BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

Pacific Northern Gas Ltd.

1998 REVENUE REQUIREMENTS APPLICATION

AND

1998 COST OF SERVICE ALLOCATION/ RATE DESIGN STUDY

DECISION

June 18, 1998

Before:

Peter Ostergaard, Chair
Frank C. Leighton, P.Eng., Commissioner
Paul G. Bradley, Commissioner

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EXECUTIVE SUMMARY

On November 28, 1997, Pacific Northern Gas Ltd. ("PNG") filed a 1998-2002 Performance Based Rates Revenue Requirements Application for Commission approval to increase its gas rates on an interim and final basis, effective January 1, 1998, and to implement a Performance Based Rates proposal for the 1999-2002 fiscal periods. On the same date, PNG also filed a 1998 Cost of Service Allocation/Rate Design Study. PNG requested that the Application be dealt with through the Alternative Dispute Resolution process as set out by the Commission.

The parties to the negotiation process were unable to reach a settlement. Accordingly, the Commission issued Order No. G-18-98 setting down a public hearing to commence March 30, 1998 in Prince Rupert for one day and to continue in Vancouver for the duration of the proceeding. On March 16, 1998, PNG filed a revision which withdrew the Performance Based Rates section of the Application and reduced it to a single year (1998) Application.

Revenue Requirements

The revised Application forecasts a revenue deficiency of $3.731 million for 1998, based upon a return on common equity of 10.75 percent and a common equity component of 38.21 percent.

The Commission has determined that the requested expenditures for Operations, Maintenance, Administration and General expenses are approved with the following exceptions. Donation expense is to be allowed at $20,750, and there is to be no recovery from ratepayers of the $92,000 budgeted for outside human resource consultants. Labour expenditures are approved; however, the Commission finds that the various increases in incentives and allowances for matters such as employee education may be becoming excessive and will be closely reviewed in future applications. The Commission accepts the changes in overhead policy, recording of supervisory costs and recording of C-Scan and pigging costs as proposed by PNG in the Application.

The Commission accepts that the capital expenditures that PNG proposes for 1998 are necessary to the maintenance of its system, and that, with the Skeena crossing successfully completed, there are no major issues related to the cost estimates. In this circumstance, there is no need for PNG to file an application for a Certificate of Public Convenience and Necessity for these projects.

PNG also requested approval for two new deferral accounts, a Year 2000 Compliance Deferral Account and a Skeena 1998 Gas Requirements Deferral Account. Both of these requests are denied. The Commission has determined that the year 2000 Compliance issue has been well known for several years and is a management problem that should have been dealt with over the years as part of the Company's ongoing obligation to provide safe and reliable service. In regards to the Skeena 1998 Gas Requirements Deferral Account, the Commission finds that the current situation does not warrant special treatment. The threat that Skeena may buy less gas than forecasted in 1998 because of vagaries in pulp markets and fibre supplies appears to the Commission to be a sales forecast and business risk that PNG assumes with any of its customers. If during the course of the year, the situation changes and PNG is facing an extreme circumstance, such as closure of the Skeena mill or bankruptcy protection, it may approach the Commission at that time for mitigation through a deferral account.

The Commission does approve the requested recovery of the 1997 Skeena Deferral Account over a three year period.

Finally, the Commission reviewed the sales forecast in the Application and, recognizing the denial of the Skeena 1998 Gas Requirements Deferral Account, the Commission has determined that the 1998 forecast of gas deliveries by PNG is to be adjusted upwards by 416,565 GJ. PNG is to adjust its compressor fuel gas estimate to account for the change in Skeena's Demand Forecast.

With respect to the issue of the capital structure, the Commission finds the appropriate equity component for the determination of rates is the actual equity component of PNG subject to a ceiling of 36 percent. Accordingly, for 1998, the Commission directs that the rates be determined based on an equity component of 36 percent. Further, the Commission directs PNG to provide to the Commission in December of each year, a forecast of its actual equity component for the upcoming year. When this forecast is 36 percent or less, this forecast will be used in conjunction with the automatic rate of return on equity adjustment mechanism to establish new rates for service. When this forecast exceeds 36 percent, an equity component of 36 percent will be deemed for the purposes of establishing rates. Any equity in excess of 36 percent will attract the short-term debt rate.

With respect to the retention of the preferred shares in the capital structure, the Commission expects PNG to redeem the preferred shares in a timely manner. The costs of the redemption may be carried forward to the next revenue requirement proceeding.

Cost of Service Allocation/Rate Design Study

With respect to the issues regarding the Fully Allocated Cost of Service study, the Commission has determined that certain refinements are desirable and should be incorporated into the next Fully Allocated Cost of Service study. These refinements are outlined in detail in the Decision. Nonetheless, the Commission finds that the current Fully Allocated Cost of Service study is of sufficient quality to allow the Commission to reach the view that for certain customer classes the revenue to cost ratios fall well outside the 0.90 to 1.10 range which has been used as a guide to the reasonableness of rates in other Decisions.

As a result, the Commission finds that for 1998, the increases to the revenue requirement for residential sales, commercial sales, small industrial sales and small industrial transportation service customers are approved. The proposed decreases to the revenue requirement for large industrial firm service are also approved, subject to the determinations made with respect to interruptible service as set out below. All rate design changes are effective July 1, 1998, with the increased or decreased revenues prorated to reflect the fact that the changes come into effect midway through the year.

In addition, the Commission invites PNG to apply for further inter-class shifts in revenue for 1999 and 2000 in line with the direction indicated in the Fully Allocated Cost of Service study submitted as part of this Application. However, such changes, when combined with revenue requirement increases associated with transportation and with changes in gas supply costs, should not result in an increase in the total revenue requirement of the class, including gas costs, of more than 10 percent. As part of such an application for an increase, the Commission will require an estimate of the impact such changes will have on the revenue to cost ratios of the classes for which changes are proposed. A new Fully Allocated Cost of Service study will not be required.

With respect to the proposed unbundling of rates and the increase in the basic charges, the Commission approves the changes as shown in PNG's Application.

The Commission does not approve the proposal to decrease interruptible transportation service rates to Eurocan, Alcan and Skeena. The Commission recognizes that in not approving the proposed rate decreases to the three large interruptible customers, PNG will obtain more revenue than anticipated in the Application. Accordingly, PNG is directed to estimate the extra revenues and to use this excess to reduce firm rates to the large industrial customers. The Commission is also concerned that the interruptible rate to Methanex may be set too low and this matter should be considered in future rate designs.

The 1998 Fully Allocated Cost of Service study also contains a plan to resell on-system interruptible gas to PNG's industrial customers at market-based prices rather than at the weighted average commodity cost of gas. The scheme proposed by PNG to set the rate for the on-system re-sale of interruptible gas was challenged by the Consumers' Association of Canada, B.C. Branch et al. as being contrary to the Utilities Commission Act, specifically Sections 61(3) and 63.

The Commission concludes that it has the jurisdiction to approve a rate formula which references market-based pricing indices, provided the Commission is of the view that the resulting price paid by the consumer can be ascertained in advance with reasonable certainty, and the pricing formula is non-discriminatory, fair, just and reasonable.

Based on the evidence before it, the Commission concludes that this market-based methodology will recover the maximum benefit from the sale of valley gas for core customers without imposing inappropriate costs on other customers. The Commission directs that, commencing the beginning of the month following the release of this Decision, PNG will price interruptible gas sold to on-system industrial customers according to the market-based formula it has proposed, and will use $0.02/GJ for both the discount off the published Station 2 daily price and the premium over the weighted average commodity cost of gas.

In the 1998 Cost of Service Allocation/Rate Design Study, PNG outlined its proposed gas cost allocation methodology. The methodology was discussed by representatives of PNG, the Consumers Association of Canada (B.C. Branch) et al., and Commission staff prior the hearing as part of the ADR process. On April 1, 1998 PNG filed its more detailed Allocation of Forecast 1998 Gas Supply Costs. As detailed in Section 9 of the Decision, the Commission is of the view that PNG's gas cost allocation methodology generally provides a reasonable balance of fairness and ease of administration. However, one area of concern is the use of volumetric peak day demand to allocate demand charges among divisions. The Commission approves PNG's gas cost allocation methodology, but directs PNG to recalculate its Pooled Demand Charge Allocation Factors for 1998 on the basis of the peak day energy demand of each division. Further, PNG is directed to review its gas cost allocation for consistency with the foregoing discussion, and to file gas costs for all classes for 1998 for Commission approval. Finally, the Commission approves the continuation of a gas supply cost deferral account for each division of PNG and its subsidiaries, and directs that rates in all divisions will become interim at the start of each calendar year, pending the approval of the applicable gas cost rate riders.

1.0 INTRODUCTION

Pacific Northern Gas Ltd. ("PNG", the "Utility", the "Company") is a natural gas utility serving more than 26,000 residential, commercial and industrial customers in west-central B.C. Westcoast Energy Inc. ("WEI") owns approximately 42 percent of the common equity of PNG and all of the voting shares. PNG's system connects to WEI's transmission system near Summit Lake, B.C. and extends approximately 588 kilometers west to Prince Rupert.

On November 28, 1997, pursuant to Sections 58 and 91 of the Utilities Commission Act (the "Act"), PNG filed a 1998-2002 Performance Based Rates ("PBR") Revenue Requirements Application (the "Application") for British Columbia Utilities Commission (the "Commission", "BCUC") approval to increase its gas rates on an interim and final basis, effective January 1, 1998, and to implement a PBR proposal for the 1999-2002 fiscal periods. On the same date, PNG also filed a 1998 Cost of Service Allocation/Rate Design Study (the "Study"). PNG requested that the Application be the dealt with through the Alternative Dispute Resolution ("ADR") process as set out by the Commission.

The Commission approved, by Order No. G-124-97, an interim rate increase effective January 1, 1998, and set down a regulatory agenda that included a pre-hearing conference and an ADR process to commence on February 17, 1998.

The parties to the ADR process were unable to reach a settlement. Accordingly, the Commission issued Order No. G-18-98 setting down a public hearing to commence March 30, 1998 in Prince Rupert for one day and to continue in Vancouver for the duration of the proceeding. The hearing lasted six days, followed by written argument completed by May 4, 1998.

2.0 THE APPLICATIONS

2.1 Revenue Requirements

PNG's Application as originally filed requested Commission approval to increase rates in order to recover the cost of providing gas service during 1998. The Application also contained a PBR proposal for the years 1999-2002 whereby operating, maintenance, administrative and general expenses ("OMA&G") would be determined by a formula based on customer growth, a productivity factor and inflation. On March 16, 1998, PNG filed a revision and update to the Application and withdrew the PBR section of the Application. The Company stated that: "... it would be in the best interests of all parties to defer consideration of the PBR structure at this time ... PNG is continuing to evaluate PBR and will consider applying for approval of a PBR model in a future application" (Exhibit 3, p. 2).

2.2 1998 Revenue Requirement

The revised Application forecasts a revenue deficiency of $3.731 million for 1998 (Exhibit 1, Tab Application, p. 8). This projected increase in operating costs is attributable to an increase in operating, maintenance, administrative and general expenses. In addition, significant increases were forecast for property tax expense, depreciation and amortization, income taxes and interest costs on long-term debt. The latter expense is partly offset by a decrease in short-term debt costs. The Company also requested the reinstatement of expenses incorporated in the $395,000 Settlement Allowance of the 1997 Settlement Agreement. In addition, the Application included a request for amortization of the previously authorized 1997 Skeena Deferral Account, and a further request to set up a Skeena 1998 Gas Requirements Deferral Account. Finally, the Company requested the approval of a Year 2000

Compliance Deferral Account to record expenditures to be made in 1998 respecting Year 2000 compliance activities.

The PNG Application is based upon a return on common equity of 10.75 percent, as set by the Commission under its automatic Return on Equity ("ROE") setting mechanism. The Company is forecasting a common equity component of 38.21 percent, which is higher than the 35 percent common equity component target previously allowed by the Commission with a plus or minus 1.0 percent band.

2.3 Cost of Service Study/Rate Design Application

The previous Cost of Service/Rate Design Decision of the Commission, in July 1996, directed PNG to file its next study by September 1, 1997. This filing date was extended to January 1, 1998, and PNG filed its 1998 Study along with the Revenue Requirements Application on November 28, 1997.

One of the main objectives of the 1998 Study was to address the concern of PNG's large industrial customers that their rates recovered significantly more than their allocated costs. PNG believes the new proposed rate structure will begin a movement towards cost-based rates for firm transportation service.

The 1998 Study also contains a plan to resell on-system interruptible gas to PNG's industrial customers at market-based prices rather than at the weighted average commodity cost of gas. As a result, the Company's rate rebalancing proposals are based upon revenue to cost ratios for firm service and do not include the impact of interruptible revenue to cost ratios. The scheme proposed by PNG to set the rate for the on-system re-sale of interruptible gas was challenged by the Consumers Association of Canada, B.C. Branch et al ["CAC (B.C.) et al."] as being contrary to the Act, specifically Sections 61(3) and 63 [CAC (B.C.) et al. letter of March 4, 1998].

2.4 Bill Impacts

Based on proposed revenue requirements, rate design and gas cost forecasts, PNG calculates that average residential gas bills will show the following changes from 1997 to 1998:

	1997 Rates	1998 Rates	Change
PNG-West	$912	$899	-1.4%
Centra Fort St. John	643	695	+8.1%
Dawson Creek	573	632	+10.3%

Notes: (1) PNG-West rate for 1998 includes rate design changes proposed by PNG in its 1998 Cost of Service/Rate Design Study, but does not include a rate rider for the 1997 gas supply deferral account.

(2) Source is Exhibit 48.

3.0 OPERATING, MAINTENANCE, ADMINISTRATIVE AND GENERAL EXPENSES

PNG's expenses were reviewed in detail during the hearing. The controversial issues were the reinstallation of the 1997 ADR Settlement amount, labour expenses, change in overhead capitalization policy, donation expense and gas control costs.

3.1 1997 ADR Settlement Amount

PNG filed its 1998 test year revenue requirements including in its OMA&G a $395,000 "1997 ADR Reduction". Commission Order No. G-21-97 (Appendix A) approved the 1997 Settlement Agreement. There was no allocation of the lump sum reduction imposed on the Utility by the Settlement Agreement.

As the Company states in the Application, "for the purposes of presenting the "Decision 1997" figures in the current Application, PNG has allocated the $395,000 settlement allowance as a reduction to certain budgeted 1997 OMA&G expenses" (Exhibit 1, Tab Application, p. 4). The 1998 revenue requirement does not carry forward the 1997 ADR Reduction in expenses, although in the March 16 revision to the Application $100,000 is used to offset revenues forecast to be received from the allocation of costs to Centra Fort St. John (Exhibit 13).

