IN THE MATTER OF

the Utilities Commission Act
S.B.C. 1980, c. 60, as amended

and

IN THE MATTER OF

Revenue Requirements Application

BC GAS INC.

DECISION

August 5, 1992

BEFORE:

J.G. McIntyre, Chairman
J.D.V. Newlands, Deputy Chairman
N. Martin, Commissioner

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1.0 INTRODUCTION

1.1 BC Gas Inc.

BC Gas Inc. ("BC Gas", "the Utility", "the Company" or "the Applicant") is a company incorporated in the Province of British Columbia. It was formed as a result of the acquisition by Inland Natural Gas Co. Ltd. ("Inland") of the British Columbia Hydro and Power Authority ("B.C. Hydro") Lower Mainland Gas Division in 1988. Following this acquisition, the four distribution companies of Inland, Columbia Natural Gas Limited ("Columbia"), Fort Nelson Gas Ltd. ("Fort Nelson") and B.C. Gas Inc. ("Lower Mainland") were amalgamated in July 1989 pursuant to the Company Act and the Hydro and Power Authority Privatization Act. Following amalgamation the four companies operated as Divisions for regulatory purposes.

BC Gas provides gas distribution services to over 620,000 residential, commercial and industrial customers. The service area of the Company extends across the Province and is one of the largest served by a gas distribution utility in North America. It has centres of operation in Fort Nelson, Prince George, Kamloops, Kelowna, Penticton, Cranbrook and the Lower Mainland of southwestern British Columbia.

1.2 Privatization

Since this Application is the first for a revenue requirement of the new utility, it is important to review the significant events that led to the privatization of the Lower Mainland Gas Division of B.C. Hydro and those that followed the amalgamation.

<u>July 15, 1988</u>

Bill 45-1988, the Hydro and Power Authority Privatization Act, of British Columbia, came into force through Regulation No. 273/88. This Act authorized the privatization of the Lower Mainland Gas Division of B.C. Hydro, permitting the sale to Inland.

<u>September 30, 1988</u>

Order In Council ("OIC") 1819/88 confirmed the Resale Restriction Agreement entered into between the Province of British Columbia and Inland, Columbia and Fort Nelson that froze all rates for the sale of gas by the three distributors until the end of September 1991, except for changes in certain identified expenses.

<u>September 30, 1988</u>

OIC 1823/88 authorized the transfer of all shares of B.C. Gas Inc. (previously the Lower Mainland Gas Division of B.C. Hydro) to Inland.

<u>September 30, 1988</u>

OIC 1824/88 confirmed the September 29, 1988 Rate Agreement and exempted Inland, Columbia and Fort Nelson from certain provisions of the Utilities Commission Act ("the Act") with respect to transactions related to the acquisition of B.C. Gas Inc.

<u>September 30, 1988</u>

OIC 1830/88 established the rate base of B.C. Gas Inc. as of July 16, 1988, for the setting of rates and all other purposes, depreciation rates, capital cost allowance, notice requirements for changes in costs, deferral accounts, and other matters related to the BC Gas rate freeze.

<u>May 5, 1989</u>

By OIC 681/88, approval was given to the amalgamation of Inland, Columbia and Fort Nelson with BC Gas.

<u>June 29, 1989</u>

OIC 953/89 rescinded OIC 1824/88, repealed Sections 4 to 11 and Schedule 2 of OIC 1830/88 and, through an appendix, effectively extended the conditions from OIC 1830 to each of the four BC Gas Divisions for the period July 1, 1989 to the end of September, 1991.

Section 18 of the Hydro and Power Authority Privatization Act resulted in the regulatory responsibilities with respect to BC Gas, as contained in the Act and the Gas Utility Act, being transferred from the British Columbia Utilities Commission ("BCUC", "the Commission") to the Lieutenant Governor in Council ("LGIC") until the end of September, 1991. During this period, all the rights, powers, obligations, duties and functions of the BCUC under the Act and the Gas Utility Act were transferred to the LGIC.

Section 22 of the Hydro and Power Authority Privatization Act stated that Sections 12 to 15 and 18 to 20 were repealed on October 1, 1991. That meant that the regulatory powers and responsibilities were transferred from the LGIC to the BCUC. That Section also states that the BCUC:

> "shall not on or after the date of that repeal
>
> (a) review or reconsider a certificate, order, approval, rule, regulation endorsement or decision under the Utilities Commission Act or the Gas Utility Act made before that date by the Lieutenant Governor in Council in exercising any of the rights and powers and in performing any of the obligations, duties and functions given to him under this Division, or
>
> (b) exercise its powers under section 114 of the Utilities Commission Act in respect of anything done before that date by the Lieutenant Governor in Council in exercising any of the rights and powers and in performing any of the obligations, duties and functions given to him under this Division except in accordance with terms of reference that the Lieutenant Governor in Council may by order specify."

