SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-72-01

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF

the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Pacific Northern Gas (N.E.) Ltd.
for Approval of 2001 Revenue Requirements

BEFORE:	P. Ostergaard, Chair P.G. Bradley, Commissioner N.F. Nicholls, Commissioner	July 5, 2001

O R D E R

WHEREAS:

A. In a 2001 Revenue Requirements Application, dated December 1, 2000 and revised December 18, 2000, Pacific Northern Gas (N.E.) Ltd. ["PNG(N.E.)"] applied to increase its rates on an interim and final basis, effective January 1, 2001 ("the Application"), pursuant to Sections 91 and 58 of the Utilities Commission Act; and

B. Commission Order No. G-128-00 accepted PNG(N.E.)'s December 18, 2000 projection of total natural gas purchase costs for 2001 and approved the Gas Supply Charges for Fort St. John and Dawson Creek as interim rates, effective January 1, 2001, subject to refund with interest. Gas Supply Charges for Tumbler Ridge were approved as final, effective January 1, 2001, as set out in the Application; and

C. Commission Order No. G-129-00 approved interim increases in the Delivery Charges, effective January 1, 2001, subject to refund with interest, to recover the projected revenue deficiencies. The Order also established a Regulatory Agenda for a written hearing process; and

D. The Commission has reviewed the Application and the evidence adduced thereon, all as set forth in the Reasons attached as Appendix A.

NOW THEREFORE the Commission orders as follows:

1. The Commission has reduced the revenue deficiency to $5,000 for the Fort St. John/Dawson Creek Division and to $122,000 for the Tumbler Ridge Division, as filed in the schedules accompanying the PNG(N.E.) Final Argument and adjusted in the Reasons attached as Appendix A to this Order.

2. The Commission approves as final the Gas Supply Charges for the Fort St. John/Dawson Creek Division, as filed in the schedules accompanying the Final Argument.

3. PNG(N.E.) is to inform all affected customers of the final rates by way of a customer notice.

4. The Commission approves the proposed new main extension test, subject to review of the actual tariff when it is filed.

5. Since the approved rates are less than the interim rates, which have been in effect since January 1, 2001, PNG(N.E.) is to file an amended Summary of Rates and Bill Comparison schedule conforming to the terms of the Reasons attached as Appendix A to this Order, along with a method for refunding excess payments back to customers.

6. The Commission will accept, subject to timely filing, amended Gas Tariff Rate Schedules in accordance with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this *tenth* day of July 2001.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

Attachment

PACIFIC NORTHERN GAS (N.E.) LTD.
APPROVAL OF 2001 REVENUE REQUIREMENTS

REASONS FOR DECISION

1.0 INTRODUCTION

1.1 Background

Pacific Northern Gas (N.E.) Ltd. ["PNG(N.E.)"] is a wholly-owned subsidiary of Pacific Northern Gas Ltd. ("PNG"), a British Columbia natural gas utility. Westcoast Energy Inc. ("WEI") owns about 42 percent of the common equity of PNG and all of the voting shares. PNG is primarily an industrial gas transmission system serving communities west of Prince George extending to Kitimat and Prince Rupert. PNG(N.E.) operates the Fort St. John/Dawson Creek and the Tumbler Ridge Divisions, serving over 15,000 customers. Although PNG(N.E.) has its own field staff, PNG provides the administrative services such as Executive Management, Human Resources, Accounting and Financial Reporting, Treasury Services, Gas Supply and Regulatory Services, Planning and Budgeting, Information Technology Support, Corporate Governance and other services, which are provided by WEI under its Administrative Services Agreement with PNG.

Due to the rapidly increasing cost of gas and, in PNG's case, the shutdown of its largest industrial customer, the companies implemented a major restructuring plan in 2000 to reduce operating, maintenance, administrative and general expenses.

1.2 The Application

On December 1, 2000, PNG(N.E.) applied to the Commission for interim and permanent rates effective January 1, 2001 ("the Application") pursuant to Sections 91 and 58 of the Utilities Commission Act. The Application included a request for approval to flow through projected higher natural gas purchase costs for 2001 under the approved gas supply contracts for the service areas, based on November 23, 2000 forward gas prices for 2001 that averaged US$5.47/MMBtu at Sumas and a currency exchange rate of US$0.650/$Cdn. The gas cost allocation calculation for Fort St. John and Dawson Creek deemed that the gas commodity purchase costs are 25 percent fixed charges and 75 percent variable charges.