Two of the intervenors objected to the failure to maintain the 1997 ADR Reduction in the 1998 test year. Both of the objections were based upon their belief that the $395,000 amount was a permanent decrease to costs and represented an ongoing commitment by PNG to keep its OMA&G costs reduced by that amount. Both Methanex and CAC (B.C.) et al. also stated that if the Commission allows for the recovery in 1998 of the 1997 ADR Reduction there may be less willingness by parties to engage in future negotiated settlements.

The Commission has reviewed the Application and 1997 Settlement Agreement and notes that there is no specific allocation of the 1997 ADR Reduction and that the Settlement Agreement states that "it is agreed that the 1997 revenue requirement will be further reduced by a lump sum of $395,000" (Exhibit 14). PNG appears to have used a zero-based budget approach to the preparation of the 1998 Revenue Requirement Application and as part of that approach has determined that to meet its allowed ROE the $395,000 is required. Based upon its own allocation as to how the 1997 ADR Reduction was to be realized in 1997, the Company has allocated the addback of the $395,000 for the 1998 Revenue Requirement. PNG states that it achieved the $395,000 reduction in 1997 in a number of ways, including "one time cost reductions; deferring costs; achieving lower company use gas; and increasing other revenue mainly by providing additional services to Centra Gas Fort St. John". The Company also takes the position that to suggest that PNG "agreed to permanently reduce its controllable costs is simply wrong" (T: p.993).

The Commission notes the concern the intervenors have regarding the future use of the ADR process. However, it does concur with PNG that there was no specific allocation of the 1997 lump sum reduction and that the amount was determined during the ADR process as a blanket reduction to costs and as part of an overall settlement package. Due to the confidentiality constraints imposed on the negotiations leading up to the ADR Settlement Agreement, neither the Commission nor intervenors were able to reach any conclusion as to the intent of the Agreement in terms of the possible ongoing reduction to costs that the $395,000 reduction possibly represented. Previous ADR Settlement Agreements approved by the Commission have specifically allocated reductions to certain costs.

Commission Order No. G-21-97 approved the Settlement Agreement for PNG's 1997 test year. The Settlement Agreement allowed for a $395,000 reduction to the 1997 test year and the Commission takes the view that this reduction was to be applied to the 1997 year only. As a result, the Commission determines that it is not improper for this $395,000 to be included in the 1998 revenue requirement as reflected in the Application, provided that the individual cost categories are substantiated. This methodology is consistent with the Commission's practice for annual hearings where the costs of each expense category are reviewed individually.

3.2 Labour Expense

PNG is forecasting an increase in labour costs for 1998 of $431,000 for operations and maintenance expenses and an increase of $248,000 to the general and administrative labour costs. The largest component of this increase is $180,000 due to wage settlements with employees, both union and non-union. Four additional employees are forecast to be added in 1998: a clerical worker in Terrace, a customer service representative in Vanderhoof/Fort St. James, an accountant in the Vancouver head office and a manager of human resources. In addition, benefit costs beyond the control of PNG due to increases in Canada Pension Plan contributions amount to $33,000. Fringe benefit costs have increased by $47,000. Other smaller amounts increase the labour costs to those indicated above.

PNG is requesting that the Commission approve an expenditure of $129,000 including fringe benefits, for the hiring of a manager of human resources and the head office accountant. No breakdown was provided as to the actual compensation of the human resources manager. However, PNG indicates that it has also budgeted a further $92,000 for the use of outside human resource consultants.

The intervenors focused primarily on the issue of the manager of human resources and the human resources function. Both Methanex and CAC (B.C.) et al. noted that the Coopers and Lybrand study examining the issue of shared services indicated that PNG should be able to fulfill the function of a human resources manager in-house at a cost comparable to that being charged by WEI. The BCUC Decision regarding the shared services costs determined that $75,000 was a fair price to pay for human resource requirements.

PNG has based its justification for the human resources expense on a measurement of the dollar per employee expended on that function. The Utility states that the amount allowed for in the Shared Services Study would provide for a budget of approximately $400 per employee, an amount it felt was clearly inadequate. In support of this assertion, PNG provided, in Exhibit 32, highlights of a study of Human Resources Cost Statistics prepared by the Saratoga Institute. The document provides statistics on the dollar amount spent per employee for companies of various sizes. PNG concludes that its budget of $1,400 per employee would place it in the 59th percentile for a company its size (PNG Reply Argument, p. 6). However, as pointed out by CAC (B.C.) et al., the measurement of expenditure per employee does not provide justification for that amount.

On the issue of the human resources department the Commission has reviewed the Shared Services Study conclusions, the evidence presented and the arguments by both PNG and intervenors. The Commission has come to the conclusion that the human resources manager is a valued addition to the management team. However, the amount budgeted for outside consultants appears to be unnecessary if the human resources function is being performed efficiently. PNG presented no evidence to support the required outside services, other than to point to the Saratoga Institute report, which the Commission finds inadequate.

The Commission is generally satisfied with the level of other increases in employee staffing and cost increases with the labour component for both operations and administration. The Commission finds that various increases in incentives and allowances for matters such as employee education may be becoming excessive. In future, it intends to keep a close watch on the amounts expended on the employee incentive plans and ensure that the funds are truly reflective of improved efficiency and productivity.

As a result, the Commission accepts the total labour costs of PNG for 1998 as forecast, but denies any recovery from ratepayers for the costs of outside services for human resources in the amount of $92,000.

3.3 Donation Expense

PNG included 100 percent of its donation expense, $41,500, in its 1998 expenses. In prior decisions, the Commission has determined that the benefits of a modest donation program should be shared between customers and shareholders. Methanex argued that there was no new evidence supporting PNG's position in this matter and that the Commission should require the equal splitting between shareholders and ratepayers. The Commission's previous decision stated "While the Commission is willing to consider changes in methodologies and cost treatments, the Applicant is required to identify the changes and provide evidence and justification to support such changes" (PNG Revenue Requirement Decision, May 29, 1996, p. 27).

The Commission concurs with the intervenor that there is no new evidence before it of changes in the donation expense treatment or methodologies. It is noteworthy that determinations related to the Retail Markets Downstream of the Meter ("RMDM") guidelines identified "goodwill" as a shareholder asset. **Consequently, the Commission finds that $20,750 is a fair allocation to ratepayers for revenue requirement purposes.**

3.4 Change in Overhead Policy

Due to changes in the recording of costs for overhead and capital purposes, PNG is forecasting an increase in operating expenses of $183,000 for operations and maintenance and $106,000 for administration and general expenses. In addition, a further $80,000 previously recorded in a rehabilitation deferral account for C-Scan and pigging activities is proposed to now be recorded as a current expense.

Supervisory costs for operations and maintenance are now to be recorded in an account that does not allow for transfers to capital. The Company states that these changes will allow for a better accounting of costs, consistent with Generally Accepted Accounting Principles. The changes to the rehabilitation costs recorded in a deferral account are necessary as PNG now considers the pigging and C-Scan costs to be routine maintenance and not part of the work to upgrade the original pipeline.

CAC (B.C.) et al. was concerned that PNG was intentionally increasing its current expenditures. Methanex also raised the same issue and stated that it did not believe 1998 was the appropriate time to be changing its capitalization policy, in particular that regarding the pipeline rehabilitation costs.

The Commission recognizes that the effect of the decreased overhead capitalization will result in rate increases for 1998, but over the long-term, views the change as being positive in that costs should only be deferred and recovered at a later date if proper support for that policy is maintained. The Commission accepts PNG's statement that the C-Scan and pigging activities have reached the point of being routine maintenance.

The Commission therefore accepts the changes in overhead policy, recording of supervisory costs and recording of C-Scan and pigging costs as proposed by PNG in the Application.

3.5 Gas Control Costs

PNG contracts out its gas control to WEI and pays for the service under a shared services agreement between the two companies. The Shared Services Decision of August 7, 1997 reviewed the issue of PNG's gas control and measurement function and concluded that it was more cost effective for the Utility to contract with WEI than to set up its own office. The cost of going in-house was estimated at $480,000 per year, while in 1997 PNG was proposing to pay $174,850.

The 1997 forecast was almost double the amount of $93,700 that was paid in 1996, and the Commission stated:

> "In the absence of adequate justification the Commission is limiting the 1997 cost allocation to the 1996 cost plus inflation. This results in an allowed shared service charge in 1997 of $95,200 ($93,700 x 1.016) (estimated B.C. inflation rate, 1.6 percent, spring 1997)" (Commission Shared Services Decision, August 7, 1997, p. 17).

In the 1998 Application PNG has stated that it will be paying $185,379 to WEI for gas control services and the Utility provided information as to how the amount was determined. PNG appears to be paying on a time-effort basis on the assumption that 3.16 hours per day is taken up by WEI on the Utility's gas control and measurement function. Adding in the costs of supervision and overhead provides a cost per hour which is then multiplied by days per year to arrive at the $185,379 amount.

Both Methanex and CAC (B.C.) et al. argued that PNG should only be allowed to recover the cost of one WEI employee working the 3.16 hours per day, and not the cost of overhead and supervisory personnel. PNG countered that it would be unreasonable to expect PNG to not pay for the full cost of having WEI provide the necessary service and that to pay the cost for only one person in the gas control centre is misleading (T: p. 998).

The Commission's Shared Services Decision denied the majority of the cost of the gas control function based upon inadequate information to support a doubling of costs over a one-year period. In the current application, PNG has provided support for its negotiated fee to WEI and the Commission accepts the information provided. **As a result the Commission will allow PNG to recover the full amount requested for the gas control and measurement function of $185,379.**

4.0 RATE BASE

4.1 Capital Projects

Four transmission plant rehabilitation projects make up a significant part of PNG's capital budget for additions in 1998 of $10.171 million in direct costs, or $12.674 million including overheads.

<u>Skeena Crossing at Milepost 300-301</u>

PNG intended to replace this crossing in 1997, but later deferred the work to 1998. The Utility considered that the existing crossing would not survive the spring run-off in 1998. At the time of the hearing, PNG was proceeding with a directionally-drilled crossing which it estimated would cost $2.124 million, although there was a concern that the drilling attempt might not succeed due to the subsurface soil conditions (T: pp. 163-65). Subsequent to the completion of the hearing, PNG advised Commission staff that the drilled crossing has been successfully completed.

Arden Creek and Bowling Alley

These rehabilitation projects on the pipeline between Terrace and Prince Rupert have an estimated cost of $3.88 million in total. Several temporary repairs have been made to this section of the line, which is exposed in several locations and is subject to damage from rockslides and falling rock. PNG developed heavy equipment access to the area in 1996, in conjunction with other rehabilitation work. The work was originally scheduled for 1997 but was deferred to 1998 (Exhibit 2, Tab 1; p. 30). PNG is confident that the projects will be completed in 1998 and that the cost estimate is reliable within 10 percent, unless unusual weather conditions are encountered (T: pp. 168-69).

Kitimat River Crossing

Ongoing erosion and migration of the river channel threatens the pipeline crossing that serves Eurocan and the municipality of Kitimat. PNG proposes four projects that would have a total cost of $0.802 million and would rely on the larger diameter crossing that serves Methanex, as an alternative to replacing the river crossing. This work is scheduled for the fall of 1998 (T: p. 171).

There was some discussion in the hearing about the level of confidence in the cost estimates and schedules for these projects, and how the approval process might accommodate any concerns. PNG resisted suggestions that applications for Certificates of Public Convenience and Necessity ("CPCN") should be filed, on the basis that a CPCN is more appropriate for new facilities that connect new load. In particular, PNG views the Skeena crossing effectively as a maintenance project which was already in progress at the time of the hearing (T: 1, p. 165).

PNG included the cost of these projects in its forecast rate base for 1998. One alternative would be for PNG to accumulate project costs plus an Allowance for Funds Used During construction ("AFUDC") throughout 1998, and then add the total amount to rate base at the beginning of 1999. The Utility agreed that this accounting approach would keep it whole (T: pp. 166, 169). In its Argument, PNG stated that all projects should be transferred from construction work-in-progress accounts to plant-in-service accounts when they are completed. The Utility felt that delaying the transfer until the start of the next year defers to future periods the recovery of the cost of such projects.

Commission Determinations

The Commission accepts that the capital expenditures that PNG proposes for 1998 are necessary, and that, with the Skeena crossing successfully completed, there are no major issues related to the cost estimates. **In this circumstance, there is no need to file CPCN applications for these projects.**

With regard to the accounting treatment of project costs, the Commission notes that PNG has successfully deferred projects on a number of previous occasions. The Commission does not wish to defer the recovery of costs, but sees value in the approach described earlier which would have PNG accumulate project costs and AFUDC until the beginning of the following year. This approach would keep both the Utility and its customers whole in the event circumstances change and PNG defers the project. Moreover, some deferment of cost recovery for capital projects would offset PNG's proposal to reduce the amounts of overheads and expenses that are capitalized in 1998.

The Commission directs PNG to use the actual cost of the Skeena crossing to calculate the amount to include for the project in its rate base for 1998. PNG is directed to accumulate project costs for Arden Creek/Bowling Alley and Kitimat Crossing, including AFUDC, for 1998 and to transfer these amounts to plant-in-service at the beginning of 1999. PNG is to file monthly and final construction progress reports for each of the projects, in a format that is to be established in consultation with Commission staff.

4.2 Year 2000 Compliance Deferral Account

Because of computer resource constraints in the 1960s and 1970s, programmers abbreviated dates using 2-digit numbers for the year (yy) instead of 4-digit numbers (yyyy). Some of the old conventions, as well as some old programs, still survive. As a result, certain computers (or any date-activated microprocessors) may be unable to distinguish between 1900 and 2000, or will see January 1, 2000, as 00-01-01, a smaller number than the day before.

PNG is seeking Commission approval of a deferral account to record expenditures to be made in 1998 respecting year 2000 ("Y2K") compliance activities, stating that it has a much better appreciation of the scope of the work involved. PNG now expects that the incremental cost of Y2K activities in 1998 will be at least $220,000.

The Y2K problem was probably first raised among information technology specialists in the early 1990s and by now most organizations know of the problems that will be caused. The Commission is concerned as, despite this and the extensive costs being incurred to upgrade their financial and customer information systems, PNG management seemed to be taken by surprise. Y2K compliance is a management problem that should have been dealt with over the years as a part of the Utility's ongoing obligation to provide safe and reliable service. **Consequently, the request for a deferral account is denied.**

Based on the answers to cross-examination and the information provided in Exhibit 19, the Commission is reasonably confident that PNG will be Year 2000 compliant in all areas. However, by separate letter, all utilities under Commission jurisdiction have been requested to provide the Commission with quarterly reports identifying management actions in this area.