April 11, 1990

OIC 594/90 reassigned to the BCUC the majority of the rights, powers, obligations, duties and requirements that had been transferred to the LGIC by Section 18 of the Hydro and Power Privatization Act. This action allowed the BCUC to deal with many day-to-day regulatory requirements of BC Gas, but the Commission did not have the responsibility for other actions taken by the Utility.

1.3 BCUC Regulation

On October 1, 1991, BC Gas returned to full regulation by the BCUC. The first formal proceeding before the Commission involved an application on August 8, 1991, for approval of:

(i) A revised methodology for allocating gas supply costs to customers;

(ii) Tariff Rate Schedules 10 and 13 relating to the sale of large volume interruptible gas and peaking gas;

(iii) Schedule 22 relating to large volume transportation customers; and

(iv) The matter of confidentiality of gas purchase prices.

By Order No. G-92-91 dated September 23, 1991, the Commission established an agenda to deal with the foregoing Application. The Application for revenue requirements (the subject of this Decision) and a rate design hearing to be held later this year.

The first hearing, known as Phase A Rate Design, commenced on December 3, 1991 and resulted in the Commission's Decision of February 21, 1992 under Order No. G-22-92.

1.4 BC Gas Inc. Structure and Mandate

On July 1, 1989, the Province and BC Gas concluded a new Resale Restriction Agreement ("the Agreement") (Appendix "A"). This Agreement acknowledged certain intentions of the parties, including:

(i) The desire of the Minister of Energy, Mines and Petroleum Resources that the common equity component of the capital structure of the utility operations be not less than 35 percent on or about October 1, 1991;

(ii) Separate natural gas rates for the four Divisions after amalgamation;

(iii) BC Gas' expectations that its revenue requirements included in natural gas rates for customers of each of the Divisions will increase by less than 3 percent in the 12-month period following the end of September 1991; and

(iv) The identification by BC Gas of various economic development initiatives in the Province.

The Agreement established the 3-year rate freeze. It required a report on or before October 1, 1991 on the feasibility studies listed in Schedule "C", and it required the appointment of a consultant to review and report on the management of BC Gas. This appointment is required on or about October 1, 1992 and every four years thereafter. With regard to the report on the feasibility studies, Commission counsel requested (T. 3685) that the Company file the report that was given to the Minister of Energy, Mines and Petroleum Resources. Subsequent to the hearing, by letter dated June 10, 1992, BC Gas advised that the report contained confidential information. Accordingly, the Applicant submitted a summary report on the economic initiatives covered in Schedule B of the Agreement (Appendix "B").

In his opening remarks at the hearing, Mr. Kleven, Senior Vice President, outlined the goals and the challenges of the new company. These were formidable, given the fact that the new entity was some six times larger in size, subject to a rate freeze, and had a highly leveraged balance sheet. The following goals were set in 1988 (T. 51, 52):

1. To achieve superior growth and earnings in order to continue to attract investment capital to realize the industries growth potential in B.C.

2. To meet or exceed the customer and employee satisfaction levels that Inland had enjoyed.

3. To become a major energy platform for British Columbia.

4. To recognize the importance of environmental responsibility.

Team building programs and an organizational structure were developed to ensure employee involvement and good communications. New management information systems were developed. New gas supply contracts were negotiated in a deregulated environment. BC Gas also acted to meet its financial obligation and achieve investment grade credit ratings. During the three-year period to September 1991, the utility experienced unprecedented growth. The organization of BC Gas has evolved during the "regulatory holiday" period to its present configuration (Exhibit 1, Tab 6) (Appendix "C", "D", "E", "F").

Mr. Kleven stated (T. 59):

> "This rate freeze went hand in hand with a regulation holiday, which created both the potential for risk and reward. Although the benefits of efficiency would flow through to the bottom line during this period, there would be no regulator to appeal to if inflation increased to the levels experienced in the early 1980s."

