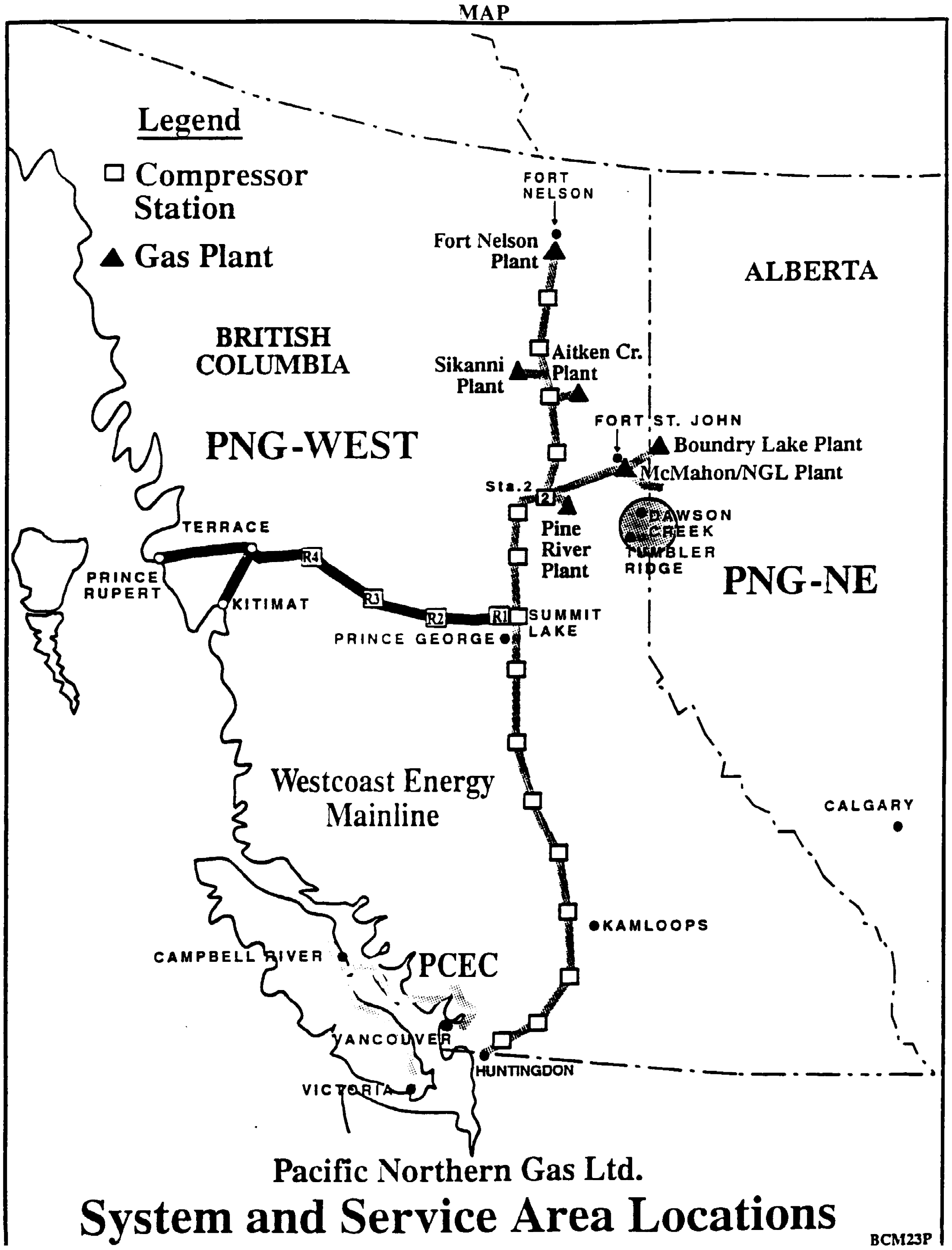
MAP



System and Service Area Locations Map

1.0 BACKGROUND

1.1 Description of the Pacific Northern Gas System

The Pacific Northern Gas Ltd. system, operating in three divisions, serves approximately 26,000 customers in northern British Columbia. Pacific Northern Gas Ltd. ("PNG") serves customers in the PNG-West Division. Its wholly owned subsidiary, Pacific Northern Gas (N.E.) Ltd. (also referred to as "PNG") was purchased as Northland Utilities (B.C.) Ltd. from Northwestern Utilities Limited in 1993 and is composed of two divisions; namely, PNG-Dawson Creek and PNG-Tumbler Ridge. The service area of each of the divisions is shown on the Map, p. 1. A description of each service area is given below.

