNG to:

> "essentially mirror the situation of funded debt and say whatever it was contracted for, that's what you will get compensated for."
>
> (T. 636)

In his prepared evidence, Dr. Waters suggested that it would be desirable to investigate the possibility of having PNG's times interest coverage provisions renegotiated to reflect an after-tax rather than pre-tax coverage ratio. However, neither of the expert witnesses were able to cite any utility indenture provisions which contained after-tax coverage provisions. Further, Ms. McShane testified that she would be "quite surprised" (T. 462) if such a change to PNG's indenture provisions could be negotiated.

Ms. McShane stated that the cost of issuing new long-term debt would likely be in the order of 11.8 percent (T. 461) while Dr. Waters indicated that the cost would likely be in the order of 11.6 percent (T. 644).

3.6.5 Non-Coat-Tailed Common Share

The Commission heard evidence presented by Mr. William Wheeler, of Leith Wheeler Investment Counsel Ltd., that there is a structural problem in the equity capital of PNG. The witness stated that the Class A (non-voting) shares were not subject to a coat-tailing provision which would guarantee that Class A shareholders would participate equally with Class B shareholders in any takeover bid for the control block. Accordingly a buyer might pay a very high price for the control block and the public would have no participation.

Mr. Wheeler testified:

> "The risk here to a public shareholder is that first of all he misses the opportunity to participate in the premium on the control block. But even more so, the person or the company that gains control may not be a suitable partner, and I think that risk has been driven home by events in the market in the last few years, and the public markets are now more aware of the risks of these non-voting or non-coat-tailed securities.

> There is more risk to these stocks and because there is a risk in them, there is going to be a cost to them"
>
> (T. 599)

Mr. Wheeler stated that as a result of the lack of coat-tail provisions, PNG would find it difficult to issue equity to the public and that it might fall from institutional investors' list of desirable stocks.

Mr. Wheeler testified:

> "In my evidence I show you a survey of my competitors in Vancouver and they are heavily biased against non-voting, non-coat-tailed stock and none of us will buy a new issue of non-voting, non-coat-tailed stock"
>
> (T. 602).

Mr. Wheeler stated that:

> "I think it is interesting to note that this stock peaked about the time of when the issue of non-voting and non-coat-tailed stocks rose in this country and since then it has been on a down trend and I can tell you this stock would have traded lower if it was not for our firm buying it and when I went to the investment committee to talk about that, the condition I agreed to was that if we bought the stock I would make every effort to get this company to coat-tail its stock, and that is why I am here today. If I can't do it we will be gone".
>
> (T. 608)

However, Mr. Wheeler agreed that from an overall investment perspective whatever you lose on PNG you make up on Westcoast.

In response to Mr. Wheeler's evidence, Ms. McShane stated that as long as the return on equity was set with respect to non-regulated industrial companies, the lack of a coat-tail would not inflate PNG's required ROE. In addition, PNG's counsel introduced evidence indicating that the original financing was contingent upon a two class share structure being implemented which would allow it to be operated in the fashion of a wholly-owned subsidiary. From the evidence given by Mr. Wheeler this structure would not have been a concern to financial markets at the time of issue.

3.6.6 Commission Conclusion

Capital Structure

It is normal regulatory practice to set the allowed revenue requirement at a level that recovers the full cost of debt, prudently acquired by the utility. Such practice reflects the fact that the cost of debt is generally outside the control of the utility and removes an element of financial risk that would otherwise be borne by the utility's shareholders.

Typically, substantially all of a utility's debt is long-term with a known and fixed interest rate so that the cost of debt is "locked in". In this particular case, PNG's inability to meet the times interest coverage provisions of its current long-term debt indenture provisions has meant that it has been forced to rely on short-term debt funding for over 17 percent of its capital structure. Since short-term interest rates tend to be variable, the actual future cost of this portion of PNG's debt load cannot be known with certainty. Without a deferral account, as proposed by PNG, its shareholders would be exposed to an element of risk from which they are more normally exempt. Depending on the level of the short-term interest rate forecast and the actual level of short-term rates that come to pass over the year, PNG's shareholders could become liable for debt costs intended to be borne by customers in the event rates are higher than expected, or alternatively, receive an unintended bonus if interest rates are lower than expected when the revenue requirement was set.

Therefore, the Commission orders PNG to establish a short-term interest rate deferral account into which deviations from forecasted short-term interest rate costs will be accrued.

The Commission appreciates the appearance of Mr. Wheeler on behalf of the certain Class A non-voting shareholders of PNG, but believes that it would be inappropriate to interfere in the competing legal rights between classes of existing shareholders. The Commission concurs with the evidence given in this regard by Ms. McShane with regards to the allowed return but recognizes that this particular share structure could depress the market to book ratio from that which it otherwise would be.