On December 19, 2000, PNG(N.E.) provided a gas cost allocation calculation for Fort St. John and Dawson Creek that deemed gas commodity purchase costs as 100 percent variable charges. This calculation yielded Gas Supply Charges that are more comparable to the market value of the natural gas commodity, especially for large commercial and small industrial customers.

On December 18, 2000, PNG(N.E.) revised the Application and included a request to increase the gas supply cost deferral account Rider from $0.10/GJ to $0.30/GJ based on recovery of the account balance to the end of 2000 over three years. The revised Application proposed to establish an approved revenue deficiency of $235,000 for the Fort St. John/Dawson Creek Division (a 0.68 percent increase) and $174,000 for the Tumbler Ridge Division (an 8.61 percent increase). PNG(N.E.) made further amendments to its Application as part of the Final Argument filed on March 19, 2001, increasing the Fort St. John/Dawson Creek Division revenue deficiency by $60,000 and decreasing the Tumbler Ridge Division revenue deficiency by $9,000.

1.3 Commission Orders

Commission Order No. G-128-00 accepted PNG(N.E.)'s December 18, 2000 projection of total natural gas purchase costs for 2001 and approved the Gas Supply Charges for Fort St. John and Dawson Creek as interim rates, effective January 1, 2001, subject to refund with interest. The interim approval allowed participants to review the merits of the PNG(N.E.) proposal to set gas costs on a 100 percent variable methodology. Gas Supply Charges for Tumbler Ridge were approved as final, effective January 1, 2001, as set out in the Application.

Commission Order No. G-129-00 approved interim increases in the Delivery Charges, effective January 1, 2001, subject to refund with interest, to recover the projected revenue deficiencies. The Order also established a regulatory agenda for a written hearing process.

1.4 The Written Hearing Process

Interventions were received from the Peace River Regional District, the City of Dawson Creek, the Mayor of Dawson Creek, Canadian Forest Products Ltd., and the B.C. Public Interest Advocacy Centre on behalf of the Consumers Association of Canada (B.C.) et al. ("CAC (B.C.) et al."). After a series of Information Requests and Responses, submissions were received from the Peace River Regional District, the Mayor of Dawson Creek, and CAC (B.C.) et al. PNG(N.E.) filed its Final Argument on March 19, 2001.

2.0 REVENUE REQUIREMENTS

2.1 Expenses

The Application, as amended December 18, 2000, is a two-part document consisting of independent applications for the two divisions. PNG(N.E.) stated that the majority of the cost increases were due to factors beyond their control as they relate to higher gas supply prices and depreciation and financing costs due to higher rate base. As well, the Quintette Mines Limited ("Quintette") coal mine ceased operations in September 2000 and the reduction in margin is the main reason for the Tumbler Ridge revenue deficiency.

In general, capital expenditures have decreased in both divisions; however, this increases annual expenses as it results in lower transfers of construction costs to capital. The bulk of the rate base changes and related costs in the Fort St. John/Dawson Creek Division is due to customer growth, which requires new mains and services. Tumbler Ridge added new purification equipment in the gas processing facility. As well, working capital requirements for both divisions increased mainly due to the higher cost of financing purchases of natural gas. In general, the costs are considered reasonable by the Commission.

The Application has fully amortized (net of income tax) $188,000 in restructuring costs incurred in 2000. The response to BCUC Information Request No. 1, page 1, noted that the actual costs were less at $156,000 and that this cost was more than offset by ongoing cost reductions of approximately $349,000 per year. The reduction in actual costs was reflected in the schedules accompanying Final Argument for the PNG(N.E.) Fort St. John/Dawson Creek Division.