PNG-West

Service to PNG-West is supplied by a 600 kilometer transmission line that stretches from the interconnection with the Westcoast Energy Inc. ("Westcoast") transmission pipeline at Summit Lake to the western limit of the service area at Prince Rupert and Kitimat. Approximately 38.9 petajoules ("PJ") per year of natural gas are transmitted for this Division. Customer classes include residential, commercial, small industrial, natural gas vehicles ("NGV"), off-season sales and large industrial. Methanex Corporation ("Methanex"), Skeena Cellulose Inc. ("Skeena"), Eurocan Pulp and Paper Co. ("Eurocan") and Alcan Ltd. ("Alcan") make up the large industrial class. This class consumes approximately 87% of the total throughput, or 33.7 PJ. Methanex alone accounts for 26.2 PJ or 67% of the total throughput.

The gas demand of firm sales to residential, commercial, small industrial, off-season, and NGV customers, for the most part is temperature sensitive resulting in a winter peak demand. Therefore, there is surplus gas available from these classes in the summer months when consumption is less than contract demand. PNG sells this "valley" gas under interruptible sales contracts, at the PNG weighted average variable cost of gas, to the four large industrial customers. Transportation contracts with PNG allow the large industrials to transport interruptible gas purchased from PNG or firm and interruptible gas purchased from other suppliers.

PNG-Dawson Creek

The Peace River Transmission Co. transports gas from the Westcoast interconnect to the PNG system at Dawson Creek. The distribution system serves approximately 5,000 customers. There are no large industrial accounts in the Dawson Creek service area.

PNG-Tumbler Ridge

Local gas wells provide raw gas which is processed by PNG into residue gas and then transported over a PNG transmission line to serve the District of Tumbler Ridge and two large industrial customers, Quintette Coal Ltd. ("Quintette") and Sceptre Resources Ltd. ("Sceptre"). Quintette and Sceptre consume approximately 141,000 gigajoules ("GJ") and 193,000 GJ per year respectively. There are approxi-mately 174,000 GJ planned for delivery to the 1,300 other customers on the system.

1.2 The 1991 Rate Design Hearing

In response to a complaint by Ocelot Chemicals Inc. ("Ocelot") (the operator of the methanol and ammonia plants at Kitimat prior to Methanex) and a Rate Design Application by PNG, the Commission held a hearing in 1990 and on February 27, 1991 issued its Decision. The Commission in its Decision reached a number of conclusions and recommendations that provide the background for the present Cost of Service Study and Rate Design Application.

1.2.1 1991 Rate Design Decision

Typically, a primary issue to be addressed by a rate design application is the appropriate allocation of utility costs among customer classes, while intraclass rate design issues are often a second priority. A fully allocated cost of service study is used to measure the extent to which the revenues contributed by a particular customer class, cover the historical costs attributed to serving that customer class. Ratios in excess of 1.00 indicate that the class revenues exceed allocated costs while ratios less than 1.00 imply the opposite.

The Commission recognizes that considerable reliance on judgement is involved in the undertaking of a cost of service study. Significant judgement is required to classify the costs between capacity, commodity and customer-related components. Even greater judgement is required in determining the appropriate method of allocating these costs among rate classes. Given the imprecision inherent in such studies, the Commission has, to date, generally found that as long as revenues from a particular class of service do not differ by more than 10% from costs allocated to that class, there is no compelling evidence that rate restructuring is required. Although different rate design practicioners advocate more narrow or broader bands of reasonableness, the Commission's decisions, to date, have generally followed the more common criteria of plus or minus 10%.

The 1991 Decision made the following determinations:

- The Commission accepted that revenue to cost ("revenue/cost", "R/C") ratios between 0.90 and 1.10 fall within a "zone of reasonableness".

- The Commission accepted the gross cost allocation using the distance-weighted coincident peak day allocation method. This method allocates capacity responsibility, based on usage at peak demand, weighted by the distance gas is transported. No capacity costs were allocated to interruptible customers.

- The fact that interruptible customers were not allocated capacity costs was not interpreted to mean that they do not benefit from the use of line capacity installed and paid for by firm service customers. To the extent that this usage has value to interruptible customers, it was deemed fair that interruptible rates be set to capture this value. The Commission determined that the difference between this value and the cost of supplying the interruptible service was to be quantified and applied as a credit to the costs allocated to the firm service customers.

- Residential and commercial rates were found to have R/C ratios substantially less than 0.90. Accordingly, residential rates were increased by 5% per year and commercial rates were raised by 3% per annum for three years exclusive of any cost of gas changes. The increased revenues received from residential and commercial customers were used to lower firm rates to those customers whose rate levels were in excess of the zone of reasonableness. The Commission lowered the rates for small industrial customers, natural gas vehicles, Skeena, Eurocan and Alcan.