The many decisions taken by the Applicant during this period have served to not only establish the foundations of the new company, but also to reinforce its vision of its mandate in the Province. In its view, historical data or historical approaches would not provide a satisfactory perspective on which to review the new utility (T. 64):

> "This application is the first for BC Gas, and as such, the outcome will dictate how this utility will serve its customers and assist in the development of British Columbia in the next century. We have focused an incredible amount of our time and resources to preparing this application. BC Gas is still in its infancy as a utility, and its systems are still evolving and emerging. It's people are still learning about the company and about each other. The integration of different systems and cultures is ongoing. For the last three years we have been grappling with these issues. BC Gas must be looked upon as a new utility, a new entity. It is not the sum of its four predecessor companies. The management, the organization, the people, and the systems are all new. Attempts at looking at historical information solely as the measure of reasonableness will only lead to confusion and frustration. This Commission has not had the opportunity to review a newly created utility the size of BC Gas in the past. A fresh approach is needed."

Mr. Lloyd, Senior Vice President, Corporate Development, Gas Supply and Secretary, in response to a question in his written evidence, (Volume 2, Tab 1, pages 17-18) stated the Company's view of its economic role in the Province:

> "Q: What is the nature of the positions taken by BC Gas with respect to economic development in the Province?
>
> A: BC Gas is absolutely committed to do whatever it can to help B.C.'s economy grow and prosper. As a company anchored in and committed to B.C. and with its head office in B.C., BC Gas represents one of the very few B.C. based large corporations subject to minimal direction from parties located in other jurisdictions.
>
> Our customers, our employees, our directors, our offices, our supplies, and our business activities are almost totally B.C. based. And unlike many other large B.C. companies, we have no dominant shareholder from another jurisdiction influencing our decision making. Furthermore, we do business in most areas of B.C. Hence BC Gas is ideally positioned to work actively with government and municipalities to help develop this Province.
>
> BC Gas' commitments to this end are grouped into two significant areas:
>
> 1. First and foremost, BC Gas' efforts to keep the cost of supply and transportation of natural gas to as low a level as possible for all customers who have no competitive alternatives. This improves the cost advantage of businesses in B.C. making B.C.'s goods and services more competitive.
>
> 2. Secondly, BC Gas' efforts to actively assist specific natural gas related projects or activities. Some such activities were identified in the Resale Restriction Agreement.
>
> While such commitments in the Resale Restriction Agreement are commitments made on behalf of the shareholders of BC Gas, nonetheless we believe many of these commitments are also in the public interest of our customers."

In his opening remarks, the Chairman stated (T. 3):

> "This process of review, therefore, is vital to the ongoing regulation of the utility and many decisions made this year will continue to impact ratepayers and the utility for many years to come."

The review of this Revenue Requirements Application will draw into focus the appropriateness of the Utility's vision, its mandate, and its operating efficiency. The Commission must verify the accounts and operations of the new company as a basis to move forward, and the Commission must confirm or alter the vision of management.

Following the two months of public hearings, the Chairman reaffirmed the importance of this first public review of the structure and revenue needs of BC Gas as a basis of future cost setting.

In his remarks at the close of the hearing (T. 4381) the Chairman stated:

> "While the matters in the Application are generally quite specific, it is clear that not only approval is being sought on these matters, but also an overall endorsement of the goals that the Applicant has set. In this regard, the Commission will find itself to some degree, fishing in new waters, by comparison at least to many of its previous hearings."

The evidence addressed during the hearing covered numerous areas of the business activities of BC Gas which were not the subjects of basic review in previous hearings of the operating Divisions. Some of these areas are tied directly to the issues of mandate and management philosophy.

2.0 THE APPLICATION

2.1 Events Leading to the Public Hearing

BC Gas applied on November 20, 1991, pursuant to Sections 64, 67 and 106 of the Act for interim and permanent rate increases effective January 1, 1992. The Application sought an increase of 3 percent over the existing total revenue. In support of the interim increase, BC Gas gave evidence to the following special circumstances (Interim Application, page 2):

(i) Without rate relief, a rate of return on common equity of 10.72 percent for the 1992 test year was forecasted which translates into a revenue deficiency of $18,711,000;

(ii) The Company and its Divisions did not have a revenue requirement rate increase for more than three years;

(iii) Customers increased from 546,205 in 1988 to over 624,000 at the end of 1992;

(iv) Gross plant in-service over the same period increased 50 percent or $411 million;

(v) BC Gas signed a 3-year collective agreement with its unions in 1991. The 1992 wage increase was 5 percent;

(vi) The Company needed additional revenue to meet the financial tests for its financing requirements;

(vii) The revenue deficiency represented 54 cents per common share;

(viii) The increase was required to provide continued and necessary services for the customers; and,

(ix) Approval of an interim increase by the Commission would dispel some regulatory uncertainty.