The restructuring consisted of the termination of over the counter service and the creation of a Customer Care Centre in Terrace. This resulted in the elimination of nine clerical positions in the Fort St. John and Dawson Creek offices and an increase in the shared service costs charged by PNG. Several positions have also been eliminated in the PNG Vancouver head office and the shared services accounts were reduced to reflect this [CAC (B.C.) et al. IR 1, p. 4]. The Mayor of Dawson Creek, the Peace River Regional District, and CAC (B.C.) et al. were all concerned with PNG's decision to move local customer service functions to the Terrace Call Centre. In its response to BCUC Information Request No. 1, page 2, PNG(N.E.) stated that the reorganization focussed on the administrative and customer accounting activities, and that no outside field workers or emergency response personnel positions were impacted. However, the Peace River Regional District remained concerned that the pressure created by higher gas prices may lead to a future decrease in the number of these positions and safety-related investments (Peace River Regional District Argument, p. 3). The Commission will continue to monitor the situation to ensure that safety concerns are addressed. In addition, the Commission is aware of startup problems with the Terrace Call Centre and will review PNG's actions to ensure customers receive adequate service at lowest cost.

Income taxes have increased, partly because rate base is higher and partly because PNG(N.E.) is regulated on a taxes payable basis and depreciation now exceeds the capital cost allowance in both divisions. However, the schedules in Final Argument do properly reflect the decrease in the income tax rate. These schedules also correct the B.C. Capital Tax calculation as noted in the response to CAC (B.C.) et al. Information Request No. 1, page 2.

2.2 Shared Services

The costs of shared services provided by PNG are allocated to the divisions based on the number of employees or the number of customers served. CAC (B.C.) et al. submitted that without additional service, or any indication of possible cost offsets, it is inappropriate to charge higher costs to Tumbler Ridge customers. However, according to the response to BCUC Information Request No. 1, page 6, the customer service function was previously being performed by staff in the Dawson Creek office and should be viewed in the context of the overall reduction in PNG(N.E.) costs.

2.3 Financing

All submissions noted the hardships caused by rapidly escalating natural gas prices. CAC (B.C.) et al. argued that "the utility shareholder cannot be held whole in this environment" [CAC (B.C.) et al. Argument, p. 1]. However, PNG(N.E.) argued that the Commission does not have the authority to reduce the opportunity for the shareholder to earn its return on the approved rate base to offset the effect of high gas commodity prices on rates [PNG(N.E.) Final Argument, p. 6]. PNG(N.E.) has appropriately incorporated in these schedules the 9.75 percent return on common equity for the Fort St. John/Dawson Creek Division and the 10.00 percent for the Tumbler Ridge Division, as predetermined by a Commission-approved mechanism.

PNG(N.E.) is not able to obtain financing on its own and is mainly financed by PNG through an equity position and through the PNG operating line of credit and secured debentures. The secured debentures have a fixed 8.75 percent interest rate, and $8 million of the long-term debt is subject to an interest rate swap arrangement with the Canadian Imperial Bank of Commerce at an effective fixed rate of 8.45 percent. This arrangement formed part of the approval of PNG's acquisition of Centra Gas Fort St. John Inc. in 1996 and the rate was reflected in this Application. However, in its response to BCUC Information Request No. 1, page 18, PNG(N.E.) stated that the embedded rate will need to be increased as a result of the higher interest rate being paid by PNG for its operating line of credit. The Commission is aware of the short-term credit difficulties that PNG is experiencing with the Royal Bank of Canada due to the Methanex Corporation plant shutdown. The PNG(N.E.) Application already increases the short-term interest rate by 2 percent as a result of PNG's banker increasing the rate. **However, there is insufficient evidence to allow the Commission to accept the 9.49 percent long-term debt rate incorporated into the schedules in Final Argument. PNG(N.E.) is directed to refile schedules using the Application rate of 8.52 percent for the Fort St. John/Dawson Creek Division.**

In its response to BCUC Information Request No. 1, page 3, concerning the high probability that the prime lending rate could be expected to decrease, PNG(N.E.) noted that customers will be protected by the short-term interest rate deferral account maintained by the company. However, the same account can be used to protect the company. **PNG(N.E.) is directed to file schedules using a short-term rate of 6.0 percent for both divisions.**

3.0 LOAD FORECAST

3.1 Fort St. John

3.1.1 Residential Load Forecast

PNG(N.E.) forecast residential and commercial sales by estimating use per account and the weighted average number of customers. The Company forecast use per account for residential customers in Fort St. John at 154.4 GJ based on the average value from 1992 to 1999. The weighted average number of customers was forecast at 7,964 based on the number of customers at the end of 1999 and the load growth expectations of service area personnel. The resulting load forecast was 1,229,728 GJ.