4.3 1997 Skeena Deferral Account

The issue of the 1997 Skeena Deferral account has been previously dealt with by the Commission in terms of allowing for the set up of the deferral account and eventual recovery of recorded amounts. In a separate proceeding the Commission issued Letter No. L-14-97 allowing for the recording of costs and revenue deficiency related to the protection given to Skeena Cellulose Inc. under the Companies' Creditors Arrangement Act and Letter No. L-53-97 allowing for the recovery of rates commencing in 1998.

In the current application, PNG is requesting that the deferral account be amortized over a period of three years commencing January 1, 1998. The amount recorded in the deferral account, net of tax, is $806,713 as of the March 13, 1998 revision to the Application.

Methanex argued that PNG should not be allowed to recover the 100 percent loss of Skeena revenues, but rather, should be entitled to recover the 80 percent take-or-pay minimum set out in the sales contract. PNG replied that the 1997 revenue requirement was based upon a 100 percent purchase by Skeena of its contract demand and that the Commission's L-letter allows for the recording of any revenue deficiencies.

The Commission is sensitive to the Methanex argument as it would apply to normal load forecasting variations but, in this instance, the Commission found the Skeena situation was extraordinary. The Commission has previously determined that the recovery of the 1997 Skeena Deferral account balance will be permitted commencing in January 1998. The amounts recorded in the account have been reviewed and determined to be appropriate. **Consequently, the Commission will allow for the recovery of the 1997 Skeena Deferral account over the three-year period requested by PNG.**

4.4 Skeena 1998 Gas Requirements Deferral Account

In the March 16, 1998 revision to its Application, PNG requested the addition of a gas requirements deferral account to record the extent to which Skeena's actual deliveries in 1998 vary from the 100 percent load factor figure of 2,963,435 GJ.

The Utility maintains that there is still much uncertainty regarding Skeena's operations and that the deferral account will operate to protect the ratepayers from large revenue swings. If the customers take more gas than forecast in 1998, the additional revenue would be credited against rates in the future and, conversely, any shortfall in the deferral account would be amortized against future rates. If approved, PNG intends to apply to eliminate the deferral account at the end of 1998, assuming that the Skeena restructuring plan has taken hold. The Skeena 1998 Gas Requirements Deferral Account relates to the gas delivery margin received by PNG, and has been requested by PNG due to an unusual situation with one of its major customers. The company views this situation as being significant enough to warrant special treatment.

The Commission does not share PNG's opinion as to the necessity of the deferral account. The type of account being requested by the Utility should be permitted only in the most extreme circumstances and the Commission recognized this when it approved the 1997 Skeena Deferral Account to record the lost revenue due to the possibility that Skeena would permanently close. The closure of the Skeena mill was an extraordinary event that was not foreseeable at the time of the rate setting for 1997. However, PNG is now asking for mitigation from the threat that Skeena may buy less gas than forecasted in 1998 because of vagaries in pulp markets and fibre supplies. This would appear to the Commission to be a sales forecast and business risk that PNG assumes with any of its customers, large or small.

The Commission therefore denies the request to set up a Skeena 1998 Gas Requirements Deferral Account. If, during the course of the year, the situation changes and the Utility is facing an extreme circumstance, such as closure of the Skeena mill or bankruptcy protection, it may approach the Commission at that time with a request for mitigation through a deferral account.

5.0 SALES FORECAST

PNG is forecasting a drop in energy sales in 1998 to total deliveries of 36,887 TJ. Normalized sales in 1997 were 37,896 TJ. Actual sales were 37,683 TJ (Exhibit 1, Tab 1, p.1).

As explained by PNG:

> "Forecasts of delivery volumes are developed by economic sector, with disaggregation for large-volume industrial users by customer. Forecasts take into account the normalizations of recorded gas deliveries and consumption volumes in the period up to and including 1996, and projections for deliveries for 1997. The latter have been checked against actual deliveries to October 31, 1997" (Exhibit 1, Tab 1, p.3).

The 1998 test year forecast of the Utility's customer and company use gas requirements is summarized in Table 1-1 in the Application (Exhibit 1, Tab 1, p. 18). On March 16, 1998, PNG filed revisions to the Application which included an update to the forecast of gas deliveries. Two major changes resulted in the revenue deficiency for the year increasing from $2.945 to $3.767 million (Exhibit 3, p. 1).

The primary reason for the increased revenue deficiency is a forecast of reduced gas deliveries to Skeena Cellulose Inc. This decrease to margin is offset by an increase in margin from Methanex Corporation due to a new gas heat content posted by Westcoast Energy after the original Application was filed.

Methanex, in argument, took issue with the forecast sales volumes and stated its position that PNG had under-forecast for 1998. This assertion was based upon graphs prepared by the intervenor which, when "eyeballed", suggest a lower use per customer for both the residential and commercial classes (Exhibit 16; T: p. 934).

PNG responded that an historical analysis clearly shows a decline in per customer use in the residential sector and that commercial deliveries are not forecast based upon use per customer (T: p. 1008). The Utility has used a regression analysis to obtain a 1996 base value and then built on those amounts to provide the 1997 and 1998 forecasts.

The Commission has reviewed the sales forecasts in the Application and generally agrees with the assumptions and results as revised on March 16, 1998. However, the Commission is concerned with the adjustments made in relation to sales to Skeena, which as noted above is a primary reason for the increase in revenue deficiency. The Application states that PNG requested Skeena to review PNG's original 1998 forecast, as the Utility had concerns regarding the customers' restructuring plans and the outlook for pulp markets in 1998. Skeena responded by lowering its original forecast by 520,000 GJ. PNG considered that Skeena was still being overly optimistic and revised the forecast downward by a further 416,565 GJ.

During the hearing, Commission staff queried PNG as to why the Company felt that it could better predict the sales of a major customer, rather than accepting the forecast produced by Skeena itself. PNG responded:

> "I don't think we're in a better position. I think that offsetting the fact that we have reduced the estimate from what Skeena had provided to us is the fact that we are recommending a deferral account be established so that customers are not hurt if the deliveries are indeed higher than what we forecasted" (T: p. 135).

The Commission, in Section 4.4 of this Decision, has determined that the Skeena 1998 Gas Requirements Deferral Account will not be allowed for 1998 as requested by PNG. Consequently, the issue of the revision downward by the Company of the forecast deliveries to Skeena takes on added importance. This particular customer is the only one that the Utility has taken issue with regarding its gas volumes, despite the fact that a revision was requested from and made by Skeena.

The Commission can discern no valid reason to accept the explanation by PNG that Skeena is being "overly optimistic having regard to the slow recovery of pulp markets in 1998 and other problems Skeena may encounter with respect to fibre shortages" (Exhibit 3, p. 2). PNG produced an analysis that indicates a decrease in revenues of $423,000 if Skeena's demand forecast is not accepted and an additional effect of reducing PNG's compressor fuel gas by 30,438 GJ if the lower demand estimate is used (Exhibit 29). **As a result, the Commission determines that the effect is significant enough to warrant an adjustment. Therefore, the 1998 forecast of gas deliveries by PNG is to be adjusted upwards by 416,565 GJ and the Company is to adjust its compressor fuel gas estimate to account for the change in Skeena's Demand Forecast.**

6.0 CAPITAL STRUCTURE

6.1 Introduction

In its 1996 Revenue Requirement Decision, the Commission determined that for ratemaking purposes, PNG should strive to maintain a common equity component of 35 percent within a 1 percent band on either side. In this Application, PNG has applied for a common equity component of 38.21 percent within an overall capital structure as shown in the table below. The capital structure approved in the 1996 Commission Decision is provided for comparison purposes.

	1996 Decision	1998 Application
Short-Term Debt	6.04%	-2.31%
Long-Term Debt	54.46%	60.70%
Preferred Shares	3.52%	3.40%
Common Equity	35.98%	38.21%
	100.00%	100.00%

In its pre-filed evidence, PNG stated that two key issues arose from the 1996 decision: (i) can a small publicly traded utility reasonably be expected to manage its common equity ratio within one percentage point from year to year, and (ii) is the forecast common equity ratio of 38.21 percent compatible with the allowed common equity return as determined using the BCUC's automatic adjustment mechanism? (Exhibit 1, Tab 5, p. 2). During the course of the hearing, two additional issues were raised with respect to the capital structure. These are: (i) is there sufficient common equity within PNG to support the applied for common equity, and (ii) should PNG continue to hold preferred shares within its capital structure?

6.2 The Appropriate Common Equity Component

PNG retained Kathleen McShane, Foster Associates Inc., to render an opinion as to the reasonableness of PNG's proposed common equity component. In her evidence Ms. McShane noted that the 1996 Decision determined that a 35 percent common equity component is optimal for PNG. While Ms. McShane suggested that the optimal common equity component for PNG is in the upper 30 percent range, assuming a 75 basis point premium above a low risk, high grade utility, she indicated that it is not possible for a small investor owned utility such as PNG to manage its capital structure so as to maintain the optimal component at all times (T: 372, Exhibit 1, Tab 5, p. 8). Although Ms. McShane showed that over the period 1987 to 1996, PNG's actual equity ratio has ranged from 32.5 percent to 36.3 percent, she indicated that the narrow range has been a result of using significantly higher proportions of short-term debt in the capital structure than the typical utility (Exhibit 1, Tab 5, p. 5, T: 356-67). She indicated that the use of the short-term debt has been driven by the need to finance major capital additions and has been done at the expense of maintaining a capital structure which is truly reflective of the Utility's business risk (Exhibit 1, Tab 5, pp. 7-8). Further, she noted that PNG has been able to use the levels of short-term debt which it has employed because the Commission has approved a deferral account on short-term interest expense (T: 377).

Ms. McShane recognized that, as a general proposition, it is easier for a utility that has relatively modest capital investment plans to control the size of the equity component (T: 358). She acknowledged that PNG forecasts no special projects over the next five years but stated that PNG needs to have sufficient equity in place to meet the financing requirements that would be imposed by an additional major industrial customer without going to the market, since the likely needed increase in equity would be too small to justify a new equity issue (T: 358). Ms. McShane acknowledged that dividends could be used to reduce common equity levels when they are judged to be too high but warned against doing so for two reasons. First, she stated that it might lead investors to expect a level of dividend which could not be maintained. Second, she indicated that it makes little sense to pay out equity in the form of extra dividends if additional equity is going to be required to appropriately fund capital expenditures but in an amount insufficient to justify a public issue (T: 358-59). She also indicated that it is more expensive to float a small issue (T: 360) and suggested that there might be a self-serving interest in a report by Nesbitt, Burns that shows that PNG can raise equity capital as required (Exhibit 2, Tab 2, p. 9).

In her pre-filed evidence, Ms. McShane testified that management should retain the discretion to determine the capital structure for the Utility, and that rates should reflect the actual capital structure, as long as the resulting ratios are reasonable and there is no prima facae evidence that cross-subsidization between utility and non-utility operations has occurred (Exhibit 1, Tab 5, p. 2). As noted earlier, Ms. McShane suggested that the optimal common equity component for PNG is in the upper 30 percent range, assuming a 75 basis point premium above a low risk, high grade utility, and that, assuming the same spread, an equity component in excess of 40 percent would be unreasonable (T: 372, 395). Ms. McShane stated that there are five principal factors used to determine whether the capital structure proposed by PNG is reasonable. These are: (i) how PNG's capital structure compares with the capital structures maintained by other utilities; (ii) the guidelines of the ratings agencies; (iii) how the investment community views those capital structures as evinced through the debt ratings; (iv) the coverage ratios, in conjunction with the capital costs, which are achievable and whether those coverage ratios provide a similar degree of financial integrity to that achieved by peer companies; and (v) whether the proposed capital structure is compatible with the return on equity (Exhibit 1, Tab 5, p. 10).

Ms. McShane testified that PNG's forecast common equity ratio for 1998 lies slightly above the average allowed other Canadian utilities for regulatory purposes, as does its debt component. However, if preferred shares are treated as comprising 75 percent debt and 25 percent common equity, the common equity component of PNG lies closer to the average. With respect to the bond ratings guidelines, Ms. McShane noted that PNG meets certain of the criteria necessary to receive an A bond rating; however, she noted that both bond rating agencies have rated PNG B++, reflecting its small size. Ms. McShane stated that debt rating agencies have typically required more conservative capital structures (and higher interest coverage ratios) of small utilities. With respect to coverage ratios, Ms. McShane noted that over the past five years, PNG has not achieved the average coverage ratios achieved by rated electric/gas distribution companies (Exhibit 1, Tab 5, p. 16) nor will the approved rate of return on equity for 1998 be sufficient to allow PNG to achieve the average coverage ratios for electric/gas distribution in the upcoming year (Exhibit 1, Tab 5, p. 17). With respect to business risk, Ms. McShane testified that PNG is heavily reliant on three industrial customers, all of whom operate in relatively high risk, cyclical industries and that this leads to PNG being viewed as having a higher business risk than the average Canadian gas distribution utility (Exhibit 1, Tab 5, p. 15).

As a result of all of these factors, Ms. McShane concluded that the proposed actual capital structure, including an equity component of 38.21 percent, should be used to set rates (Exhibit 1, Tab 5, p. 21).

In their evidence on behalf of Methanex Corporation, Dr. W.R. Waters and Dr. R.A. Winter agreed with Ms. McShane that the management of a regulated utility should have better information than the regulator on the appropriate capital structure for the Utility and that setting the equity ratio equal to the actual equity ratio would ensure that the information and judgment of managers, not regulators, influenced the actual equity ratio. In addition, they stated that allowing utility management complete discretion in adjusting the actual equity ratio as market conditions change, without the influence of regulatory incentives, provides for maximum flexibility (Exhibit 22, p. 11).

However, Drs. Waters and Winter maintained that a ceiling on the rate setting common equity ratio might be necessary to prevent the actual common equity from increasing unduly (Exhibit 22, p. 3). Accordingly, they recommended that one should incorporate an automatic adjustment into the rate-setting common equity ratio to follow the actual common equity ratio whenever the latter is below a specified level, i.e. to set a ceiling on the approved ratio (Exhibit 22, p. 10). They argued that allowing the rate-setting equity ratio to track the actual equity fully up to a specified ceiling protects customers against excessive and unfair upward influences of capital structure on rates while allowing the Utility management substantial flexibility in adjusting the equity ratio to changing market conditions. (Exhibit 22, p. 12). At the same time, they argued against establishing a floor for the equity ratio for rate setting purposes unless the regulator required the Utility to maintain that floor in its actual capital structure. They suggested that if the regulator deemed an equity component, which is in excess of the actual equity component, the Utility would experience perverse incentives. Specifically, in the absence of full and frequent rate hearings, the Utility would have an incentive to keep its equity component below the deemed rate since it would receive an equity return for rate base which is actually funded through debt.