In summary, BC Gas made the following forecasts for the 1992 test year (Exhibit 1, Tab 1, page 3):

(i) Total gas volume of 220 PJ;

(ii) Total revenue of $631 million, before the applied for increase;

(iii) Operations and Maintenance ("O&M") expenses of $90 million;

(iv) Average number of customers of 612,799;

(v) Capital additions of $168 million;

(vi) A mid-year rate base of $1,030 million;

(vii) A 5 percent increase in wages; and,

(viii) A requirement for a rate of return on common equity of 13.5 percent based on a common equity component of 37.5 percent.

The results of the 1992 test year forecast contained in the initial Application would require a rate increase of 3.03 percent on total revenue. However, in order to meet its expectation in the Agreement, BC Gas limited the rate increase to 3 percent, across-the-board, for all Divisions.

By Order No. G-115-91 dated December 2, 1991, the Commission approved an interim, refundable increase of 3 percent effective January 1, 1992 for all Divisions other than Fort Nelson. Order No. G-122-91 set the public hearing date for March 24, 1992. The public hearing was subsequently re-scheduled to commence on March 30, 1992 in Vancouver, with consecutive regional hearings to be held between April 6 to 10, 1992 in Cranbrook, Kelowna, Prince George and Fort Nelson.

Commission staff held two pre-hearing conferences for the Applicant and the intervenors. A Management Information System ("MIS") seminar was also conducted on March 24, 1992 for the benefit of intervenors and interested parties.

2.2 Requests in the Application

BC Gas, in its Application, requested the following specific actions:

(i) A 3 percent increase across-the-board on the total revenue of all four Divisions by imputing the gas cost component of similar sales rates onto the transportation service rates but excluding the "non-captive" revenue, which amounted to approximately $36 million, was not subject to an increase;

(ii) Approval of consolidation of all four gas Divisions for regulatory purposes;

(iii) Approval of depreciation rates for certain new classifications of assets;

(iv) Discontinuation of the deferred income tax method for Fort Nelson in favour of flow-through tax accounting; and

(v) Setting up of certain deferral accounts.

The above requests were further explained in Exhibit 6, Tab 1.

In support of the Application, BC Gas testified that the 3 percent increase was substantially less than inflation over the three years of rate freeze. BC Gas did not provide a normal base year comparison. Rather, it relied on the evidence of Price Waterhouse to demonstrate that the required rates were fair and reasonable. This evidence compared the rates of the Utility to the Vancouver Consumer Price Index ("CPI"), to other utilities and to certain operating statistics.

2.3 The Public Hearing

The public hearing commenced in Vancouver on March 30, 1992 and concluded on June 4, 1992. During this period, regional hearings were held between April 6 and 10, 1992 in Cranbrook, Kelowna, Prince George and Fort Nelson. Thirteen panels of Company and expert witnesses were scheduled by the Applicant to appear and give evidence. These appearances were expanded during the hearing to include witnesses to address issues relating to the imputed cost of gas and executive compensation. Commission staff also presented expert witnesses to give evidence on BC Gas' MIS, executive compensation, appropriate capital structure and return on common equity.

Intervenors included representatives from BC Gas' industrial customers, British Columbia Public Interest Advocacy Centre ("BCPIAC") and other interested parties. A full list is shown on page (i) of this Decision. BC Gas' industrial customers, particularly the forest companies, have suffered severe economic hardship for some time and their participation in the hearing was significantly reduced due to budget restraint (T. 4218).

The importance of this hearing was echoed by all participants. The opening remarks by the Chairman and Mr. Kleven set the stage on the first day of the hearing. Mr. Kadlec, President and Chief Executive Officer of BC Gas, as the last witness, further emphasized this point:

> "Mr. Chairman, this year marks a very important milestone in our Company. It's our return to regulation under your Commission. The importance of this hearing has been stressed not only by our senior people, but reflected even by you in your opening remarks. I personally cannot over-emphasize the financial significance of the results that will flow from the decision of this Commission with regards to our revenue requirements.
>
> The problems that we have experienced as a result of an exceptionally warm weather only serves to accentuate the importance of the thickness of our equity and our return.
>
> The demand for capital and growth forecasted is an exciting challenge to our Company, but it greatly emphasizes the importance of our ability to raise money to meet these demands." (T. 3574)

Mr. Johnson, counsel for BC Gas, in his final argument stressed that:

> "Dealing with the first item, the importance of the hearing, Mr. Chairman, this is the first revenue requirement hearing for BC Gas. While its predecessor companies have been before the Commission this is the first hearing in which the Commission has examined the revenues and expenses of the new company and BC Gas is indeed that, it is a new company. As was noted by Mr. Kleven and others at various points in the transcript, BC Gas Inc. is more than the sum of its former parts.
>
> This hearing, and the decisions relating to it ... It will have long-term effects on the perception of BC Gas in the eyes of the financial community to which BC Gas must turn for financing." (T. 3751)

2.4 Regional Hearings

Mr. C.I. Kleven was the chief policy witness in the regional hearings. With him were Mr. B. Newton, Vice President, Interior Operations, and the Regional or District Manager of the related service area to each regional hearing location (Mr. R.G. Bowman in Cranbrook, Mr. B. Evans in Kelowna, Mr. J. Heaslip in Prince George, Mr. C. Ashdown in Fort Nelson). Although BC Gas had extensively publicized these hearings, the overall participation of the public was limited.