CAC (B.C.) et al. indicated that PNG(N.E.)'s use of a historical average to estimate use per residential account is not consistent with the methodology used by PNG(N.E.) or PNG-West in other applications.

The use per account forecast by PNG(N.E.) in its 2000 Revenue Requirements Application was based on the normalized trend value for 1998, not the actual normalized value as suggested by CAC (B.C.) et al. Applying the methodology used by PNG(N.E.) in its 2000 Revenue Requirements Application to the 1999 trend value would result in a 2001 forecast only slightly higher than the forecast in PNG(N.E.)'s 2001 Application. PNG(N.E.)'s forecast of the weighted average number of customers (7,964) is slightly higher than the linear trend value based on data from 1987 to 1999 (7,786).

PNG(N.E.)'s residential load forecast of 1,229,728 GJ for Fort St. John appears to be acceptable. The linear trend in the use per account data could be used to argue for a small increase over PNG(N.E.)'s forecast, but the average figure underlying PNG(N.E.)'s forecast is also equally likely. The Commission accepts the PNG(N.E.) residential load forecast.

3.1.2 Commercial Load Forecast

For Fort St. John and Dawson Creek, PNG(N.E.) estimated the 2001 sales to all commercial customers based on an analysis of historical data, then estimated sales to large commercial customers. Estimated sales to small commercial customers were then derived as the difference between the two. This methodology may be appropriate where there is a lot of movement between rate classes, but it can produce undesirable results if movement between rate classes is not expected. For example, if PNG(N.E.) projects a modest increase in total commercial deliveries but a large increase for large commercial customers, then forecast deliveries to small commercial customers decline. If historical analysis suggests that deliveries for all commercial customers will go up and large commercial customers expect a significant increase in load, this would seem to support an increase in load to small commercial customers (unless the increase in load to large commercial customers is due to customers switching rate classes), not the decline projected using PNG(N.E.)'s methodology. The potential for inconsistent results suggests that PNG(N.E.) should consider projecting load for the small commercial class separately, rather than deriving the value as the difference between the forecast for all commercial customers and the forecast for large commercial customers.

PNG(N.E.) forecasts commercial use per account at 796.7 GJ for 2001 based on the average normalized use per account in 1998 and 1999, adjusted upwards by 1 percent for 2000 and another 1 percent for 2001. The weighted average number of commercial customers is forecast at 1,287 based on the 1999 value and expectations of PNG(N.E.) service area personnel concerning new construction and customer additions. The resulting 2001 load forecast for commercial customers is 1,024,986 GJ.

PNG(N.E.)'s use per account forecast is slightly higher than the average normalized customer use from 1993 to 1999 (789.1 GJ), but lower than the average from 1995 to 1999 (808.0 GJ), the average from 1997 to 1999 (807.2 GJ), and the linear trend value for 2001 (840.4 GJ). PNG(N.E.)'s estimate of the weighted average number of customers (1,287) is slightly below the trend value for 2001 based on data from 1990 to 1999 (1,294).

On balance, the Commission determines that PNG(N.E.)'s estimate of average commercial consumption appears somewhat low. The average from 1995 to 1999 (808.0 GJ) is considered appropriate. The Commission finds that PNG(N.E.)'s estimate of the weighted average number of customers is reasonable. Assuming a use per account of 808.0 GJ and 1,287 customers, the Commission approves a load forecast of 1,039,896 GJ. The Commission accepts PNG(N.E.)'s load forecast of 165,555 GJ for large commercial customers in Fort St. John. The resulting forecast for small commercial customers is 874,341 GJ.

3.1.3 Industrial Load Forecast

PNG(N.E.) forecasts industrial sales and transportation deliveries in 2001 at 1,300,970 GJ based on discussions between service area personnel and customer representatives. Actual deliveries in 1999 and 2000 were 1,224,064 GJ and 1,417,694 GJ, respectively [PNG(N.E.) 2001 response to BCUC IR 1, Question 3.3; PNG(N.E.) 2000 response to BCUC IR 1, p. 3]. PNG(N.E.)'s forecast is close to the average of actual deliveries for 1999 and 2000 (1,320,879 GJ) and incorporates customer expectations.

The Commission accepts PNG(N.E.)'s industrial load forecast for Fort St. John.