Ms. McShane disputed the existence of the perverse incentives identified by Drs. Waters and Winter, stating that if the Utility reduced the common equity ratio below that which is consistent with its business risk, there would be an adverse reaction from investors. Further, she suggested that if the Utility did respond in this way, the Commission would be able to review the situation (T: 393). Finally, Ms. McShane indicated that if the Utility's actual common equity component dropped below a level consistent with its business risk and the Commission was unwilling to deem a common equity component above the actual component, then the equity return should rise (T: 390-91).

With respect to the appropriate level of the ceiling, Dr. Waters and Dr. Winter stated that there was no evidence adduced at this hearing to suggest that the 35 percent common equity ratio established at the previous hearing is inadequate (Exhibit 22, p. 3). They stated that the common equity ratio should be raised only with compelling evidence that: (i) the Utility's access to debt capital is being compromised, and, (ii) that the Utility's flexibility in matching financing sources with capital expenditures and other financing requirements is inadequate (Exhibit 22, p. 13).

Drs. Waters and Winter stated that the principal source of risk for PNG derives from its relatively heavy reliance on a concentrated set of industrial customers (Exhibit 22, p. 16). However, they noted that PNG has enjoyed stable earnings over the period 1985 to 1997 and that this should provide comfort to investors (Exhibit 22, p. 17). In final argument, PNG agreed that it has been able to earn returns in the past which were close to the allowed rate of return, but indicated that this did not guarantee that it would in the future. PNG stated that trends towards greater reliance on competitive forces, and the potential threat of bypass are likely to convince investors that the future will not be a repeat of the past (T: 909).

Drs. Waters and Winter suggested that PNG has a greater ability to manage its capital structure to achieve a particular equity component than the Utility suggests. In support of this view, they noted that PNG's financing requirements are declining (Exhibit 22, p. 17) and that PNG has managed its equity component within a narrow range over the period 1987 to 1998. They stated that this reflects the stability of PNG's cash flows, the stability of its predicted capital expenditure outflows and the historical stability of its common equity ratio.

As further evidence of PNG's ability to manage its capital structure with the currently allowed equity ratio, they cited the fact that PNG has a short-run debt capacity of $35 million. They stated that this provides additional flexibility for cash flow management without imposing new risks and provides PNG with the ability to use short-term financing to offset gaps between cash inflow and the issuing of long-term debt obligations (Exhibit 22, p. 18). Finally, they stated that a review of PNG's bond ratings and coverage ratios indicates that the 35 percent common equity ratio is adequate (Exhibit 22, p. 22).

In final argument, Methanex argued that PNG's debt and equity ratios could be meaningfully affected by its cash levels, which can be significantly influenced by the timing of PNG's investments in its subsidiaries. Methanex argued that if PNG postponed its investments until after the end of the test year, leading to an increase in the cash component of its capital structure which it shows as negative short-term debt, the effect would be to increase the common equity component of PNG's capital structure. Methanex stated that if the Commission were to approve the capital structure as shown by PNG at Schedule 5, as revised, and at some later point PNG were to use the cash for funding additional investments, the result would be that PNG utility would be earning a return on a 38.21 percent common equity component although the actual common equity component would be lower (T: 949-50).

In response to this argument, PNG indicated that it has already forecast the capital needs of its subsidiaries for 1998 and that it could not significantly alter the amount or timing of additional capital. Further, it suggested than any differences between the actual and forecast capital requirements of its subsidiaries would be immaterial (T: 1016). Indeed, PNG argued that Methanex's argument amounted to nothing more than observing that the annual capital additions and year end balance sheets are based on forecasts (T: 1019).

Drs. Waters and Winter also addressed the question of whether PNG has sufficient equity to support the proposed capital structure. Dr. Waters stated that, while the reconciliation of PNG's consolidated equity to its regulated equity showed a discrepancy of only $2,000, one major adjustment to the consolidated equity is missing, specifically the $2 million of acquisition premiums paid for the recent subsidiary acquisitions of PNG. He stated that this amount should be deducted from the Company's common equity because the premium is not an investment upon which PNG can earn a rate of return. In final argument, Methanex argued that reconciliation of PNG's consolidated equity to its regulated equity showed that PNG is earning a return on regulatory equity of $64.2 million when it only has a consolidated equity of $63 million. Further, Methanex argued that the $63 million of consolidated equity includes at least $1 million of equity related to the premium paid on the purchase of the Fort St. John utility and on which PNG should not be allowed to earn a return. Methanex argued that PNG should not be allowed to earn a before tax equity rate of return on capital which is actually financed with tax-advantaged debt (T: 952-53).

In response to this argument, PNG stated that it has financed its common equity component in Centra Fort St. John and PNG (N.E.), including the acquisition premium, with 50 percent common equity and 50 percent debt, and that this financing was approved by Commission Order No. G-127-96 (T: 732). However, PNG stated that no part of the acquisition premium is included in the capital structures of PNG-West, PNG (N.E.) or Centra Fort St. John (Exhibit 18). PNG stated that it appeared that Methanex is arguing that an equity investor in a utility should not earn a full common equity return if it has leveraged its common equity investment with a component of debt. PNG stated that if the Commission were to follow Methanex's argument to its logical conclusion, the Commission would have to inquire of all the shareholders in the utilities it regulates, whether any of the shareholders have leveraged their investment and to deny an equity return on that portion of their common equity investment that had been financed with debt (T: 1017-18).

6.3 Rate of Return on Common Equity

In their prefiled evidence, Drs. Waters and Winter identified three matters which they maintained resulted in an overstatement of the equity risk premium implicit in PNG's applied for return on common equity.

First, Drs. Waters and Winter were critical of a 1997 Decision by the BCUC which modified the ROE automatic adjustment mechanism, set out in a Decision dated June 10, 1994. The 1994 Decision determined that the appropriate spread over long-term Canada bonds for a high grade, low risk utility was 300 basis points and that the additional appropriate premium for PNG was 75 basis points. The 1997 modification introduced a sliding scale whereby the spread for a high grade, low risk utility widened when interest rates fell and narrowed when interest rates rose. The 75 basis point premium for PNG above the high grade, low risk utility was maintained.

Drs. Waters and Winter calculated that the ROE for 1998 is 60 basis points higher than would have been set if the previous unmodified formula had been used. They indicated that they believed that the increase was unwarranted since: (i) the theory supporting the change is controversial and the empirical data unconvincing, and (ii) capital market data indicates that the risk premium required for both utility bonds and common shares have declined since 1994. As a result, Methanex argued that the Commission should either implement Dr. Waters' and Dr. Winter's proposed adjustment for PNG immediately or hold a generic review of that adjustment, the results of which review should be effective for all utilities.

Second, with respect to the specific risks of PNG, the witnesses noted that recent regulatory treatment of PNG has effectively removed several sources of risk so that the major remaining source of risk is that the PNG will become uneconomic at some time in the future (Exhibit 22, p. 27). Accordingly, they suggested that the risks faced by PNG were less than at the time of the generic hearing and that the rate of return on equity for PNG should be reduced 20 basis points to reflect this lessening (Exhibit 23, Q. 2). Indeed, Methanex argued that it is unfair to ask ratepayers to pay amounts accrued in deferral accounts and pay a return for risks from which PNG is insulated as a result of those deferral accounts (T: 944-45). At the same time, however, Dr. Waters agreed that there had not been a fundamental change to PNG's business risks (T: 447).

Finally, Drs. Waters and Winter pointed out that the increase in the ROE is occurring at a time when PNG is requesting an increase in the equity component of its capital structure.

As a result of the first two elements, they recommended a reduction in PNG's allowed rate of return on equity of 60 to 80 basis points (Exhibit 22, p. 4). With respect to the third item, they reiterated their recommendation that PNG's equity component be capped at 35 percent.

Ms. McShane assessed the current risk premium to see if it is compatible with the actual forecast capital structure. Based on the spread over long-term Canada bonds at which PNG recently issued 30 year debt, the spread in debt costs between A and BBB rated utilities, and the trend in the relative market/book ratios and relative price/earnings ratios of PNG compared with larger higher grade utilities, Ms. McShane concluded that the 75 basis point adjustment to the benchmark rate of return found to be reasonable in 1994 should not be altered. (Exhibit 1, Tab 5, pp. 18-21)

PNG argued that the recommendation by Drs. Waters and Winter is really a request for a review and variance of the Commission's generic ROE Decision as amended by Commission Order No. G-49-97 dated April 24, 1997, without establishing the existence of appropriate grounds to support such a review. Further, PNG argued that the establishment of deferral accounts by the Commission could only be seen as evidence of PNG's higher business risk. Finally, PNG argued that if the recommendation of Drs. Waters and Winter is accepted it could lead to PNG earning less than both BC Gas and West Kootenay Power even though the Commission has, in past decisions, found PNG to be more risky than either of these companies (T: 912).

6.4 Preferred Shares

PNG's proposed capital structure contains $5 million of preferred shares or 3.4 percent of the capital structure. The preferred shares were issued in 1968. At that time they were seen as desirable since the coupon rate was six and three quarters percent, they were perpetual, and they provided interest coverage protection (T: 340). PNG testified that the current benefit to holding preferred shares includes protection with respect to the interest coverage ratio and the fact that analysts appear to believe that the perpetual nature of the preferred shares add to the overall quality of the capitalization of the Utility (T: 341). PNG agreed that the current cost of the preferred shares is greater than the current cost of short-term debt and that preferred share dividends are paid out in after tax dollars (T: 342). However, PNG disagreed with the proposition that the preferred shares offer a relatively minor benefit to the capital structure. PNG indicated that it did not know what impact the loss of the preferred shares would have on the interest coverage ratios but that there were no plans to retire the preferred shares and that there would be a cost of about $200,000 to redeem them (T: 342-43).

6.5 Commission Determinations

In its 1996 Revenue Requirement Decision, the Commission determined that for ratemaking purposes, PNG should strive to maintain a common equity component of 35 percent within a 1 percent band on either side. As described above, during the course of the current hearing, there was significant discussion regarding the extent to which PNG could be expected to manage its actual capital structure so as to ensure that the equity component stayed within this band. In addition, there was discussion as to whether a band is appropriate or whether the Commission would be better advised to establish an equity component ceiling and allow the Utility complete flexibility to manage its capital structure subject to that ceiling.

After review of the evidence, the Commission is convinced that there is significant benefit to allowing management as much flexibility in determining its capital structure as is consistent with sound rate making. Indeed, the Commission agrees with the expert witnesses provided by both PNG and Methanex, that the views of management with respect to the capital structure should be reflected in rates except where the resulting ratios are clearly unreasonable or there is evidence that cross-subsidization between utility and non-utility operations has occurred.

The Commission believes that the best way to ensure that management has maximum flexibility to manage its capital structure is to determine a ceiling for the equity component. Provided that the actual capital structure does not exceed this ceiling, the Commission finds that the equity component for ratemaking purposes should be the actual equity component of the Utility.

In making this determination, the Commission is cognizant of the arguments put forward by PNG with respect to the relationship between the capital structure and the rate of return on equity and the potential need to deem an equity component above the actual equity component of the Utility. In this case, the Commission believes that PNG possesses sufficient flexibility to ensure that its equity component is reasonably matched to the rate of return on equity. Given the potential for perverse incentives to arise, the Commission is not persuaded that a deemed floor on the equity component of the Utility is either necessary or desirable.

With respect to the question as to the actual equity available in the consolidated company to support the equity in the Utility, the Commission agrees with Methanex that acquisition premiums should be funded entirely through non-earning equity. The Commission recognizes that Commission Order No. G-127-96 may have led to a misapprehension of the Commission's intentions in this regard. However, this determination is consistent with the determinations made in the BC Gas Utility Ltd. Decision dated August 5, 1992. At that time, the Commission wrote as follows:

> "With regard to the premium paid on TMPL shares by BC Gas, the Commission starts from the understanding that the shareholders of Inland chose to pay a premium above book value for the TMPL shares and any appreciation or loss of the premium is solely to the shareholders account. The issue before the Commission is whether to attribute a part of the Company debt to the premium. Any allocation is somewhat arbitrary and arguments regarding debt incidence are equally persuasive by both the Company and Dr. Waters. In the final determination the Commission will not know the reality of whether this shareholder investment in the acquisition premium was, or is now, supported by any debt.
>
> However the Commission believes the value associated with the premium will only be realized when the TMPL shares are sold. Therefore, the Commission is not convinced that Inland's shareholders did, or could have, borrowed money at the time of purchase of TMPL shares secured only by the potential value of the assets above that book value supported by ratepayers....
>
> With respect to the appropriate method of financing the acquisition premium of the Lower Mainland gas distribution assets of B.C. Hydro, the Commission finds that the

> acquisition premium provides value to the Company to the extent that it generates tax savings. However the Commission is of the view that the source of funds for the additional $35.8 million included in the acquisition premium should be more appropriately financed out of retained earnings." (pp. 120-21)

Based on Exhibit 18, the Commission finds that PNG has approximately $54.1 million of equity available to support PNG. This is approximately 36.7 percent of its capital structure. The dollar value was calculated by subtracting from the consolidated equity value of $63.041 million: (i) $1 million for the acquisition premium related to Fort St. John, and (ii) the common equity shown for PNG N.E. and for Fort St. John in Exhibit 18.

With respect to business risk, the evidence adduced at this hearing has not led the Commission to believe that the risks faced by PNG have changed in any material way from those faced at the time of the last hearing. As a result, the Commission finds that the 75 basis point premium contained in the rate of return on equity awarded PNG through the automatic adjustment formula continues to be appropriate.

Therefore, the Commission finds that the appropriate equity component for the determination of rates is the actual equity component of PNG subject to a ceiling of 36.0 percent. Accordingly, for 1998, the Commission directs that the rates be determined based on this equity component. Further, the Commission directs PNG to provide to the Commission in December of each year a forecast of its actual equity component for the upcoming year. When this forecast is 36.0 percent or less, this forecast will be used in conjunction with the automatic rate of return on equity adjustment mechanism to establish new rates for service. When this forecast exceeds the ceiling, an equity component of 36.0 percent will be deemed for the purposes of establishing rates. Any equity in excess of 36.0 percent will attract the short-term debt rate.