In Cranbrook, Crestbrook Forest Industries Ltd. presented its company witnesses Mr. B.J. Clifford and Mr. R.H. Langin, to speak to their natural gas requirements and efforts to reduce costs during the current economic downturn. In Kelowna, Mr. Darling, a local resident and a retired geologist, cross-examined BC Gas witnesses and expressed concern that BC Gas' involvement in oil and gas exploration is too risky for a utility (Transcript Volume 7A, page 74). Consumers Packaging Inc. and Hiram Walker & Sons Ltd. also gave evidence through their witnesses, Mr. B.E. Howell and Mr. F.M. Bechard respectively.

In Prince George, Ms. V. Candy, an advocate for people with disabilities, spoke on the hardship of low income people and suggested a discount on utility bills for such customers. Mr. C.I. Kleven replied that such a proposal could be addressed in the BC Gas Phase B Rate Design Hearing (Transcript Volume 8A, pages 24-25). Ms. L. Dong, Pulp Mill Financial Analyst for Northwood Pulp and Timber Limited also cross-examined BC Gas witnesses on industrial gas rates.

In Fort Nelson, Mayor F. Parker of Fort Nelson and Mr. C.J. Griffith, Administrator for the Fort Nelson-Liard Regional District, gave evidence to oppose the BC Gas consolidation proposal.

Matters raised throughout the regional hearings have been incorporated into the overall discussions in this Decision.

2.5 Forecasts and Updates

Mr. K.J. McDonald, Director, Planning and Budgets, testified regarding the planning and budgeting processes followed by BC Gas. He stated in his written evidence that "For all employee groups, rates of 6 percent and 5 percent respectively were used for the periods January 1, 1992 to March 31, 1992 and April 1, 1992 to December 31, 1992" and "Materials and services have been inflated at 4 percent for 1992" (Exhibit 2, Tab 15, page 4). Further in Exhibit 6, Tab 4, page 1.1, BC Gas restated that "An escalation factor of 5.5 percent was applied to management and exempt employee salaries for the period January 1, 1992 to December 1, 1992." For union wages BC Gas believed that the rates were a reflection of similar settlements of the same vintage. Salaries and wages are further discussed under Sections 5.7 and 5.8.

For materials and services excluding gas purchases, BC Gas selected a 4 percent inflation forecast from a number of surveys (ranging from 3.5 percent to 4.4 percent) predicted in 1991. Similar information published in February to March, 1992 showed that forecasted price escalations for 1992 had reduced to the range of 2.3 percent to 3.1 percent (Exhibit 7, Tab 24, item 3).

On the basis of the above forecasts, BC Gas revised its inflation forecast for 1992 to 3.0 percent. Exhibit 56 reflected this change by a reduction of $362,000 in O&M, 4 percent was retained for capital materials and services (T. 1099).

With regard to forecast changes and updates, the Commission considers that the reasonable forecast inflation rate for materials and services should be 2.5 percent on the operating and maintenance portion and 3.5 percent on the capital portion.

Exhibit 56 was the Applicant's first update of its Application and reflected a further increase in revenue requirement of $3.255 million due to changes in sales and expenses which altered the 3 percent rate increase to 3.56 percent. In light of the Resale Restriction Agreement, item I of which states:

> "BC Gas expects that its revenue requirements included in natural gas rates for the customers of each of the Divisions will increase by less than three percent in the twelve month period following the end of September, 1991,"

Mr. Johnson clarified that:

> "I can advise you that BC Gas is not seeking to amend its existing application. In other words, the company seeks from you a determination that its appropriate revenue requirement increase is 3.56 percent ... but just as it agreed in paragraph 14 to limit its increase to three percent ...
>
> I also wish to indicate to the Commission that this limitation by BC Gas is for the period to September 30, 1992. ... The Company reserves the right to apply at a later date for an increase above three percent to be effective November 1, 1992, but it doesn't do so as part of this application." (T. 1149-1150)

Mr. Johnson further stated that any amendment to the rates will be based on a new application with evidence (T. 1247).