3.2 Dawson Creek

3.2.1 Residential Load Forecast

PNG(N.E.) forecast use per account for Dawson Creek residential customers at 138.1 GJ and forecast the weighted average number of customers at 5,057. The resulting load forecast was 698,309 GJ.

CAC (B.C.) et al. submitted that the average use per customer forecast is too low and that the methodology used in the 2000 Revenue Requirement Application would yield a figure of 148.4 GJ per residential customer.

Although PNG(N.E.)'s forecast is below the historical average from 1987 to 1999 (146.1 GJ), the data indicates a downward trend. The forecast made by PNG(N.E.) in its 2000 Revenue Requirements Application was based on the normalized trend value for 1998, not the actual normalized value as suggested by CAC (B.C.) et al. Applying the methodology used by PNG(N.E.) in its 2000 Revenue Requirements Application to the 1999 trend value would result in a 2001 forecast use per account which is slightly lower than the forecast in PNG(N.E.)'s 2001 Application.

The Commission accepts the PNG(N.E.) forecast of Dawson Creek residential sales volumes.

3.2.2 Commercial Load Forecast

PNG(N.E.) forecast use per account for Dawson Creek commercial customers at 863.2 GJ based on the average of data from 1995 to 1999 adjusted upwards by 1 percent per annum. This is slightly lower than the average from 1990 to 1999 (874.2 GJ), but higher than the linear trend value for 2001. PNG(N.E.) forecast the weighted average number of customers at 678 for 2001 assuming that there will be five new customers in 2000 and five more in 2001. The resulting 2001 load forecast for commercial customers in Dawson Creek was 585,007 GJ.

The Commission finds that the load forecast for commercial customers in Dawson Creek is reasonable.

3.2.3 Industrial Load Forecast

PNG(N.E.) forecast industrial sales deliveries in 2001 at 85,000 GJ based on consumption of 60,000 GJ at Louisiana Pacific's board plant and 25,000 GJ at a new veneer plant. PNG(N.E.) indicates that these estimates are based on the reduction in gas consumption anticipated by management at Louisiana Pacific.

The 2001 Application indicates that Louisiana Pacific's consumption has varied from 20,000 GJ to 227,000 GJ from 1990 to 1999. The 2000 Application indicated that Louisiana Pacific's consumption from 1990 to 1998 has varied from 20,000 GJ to over 70,000 GJ. This suggests that actual 1999 consumption was 227,000 GJ. A figure of 197,600 was used in the 2000 Settlement but actual consumption may have been higher.

The Commission finds that the industrial sales have been very volatile and that it would be reasonable to implement a deferral account to record the variance between actual and forecast sales. Forecast sales for 2001 are set at 150,000 GJ.

3.3 Tumbler Ridge

3.3.1 Residential Load Forecast

PNG(N.E.) forecast 2001 residential use per account in Tumbler Ridge at 94.0 GJ. This is slightly above the average normalized value from 1987 to 1999 (93.5 GJ) and above the linear trend values.

PNG(N.E.) forecast the weighted average number of residential customers at 1,103 for 2001. The weighted average number of customers in 1999 was 1,146, so PNG(N.E.)'s forecast is equivalent to a reduction of about 2 percent per annum from 1999 to 2001. This is more than the historical decline in Tumbler Ridge, but is reasonable given the closure of Quintette.

The load forecast resulting from PNG(N.E.)'s forecast use per account and forecast weighted average number of customers is 103,669 GJ.

The Commission accepts the PNG(N.E.) Tumbler Ridge residential load forecast.

3.3.2 Commercial Load Forecast

PNG(N.E.) forecast the 2001 commercial use per account at 659.6 GJ based on a linear trend using data from 1995 to 1999. PNG(N.E.) forecast the weighted average number of customers in 2001 at 57 based on the number of customers at the end of 1999 minus projected customer losses of 7 in 2000 and 3 in 2001 [PNG(N.E.) response to CAC (B.C.) et al. IR 3b]. The resulting load forecast for commercial customers in Tumbler Ridge is 37,269 GJ.

CAC (B.C.) et al. argued that the reduction in deliveries between 1999 and 2001 implied by PNG(N.E.)'s forecast was about 10 percent per annum, which exceeded the historical average annual reduction of about

2.4 percent. CAC (B.C.) et al. suggested that 45,166 GJ would be a more reasonable projection of commercial deliveries for 2001.