- The Commission did not object to the introduction of a demand/commodity charge for large industrial customers and accepted PNG's request for further negotiations to take place. PNG was directed to complete negotiations and report back to the Commission on or before July 1, 1991.

- The Commission accepted the Ocelot position that rates for large industrial interruptible service should be based on value of service. The absolute value of the interruptible rates was to be a matter of negotiation between the utility and its customers. Until such time as the agreements were completed, the existing rate levels for interruptible service were to remain in effect.

- Negotiations on interruptible rate levels were to be completed by July 1, 1991 and presented to the Commission for consideration.

- PNG was further directed to file an updated cost of service study prior to November 1, 1993.

1.2.2 Events Following the 1991 Decision

Inquiry into Interruptible Rates

Notwithstanding the direction to negotiate interruptible rates, on June 28, 1991 PNG advised the Commission that its large industrial customers wished to maintain interruptible rates at existing levels rather than attempt to negotiate value of service rates. An Inquiry Officer was appointed and a report dated October 24, 1991 was prepared. The Commission accepted the recommendations contained in the report and issued Order No. G-106-91. The then current interruptible service rates were accepted in accordance with the value of service pricing methodology established in the Decision. The level of margin in the interruptible rates was used to determine the priority in which service to customers would be interrupted.

Methanex Purchases Ocelot Chemicals Inc.

The Ocelot methanol and ammonia plants at Kitimat were sold to Methanex Corporation following the 1991 Decision. Methanex is a global conglomerate with several locations throughout the world that produce methanol. The production costs in Kitimat are evaluated on a world wide basis and output is controlled according to the market. Methanol prices tend to go through extreme price swings, consequently a high degree of flexibility in the purchase of natural gas as feedstock is desirable to maximize profitability at the plant. This is a dilemma which Methanex faces as it attempts to balance the risk on product prices with the commitment of high contract demand requirements for firm gas purchases and pipeline transportation.

Regulatory Events Following the 1991 Decision

Following the directions in the 1991 Decision, PNG undertook a cost of service allocation study dated November 1, 1993, which was based on 1993 contract demands and projected load patterns. A series of interrogatories from the Commission staff and responses from the applicant resulted in amendments to the study. This study provided a basis for PNG's 1995 rate design filing.

Subsequently, in late 1994 PNG submitted an application to amend rates effective January 1, 1995 which was based on the 1995 test year. Commission Orders No. G-97-94 and G-11-95 set the matter down for a public hearing. Following a Pre-Hearing Conference, Commission Order No. G-16-95 directed that the 1995 Revenue Requirements and Rate Design/Integrated Resource Planning aspects of the application would be examined in separate hearings.

The 1995 revenue requirement was established through an Alternate Dispute Resolution ("ADR") process and approved by Commission Order No. G-32-95. It was agreed by all parties involved, and strongly advocated by Methanex, that a hearing on rate design would follow. PNG decided to update the 1993 study with the approved 1995 revenue requirements and expand it to include Dawson Creek and Tumbler Ridge.

The PNG Integrated Resource Plan ("IRP") was originally scheduled to be a component of the rate design review, however, the IRP was considered separately by the Commission and the PNG plan was approved on July 26,1995 (Letter No. L-32-95).

The Commission by Order No. G-59-95 set the 1995 Rate Design Application down for a public hearing. The oral hearing on the Rate Design Application and amendments commenced on October 23, 1995 and concluded on October 25, 1995. Written Final Argument was to be filed by PNG by October 31, 1995 and by Intervenors no later than November 3, 1995. PNG was given until November 6, 1995 to file Reply Argument.

2.0 THE 1995 RATE DESIGN APPLICATION

A fully allocated cost of service study, the 1995 Cost of Service Allocation/Rate Design Study dated July 6, 1995 (the "Application") was prepared by Barakat & Chamberlin, a consultant for PNG. The primary objective of the Application was to analyse the fairness of PNG's present rates and to propose modifications where appropriate. The Application as filed with the Commission, and the proposals which it contains, reflected the combined views of PNG and its consultant (T. 50).

PNG recommended that effective January 1, 1996:

1. Customer class rates be adjusted with the intention of achieving R/C ratios (including cost of gas) in the range of 0.90 to 1.10. PNG-West and PNG-Tumbler Ridge residential rates be increased by 5% with the additional revenues credited to those customers that have the highest R/C ratios;

2. PNG-West decrease its firm rates for small industrial customers (-11.45%) as well as Eurocan (-3.25%) and Alcan (-3.07%);

3. Revenue from the PNG-Tumbler Ridge residential increase be allocated to Quintette (-5.10%);

4. Franchise fees be recovered directly from customers located within each franchise area and be shown separately on bills rendered to customers in the PNG-West rate schedule;

5. The current two forms of service (bundled sales and transportation as well as transportation only) continue for the small industrial customers;