With respect to the retention of the preferred shares in the capital structure, the Commission acknowledges that preferred shares have played a valuable role in optimizing the capital structure in the past. However, with changes in the tax treatment of preferred shares this is no longer the case. **Accordingly, the Commission expects PNG to redeem the preferred shares in a timely manner. The costs of the redemption are to be carried forward to the next revenue requirement proceeding.**

Finally, the Commission believes that the issues related to the automatic adjustment formula raised by Drs. Waters and Winter are beyond the scope of this Decision.

7.0 COST OF SERVICE STUDY

7.1 Introduction

Over the past several years, PNG has undertaken several Fully Allocated Cost of Service Studies ("FACOS studies") to determine the extent to which the rates it charges customers for service appropriately reflect the cost of serving customers. In 1990, Ocelot Chemicals Inc., the operator of the methanol and ammonia plants at Kitimat prior to Methanex, complained that it was being charged rates for service which were excessive. After a public hearing, the Commission issued a Decision dated February 27, 1991 in which it found that residential and small commercial customers were not paying a sufficient part of the revenue requirement. Accordingly, the Commission directed that residential and small commercial rates be increased and that the increased revenues from these classes be used to decrease rates to other customer classes.

In 1995 this issue was examined again. After a hearing, the Commission directed that residential rates be increased by 10 percent in 1996 and a further 5 percent in 1997, with the additional revenue from the increases used to reduce the firm rates of industrial and other customers which had revenue to cost ratios significantly greater than 1.00. In addition, the Commission directed PNG to file a revised cost of service study and rate design application in 1998.

7.2 The FACOS Study and Proposed Revenue Shifts

The FACOS study filed by PNG as part of this Application indicates that residential and commercial customer rates continue to under-recover the costs of serving these customers while the firm service rates for large industrial customers over-recover the costs of service. Accordingly, PNG requested that the portion of the Revenue Requirement collected from residential, commercial, and small industrial customers be increased and the increased revenue be used to offset other customer class revenues so that the revenue requirement shifts are neutral in total. In addition, PNG proposed that interruptible transportation service rates for Skeena, Eurocan and Alcan be reduced slightly from current levels to better reflect the differences in the quality of the interruptible service between those customers and Methanex.

The results of the FACOS study and the rate changes proposed by PNG for selected customer classes are given below:

Table 7.1 Revenue to Cost Ratio Comparisons

	1997 Revenue to Cost Ratio	Proposed Annual Rate Design Revenue Change	Proposed Revenue Requirement Shift (%)	Proposed Revenue to Cost Ratio
Residential Sales	.66	$825,000	9.37	.72
Commercial Sales	.52	$875,000	24.63	.64
Commercial Transportation	1.35	-$19,000	-6.29	1.27
Small Industrial Sales	.66	$85,000	20.24	.80
Small Industrial Transportation	.87	$70,000	5.45	.95
Methanex Firm	1.29	-$1,356,000	-6.00	1.21
Methanex Interruptible	1.82	0	0	1.82
Skeena Firm	1.26	-$140,000	-4.13	1.21
Skeena Interruptible	11.45	-$139,700	-13.09	9.97
Eurocan Firm	1.23	-$51,000	-1.95	1.21
Eurocan Interruptible	12.62*	-$3,500	-12.96	10.98
Alcan Firm	1.45	-$93,000	-16.88	1.21
Alcan Interruptible	13.38	-$52,700	-13.08	11.68

* Adjusted to correct for error in the Application

The FACOS study which was included as part of this Application utilizes the standard three-part methodology in which costs are: (i) functionalized according to which function (e.g. transmission, distribution) causes the costs to be incurred; (ii) classified according to whether the costs are incurred to meet demand at a point in time, to meet throughput over time, or to meet increased numbers of customers; and (iii) allocated according to which customer class causes the functionalized, classified costs to be incurred. However, unlike previous FACOS studies filed by the Utility, the current FACOS study excludes gas costs so that the revenue to cost ratios which result from the FACOS study are for transportation costs and revenues only.

During the hearing, there was little discussion of the functionalization and classification of the costs although CAC (B.C.) et al. maintained that a more detailed examination could lead to further refinements which are likely to result in a higher revenue to cost ratio for the residential class (T: 986). However, there was significant discussion regarding the way in which costs are allocated in the study, the treatment of interruptible sales revenues and interruptible transportation revenues, and the interpretation of the resulting revenue to cost ratios. These issues are discussed below.

7.3 Allocation Methodology

7.3.1 Allocation of Transmission Capacity

In the FACOS study, transmission costs are classified as capacity related and allocated to customers on the basis of their distance weighted non-coincident peak usage (Exhibit 2, Tab 1, p. 7). PNG testified that transmission costs are classified as capacity related because pipelines are built to meet the peak day, i.e. to meet maximum demand at a point in time (T: 513). With respect to allocating transmission costs amongst customer classes, PNG testified that the non-coincident peak is used instead of the coincident peak because PNG could not measure the coincident peak with 100 percent accuracy for core market customers and because the use of the non-coincident peak is expected to have little impact on the results of the allocation (T: 498).

PNG indicated that the methodology used in the current FACOS study varies slightly from the methodology used in the 1995 FACOS study. Specifically, the current study uses the gross peak day demands of residential and commercial customers to allocate transmission costs instead of the gross peak day demands less line pack available to peak shave as was done in the 1995 study. Although PNG stated that the line pack would continue to be available to peak shave, PNG chose not to recognize this in the capacity allocators contained in the FACOS study since the line pack is provided both by the gas purchased to serve core market customers and the gas put in the pipe by transportation service customers (T: 570).

During the hearing there was significant discussion with respect to the development of the transmission capacity allocator for residential customers. PNG stated it derived its forecast of peak demand for non-industrial customers by calculating the average load for commercial and residential customers and determining what percentage of this load is non-temperature sensitive (T: 499). Initially, PNG determined that 30 percent of the residential and commercial load is non-temperature sensitive (Exhibit 2, Tab 2, p. 46; T: 499).

In his evidence, Mr. Drazen, an expert witness acting for Methanex, appeared to accept the use of the non-coincident peak but questioned whether PNG's forecast of peak demand for residential customers is accurate. Based on PNG's estimate of gas requirements for July 1998 versus requirements for the year as a whole, he suggested that it would be more appropriate to assume that the non-temperature sensitive portion of PNG's residential load is about 16 percent. (Exhibit 42, pp. 9-10). As a result, he maintained that PNG's methodology underestimated the amount of transmission capacity which should be allocated to residential customers.

In response to his criticism, PNG re-examined their analysis of the non-temperature sensitive portion of the residential load. Using an engineering approach which looked at actual appliance use in the PNG service territory, PNG suggested that the non-temperature sensitive portion of the residential load is 22.8 percent, which PNG then rounded to 25 percent (Exhibit 37). PNG showed that using the revised estimate of non-temperature sensitive load for residential customers acts to allocate more costs to this class of customer and reduce the revenue to cost ratio from the .66 originally calculated to .65 (Exhibit 43). Although the new PNG estimate is closer to the 16 percent suggested by Mr. Drazen, Mr. Drazen suggested that the new approach continues to overestimate the non-temperature sensitive portion of the residential load. Mr. Drazen stated that the new approach does not account for the fact that there is a temperature sensitive element to water heating. Therefore, he stood by his own estimate of 16 percent (T: 762)

Mr. Todd, an expert witness acting for CAC (B.C.) et al., expressed concern with both the engineering method put forward by PNG and the approach used by Mr. Drazen. Mr. Todd stated that taking the lowest month in the year is not the normal way of determining base load, nor is the engineering approach used as an alternate method by PNG, but that a statistical method, which employed daily degree days, should be used (T: 810). However, Mr. Todd did not provide an estimate of the results of his preferred methodology.

In addition to his concern with respect to the development of the estimate of the residential peak, Mr. Drazen also expressed concern with respect to the fact that PNG uses the large industrials' contract demand as the allocator even though PNG does not deliver the full contract capacity at all times. In particular, he noted that PNG's contract with Methanex allows PNG the right to interrupt or curtail shippers' firm service up to a maximum of 113.3 10^3m^3 per day on any day that PNG requires capacity on the pipeline system for core market peaking requirements. Further, he indicated that falling line pressures because of increased other load may require Methanex to curtail usage. Accordingly, he stated that the effect is that part of the contract capacity that is allocated to and paid for by Methanex is actually used to serve other customers on a regular basis. He suggested that this should be recognized by PNG in its cost of service study.

Mr. Drazen suggested that there are two ways in which these factors could be recognized in the cost of service study. Either PNG could reduce the Methanex contract demand by the portion that is curtailable and use the resulting demand as the allocator for transmission capacity, or the value of the right to curtail could be determined and Methanex could be credited with this value in the FACOS study (T: 792-93). Although Mr. Drazen did not provide an estimate of the extent to which such changes would affect the revenue to cost ratios, it is clear that it would act to increase the revenue to cost ratio for Methanex and reduce the revenue to cost ratios for smaller volume customers.

With respect to the issue of transmission capacity allocation the Commission finds that PNG's revised estimate of 22.8 percent is appropriate and rounds it to 23 percent. In coming to this conclusion, the Commission acknowledges the argument put forward by Mr. Drazen that the engineering approach used by PNG does not account for the fact that there is a temperature sensitive element to water heating. However, the Commission is concerned that using the month of July to determine the non-temperature sensitive base load of the residential customer class underestimates the true non-temperature sensitive load since the July residential load may be reduced for factors other than temperature, e.g. vacation impacts.

7.3.2 Allocation of Customer Costs

PNG indicated that the number of meters installed is used to allocate customer costs to core market customers. PNG stated that each small industrial customer is deemed to be equivalent to ten installed meters and each large industrial firm customer is deemed to be equivalent to 100 meters and that these weighted customer counts were developed after reviewing the cost relationship existing between large industrial customer service costs and residential service costs. The small industrial assumed customer count of ten was determined having regard to the large industrial/residential customer relationship (Exhibit 2, Tab 1, p. 6).

PNG stated that the assumed relationship of one large industrial customer equals 100 small customers is based on an analysis of customer billing, meter reading, meter testing, and measurement checks data. Further, PNG agreed that an assessment of the data provided by PNG with respect to the first three measures indicates that PNG spends approximately 475 minutes serving an industrial customer for every one minute it spends serving a residential customer (T: 574). However, upon reflection, PNG indicated that the numbers provided with respect to residential meter reading are too low and that when more appropriate numbers are used, the industrial to residential ratio drops from 475 to 1 to 220 to 1. PNG indicated that 220 to 1 is the more accurate number (T: 643) and that if this number is used the revenue to cost ratio for residential customers increases from .66 to .67 and declines from 1.29 to 1.28 for Methanex (Exhibit 44).

Mr. Drazen disagreed with the suggestion that the 100 to 1 ratio is too low. He stated that if a ratio in excess of 100 to 1 is used, the result would be that the costs allocated to the four customers would be in excess of the actual costs that would be incurred if the four large industrial customers hired someone to do the accounting related to these customers. In addition, he argued that, as shown by Exhibit 44, even if the ratio were doubled, the result would be insignificant in terms of the conclusion regarding the rates which Methanex is paying (T: 760).

With respect to the allocation of customer costs, the Commission finds that the ratio of 100 to 1 used by PNG to equate large industrial and residential customers is inappropriate and that a more reasonable ratio is 220 to 1.

7.3.3 Allocation of Commodity Costs

In the current FACOS study, commodity costs are allocated amongst customer classes based on annual throughput, weighted for the distance from Summit Lake. PNG stated that the forecast annual throughput used in the FACOS study is normal for a year in which Methanex is planning to carry out a three-week plant turn-around, an event which occurs every three years (T: 581). However, PNG agreed that if the three-week plant turn-around was averaged over three years, the volumes used in the FACOS study for 1998 would be higher and more commodity costs would be allocated to Methanex (T: 581-82).

With respect to the allocation of commodity costs, the Commission finds that PNG should use a forecast of commodity volumes which averages the effect of the three-week plant turn-around by Methanex. Given the evidence at this hearing that Methanex is shut down for 14 to 15 days for each of the other two years and for 35 days when there is a plant turn-around. For the purposes of the FACOS study, PNG should assume that Methanex is shut down 21 to 22 days each year.

7.4 Interruptible Gas Sales

Although large volume customers arrange for their own gas supply, PNG continues to arrange gas supply for core market (firm sales) customers. At certain times of the year not all the gas under contract is needed to meet core market demand. Accordingly, PNG makes the excess or valley gas available to others on an interruptible basis.

For several years, PNG has accepted that any revenues in excess of the weighted average commodity cost of gas achieved on the sales of valley gas should go to the benefit of core market customers since it is for these customers that the costs associated with the gas are charged. In 1995, PNG recognized the benefits of valley gas sales by imputing a value for these sales and including this value in the calculation of the revenue to cost ratio undertaken within the FACOS study. Specifically, the imputed value appeared as an addition to the allocated costs of customers utilizing interruptible gas and as a deduction to the costs of the core market customers that created the valley that would provide the interruptible sales gas.

The current FACOS study does not include an imputed value for interruptible gas sales. Instead, PNG now proposes to sell the valley gas at market based prices and to credit any profit from these sales to PNG's gas supply cost deferral account as a reduction to the demand charges payable by the core market customers (Exhibit 2, Tab 1, p. 9). More precisely, PNG proposes to allocate any profit from these sales amongst its three divisions, and then allocate the divisional profits amongst customer classes based on forecast peak day (T: 589-90).

In his evidence, Mr. Todd accepted the use of market based pricing but indicated that he is concerned that it may lead to fewer dollars being credited to the benefit of those parties for whom PNG buys the gas than the imputed methodology. More specifically, Mr. Todd indicated that he is concerned that PNG's new gas purchasing arrangements which included increased use by PNG of seasonal contracts and storage would lead to there being reduced volumes available for interruptible sales (T: 814). Although he recognized that these techniques help to minimize gas costs, Mr. Todd argued that the net impact on the core market customer of minimizing gas purchases may not be positive, i.e. he drew a distinction between minimizing costs and minimizing the financial impact of gas costs on core market customers (T: 815). At the same time he recognized that there would be significant risk if PNG were to contract for greater levels of gas supply than would be necessary to meet core market (T: 817).

Nonetheless, Mr. Todd suggested that it may be appropriate for the Commission to consider the merit of introducing an incentive for market based on and off system sales that would encourage PNG to strive to maximize the value of the net revenues that would be shared with firm customers. He suggested that the mechanism could be similar to the incentive mechanism that has been approved for BC Gas off-system sales (Exhibit 43, pp. 5-6)

In response to the suggestion that an incentive mechanism be introduced, PNG stated that it agreed that it would be worthwhile to have an incentive-based mechanism in place to ensure that the Company is motivated to maximize the return to the core market (T: 593).