PNG(N.E.)'s forecast of the 2001 commercial use per account is based on a trend value calculated using data from 1995 to 1999, which is somewhat lower than the trend value calculated based on data from 1990 to 1999 (675.8 GJ). Given the closure of Quintette, the reduction in the number of weighted average customers from 70 in 1999 to 57 in 2001 appears to be reasonable.

The Commission accepts the PNG(N.E.) Tumbler Ridge commercial load forecast.

3.3.3 Industrial Load Forecast

Quintette

Quintette discontinued operation of its coal mine in 2000 and is currently involved in reclamation activities. PNG(N.E.) forecasts 2001 deliveries to Quintette at 47,000 GJ based on an estimate from Quintette's management.

PNG(N.E.)'s forecast of 47,000 GJ for Quintette appears to be reasonable.

Canadian Natural Resources Limited ("CNRL")

CNRL supplies gas to the Tumbler Ridge system and delivers gas for processing and transportation to its Murray River fuel gas pipeline. PNG(N.E.) forecasts 2001 deliveries to CNRL at 270,000 GJ based on information from CNRL. Deliveries to CNRL have increased each year since 1996. In its 2000 Revenue Requirements Application, PNG(N.E.) forecast deliveries at 250,000 GJ based on information provided by CNRL. Actual deliveries in 2000 were 547,131 GJ [PNG(N.E.) response to BCUC IR 1, Question 2.1].

Since the delivery charge for CNRL is relatively low even after the proposed increases ($0.135/GJ for the first 400,000 GJ and $0.435/GJ above 400,000 GJ), revenue from CNRL is not particularly sensitive to the sales forecast. For example, increasing forecast sales to 400,000 GJ would increase forecast revenue by $17,550 and increasing forecast sales to 500,000 GJ would increase forecast revenue by $61,050.

The Commission finds that PNG(N.E.) has not adequately demonstrated sufficient reasons for its large reduction to CNRL sales. Forecast sales to CNRL are set at 500,000 GJ.

4.0 GAS SUPPLY COST METHODOLOGY

PNG(N.E.) considered that the results of deeming 100 percent of the gas purchase costs as variable charges were more reflective of market prices. This argument was supported by CAC (B.C.) et al. As stated in the Commission's Decision (Pacific Northern Gas Ltd. - October to December 2000 Rates and 2001 Revenue Requirement Application dated May 25, 2001) on pages 16 and 17:

> "Commencing with the 1997/98 gas contract year, PNG has managed the gas commodity requirements for the PNG-West service area and for Pacific Northern Gas (N.E.) Ltd. ["PNG(N.E.)"] service areas in Fort St. John and Dawson Creek as one consolidated demand and supply pool."

The Commission determined that:

> "The Commission considers that, at least for 2001, PNG's gas cost allocation methodology with 100% of gas purchase costs as variable costs results in gas commodity charges for high load factor classes that are very comparable to market prices. The methodology also reduces the premiums in the gas commodity charges for residential and other low load factor classes, relative to the corresponding market prices. The methodology is approved."

PNG(N.E.) is recommending a 100 percent variable cost methodology be used to set the unit gas supply charge and company use gas rates for 2001.

The Commission accepts the 100 percent variable cost methodology to set the unit gas charge and company use gas rates for 2001. The Commission agrees that the implementation of this methodology is more reflective of market prices for gas. The result is to reduce the premiums in the gas commodity charge for low load factor customers.

4.1 Gas Supply Costs in Proposed Rates

The gas supply costs in the proposed rates are accepted (based on the November 23, 2000 gas price strip). Gas supply costs and Gas Cost Variance Account balances are now reviewed quarterly by the Commission, effective April 2001.

4.2 Impact on Rate Classes as a Result of using the 100 percent Variable Cost Methodology

<u>Residential and Small Commercial</u> - The gas supply charge component of rates for the residential and small commercial customers decreased by about $0.21/GJ as a result of using the 100 percent variable cost methodology.

Large Commercial - The gas supply charge remained the same.

Small Industrial - The gas supply charge increased by $0.63/GJ. The 100 percent variable cost methodology is not as sensitive to higher load factor customer classes. The gas supply charge is $0.53 GJ lower than the residential rate.