6. The large industrial customers rate form be modified to a demand/commodity structure on the basis that it reduces cost recovery risk;

7. A price indexing method be proposed for Methanex and possibly other industrials to provide a prepayment charge for fixed assets. This proposal is still subject to negotiation but the intention is to mitigate the risk to PNG of having unamortized assets left on the books at the expiration of transportation agreements;

8. The current pricing of interruptible rates be maintained for the large industrials;

9. PNG-West move to flat rates for residential, commercial and industrial classes. This would bring PNG-West in line with the two other PNG divisions which have a flat rate structure;

10. Seasonal rates were not recommended; and

11. PNG implement an unbundled transportation service for commercial customers.

2.1 Amendments to the Application

By letter dated October 18, 1995, PNG proposed amendments to its original Application for the PNG-West Division.

PNG continued to recommend that residential rates be increased by 5% on a gross revenue basis effective January 1, 1996 as proposed in the original Application. However, as a result of considering the material submitted by Methanex in direct evidence and in response to information requests that explained the competitive environment of the Kitimat plant, PNG proposed that the value of interruptible service to Methanex be calculated on a 150% load factor basis. This was intended to lower the value of service determination to more accurately reflect the lower quality of interruptible service to Methanex. It is the first interruptible load to be curtailed. The 100% load factor basis for interruptible service to the other large industrials, Skeena, Eurocan and Alcan, was to remain.

The load factor basis refers to a practice of dividing the unit fixed cost of firm service by an assumed load factor to calculate the value of interruptible service (or of dividing the unit demand rate for firm service by the load factor to calculate the interruptible rate). Load factors greater than 100% are physically impossible, but are a convenient way to express discounts off a firm rate. For example, the 150% load factor that PNG proposed for Methanex is equivalent to a 33% ($0.22/GJ) discount off the fixed cost of $0.652/GJ to recognize the lower priority of its interruptible deliveries.

3.0. THE BASE COST OF SERVICE FOR PNG-WEST

The PNG-West cost of service study had six major issues that were examined in the hearing. This chapter identifies and discusses each of these six issues in turn. The determinations of the Commission on each issue are then used to develop a "base" cost of service.

3.1 Specific Issues in the 1995 Study

The following specific issues were identified in the 1995 cost of service study in the Application:

1. Is the distance weighted non-coincident peak the proper method to allocate capacity cost responsibility to all customers, or should the coincident peak method be used? Should the peaking supply from the industrials be used to reduce the design peak day demand of residential and commercial customers?

2. Should large industrials be credited for curtailments which are used to supply the needle peaks of residential and commercial classes?

3. What percentage of average daily demand should be treated as non-temperature sensitive base load when calculating the residential and commercial peak day demand?

4. What is the appropriate functionalization of administration costs and fringe benefits?

5. What are the cost of service implications of the 1993/94 Looping Agreement?

6. Is the assignment of the incremental rate of return risk premium to large industrials appropriate?

DISCUSSION OF THE ISSUES

3.1.1 Distance Weighted Non-Coincident Peak and Reduction to Residential and Commercial Design Peak Day Demands

The distance weighted non-coincident peak day firm demands of the classes were used to allocate capacity costs to customer classes in the Application. The 1991 Decision used a distance weighted coincident peak allocation method. It was shown by PNG that the two methods are similar and therefore the methodology that was used was not an issue. However, a major point of contention with intervenors was the size of the allocator for each class of customer.

PNG

In response to a Commission Staff Information Request, PNG indicated that the non-coincident peak day methodology was chosen to allocate capacity as a proxy for the coincident peak (Exhibit 4, Tab 3, p. 63). PNG stated that it had many years of experience in forecasting peak days for its customers and was confident that its forecast was a reasonable estimate of the customer requirements on the design peak day of -20^{o}C. The sum of non-coincident peaks would be the same as that of coincident peaks, since the large industrial customers generally operate at 100% load factor. PNG therefore claimed that this was a reasonable estimate of the firm requirements based on the design day peak of -20^{o}C.

In the Study, PNG reduced the peak day demands of the residential and commercial classes by 113.4 10^3m^3 (4,000 Mcf) to reflect peak shaving (Exhibit 4, Tab 2, p. 22). PNG stated that line pack contributes 56.7 10^3m^3 (2,000 Mcf) of this peak shaving and the remaining 56.7 10^3m^3 (2,000 Mcf) is associated with the curtailment of firm transportation service to the large industrial customers (T. 192 and 193).

Intervenors

Mr. Drazen, consultant for Methanex, did not argue with the distance weighted non-coincident peak allocation methodology but stated that PNG's cost of service study allocated capacity-related costs to large industrial customers based on the maximum contract demand (Exhibit 22). The consultant argued that the study therefore disregarded the fact that a portion of the firm industrial demand is curtailable in order to meet instances when the temperature drops below the -20^{o}C design peak. It was the view of Methanex that capacity-related costs should not be allocated to this curtailable amount.