Although Mr. Todd accepted the use of market-based pricing, subject to the concerns expressed above, he indicated that he would prefer to see any profit from the sales credited against the total cost of service, within the FACOS study, instead of credited to a PNG gas supply cost deferral account as a reduction to the demand charges payable by the core market (Exhibit 46, pp. 10-11). Although Mr. Todd recognized that customers should be indifferent between the two methods of crediting, (Exhibit 46, p. 7), his preferred method acts to increase the revenue to cost ratio for residential and commercial customers which results from the FACOS study. Indeed, Mr. Todd indicated that if it was assumed that valley gas volumes remained at their previous level, the residential revenue to cost ratio would increase by about 0.07 (Exhibit 46, p. 10). The revenue to cost ratio would increase by a further .016 if an imputed value for the currently expected valley gas sales is also included.

PNG stated that it would be very difficult to accommodate Mr. Todd's suggestion under market-based pricing since it would be necessary to forecast the value of the gas supply commodity that would be available. PNG stated that it was simpler to reflect the value of excess gas available in the allocated cost of supply (T: 593-94).

Commission Determination

In the Commission's view, the purpose of a FACOS study is to provide guidance to the Commission regarding the extent to which individual customer classes pay their share of the costs which the Utility has incurred to provide service. As such the FACOS study should be focused on cost causation and on providing the clearest picture with respect to what causes costs to be incurred. This does not mean that rates will be set automatically to equate with the results of the FACOS study but it does mean that any policy or value decisions with respect to rates can be made with reference to an explicit datum.

The current FACOS study does not include an imputed value for interruptible gas sales. Instead, PNG now proposes to sell the valley gas at market-based prices and to credit any profit from these sales to PNG's gas supply cost deferral account as a reduction to the demand charges payable by the core market customers (Exhibit 2, Tab 1, p. 9). Although the Commission recognizes the revenue to cost ratios calculated using this methodology are lower than would be the case if the imputed methodology were used, the actual dollar impact on the bills customers pay, if the imputed value could be known with certainty, is unchanged. In addition, the Commission believes that there are two distinct advantages to this methodology. First, the methodology provides a better matching between costs and revenues since the revenues from valley gas sales are used directly to reduce the demand charges associated with the gas supply purchases which PNG undertakes for the benefit of core market customers. Second, this methodology ensures that the total benefit of valley gas sales, and no more than the total benefit of valley gas sales, goes to the benefit of core market customers. Neither customers nor shareholders are asked to bear the risk of a mis-forecast of the imputed value. **Accordingly, the Commission accepts the methodology proposed by PNG with respect to the credit for valley gas.**

7.5 Interruptible Transmission Service

In addition to an imputed value for valley gas sales, the 1995 FACOS study included an imputed value for interruptible transportation service. As with the imputed value for valley gas sales, including an imputed value for interruptible transportation service within the FACOS study acted to increase the revenue to cost ratios for residential and small commercial customers calculated by the FACOS study. The current FACOS study does not include an imputed value for interruptible transportation service.

PNG stated that it chose not to include an imputed value for interruptible transportation service in the current FACOS study but that it is possible to do so. For example, PNG stated that it could take the difference between the allocated cost of interruptible service and the revenues associated with that service and deduct the difference from the allocated costs of core market customers. This would act to raise the revenue to cost ratios for these customers (T: 599-600). Indeed, assuming the imputed value for interruptible transportation service on a per unit basis that was used in the 1995 Decision but the volumes used in this Application, the revenue to cost ratio for residential customers increases from .66 to .72 (Exhibit 26, p. 5). PNG stated that when rates are redesigned sufficiently that the revenue to cost ratios for the core market is approaching one, they would be amenable to including an imputed value for interruptible transportation in the FACOS study. However, at the current time, PNG indicated that the resulting change in the revenue to cost ratio would be insufficient to alter its rate change recommendations.

In his evidence, Mr. Todd suggested that given that the net revenue should go to the benefit of those customers who caused the transportation valley to be created, the easiest method is to include the net revenues in the cost of service study as an imputed value which offsets costs in the cost of service study. Mr. Todd suggested that to do otherwise biases the results of the revenue to cost ratios so that they are not comparable across customer classes (Exhibit 46, p. 9).

Mr. Drazen accepted that it is reasonable for firm service customers to receive the benefit of any margin from interruptible transportation (T: 796) but suggested that excluding interruptible service margin from the calculation of the revenue to cost ratio is unlikely to have any material impact on the revenue to cost ratios because the total dollars associated with the margin is so small (T: 798-99).

The Commission finds that the appropriate imputed value, on a per GJ basis, is the difference between the rates for interruptible transportation service approved in Section 7.11 and the cost of providing interruptible transportation service as set out in PNG's cost of service study. When the next study is prepared the imputed value should be allocated amongst customer classes as a credit against costs within the FACOS study according to the extent to which they are responsible for the capacity used by interruptible service customers.

7.6 Additional Impact of Reduced Volumes

As noted earlier, Mr. Todd expressed concern that, although changes in the way in which PNG purchases its gas will result in a reduction in total gas costs, it will also result in reduced volumes being available from PNG for interruptible sales (Exhibit 43, p. 10). As a result, interruptible customers who desire the same volume of interruptible gas will be forced to buy that gas from someone else, although the customer's use of interruptible transportation will be unaffected. Mr. Todd stated that, to the extent gas purchased from other sources costs less than gas purchased from PNG, PNG will have room to increase the price of interruptible transportation (T: 828). Mr. Todd suggested that the FACOS study should include an imputed value to reflect this consideration (Exhibit 43, p. 12).

The Commission rejects the argument that the additional impact of reduced volumes should be recognized in the FACOS study.

7.7 Adjustments for Differences in Customer Class Risk

As part of the settlement of the 1997 Revenue Requirements Application, it was agreed that the next rate design study would include an analysis of the different risks imposed on the system by each customer class with particular emphasis on the issue of the risk imposed by the large industrial customers. In its current application, PNG stated that the FACOS study indicates that the revenue to cost ratios for the large industrial customers are sufficiently greater than one that PNG did not see value in preparing evidence on the relative risks of the various customer classes (Exhibit 2, Tab 1, pp. 15-16). Accordingly, there is no adjustment in the FACOS study to reflect differences in class risk. Nonetheless, PNG admitted that the loss of a large industrial customer has a much bigger impact on the PNG system than the loss of all the core market customers and the likelihood of losing the core market customers is less than the likelihood of losing one industrial customer (T: 554).

In his evidence, Mr. Todd discussed the relative risk of small volume customers versus large industrial customers and concluded that industrial customers impose a significant risk on the system while small volume customers impose virtually no risk. As a result, he suggested that the rate of return on capital applicable to rate base allocated to the industrial customers should be increased and that allocated to small volume classes should be reduced (Exhibit 43, p. 12).

In contrast, Mr. Drazen disputed the notion that industrial customers impose a greater risk on the system than residential customers. Further, he maintained that incorporating a risk premium in the cost of service is counter productive. He suggested that if the cost of service allocated to industrial customers is increased to account for higher levels of risk, and this translates into rates, the effect is to increase the risk that large industrial customers will leave the system because the service will become less affordable (T: 760).

Based on the evidence presented to date, the Commission has formed no opinion as to the relative risks of the various customer classes. **However, based on Exhibit 47, the Commission finds that it is unlikely that any differential allocation of capital costs would have a material impact on the revenue to cost ratios calculated for the various customer classes at this time.**

7.8 Interpretation of Revenue to Cost Ratios

During the course of this hearing, there was significant discussion concerning the interpretation of the results of the FACOS study. In his evidence, Mr. Drazen noted that the Commission has traditionally considered that rates which give rise to ratios within the range of 0.90 to 1.10 are acceptable. However, he maintained that unless there is reason to believe that costs are systematically misallocated, the goal should be to move all rates to a level such that ratios of 1 to 1 are achieved (Exhibit 42, p. 12). Mr. Drazen cautioned against accepting the view that imprecision in the cost study is a sufficient reason to accept a range of revenue to cost ratios (Exhibit 42, p. 14). He recognized that if cost of service study results, done over a period of years, show that the revenue to cost ratio for a particular class fluctuates around 1.00, this may reflect imprecision in the study. However, he stated that if the ratio is consistently above or below 1.00, it is not evidence of imprecision but evidence that the rates are misaligned (T: 802). Further, he noted that if classes were of dissimilar sizes, accepting a target at the end of the range for only one class could have a disproportionate effect on the revenue to cost ratio of other classes (Exhibit 42, pp. 14-15).

In his evidence, Mr. Todd stated that, all other things being equal, rates should be set to target a revenue to cost ratio of 1.0 for all customer classes. However, he stated that the desire to achieve this goal should be tempered by the presence of uncertainty in the cost of service study and the impacts of any rate changes in terms of rate shock and revenue requirement redistribution. As a result, he suggested that the normal practice by most regulators is to rebalance rates so as to achieve revenue to cost ratios for all rate classes which fall into an acceptable range, e.g. 0.90 to 1.10. Mr. Todd suggested that as long as the revenue to cost ratios fall within this range, no rate rebalancing is required. Specifically, he stated that as long as the revenue to cost ratios fall within the range, there is insufficient evidence to determine that the rates are misaligned (T: 873-74). He maintained that as the ratios become closer to 1.0, a higher level of proof that the rates are misaligned is required before rate rebalancing should be undertaken.

The Commission has not undertaken to recalculate the revenue to cost ratios which would arise from its determinations in this Decision. However, based on Exhibits 26, 43, 44, and 45 the Commission is convinced that the resulting revenue to cost ratios for residential and commercial sales customers are sufficiently low and for the four large industrial customers are sufficiently great that some revenue requirement rebalancing is required. More specifically, the Commission is convinced that the revenue to cost ratios for these customer classes fall well outside the 0.90 to 1.10 range which has been used as a guide to the reasonableness of rates in other decisions.

However, as alluded to above, the Commission also recognizes that its duty to set rates which are fair, just and reasonable means that it can not simply follow the results of the cost of service study without regard to issues such as rate shock, the ability of customers to pay, alternatives to a utility's service available to customers, non-quantifiable or not easily quantifiable costs, etc. Such factors may act to move the target for certain rate classes away from 1.0. These situations will need to be determined on an individual basis.

7.9 Proposed Rate Rebalancing

As indicated earlier, and as shown in Table 7.1, the FACOS study provided by PNG suggests that the rates for residential, commercial sales, small industrial sales and small industrial transportation service customers do not recover their cost of service while the rates for the large industrial customers over recover their cost of service. As a result, PNG proposed to increase the annual revenue from residential customers by $825,000, from commercial customers by $875,000 and from small industrial customers by $155,000 and to use the majority of these funds to decrease the revenue from commercial firm transportation customers by $19,000, from Methanex by $1,356,000, from Skeena by $140,000, from Eurocan by $51,000 and for Alcan by $93,000 (see Table 7.1). All revenue changes exclude the cost of gas. PNG proposed to use the remainder of the increased revenue to decrease interruptible transportation service rates to Skeena, Eurocan and Alcan.

PNG has not proposed any rate changes beyond the changes outlined above for 1998. PNG stated that it recognizes that more rate rebalancing will likely be needed to bring the revenue to cost ratios into proper alignment but wishes to postpone such actions until after it has renegotiated its contracts with Methanex. This is due to take place in the fall of 1998 (T: 503).

In his evidence, Mr. Drazen suggested that the PNG rate rebalancing proposal is deficient since the resulting revenue to cost ratio for Methanex for firm service of 1.21 is significantly above 1.0. Mr. Drazen suggested that a new rate rebalancing plan is needed and that PNG should commit to following a two step approach as long as the industrial revenue to cost ratios remain above unity. The two steps are: (i) no revenue requirements increases to those customers with revenue to cost ratios above unity, and (ii) progressive rate rebalancing to equate revenues with cost of service. Mr. Drazen suggested that the increases to other classes from rate rebalancing will be offset in part by flowback of the margins that PNG earns on interruptible gas sales (Exhibit 42, p. 3).

Mr. Drazen also acknowledged that the proposed revenue shift, when combined with the proposed rate design, resulted in high percentage impacts for low volume residential and commercial customers but stated that the need to rebalance rates had to be addressed and that postponing the rebalancing would only make the problem worse (T: 806). Mr. Drazen indicated that he understood concerns with respect to rate shock but stated that the arguments for measured change were not valid given increasingly competitive markets (T: 782). Specifically, he stated that the longer was the rebalancing process, the more likely it was that the Methanex plant would become uncompetitive (T: 806).

Mr. Stulken, a policy witness for Methanex, testified that it is essential that the revenue to cost ratio for firm service for Methanex be reduced to 1.0 as soon as possible. He stated that history shows that the revenue to cost ratios calculated for Methanex have consistently been in excess of 1.0 and that he is not prepared to accept that a revenue to cost ratio of 1.1 for Methanex is satisfactory (T: 704-5). Similarly, Mr. Drazen suggested that Methanex has consistently paid $4 to $5 million dollars above costs for the past several years (T: 756).

In contrast, Mr. Todd suggested that the rate rebalancing proposed by PNG is unjustified. Mr. Todd stated that the Company has not conducted a full cost of service study review and that there is uncertainty as to whether rate rebalancing is required (T: 875). Further, Mr. Todd suggested that before any rate rebalancing is undertaken the Commission should consider the impact on customers, the impact on the community and the other normal rate setting considerations in deciding how rapidly those rates should be changed (T: 876). Finally, Mr. Todd suggested that there are sufficient uncertainties associated with the cost of service study that the Commission should not be striving to achieve revenue to cost ratios of 1.0 (T: 882).

In final argument, CAC (B.C.) et al. stated that it believed that if PNG had conducted a full review of its cost of service study methodology, it would result in a residential revenue to cost ratio that would be higher than 0.81 and perhaps above 0.90. On this basis, CAC (B.C.) et al. concluded that the rate rebalancing increases that have been proposed by PNG are not justified.

Accordingly, CAC (B.C.) at al. urged the Commission to direct PNG to file in its next main rates case an updated cost of service study, that addresses the issues of: (i) crediting the firm customers with an amount that maximizes the contribution from interruptible service for the use of off-peak transportation capacity, and (ii) recognizing the imbalance between the risks that the small volume classes impose on large volume customers, relative to the risk that large volume classes impose on small volume customers.

Commission Determination

As discussed earlier, the Commission finds that the evidence in this hearing indicates that the rates for residential and commercial sales customers significantly under-recover the cost of serving these customers while the rates from the four large industrial customers significantly over-recover the cost of serving them. Accordingly, some level of rate rebalancing is required even though the Commission is concerned that not all the issues associated with setting rates, such as those discussed in the Commission Determinations which follow Section 7.8, have been adequately addressed.