5.0 COMPANY-USE GAS

Fort St. John

In 1999, 0.32 percent of total deliveries through the Fort St. John system were used in lineheaters and 0.99 percent of total deliveries were unaccounted for. In the test year, gas for lineheaters is assumed to be 0.37 percent and unaccounted for gas is assumed to be 0.71 percent. This results in volumes for 2000 of 12,799 GJ and 24,768 GJ and volumes for 2001 of 13,104 GJ and 25,358 GJ for lineheaters and unaccounted for gas respectively. Prior to 1998 there is insufficient historical data to determine the percentage for lineheaters and unaccounted for gas.

Dawson Creek

In 1999, 0.22 percent of total deliveries through the Dawson Creek system were used in lineheaters and 0.25 percent of total deliveries were for unaccounted for gas. For the test year, the requirement for unaccounted for gas is assumed to be 0.25 percent. This results in volumes for 2000 of 3,059 GJ and 3,470 GJ and volumes for 2001 of 3,016 GJ and 3,421 GJ for lineheaters and unaccounted for gas respectively.

Company use gas for the test period has increased by $33,000 from $287,000 to $320,000. This results from using the 100 percent variable cost of gas flow through methodology that was used to determine the allocated cost of gas by customer class for the purpose of setting the interim gas supply charge component of rates. The impact of company use gas on rates results in an increase from $0.059/GJ, using the existing gas supply cost flow methodology, to $0.065/GJ, using the variable cost methodology.

The Commission finds that the levels of company use gas are acceptable.

6.0 CNRL AGREEMENT

The Commission approved the transportation service agreement between PNG(N.E.) and CNRL with Order No. G-109-97 dated October 23, 1997. It was not made the subject of a public proceeding, but was approved by the Commission in the ordinary course of reviewing contracts. The generated incremental revenue was available to reduce the annual cost of service otherwise applicable to the core market customers.

The predecessor company to CNRL entered into the original transportation service contract with PNG(N.E.) on the understanding that PNG(N.E.) would request Commission approval to refrain from allocating to it any revenue deficiency resulting from the closure of the Quintette mine. If CNRL is not allocated any revenue deficiency the core market is in the same position it would have been if CNRL was not on the system and Quintette was closed. Section 3.2 of the transportation agreement states that:

> "PNG agrees to request the Commission to approve a toll design under which Shipper's charges will not be affected by either increases or decreases in the volume of gas purchased by PNG's largest customer, Quintette Mines Limited, such volume currently being a minimum of 141,000 gigajoules per year."

The 2001 interim rates charged to CNRL include a per unit increase that reflects an allocation of their share of the $177,000 revenue deficiency based on the forecast gross margin to be received from CNRL in 2001.

In response to BCUC Information Request No. 1, Question 1.3 PNG(N.E.) stated that:

> "Not allocating any of the revenue deficiency to CNRL merely puts the core market customers in the same position they would have been if CNRL was not on the system and Quintette closed. In fact, it appears the core market customers are continuing to benefit from the existence of the CNRL agreement as the revenue deficiency is less than the overall reduction in margin from Quintette. The 2001 interim rates being charged to CNRL, includes their the [sic] unit per GJ increase to reflect an allocation of their share of the $177,000 revenue deficiency based on the forecast gross margin to be received from CNRL in 2001."

CAC (B.C.) et al. submitted that:

> "If PNG(N.E.) wants to not allocate any of the lost revenue associated with the closing of the Quintette Mine to CNRL, it can do so by absorbing the $26,056 for the account of its shareholder. It is the right of the company to abide by the agreement it privately negotiated with CNRL and to take the consequences of the agreement. It is inappropriate for the utility to require other customers who were not parties to the agreement, and were not given any opportunity to review and accept the deal, to pay for it."

The Commission finds that there is little justification to exempt CNRL from bearing a portion of the revenue shortfall caused by the closure of the Quintette mine. CNRL anticipated the possible closure of the Quintette mine and took a risk that the Commission may exempt it from sharing in a revenue shortfall if

one developed. CNRL could have made it mandatory that it would not join the PNG(N.E.) system if it were not exempted from a revenue shortfall. This, of course, would have required Commission approval. CNRL, however, was not prepared to seek such a decision from the Commission at that time. The Commission determines that there is insufficient evidence to merit a load retention rate or other special treatment of CNRL at this time.