There was a concern that if the Commission accepted 3.56 percent as reasonable and required but approved only 3 percent as requested, then, pursuant to the Court of Appeal Decision on the Hemlock Valley Electrical Services Limited, BC Gas might request the makeup of the difference at a later date. Mr. Johnson stated that (T. 1244):

> "...I don't think there is any new law in the Hemlock Valley case, and nor do I consider it particularly relevant to the discussion we were having."

In response to the Chairman's question whether BC Gas was revising its Application, Mr. Kleven confirmed that Exhibit 56 reflected a correction of the Application to a 3.56 percent increase. Exhibit 56A reduced the increase to 3.33 percent, and finally Exhibit 144, page 2 (T. 3390-3394) made a further adjustment which kept the increase to 2.9 percent. This position was restated in Exhibit 171.

2.6 Imputed Cost of Gas

In the implementation of the 3 percent increase, the Applicant proposed that:

> "The distribution of the additional revenue requirements as between customers is across all divisions (i.e. all customers designated as "captive" receive a 3 percent increase)."

and

> "In order to maintain neutrality and parity between sales and transportation service rates, the increase sought has been applied in a manner which maintains an equal increase for the sales rate and transportation service rates. This has been achieved by imputing the gas cost component of similar sales rates onto the transportation service rates to determine the appropriate rate increase." (Exhibit 1, Tab 1, pages 5-6)

The matter of "across all divisions" is discussed under Section 2.7 - Consolidation.

BC Gas stated that the imputed cost of gas component consists of the commodity cost of gas, demand charges and pipeline transportation tolls which "are comparable to gas costs which would be paid in the 1991/92 contract year by sales customers having similar load characteristics" (Exhibit 1, page 1-02-06.5). The Applicant's methodology was guided by the Commission's 1991 Rate Design Decision for Pacific Northern Gas Ltd.

The Applicant stated that its reasons for choosing the methodology was to maintain rate neutrality by keeping the burner tip impact for sales and transportation service approximately the same as for other customers. Otherwise there would be a distortion. Mr. Lloyd stated that the choice of the methodology has no impact on the Application and there was no intent by doing so to meet the 3 percent limitation indicated in the Agreement (T. 185).

The transportation customers strongly protested the BC Gas proposed imputed cost of gas methodology. Some suggested that the 3 percent increase should be applied only to the BC Gas tariff rates. It was noted that if the proposed customer increases are expressed on a gross margin basis, the percentage increases would be erratic and result in as much as a 158 percent increase in the case of Westar-Balmer, as opposed to an equal 7.836 percent if the increase was applied equally to gross margin of all customers [Exhibit 5, Tab 3, item 1.3(b), page 4.1 Columbia and Exhibit 6, Tab 2, item 2(a) and (b)]. They also suggested that the excerpt from the Pacific Northern Gas Ltd. Decision was quoted out of context by applying a rate design methodology to the revenue requirements process. BC Gas disagreed and argued that its method was the consistent way to achieve the revenue to cost ratios, and the appropriateness of the sales margin as a result of the imputed cost of gas increase should be addressed in the Phase B Rate Design hearing.

BC Gas provided an additional panel of witnesses to deal with related imputed cost of gas issues. Among other alternatives, the gross margin method was suggested by the Commission counsel. The Applicant believed that there were shortcomings in each of the methods and agreed that the gross margin method would not require an arbitrarily imputed cost of gas for the Transportation

Service customers (T. 598-599). Mr. Johnson, in final argument, stated that the gross margin method carried the assumption that the present gross margins on the rates are correct (T. 4085).

Mr. Wallace, in final argument stated that this was the single most important issue to his clients (T. 4102), and maintained that BC Gas had a commitment to limit the rate increase after the rate freeze to less than 3 percent. He argued that the increases sought by BC Gas had nothing to do with the cost of gas, but were related to gross margin, and would be approximately 8 percent on a gross distribution margin basis. He also made reference to Mr. Wessler's testimony that the methodology was to keep the rates within 3 percent:

> "In the next application ... we could very well spread our revenue requirement on a gross margin basis, but we could not do it this time." (T. 575; 4112)

Mr. Wallace argued that fairness and avoidance of rate shock required:

> "...that you should implement the required increase to all customers based on an equal percentage increase in the margin of each, the 7.836 percent scenario." (T. 4121)

Mr. Weafer, counsel for the Lower Mainland Large Volume Gas Users' Association ("LMLVGUA"), stated:

> "we probably stand a slight benefit from the imputed cost of gas methodology as put forward by the company, but we oppose this methodology, sir." (T. 4167)

The imputed cost methodology was said to have rate design implications. His position was that the 3 percent should apply to the total bill rendered by BC Gas (T. 4168).