In determining how best to approach this problem, the Commission must be concerned with both the short-term and long-term impacts of rebalancing rates and of failing to rebalance rates. Based on the evidence before it, and after adjusting for the determinations made earlier in this Decision, the Commission is concerned that increasing residential, commercial and small industrial sales rates such that a revenue to cost ratio of 1.0 is achieved could require increasing the residential and small industrial sales revenue requirement, exclusive of gas supply costs, by as much as 50 percent and the commercial sales revenue requirement, exclusive of gas supply costs, by as much as 100 percent. Clearly, such a revenue shift would impose a substantial burden on these customers.

At the same time, it is unfair to expect large industrial customers to pay rates which are substantially in excess of the costs which they impose on the system. Further, if these customers possess alternatives which will allow them to leave the system, it may not be in the best interests of the other customer classes to allow the imbalance in the rates to continue.

As a result, the Commission finds that for 1998, the increases to the revenue from residential sales, commercial sales and small industrial transportation service customers are approved. The proposed decreases to the revenue from large industrial firm service are also approved, subject to the determinations made with respect to interruptible service as set out below. All rate design changes are effective July 1, 1998.

In addition, the Commission invites PNG to apply for further inter-class shifts in the revenue for 1999 and 2000 in line with the direction indicated in the FACOS study submitted as part of this Application. However, such changes, when combined with revenue increases associated with transportation and with changes in gas supply costs, should not result in an increase in the total revenue due from the class, including gas costs, of more than 10 percent. As part of such an Application for an increase, the Commission will require an estimate of the impact such changes will have on the revenue to cost ratios of the classes for which changes are proposed. A new FACOS study will not be required.

7.10 Redesign of Residential and Commercial Rates

In addition to the revenue requirement shifts discussed above, PNG proposed to redesign the form of the residential and commercial rates. With respect to the residential rates, PNG proposed that the monthly minimum charge of $7.772, which contains an allowance for 1 GJ of gas, be replaced with a basic charge of $10.75 with no allowance for a minimum GJ take, and that the current bundled rate for gas and transportation be replaced with an unbundled rate.

With respect to commercial firm service sales rates, PNG proposed that the minimum monthly charge of $6.506 be replaced by a basic charge of $10.75 and that the delivery and gas charges be unbundled. In addition, PNG proposed to unbundle the commercial interruptible sales rates but not change the revenue requirement associated with the rate.

In its Application, PNG indicated that the rate design changes would result in an annual bill increase, inclusive of gas costs, of 5.7 percent for a typical residential customer, 11.8 percent for a typical commercial customer and 7.9 percent for a typical small industrial customers. For a typical small industrial transportation customer, the annual bill increase would be 5.7 percent. However, the range of bill impacts is much greater. For residential customers taking 25 GJ, the annual bill increase is 56.01 percent while for those who take more than 200 GJ per year, the annual bill is reduced by 3.52 percent or $59.13. Approximately 20 percent of residential customers will experience annual bill increases of greater than 10 percent (Exhibit 26). For commercial sales customers, the annual bill impacts range from increases of 88.55 percent or $122.55 for customers who take less than 25 GJ per year to decreases of 7.39 percent or $670.33 for customers who take over 1000 GJ per year. Approximately 75 percent of commercial sales customers will experience bill impacts in excess of 10 percent.

PNG acknowledged that the high percentage impact on low volume residential and commercial customers was the result of both moving to a basic monthly charge from a minimum monthly charge that included 1 GJ of gas and the result of increasing the level of the charge. However, PNG stated that it considered the basic monthly charge it was proposing to be appropriate since it was important to reflect in rates the fact that there are certain facilities that attract costs regardless of the volumes delivered (T: 618). Further, PNG indicated that the basic monthly charge for residential customers had been set to ensure that the customer-related operating and maintenance expenses, i.e. the customer-related variable costs, were recovered (Exhibit 2, Tab 1, p. 79). Finally, PNG suggested that the actual dollar increases associated with bills for low volume customers had to be considered and that these were not excessive (T: 617-18).

Commission Determination

In its Application, PNG has proposed to unbundle its rates for residential and firm commercial sales customers. The Commission accepts that such unbundling provides customers with clearer price signals and is in the best interest of customers. Accordingly, the Commission approves the unbundling proposal.

With respect to the increase in the basic charges proposed by PNG, the Commission notes that the basic charges proposed exceed those which are in place for the British Columbia Hydro and Power Authority, BC Gas Utility Ltd. and West Kootenay Power Ltd. Further, the Commission recognizes that these changes result in substantial bill impacts for low volume customers when the impacts are viewed on a percentage basis. As a result, the Commission has some concern about the level of the proposed basic charges.

At the same time the Commission notes that, for residential customers at least, the basic charge is being proposed to recover only about a third of the customer costs, as indicated by the FACOS study. Further, the Commission is of the view that the bill impacts are manageable when viewed in dollar terms.

Accordingly, the Commission approves the rate redesign as filed by PNG.

7.11 Determination of Appropriate Interruptible Transportation Rate

Presently, Skeena, Eurocan and Alcan pay approximately 4.5 times as much for interruptible service as does Methanex. In the past, this differential has been defended on the grounds that Methanex receives a lower priority of interruptible service than do the other three customers. In this Application, PNG proposes to reduce the interruptible transportation service rates charged these three customers by approximately 13.0 percent because it believes that the large relative difference in the interruptible rates overvalues the relative difference in priority of interruptible service (Exhibit 2,Tab 1, p. 11).

PNG stated that the interruptible transportation service rates applicable to PNG's large industrial customers were negotiated several years ago and suggested that the rates should continue to be set by negotiation (T: 609). Although PNG agreed that interruptible rates should be set to maximize the return to the core markets, PNG stated that care had to be taken that rates are not set so high that sales are negated (T: 610). PNG indicated that it believed that the interruptible rates which it is proposing for interruptible service are as high as they could reasonably be (T: 601).

Some parties suggested that the differential in the interruptible rates for Methanex and the other large industrial customers could be reduced by raising the rate to Methanex. However, PNG stated that the rate for Methanex is set low in order to retain Methanex and to encourage it to take at a high load factor and reduce its average unit cost (T: 611).

In its direct evidence, Methanex indicated that it supports PNG's decision to leave Methanex's interruptible prices at its current level, although Methanex believes that in the longer term it would be beneficial to both PNG and Methanex if a price for interruptible service could be negotiated which would recognize that the value of transportation varies with methanol prices. Methanex stated that operationally this approach would require that when Methanex has excess production capacity, the price of interruptible transportation service would be set below the current rate and when the demand for methanol is high, the price of transportation would be established above current rates (Exhibit 38, p. 5).

In response to this suggestion, PNG stated it hadn't looked at the actual mechanics of the proposal in detail, and that certain operational details would need to be considered, but that it believed the concept had merit (T: 612).

Commission Determinations

As suggested earlier in this Decision, the Commission is of the view that the value of interruptible transportation service should be credited to the benefit of those firm service customers who cause a transportation service valley to be created. The logical progression of this view is that interruptible transportation service should be priced to maximize the return to those firm service customers.

The Commission agrees with PNG that maximizing the return to these customers requires an evaluation of the effect of the per GJ price for interruptible service on the volumes of interruptible service taken. More specifically, what is required is to set the price such that the total profits from interruptible service are maximized.

In this case, the Commission finds that PNG has not presented sufficient evidence for the Commission to form the view that total profits from interruptible transportation service will be maximized if the rates for interruptible transportation service to Skeena, Eurocan and Alcan are reduced. **Accordingly, the Commission does not approve the proposed interruptible rate decreases to these customers. The Commission is also concerned that the interruptible transportation service to Methanex may be priced too low; however, there is insufficient evidence to verify this concern.**

The Commission recognizes that in not approving the proposed rate decreases to the three large interruptible customers, PNG will obtain more revenue than anticipated in the Application. **Accordingly, PNG is directed to estimate the extra revenue and to use this excess to reduce firm rates to all large industrial customers.**

8.0 ON-SYSTEM INTERRUPTIBLE GAS SALES

PNG frequently has gas (including company use gas) available under its supply contracts that is surplus to the needs of its firm sales or core customers. PNG sells this "valley gas" to on- and off-system customers when possible, and credits the net revenue to the firm sales customers. On-system interruptible customers currently pay the weighted average commodity (variable) cost of the gas, but PNG proposes to begin charging a price that reflects the market value of the commodity. This change is reflected in the 1998 Rate Design Study, which no longer includes an imputed value of interruptible gas sales similar to that calculated in the 1995 Rate Design Study.

8.1 Market-Based Pricing Proposal

PNG proposes to sell interruptible gas to on-system industrial customers at Summit Lake, at a price that is based on the Gas Daily Price Reporter daily index at Station 2 (Exhibit 2, Tab 1, p. 10; Exhibit 2, BCUC IR No. 1, pp. 47-54). The following pricing terms would be incorporated into the Firm Transportation Service and Interruptible Sales Agreements with the customers;

"4.2 Shipper shall pay to Pacific Northern for Interruptible Gas sold and delivered to Shipper in each Day in the term of this Agreement an amount equal to the sum of:

(a) daily commodity charges equal to the sum of:

(i) the greater of the midpoint of the Westcoast Energy Inc. ("Westcoast") Station #2 Daily Price as published in the Gas Daily Price Reporter less

$____/GJ and the weighted average commodity cost of gas purchased by Pacific Northern for system supply plus $____/GJ; plus

(ii) the firm Westcoast Transportation-South toll payable by Pacific Northern to Westcoast at a 100 percent load factor; ..."

PNG states that its objective is to maximize the return to core customers from interruptible commodity sales, and believes that a discount of $0.02/GJ off the daily index price is sufficient to ensure that industrial customers will buy interruptible valley gas when it is available (T4: 625-28). A floor price is included so that interruptible sales will return some contribution above the weighted average commodity cost of the gas, but PNG feels the premium above commodity cost will not be large (T4: 629). The Westcoast Transportation-south charge would include the cost of Westcoast fuel and motor fuel tax (T4: 630).

PNG proposes to establish the details of the new pricing terms through annual negotiation with its industrial customers, and to file the amended price terms for Commission approval pursuant to Section 61 of the Act. On receiving Commission approval, the price terms would form part of PNG's tariff. PNG would file a quarterly report with the Commission that would show the prices actually charged to industrial customers for interruptible gas during the previous quarter. This information will be available to the public (PNG Reply Argument dated April 27, 1998).

8.2 Commission's Authority to Approve Index-Based Prices

CAC (B.C.) et al. filed Argument regarding On-System Sales of Interruptible Gas on April 20, 1998, in which it made several points, including:

1. PNG is a public utility under the Act;
2. The price charged by PNG for interruptible gas is a "rate" for a "service", as those terms are described in Section 1 of the Act;
3. The Act requires the Commission to set rates for services provided by public utilities;
4. The proposed pricing scheme for interruptible gas contravenes Section 61 of the Act; and,
5. One of the central purposes of the Act is to provide a regulatory process whereby the Commission sets rates for services provided by public utilities. The Act does not permit rates to be set by the unregulated market place. The Commission has a duty to set rates in accordance with the procedures and considerations provided under the Act.

In its Reply Argument dated April 27, 1998 to the CAC (B.C.) et al. Argument, PNG submits that its proposal is consistent with Section 61. PNG further argues that the proposed formula for interruptible gas prices is a "rate" as defined by the Act. Finally, PNG submits there is nothing in the Act that fetters the Commission's discretion to approve a rate that references and incorporates the actual daily market price for gas or PNG's weighted average commodity cost of gas.

Methanex addressed CAC (B.C.) et al.'s arguments (Methanex Final Argument, p. 25) by submitting that PNG's proposal is both beneficial and legal. It takes the position that there is nothing in the Act that requires a fixed "price" for gas rather than a formula. Further, Methanex submits that formula-driven prices are a practical necessity in commerce and have long been accepted by the courts and contracting parties. Methanex submits that the Commission should accept a "formula" based rate, provided all of its essential elements are in place and have been approved and published by the Commission in advance.

In its Reply Argument, CAC (B.C.) et al. submits that "rate" means a fixed amount or price. Furthermore, it argues that Sections 60 and 61 describe the specific rate-making process to be used by the Commission. Finally, in response to Methanex's argument, CAC (B.C.) et al. submits that the fact a rate formula may be preferable in a commercial context does not answer whether the Commission has the jurisdiction to approve the scheme proposed by PNG.

Issues

The central issue raised by CAC (B.C.) et al. is whether a "rate" pursuant to the Act must be a fixed price described in the tariff (eg. $1.50 per GJ) or whether it can also be a "formula" which describes the components that make up the eventual price that is paid, without prescribing the actual fixed price to be paid. CAC (B.C.) et al. argues a rate must be a fixed price, while both Methanex and PNG argue a rate includes a formula, provided the formula is approved by the Commission and published in a tariff schedule. A second issue is whether the formula can reference market-based price indices.

Legislative Framework

The Commission can only implement a rate proposal if it is within the Commission's jurisdiction to do so. In this respect, the comments of the Commission set out in the Rate Design Application by BC Gas Inc. Decision dated February 21, 1992 (the "Phase A Decision") are particularly noteworthy. Specifically, at p. 8 the Commission stated:

> "It is not uncommon for regulatory tribunals, particularly in times of rapidly changing social and economic circumstances, to find themselves in a position where there are apparent conflicts between their statutory duties and the evolving social and economic circumstances. Trends develop within regulated industries that may influence the approach of regulators. Similarly, government policy statements are made from time-to-time which also may affect regulatory decision making. The pace of the legislation may not keep up and this can lead to difficulties in the correlation between evolving views and policies and the statutory framework within which the Commission must function. In the final analysis, the statute must remain paramount."

In the absence of legislative amendments the Commission is bound to follow the provisions of its enabling legislation, even if the outcome may not be preferable. When markets are evolving, it is possible that the existing statutory framework, established in a different economic environment, may no longer be optimal.

Formula Based Rates

Section 1 of the Act defines "rate" as including:

> "(a) a general, individual or joint rate, fare, toll, charge, rental or other compensation of a public utility;
> (b) a rule, practice, measurement, classification or contract of a public utility or corporation relating to a rate, and
> (c) a schedule or tariff respecting a rate."

"Compensation" is defined in Section 1 as meaning:

> "a rate, remuneration, gain or reward of any kind paid, payable, promised, demanded, received or expected, directly or indirectly, and includes a promise or undertaking by a public utility to provide service as consideration for, or as part of, a proposal or contract to dispose of land or any interest in it."

The definition of "rate", which incorporates by reference the definition of "compensation", is very broad. It does not specifically state that a "rate" must be a fixed unit price, nor does it expressly state that a "rate" can include a formula.