7.0 MAIN EXTENSION POLICY

7.1 Current Main Extension Policy in Fort St. John

Customers in Fort St. John are required to pay a refundable advance payment and/or a non-refundable contribution towards estimated construction costs. For a period of five years, a prorated rate per unit of the refundable portion of the contribution is refunded to the original customers as each new load connects and gas service commences. Where a developer asks PNG(N.E.) to install facilities in a subdivision, the developer pays PNG(N.E.) the estimated construction cost. For a period of five years, a prorated per unit portion of the refundable portion of the contribution is refunded by PNG(N.E.) to the developer as each new load connects and gas service commences.

7.2 Current Main Extension Test for Dawson Creek and Tumbler Ridge

PNG's current main extension test for customers in Dawson Creek calculates the annual cost of delivering a unit of energy to a customer on a proposed extension based on the utility's current cost of service. It then calculates the maximum investment in a proposed main extension project that the utility can make without causing the net present value of the cost of delivering energy to exceed that of existing customers in the same rate class. If the maximum allowable capital investment is greater than the estimated cost of the proposed extension, the extension will be constructed with no contribution required from the customers who will be served from it. If the estimated cost of the proposed extension is greater than the allowable capital investment, the difference is allocated to the expected customers over a five-year period.

PNG(N.E.) indicates that had the need arisen for a main extension in Tumbler Ridge, PNG(N.E.) would have adopted the methodology used in Dawson Creek with modification of financial parameters to reflect Tumbler Ridge's conditions.

7.3 Proposed Main Extension Test for Fort St. John, Dawson Creek and Tumbler Ridge

PNG(N.E.) proposed revisions to the main extension policies in its response to BCUC Information Request No. 1, Question 4.1. The changes proposed by PNG(N.E.) would implement the policy recently approved for PNG-West in the Fort St. John, Dawson Creek and Tumbler Ridge service areas. The objective of the proposed new extension test remains the same as the current test for Dawson Creek/Tumbler Ridge: to determine the maximum amount that can be invested in a proposed extension without adding costs to existing customers. However, the new test is based on the current margins of the appropriate rate class instead of the difference between the actual revenues and the approved allocation of costs.

PNG(N.E.) offered several reasons to support the revised test. First, PNG(N.E.) stated that it prevents a rate class that is under-recovering its actual cost of service from transferring additional costs to other rate classes. Second, the new test can be updated easily by simply updating fixed fees and margins. Third, the proposed test can be easily applied to any rate class, whereas the old test had been difficult to use for industrial or interruptible customers. Fourth, PNG(N.E.) noted that the revised test enabled the utility to depreciate the rate base associated with a particular main extension over the same time period as used for the net present value calculations. The Utility considered this aspect of the new test to be useful in situations where a main extension was being requested to serve a load with an uncertain and potentially short operating life.

PNG(N.E.) also proposed to end any utility financing for main extension contributions because, in order to provide financing under its present circumstances, PNG(N.E.) would have to raise its lending rate to approximately the same level as should be commercially available to credit-worthy customers.

The impact of the proposed test, in most cases, would be to decrease the maximum company contribution [PNG(N.E.) response to BCUC IR 1, pp. 14-16] and increase the required customer contribution relative to the current test for Dawson Creek/Tumbler Ridge. The proposed test also tends to decrease the required customer contribution of low volume consumers in a given customer class relative to larger volume consumers. This occurs because the proposed test recognizes that low volume customers pay a higher rate per GJ due to the monthly charge. Consequently, a base level of company investment is justified simply on the basis of the monthly charges it will receive.

Under the proposed main extension policy, PNG(N.E.) would collect customer contributions by requiring the initial (pioneer) customers to pay the full amount of any required customer contributions. Customers connecting to the extension in the following four years would be required to pay an appropriate share of the total customer contribution, and the pioneer customers would receive a proportional share of any such subsequent contributions.

The CAC (B.C.) et al. supported the proposed revisions to the main extension policy and test on the basis that it would provide the correct price signal for customers deciding whether to install natural gas.

The Commission approves the proposed new main extension test, subject to review of the actual tariff when it is filed.