Mr. Gustafson also stated that his clients strongly objected to an increase based on imputed cost of gas (T. 4221) which could discriminate unduly against industrial customers (T. 4232). He supported the gross margin method and asked the Commission to assume that the current rate structure is correct until proven otherwise (T. 4233).

Mr. Johnson, in reply, emphasized that the objectives of neutrality and consistency were the prime reasons for choosing the imputed cost of gas method. The 3 percent limitation was only a factor, not the sole reason, in the consideration (T. 4303-4304).

The Commission rejects the imputed cost of gas concept in this Revenue Requirement Application. The Commission concurs with the intervenors and it accepts the current rate structure as correct and fair at this time. The rate increase applied for in this Application is solely related to cost elements making up the gross distribution margin and the Commission finds that the revenue requirement should be applied on an equal percentage basis to gross distribution margin. Neutrality and consistency should be achieved accordingly.

Finally, the Commission will explore the reasonableness of revenue to cost ratios, based on the gross distribution margin versus costs excluding the cost of gas, in the Phase B Rate Design Application. In future rate cases, the requested revenue increase should be expressed as percentages of both total revenue and gross margin, unless decisions from the Phase B Rate Design hearing indicate a resolution of this matter.

2.7 Consolidation

2.7.1 Background

The Chairman in his opening remarks set in context the consolidation request in the Application (T. 5-6):

> "Although the Commission has acceded to the interim request for consolidated rate increases as requested by BC Gas that interim increase has no bearing on the future determination to support the matter of consolidation or not."

When Inland purchased the Columbia and Fort Nelson Divisions in 1979 and 1985 respectively, there were undertakings that the rates of these Divisions would not be consolidated with those of the Inland Division (T. 286). In December, 1987 Inland applied for Commission approval for consolidation with Columbia and Fort Nelson. Inland indicated that the Divisions would be kept separate for regulatory purposes (T. 289). That Application was eventually withdrawn. In considering requests for the approval of a merger, acquisition, amalgamation or consolidation, the Commission has historically applied a set of criteria:

> "One, the utility's ability to finance future capital requirements; two, the continuation of existing covenants that would preserve the customer's interests; three, the utility's ability to maintain the required level of service into the future;

> four, the preservation of the public interest; and five, compliance with pertinent legislation and regulations." (T. 287)

Upon the purchase of the Lower Mainland Gas Division, Inland entered into a series of agreements with the Province. Item I of the original Resale Restriction Agreement states:

> "Inland intends that the customers of each of the Company, Inland, Columbia and Fort Nelson will, after the reorganization, continue to be charged separate natural gas rates; ..."

The amalgamation of the four gas Divisions took effect on July 1, 1989. OIC 953, dated June 29, 1989 (Exhibit 15), required among its conditions that:

> "2. (1) BC Gas shall, from July 1, 1989 until the end of September, 1991, establish and maintain its rate base on a divisional basis, with a separate rate base for each of the Lower Mainland Division, the Inland Division, the Columbia Division, and the Fort Nelson Division."

The Order also required the Divisions to maintain separate accounts on a divisional basis, and separate schedules of divisional rates. The BC Gas Application of November 20, 1991 proposed to consolidate the four divisional rates effective January 1, 1992. Upon further instruction of the Commission, BC Gas filed divisional rates on December 16, 1991 (Exhibit 4).

2.7.2 Definition

Consolidation for the purpose of the BC Gas Application was defined as "the determination of the utility's revenue requirement (exclusive of gas supply costs) as one regulated entity and not on the basis of four separate divisions" and "includes the act of spreading just the increase in revenue requirement equally" (T. 253-254). BC Gas intended to operate on a consolidated basis, integrate all of its activities and pool all its costs. This would result in the elimination of divisional cost allocations and separate revenue requirement justifications and hearings. Basically, BC Gas proposed to keep the margin in all rates constant so that the historical differentials would be preserved by applying the same percentage of rate increase across-the-board as in this Application.

2.7.3 Benefits

The incremental savings attributed to efficiency in consolidation were estimated at $600,000 per year (T. 256). In addition to the evidence of Messrs. Kleven and Lloyd, Mr. John C. Butler, a consultant with A.E. Sharp and Associates Ltd., was retained by the Applicant to review "matters relating to regulation of the gas utility operations of the Company on a consolidated basis" (Exhibit 3, Tab 3, page 1). He gave evidence at the hearing on regulatory practice in other provinces and judgementally described some benefits and disadvantages of consolidation.