Market Pricing

PNG proposes to calculate its interruptible gas rates, in large part, on the basis of reported market indices. This raises the question as to whether the Commission has the jurisdiction to set rates that are determined in whole or in part by the marketplace. There are no express prohibitions against market-based pricing in the Act.

Methanex referred in its Argument to the current BC Gas rate for interruptible customers. Since November 1993, the Commission has approved a formula-based approach for BC Gas that is similar to the PNG proposal (BC Gas Schedule 10 Rates for Large Volume Interruptible Sales). There is currently no reference to a specific, fixed price in Schedule 10. Rather, the Table of Charges refers to an "Index Price" which in turn references Inside FERC's Gas Market Report and the Canadian Gas Reporter.

Moreover, PNG's current price for interruptible sales relies on the Commission's ability to approve a price calculation methodology rather than a fixed price. The purchase price that PNG pays for gas is largely based on reported indices. PNG has described how it estimates its weighted average commodity cost of gas for a month during the first four or five days of the month and advises its industrial customers (T: 629). Also, PNG occasionally buys spot gas at the market price to supplement its valley gas supplies, and the cost of this gas is generally allocated to the interruptible industrial customers (T: 631-32). In neither case does PNG obtain prior approval for the specific unit prices that it will charge the customers.

Commission Determination

The Commission concludes that it has the jurisdiction to approve a rate formula, provided the Commission is of the view that the resulting price paid by the consumer can be ascertained in advance with reasonable certainty, and the rates are non-discriminatory, fair, just and reasonable.

The Commission has a fairly broad, discretionary power to set rates, provided the resulting rates satisfy the prescribed statutory criteria. Moreover, PNG proposes to file the actual prices it charges customers with the Commission on a non-confidential basis.

While the PNG proposal uses reported market indices in the calculation of prices charged to customers, the Commission does not consider that PNG is asking the Commission to delegate its ratemaking authority to the market. Rather, the Commission concludes that rate schedules that reference market-based price indices can provide ratepayers with non-discriminatory, fair, just and reasonable rates at prices which the customer can determine with reasonable certainty prior to committing to the purchase.

8.3 Implementation of Market-Based Pricing

CAC (B.C.) et al. questions the Commission's jurisdiction to approve PNG's interruptible pricing proposal, but does not address the timing of implementation should the Commission find the rate methodology to be in the public interest.

Methanex supports the interruptible sales pricing approach that is proposed by PNG. The company recognizes that market-based pricing will increase the cost of the valley gas it buys, but accepts this increase as a necessary part of ending the imputation of the value of gas sales for rate design purposes (Methanex Reply Argument, pp. 15-16).

Having concluded that it has authority to deal with PNG's proposal, the Commission notes that no concerns were raised about the merits of the approach. **Based on the evidence before it, the Commission concludes that this market-based methodology will recover the maximum benefit from the sale of valley gas for core customers without imposing inappropriate costs on other customers**. It remains necessary to quantify several parameters in the formula, which raises the issue of how and when the changes should be implemented.

Market-based pricing will generate revenue that will be used to partially offset the gas supply costs of core market customers. Therefore, there is reason to implement the new pricing as soon as possible. It is unclear how long PNG would need to negotiate the details of the arrangement. Considering the general lack of discussion about the formula that PNG proposes and the modest impact of small changes to the outstanding parameters, the Commission concludes that it should approve a pricing formula as a default. In the event PNG determines some modifications are appropriate, it can request approval of an amended Rate Schedule, or a Tariff Supplement for an individual customer. In any case it is likely that the parties will wish to review the matter prior to the start of the next contract year.

The Commission directs that, commencing July 1, 1998, PNG will price interruptible gas sold to on-system industrial customers according to the market-based formula it has proposed, and will use $0.02/GJ for both the discount off the published Station 2 daily price and the premium over the weighted average commodity cost of gas.

9.0 GAS COST ALLOCATION

In its 1997/98 gas contracting plan, PNG recommended that natural gas requirements for the PNG-West service area, the Dawson Creek service area of Pacific Northern Gas (N.E.) Ltd. and the service area of Centra Gas Fort St. John Inc. be amalgamated into one demand and supply pool. Commission Letter No. L-19-97 accepted this approach, and directed PNG to file a gas cost allocation methodology to distribute pooled supply costs among these service areas. In its 1998 Cost of Service Allocation/Rate Design Study, PNG outlined its proposed allocation methodology. The methodology was discussed by representatives of PNG, CAC (B.C.) et al. and Commission staff prior to the hearing as part of the ADR process. On April 3, 1998 PNG filed its more detailed Allocation of Forecast 1998 Gas Supply Costs (Exhibit 24).

9.1 Gas Cost Allocation Methodology

Demand (Fixed) Charges

Demand charges are fixed costs that are payable whether or not any gas is purchased. PNG proposes to allocate demand costs between service areas ("divisions") and among firm sales rate classes within a division (including company use gas) based on forecast volumetric peak day gas requirements. The volumetric peak day numbers are derived from forecast peak day energy demands, using the projected heat content published by Westcoast for each division. For 1998, PNG applied heating contents of 39.30, 40.12 and 39.18 $GJ/10^3m^3$ for PNG-West, Fort St. John and Dawson Creek respectively.

The Fort St. John and Dawson Creek divisions have access to Westcoast Off-line service for a portion of the baseload gas purchases that are allocated to them. The allocation of regular Westcoast gathering, processing and Transportation-north demand charges recognizes the use of Off-line service.

Baseload gas supply demand charges and Westcoast demand charges that are incurred to deliver gas to Aitken Creek storage during the injection period are accumulated in the cost of storage gas inventory, and recovered when the storage gas is delivered to customers. Also, demand charges that are incurred specifically to serve one division, such as Westcoast Transportation-south to serve PNG-West, are allocated directly to that division.

In the case of seasonal gas supply contracts that require PNG to purchase gas at 100 percent load factor over the delivery period, PNG deems 25 percent of the gas price to be a demand charge.

Commodity (Variable) Charges

PNG proposes to allocate pooled commodity charges each month, based on deliveries to each division during the month. Charges that relate to a specific division are allocated directly to that division. Commodity charges are allocated to the classes in a division each month based on deliveries to the class.

Westcoast Off-line service commodity charges to a division for a month are calculated based on purchases for the division during the month. These Off-line charges will be allocated based on the deliveries to the division, purchases for the division that are used for storage injection, and purchases for the division that are used for valley gas sales (Exhibit 24, pp. 12-3; T5: 649).

Charges that are accumulated respecting the cost of gas injected into storage will be recovered on an average cost basis as gas is withdrawn from storage. Also, PNG proposes that the cost of seasonal and peaking gas will not be allocated to commercial interruptible and seasonal off peak customers in PNG-West (T: 656-57).

9.2 Revenue from Interruptible Gas Sales

As discussed in Section 8.3, PNG intends to sell valley gas to on-system interruptible customers at market-based prices, and credit the net revenue to the cost of gas for firm sales customers. The Commission approves this approach commencing in 1998. Any net revenue from off-system sales will be included in valley gas revenue.

The net revenue from valley sales has two components, as illustrated by the pricing terms set out in Section 8.1. The gas portion relates to the sale of the gas commodity, and will be calculated as the selling price less the variable cost of the gas. PNG proposes to allocate the gas part of the revenue among the three divisions based on the demand charges allocated to each division. Demand charges such as Westcoast Transmission-south that are specific to a division will be deducted prior to calculating the allocation factors (T: 589-90).

The other component of interruptible sales revenue relates to the use of Westcoast Transportation-south. Since PNG-West customers pay the demand charges for this service, all revenue from its use for interruptible sales will be used to reduce the demand charges payable by PNG-West firm sales customers (T: 648).

Within a division, the valley gas credit will be used to reduce the total demand charge, and hence will flow back to each class based on its peak day demand.

PNG proposes to include $250,000 of net revenue from valley gas sales in its allocation of forecast gas costs for 1998. This is considerably less than its earlier estimate of $545,000 of net revenue for June through December 1998 (Exhibit 2, BCUC I.R. No. 1, p. 54). PNG considers that $250,000 is a conservative number which will avoid the under-collection of costs. The number does not include revenue from the use of Transportation-south (T: 645-46).

9.3 Implementation of Gas Cost Allocation Methodology

PNG proposes to continue its practice of forecasting annual gas costs prior to the start of each calendar year, and will seek Commission approval of rates effective January 1 that are calculated using the cost forecast and the foregoing allocation methodology. Immediately after the end of the year, the Utility will compare actual demand and commodity charges to forecast gas costs. Actual gas costs will be allocated to each division and customer class using the same methodology that was used for forecast costs. Differences between actual and forecast costs will be recorded in a gas supply cost deferral account for each division, and will be recovered through rate riders over the following two years. Rates at the beginning of each year will be interim, pending the determination of the rate riders.

CAC (B.C.) et al. states that the proposed allocation methodology reflects consultations with CAC (B.C.) et al., and that it does not object to approval of the proposal (T: 988). Methanex supports the allocation of revenue from valley gas sales to the cost of gas to the core market (T: 988).

Commission Determinations

The Commission is of the view that PNG's gas cost allocation methodology generally provides a reasonable balance of fairness and ease of administration.

One area of concern is the use of volumetric peak day demand to allocate demand charges among divisions. A review of the summary of its gas supply contracts indicates that PNG generally buys supply on an energy basis, i.e. per GJ. Also, the Westcoast gathering, processing, Transportation-north and Off-line charges that apply to the baseload contract are discussed in terms of energy, and PNG uses energy quantities to calculate factors to allocate these charges. Consequently, energy peak day appears to be a more appropriate basis for inter-divisional allocations than volumetric peak day. The expression of peak day demand on a volumetric or energy basis has no effect on the allocation of gas costs within a division, where the same heating value applies for all classes.

The Commission approves PNG's gas cost allocation methodology, but directs PNG to recalculate its Pooled Demand Charge Allocation Factors for 1998 on the basis of the peak day energy demand of each division. Further, PNG is directed to review its gas cost allocation for consistency with the foregoing discussion, and to file gas costs for all classes effective January 1, 1998 for Commission approval.

The Commission approves the continuation of a gas supply cost deferral account for each division of PNG and its subsidiaries, and directs that rates in all divisions will become interim at the start of each calendar year, pending the approval of the applicable gas cost rate riders.

10.0 COMMISSION DECISION

Based upon the evidence before it, and arguments made by the participants, the Commission hereby directs PNG to abide by the determinations made in this Decision and the attached Order No. G-53-98.

Dated at the City of Vancouver, in the Province of British Columbia this 18th day of June, 1998.

Peter Ostergaard

Peter Ostergaard
Chair

F.C. Leighton

F.C. Leighton, P.Eng.
Commissioner

Paul G. Bradley

Paul. G. Bradley
Commissioner

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ORDER
NUMBER G-53-98

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

and

An Application by Pacific Northern Gas Ltd.
for Approval of a 1998 Rate Increase and its 1998 Rate Design Study

BEFORE:	P. Ostergaard, Chair	)	
	F.C. Leighton, Commissioner	)	June 18, 1998
	P.G. Bradley, Commissioner	)	

O R D E R

WHEREAS:

A. On November 28, 1997, Pacific Northern Gas Ltd. ("PNG") filed, pursuant to Sections 58 and 91 of the Utilities Commission Act, a 1998-2002 Performance Based Rates ("PBR") Revenue Requirements Application ("the Application") for Commission approval to increase its gas rates on an interim and final basis, effective January 1, 1998, and to implement a PBR proposal for the 1999 to 2002 fiscal periods; and

B. On November 28, 1997, PNG filed its 1998 Cost of Service Allocation/Rate Design Study ("the Study") which included a methodology for the allocation of gas costs among the PNG service area, the Dawson Creek service area of Pacific Northern Gas (N.E.) Ltd., and the service area of Centra Gas Fort St. John Inc.; and

C. On December 4, 1997, the Commission, by Order No. G-124-97, approved an interim rate increase for PNG, effective January 1, 1998, and set down a Pre-hearing Conference to discuss various facets of the Application and the Study along with a regulatory agenda; and

D. On January 15, 1998, the Commission, by Order No. G-7-98, set a regulatory agenda which included an Alternative Dispute Resolution ("ADR") process to commence on February 17, 1998; and

E. As the participants to the ADR process were unable to reach a settlement, on February 19, 1998, the Commission, by Order No. G-18-98, set the public hearing to commence on March 30, 1998, in Prince Rupert and to continue on March 31, 1998, in Vancouver; and

F. On March 16, 1998, PNG filed a revision and update to the Application and withdrew the PBR proposal; and

G. The Commission has considered the Application and the evidence adduced thereon, all as set forth in the Decision issued concurrently with this Order.

.../2

NOW THEREFORE the Commission, for reasons stated in the Decision, orders PNG as follows:

1. The interim rates approved as of January 1, 1998, by Order No. G-124-97, are hereby cancelled subject to the timely filing by PNG, and acceptance by the Commission, of amended Gas Tariff Rate Schedules conforming to the terms of the Commission's Decision.

2. PNG is to refund any overpayment in rates from its customers with interest calculated at the prime rate of the principal bank with which it conducts its business. PNG is to provide the Commission with a detailed Summary of Rates and a reconciliation schedule verifying any refund. PNG will provide all customers with an information notice and summary of the Commission's Decision.

3. PNG is to file, on a timely basis, amended Rate Schedules 1 - 5 as found in the revised Application of March 16, 1998, conforming to the terms of the Commission's Decision.

4. Rate design changes required by the Decision are to be implemented effective July 1, 1998.

5. Gas cost changes required by the Decision are to be implemented effective January 1, 1998.

6. PNG is to comply with all directions contained in the Decision accompanying this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 18th day of June, 1998.

BY ORDER

Peter Ostergaard

Peter Ostergaard
Chair

APPEARANCES

G.A. FULTON	British Columbia Utilities Commission, Counsel
J. LUTES	Pacific Northern Gas Ltd., Counsel
R.B. WALLACE	Methanex Corporation, Counsel
J. QUAIL P. MACDONALD	Consumers' Association of Canada (B.C. Branch) et al. [British Columbia Old Age Pensioners' Organization, Council of Senior Citizens' Organizations of B.C., Federated Anti-Poverty Groups of B.C., Senior Citizens' Association of B.C., West End Seniors' Network, B.C. Coalition for Information Access, End Legislated Poverty and the Tenants' Rights Coalition]

F.S. JAMES B. McKINLAY D.W. EMES J.B. WILLSTON J.J. HAGUE	Commission Staff
ALLWEST REPORTING LTD.	Court Reporters & Hearing Officer

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