Methanex also expressed concern that reducing the peaks for residential and commercial customers by peak shaving thereby transferred capacity costs to all other customers. By not crediting the industrials for their peak shaving contribution, the Methanex consultant considered the effect was to penalize the industrials twofold (Exhibit 22, p. 11).

In response, PNG developed an alternative cost of service case that added back 56.7 10^3m^3 (2,000 Mcf) of the previous peak shaving reduction to the residential and commercial peak day figures on a pro-rata basis (Exhibit 4, Tab 2, p. 22). That is, the alternative case includes a 56.7 10^3m^3 (2,000 Mcf) reduction for peak shaving to the residential and commercial peak day demands.

Commission Determination

The Commission agrees with PNG's distance weighted non-coincident peak methodology, but PNG is directed to add back 56.7 10^3m^3 (2,000 Mcf) in total to the peak day allocators for the residential and commercial classes. This determination reflects the understanding that PNG has this amount (56.7 10^3m^3/d or 2,000 Mcf/d) of line pack available for peaking and that extremely cold temperatures are very short in duration. By adding back one-half of the original reduction, the amount of residential and commercial peak shaving on a -20^oC design day that was associated with curtailment supply from the industrials has been removed from the cost of service study.

3.1.2 Recognition of the Value of Curtailment to Meet "Needle" Peaks

The participants at the hearing differed on the valuation of the right to curtail firm deliveries to the Industrials in order to supply needle peaks.

PNG

PNG must meet needle peaks (occurrences where the temperature drops below the design peak of -20^oC), which occur about once every five years. The impact of such an event may reach 311.6 10^3m^3/d (11,000 Mcf/d) and the large industrials provide the primary back-up source of supply to accommodate these events. When curtailed, an industrial customer provides the gas at PNG's weighted average cost of gas.

Under its contracts with each industrial customer, PNG can draw on Eurocan for up to 96.4 10^3m^3/d (3,400 Mcf/d) to a maximum of 10 days in the contract year, Skeena for up to 103.4 10^3m^3/d (3,650 Mcf/d) for up to 10 days in the contract year and Methanex for 113.4 10^3m^3/d (4,000 Mcf/d). A further 56.7 10^3m^3/d (2,000 Mcf/d) can be supplied from line pack.

The PNG cost of service study does not provide any recognition for this needle peaking service. It was the evidence of PNG that this option is exercised very rarely (T. 233).

Intervenors

It was the contention of Methanex's consultant that firm service to Methanex, Eurocan and Skeena is not firm service at all since part of it can be curtailed to meet other customers' needs (Exhibit 22). The consultant for Methanex testified that the cost of service study is flawed as PNG failed to give a corresponding credit to the large industrial customers for the provision of this peaking resource.

Methanex testified that a resource that is required one day in every five years is far from a minimal benefit to PNG and that curtailment imposes a cost on industrial customers which should be recognized. One valuation method Methanex proposed was to consider the transmission capacity cost actually installed. PNG's average transmission capacity cost is $235/GJ per year ($24,800,000 divided by 105,000 GJ). The cost of providing 255.0 10^3m^3/d (9,000 Mcf/d) of extra capacity would be about $2.1 million per year. If the peaking transmission resource was valued at one-half the cost of transmission capacity a credit of $1 million would result.

Mr. Hopp, on behalf of Skeena and Eurocan, strongly disagreed with PNG that the firm industrial curtailments are rarely used and therefore should be attributed little value. In fact, he suggested that there are significant benefits to PNG and that there are costs to the mills. For example, since Eurocan cannot operate under a 50% curtailment of gas supply, it must contract for a higher contract demand to accommodate interruption. In the event of curtailment, Eurocan would switch its energy requirements to its alternate fuel back-up facilities. However, in order to have this option available, it incurs additional expenses to maintain this equipment and the necessary oil inventory.

The representative for Skeena/Eurocan stated the curtailment provision offers an additional advantage to PNG due to the lower price of gas necessary to meet the needle peaking requirements (T. 241 and 242). Since these occurrences happen on the coldest days, the market price of gas would be relatively high but according to the contract, PNG would only pay its weighted average cost (T. 241).

Commission Determination

The Commission does not find that the approach adopted by PNG is unusual. Other utilities, most notably BC Gas Utility Ltd. in the Inland Division, have negotiated similar provisions for curtailment of supply with large industrial customers in contracts for firm service. **At this time, the Commission accepts that curtailment of large industrial firm service should continue without special crediting of its value in the cost of service study.**

In Argument, Skeena/Eurocan expressed concern that PNG's firm curtailment policy be applied consistently for all firm industrial customers. PNG responded that, if the firm curtailment rights in its contracts with Eurocan, Skeena and Methanex are used, curtailments would be made on a pro-rata basis. The Commission agrees that curtailment rights should be exercised on a pro-rata basis.