Rate of Return on Equity

In determining the appropriate rate of return on equity to be allowed PNG, the Commission assessed the business and financial risks faced by PNG and the impact of various rates on the times interest coverage ratio.

Based on the evidence presented directly and through cross-examination, the Commission believes that the business risk faced by PNG, while greater than that faced by average high-grade utilities, is nonetheless subject to a number of significant offsetting factors. These include minimum take provisions associated with firm contract demand by large industrial customers, government guarantees on the first 80 percent of Ocelot's firm sales volumes and business interruption insurance. Further, the Commission has shown itself to be favourably inclined to assist the utility in insulating it against risk through the use of deferral accounts, and pass-throughs for unanticipated and uncontrollable changes in costs.

With respect to financial risk, the Commission is not convinced that PNG's capital structure exposes it to greater risk than average high-grade utilities. Deferred taxes, which are a source of no cost capital, comprise approximately 12.65 percent of PNG's capital structure and do not expose the utility to financial risk. Similarly, capital contributed by the sale of preferred shares, which comprise 4.12 percent of PNG's capital structure, while imposing a cost on the utility, do not contribute to its financial risk. In addition, the Commission has alleviated the risk associated with short-term debt costs by ordering the implementation of a deferral account into which deviations from the forecast costs can be accrued.

Based on the considerations set out in Section 3.6 the Commission therefore finds that the appropriate rate of return on equity for PNG is 14 percent, within a range of 13.75 percent to 14.25 percent.

4.0 THE DECISION

Having taken into consideration all of the matters discussed and adjustments as set out in the Decision Schedules, the Commission determines that the 4.572 percent interim increase approved by Commission Order No. G-1-91 effective January 1, 1991 requires a downward revision. Based on a return on common equity of 14 percent, the Commission finds that PNG will require an annualized revenue requirement of approximately $66.86 million. A net revenue deficiency of approximately $1.135 million or 1.727 percent increase is required by PNG in the test year 1991 to enable it to earn a fair and reasonable return as determined by the Commission. A refund of approximately $1.756 million with interest is therefore required from January 1, 1991 to the effective date of the new tariff which is to be filed by PNG. Additionally, there will be a lump sum refund for the revenue credit resultant from the Westcoast credits discussed under Section 3.2.2 and the 1991 toll deferral approved by Order No. G-8-92.

PNG is to incorporate the above revenue requirement in the new rate schedules consistent with the directives contained in the Rate Design Decision on a timely basis prior to July 1, 1991 for the effective date of January 1, 1991. A reconciliation of the implementation of the new rates should also be provided.

In view of the setting up of several new deferral accounts, the monitoring and control of which are heavily dependent on forecasts of the Company, PNG is therefore directed to file, in the absence of a rate application, annual forecasts to the Commission at the minimum level of details as shown in Exhibit 5, Tab 3, I.R. 2(a), 30 days prior to the beginning of each fiscal year.

DATED at the City of Vancouver, in the Province of British Columbia, this day of April, 1991.

J.D.V. Newlands, Deputy Chairman

N. Martin, Commissioner

W.M. Swanson, Commissioner

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

and

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

DECISION

April 23, 1991

TABLE OF CONTENTS

APPEARANCES

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D. PERTULLA	BC Gas Inc.

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ALLWEST REPORTING LTD.	Court Reporters

LIST OF EXHIBITS

	Exhibit No.
Pacific Northern Gas Ltd. Application, December 1, 1990	1
Direct Testimony of Ms. McShane, December 21, 1990	2
Direct Testimony of Company Witnesses, December 21, 1990	3
Response to BCUC IRS 1 and 2 and Replacement Schedules 1 through 5, dated February 18, 1991	4
Response to Ocelot Chemicals IRS 1, 2 and 3 and BCUC IR Number 3, dated March 1, 1991	5
Summary of Amendments to December 1, 1990 Application	6
Executive Summary of Pacific Northern Gas, February 17, 1991	7
Interim Order No. G-1-91	8
Commission Hearing Order No. G-2-91	9
Affidavit of Marina Ireland	10
Order No. G-77-86 dated November 26, 1986	11
Order No. G-86-86 dated December 24, 1986	12
Letter of February 15, 1991	13
Pacific Northern Gas System Map	14
PNG System Map	14A
Formula regarding Construction Overheads	15
Pacific Northern Gas Facsimile Actual Revenues, Volumes and Customers for 1990	16
Graph and Data	17
Graph of Operating and Maintenance Expense	18
Page 8 of Commission Decision of August, 1983	19
Pages 6, 7, 8 and 9 from Commission Decision of January 29, 1986	20

LIST OF EXHIBITS
(cont'd)

LIST OF EXHIBITS
(cont'd)