3.1.3 Calculation of the Residential Temperature Sensitive Load

This issue relates to the correct percentage of the average daily consumption to use as non-temperature sensitive "base" load for the purpose of determining the residential peak day.

PNG

In its cost of service study, PNG calculated the peak day demand for each class of customers by applying a load factor to the temperature sensitive portion of the load. The temperature sensitive portion of the load is the total usage minus an assumed base or non-temperature sensitive portion of the load. PNG determined that approximately 30% of average daily delivery was the non-temperature sensitive base load for both the residential and commercial classes.

Intervenors

In the opinion of Methanex's consultant, the non-temperature sensitive base load is less then 30% of average daily deliveries (Schedule 1 of Exhibit 22). Methanex calculated that 10% of the peak month load is actually base load. This was later revised by Methanex to 19% (T. 433). If 19% is used to calculate the non-temperature sensitive component, the calculated residential peak day demand increases from 434.4 10^3m^3 to 484.3 10^3m^3. As a result, the residential cost of service would increase by $570,000.

Commission Determination

Methanex is correct that filed evidence indicates that the non-temperature sensitive base load for residential was 19% of the total energy consumed in 1994. However, this amount varies from year to year. While Methanex may be directionally correct in its position that the non-temperature sensitive portion of residential consumption is less than 30%, when combined with the non-temperature portion of the commercial load, the total non-temperature sensitive load will be higher. **Therefore, the Commission accepts the PNG method of determining residential and commercial peak day demand for the purposes of this study.**

3.1.4 Functionalization of Administration and Fringe Benefits

The issue of the appropriate head office charge for administering firm sales gas supply was challenged at the hearing.

PNG

PNG assessed the time spent by individuals involved in gas supply acquisition activities. If fringe benefits are included, PNG estimated this would amount to about $100,000. The cost of services provided by Westcoast Gas Services Inc. ("WGSI"), PNG's gas supply manager, was then added to the estimate for a total of $200,000, or about 10% of total administration costs.

PNG acknowledged in reviewing this question that it was a mistake to include the WGSI costs as they are part of the cost of gas supply. Therefore, PNG stated that the cost allocation study should have directly assigned only the revised estimate of $100,000 of gas supply acquisition costs to the core market customers (Exhibit 4, Tab 3, p. 93). In the cost of service study, PNG uses "core market" when referring to firm sales customers (residential, firm commercial, small industrial sales and NGV) (Exhibit 4, Tab PNG, pp. 23 and 24).

Intervenors

Methanex stated that in the 1993 cost of service study, PNG related 20% of administrative costs to gas supply. Since Methanex does not pay PNG gas supply costs, reducing the share of administrative and fringe benefit costs from 20% to 10% increased the share allocated to delivery facilities (Exhibit 22, p. 17). Methanex estimated that this resulted in roughly a $50,000 increase in costs to Methanex.

Commission Determination

The Commission accepts the distribution of administration costs in the PNG study for cost allocation purposes at this time. However, in future studies, PNG is to take care to recognize the cost causation and allocation of services such as WGSI.

3.1.5 Cost of Service Implications of the 1993/94 Looping Agreement

The issue to be determined is whether the transportation capacity which Methanex obtained through the 1993/94 Looping Agreement, should be considered on an incremental or a rolled-in basis.

The Looping Agreement is a negotiated contract between PNG and Methanex (Exhibit 16). The loops on PNG's main transmission pipeline were constructed to provide incremental capacity and also to provide greater security in the Copper River area so that additional loads could be moved on the PNG system. This would permit Methanex to expand its ammonia plant (T. 17).

Term 4 of the Looping Agreement described the calculation of the firm transportation margin rate to the methanol/ammonia plant for the additional 311.6 10^3m^3/d (11,000 Mcf/d) of firm capacity. It was calculated as 15% of the cost of the loops. The charges (for this and other firm capacity which Methanex held) were averaged so that the Methanex average firm rate went from $0.9099/GJ to $0.8349/GJ. The Commission by Order No. C-3-93 issued a Certificate of Public Convenience and Necessity for the construction of the loops referred to in the Looping Agreement, ordered that the cost of the new loops be borne entirely by Methanex and approved in principle the rate structure for Methanex illustrated in the Looping Agreement (Exhibit 16).

PNG

The position of PNG was that the transportation capacity obtained by Methanex under the Looping Agreement should be considered on a rolled-in basis. In the cost of service study, PNG considered all costs on a rolled-in basis without division of costs to reflect the incremental cost of the loop or age of the plant (T. 267). With regard to the impact of the Looping Agreement on the cost of service study, a witness for PNG stated:

"... what resulted from this letter agreement [the Looping Agreement] was a firm transportation service agreement with Methanex that became effective September 1, '94 which set forth the same firm transportation margin as set forth in the other two agreements pertaining to the Methanex facility. And so all three agreements, the one for 44 million a day, one for 2 million a day, and the ammonia plant expansion firm transportation service agreement for 11 million a day, it all adds up to 57 million and it's all treated as 57 million for the purposes of cost allocation.

So paragraph 4 [of the Looping Agreement] is completely irrelevant to that."

A policy witness for PNG stated that the expansion in 1994 was no different than a similar arrangement in 1986 when the ammonia plant came on stream.

"Same idea, we looked at the incremental costs, we applied all of the excess revenues back to Methanex in order to give the full benefit of the excess capacity we had on the system at that time to Methanex. And that really is what we did in the 1994 agreement here as well." (T. 269 and 270).

The position of PNG was supported by the evidence of its consultant, Mr. Pretto, that Canadian regulatory authorities generally prefer embedded, rolled-in cost ratemaking. Mr. Pretto, from an overall cost study standpoint, did not support the position of Methanex that the capacity related to the Looping Agreement should be treated on an incremental basis (T. 268 and 269). His response was that if part of the system was carved out for different cost treatment for Methanex, the same should be done for incremental investments that might be attributed to other customers. Over time, this would become impractical. The consultant summarized his views:

"And I think indirectly that explains why most Canadian regulatory authorities prefer embedded, rolled-in cost ratemaking as a general matter, and do not like incremental cost ratemaking, which is this, in terms of cost allocation that's what this is asking one to accept. After a while it gets to be very impractical, and for all we know, at present, maybe unfair to other people for whom PNG has undertaken marginal investments."

Intervenors

The position of Methanex was that the cost attributed in the cost of service study to the additional firm volumes should be placed at a level related to the cost of the incremental facilities, since that was the intention of the parties when they entered into the Looping Agreement. In the written evidence the consultant for Methanex stated that:

"It was clearly the intent of the contract [the Looping Agreement] that the additional firm volumes be priced at a level related to the cost of the incremental facilities, not the fully allocated cost of service." (Exhibit 22, p. 6).

Further, at pp. 13 and 14 of Exhibit 22, the following statement appears:

"PNG's cost study ignores this contractual treatment and allocates costs to the entire Methanex volumes on a "rolled-in" basis."

In the view of Methanex's consultant, the Looping Agreement contemplates that both revenue and plant should be split and shown separately for the purposes of a cost of service study. The consultant proposed that the Methanex firm load be divided into two parts; Methanex "A" that has a peak demand of 46,000 Mcf/d and throughput of 18,500,000 GJ and Methanex "B" with a peak demand of 11,000 Mcf/d and a throughput of 4,400,000 GJ. The total revenue requirement (of $44,206,000) after the deduction of $1,836,000 to Methanex "B" directly would be $42,370,000. This adjusted amount was then allocated among all the rate classes including Methanex "A" (Exhibit 22, p. 14). The decrease in the distance related non-coincident peak would result in less transmission plant being allocated to Methanex.

Notwithstanding its position regarding the Looping Agreement capacity, however, Methanex stated that rates for new large industrial customers should be based on average embedded costs, unless conditions of service and/or contract dictate that another treatment is appropriate (Exhibit 4, Tab 5, Q. 6).

In his Final Argument, counsel for Methanex argued that the treatment proposed by his client "...was approved by the Commission in Order No. C-003-93 [C-3-93].". He further argued that to adopt PNG's proposed method of treatment would make "a mockery" of the negotiations leading up to the Looping Agreement. Counsel for PNG in his Reply Argument responded that the Methanex argument on this issue was "without merit". He referred to the ammonia plant expansion agreements entered into by the parties as supporting the position that the cost of the ammonia plant expansion looping facilities was to be rolled into PNG's average embedded costs for ratemaking purposes. He submitted that was the basis for the approval of the rate structure by the Commission. (The Looping Agreement is the only "expansion agreement" which was filed as an Exhibit, although a witness for PNG [as quoted earlier] also referred to the firm transportation service agreement which resulted from the Looping Agreement.)

Commission Determination

On the issue of the intention of the parties, the Commission is left with the wording of the Looping Agreement alone. It does not consider it appropriate to have regard to the negotiations leading up to the Looping Agreement. Nor can the Commission consider argument based on documents not before it. The Commission is not persuaded on the evidence before it, that the Looping Agreement requires the rate design treatment proposed by Methanex.

On the subject of the effect of Commission Order No. C-3-93, it was not issued in the context of a rate design application and the Commission did not have the benefit of a cost of service study at that time. In deciding which rate design methodology should be applied at this time for the capacity that Methanex received due to the Looping Agreement, the Commission needs to consider the benefit of these facilities in the broader context of all of PNG's customers now and into the future. The looping provided greater reliability and increased capacity on the PNG system which benefits all of its customers.

Having considered this issue in the broader context, the Commission accepts the rolled-in methodology used by PNG, whereby the facilities which are constructed for the reliable service of all customers should be rolled into the embedded costs that are allocated to all customers.

3.1.6 Allocation of the Rate of Return Risk Premium

Following a generic hearing into Rates of Return on Common Equity, the Commission issued a Decision on June 10, 1994. In this Decision the Commission determined that the required rate of return on equity for a low-risk, high-grade utility is 10.5 to 10.75% based on a long-term Canada bond yield of 7.75%. For the purposes of calculating rates, the Commission established 10.75% as the benchmark rate of return, recognizing a risk premium of 3.0% for a low-risk, high-grade utility.

The Commission then went on to consider the capital structure and perceived business risk of the individual utilities. The Commission summarized the business risk of PNG as follows:

"The Commission recognizes the risks imposed upon PNG by the high concentration of industrial sales; however, it believes the short-term impacts of these risks to be significantly mitigated through the government guarantees [Methanex], the use of minimum bill provisions [other industrials], and the existence of a deferral account associated with interruptible sales. ..... The Commission finds that the major risk facing the shareholders of PNG is the risk of permanent impairment through the loss of one or more of the industrial customers."

The Commission accepted the capital structure put forward by PNG in its application as a reasonable basis on which to determine rates. From the evidence on business risks facing PNG, the Commission determined that an incremental premium of 75 basis points relative to the set of low-risk, high-grade utilities should be awarded. The Commission then determined the appropriate rate of return on common equity for PNG to be 11.5%.

PNG

In response to the rate of return allocated to PNG in the Commission Decision, and on the basis of comments in the Reasons for Decision, PNG decided to recover the incremental risk premium of 75 basis points from the four large industrial customers (Methanex, Skeena, Eurocan and Alcan) (T. 142). This results in an additional cost recovery of $630,000 from the industrial customers which is subtracted from the cost of serving the remaining customers (Exhibit 4, Tab PNG, p. 28).

Intervenors

The consultant appearing on behalf of Methanex disagreed with the incremental risk premium assignment to the large industrial customers (Exhibit 22, p. 15). He suggested there is no evidence that industrial customers are systematically riskier to serve than other customers. In his view, the variation in income around an acceptable level is the primary determinant of risk. Industrial customers using gas in their manufacturing processes do not exhibit a high degree of variation while customers using gas for space heating have consumption patterns which vary with the weather.

"A much riskier investment might be one that has the potential to provide a return several points higher or lower than the target level - say, between 2% and 16% annually. An extremely risky investment might be one that has the potential for producing negative returns (i.e., losses), but very high returns on the plus side." (Exhibit 22, p. 15).

He believed the risk associated with industrial customers is actually no greater than that of other customer classes. This view was shared by Eurocan and Skeena who maintained in Argument that the allocation of incremental risk premium should be borne by all customers.

The consultant for Methanex also suggested that the assignment of the incremental risk premium as proposed by PNG is counter-productive to ensuring that industrial customers remain on the system. He testified that increasing the cost to industrial customers actually has the effect of increasing the utility's total risk. It was his evidence that the higher cost of gas makes that utility less competitive and, therefore, more likely to lose industrial sales. It was further his evidence that, by over-relying on industrial sales for the recovery of return, the loss of industrial sales has a greater effect (Exhibit 22, p. 17).

Commission Determination

To evaluate the appropriate rate of return on equity, the Commission applies tests which estimate the necessary premium over and above the risk-free interest rate, usually as measured by long-term government bonds. The amount of the premium allowed is based on the perceived risks to which the utility is exposed. The revenue requirement is based on the cost of service plus the allowed rate of return on common equity. It is normal utility practice to recover this return equally from all customer classes.

With respect to the proposal by PNG to allocate the 75 basis points incremental risk premium to the four large industrial customers, the Commission is not persuaded, on the basis of the evidence presented in this proceeding, that it should depart from the normal practice of allocating the premium for recovery equally to all customer classes. **Therefore, the Commission rejects PNG's proposal in the Application to allocate the incremental risk premium to the four large industrials only.**

3.1.7 PNG-West Base Cost of Service

The "Base" cost of service incorporating the Commission's determinations in sections 3.1.1 to 3.1.6 is shown in Table No. 1.