Dr. W. Waters, an independent financial consultant, retained by Commission staff, agreed that consolidation is a reasonable sequence to the BC Gas amalgamation. He estimated that savings of approximately $500,000 annually can be achieved in the Columbia and Fort Nelson Divisions (Exhibit 43 and T. 3263).

Mr. Rawlyk perceived some benefits in the consolidation of the daily operations of BC Gas and stated:

> "...I support BC Gas on their request for approval of consolidation, but with a caveat that Fort Nelson be excepted for the time being." (T. 4279)

2.7.4 Considerations

The evidence indicated that consolidation would achieve savings and efficiency. Consolidation would not impede BC Gas' ability to finance future capital requirement, to continue the existing covenants, or to maintain service at the required levels. There was some concern, however, as to whether the consolidation proposal is in tune with the intent of the Agreement and OIC 953/89. With respect to the requirement of divisional rates, Mr. Lloyd stated:

> "I think that the government wanted to make sure that there was a review and it was thought out before we pushed all the rates together." (T. 249)

Mr. Kleven further clarified:

> "...I believe in approving the amalgamation they were not approving consolidation, and that was the intent." (T. 249)

Although Mr. Butler did not know why there were the requirements for separate rate base and divisional accounts in OIC 953, he agreed with Commission counsel that "...if a cost of service study was performed for each of the Divisions, that the customers within those Divisions would be in a better position to determine the true cost of service and identify any real benefits that there might be of consolidation before the consolidation took place" (T. 2954).

The Commission is concerned with the preservation of the public interest. BC Gas held public meetings in its service areas with respect to its Application and found little concern regarding the proposed 3 percent rate increase. The matter of consolidation was raised in the Inland and Columbia service areas and no objections were noted, perhaps due to the fact that consolidation appeared to be beneficial or at least neutral from the perspective of the local customers. However, the content of the Application was not conveyed to the residents of Fort Nelson in advance.

The Commission held a regional hearing in Fort Nelson on April 9 and 10, 1992. Mayor F. Parker and Mr. Griffith, Administrator for Fort Nelson-Liard Regional District, appeared before the Commission to oppose the BC Gas Application for consolidation of rates. Their submission, filed as Exhibit 35 stated in part:

> "...we only met with BC Gas for the first time last night, when they provided us with considerable detail concerning their rate proposals.
>
> ...BC Gas has stated that a consolidated approach could have additional benefits to the Fort Nelson division in terms of ensuring that large capital expenditures, loss of major industrial customers, or other major factors would not see shifting of the rate load onto customers within the Fort Nelson division, as those impacts would be absorbed across the consolidated company.
>
> ...our community expressed concern that Fort Nelson's lower gas prices should be protected.
>
> We believe that the Fort Nelson Gas division can operate as a going concern on an independent basis and would continue to provide an adequate return to BC Gas with rates being established on a completely separate and individual basis from the rest of their divisions. We also believe that Fort Nelson Gas should be able to pay for its share of capital costs and face certain economic fluctuations on an independent basis.
>
> It is our intention to oppose, on principle, any increase that is tied into the concept of consolidated or postage-stamp rates for BC Gas."

While the residents of Fort Nelson and the intervenors suspected that consolidation was the first step towards postage-stamp rates, the Applicant was not able to confirm or deny the suspicion. Mr. Lloyd stated:

> "I think we have a bias in favour of moving in that direction but we haven't looked at the data explicitly enough to know whether we're going to come forward and propose that." (T. 193)

Mr. Wallace in final argument stated:

> "What was not clear to me now is, what is actually sought by the Company. It appeared to me that BC Gas has agreed to keep the divisional data until the rate design hearing is done.
>
> If that is the case, then I'm not sure what Order is being sought now, and it would be our suggestion that the final Order on whether divisional data should continue to be kept could await that hearing where its value is determined.
>
> The concern of the industrials is, or was at least, that you were being asked to do away with divisional information before we knew that ramifications of what it would mean with respect to rate design." (T. 4126)

Mr. Johnson maintained that the Application was to:

> "...get rid of the divisional bookkeeping. The Company still keeps lots of accounting information..." (T. 4297),

and proposed that the 3 percent across-the-board increase to Fort Nelson could be offset with its deferred income tax account.

2.7.5 Commission Decision

The Commission recognizes that a financial benefit would accrue to the utility customers as a result of consolidation. While this saving is material, the canvassing of the full impact on all customers is more important. The Commission believes that the Phase B Rate Design hearing will provide an appropriate forum for resolution of the consolidation issue. Therefore, the Commission directs BC Gas to file its cost of service studies on a divisional basis for that hearing. In the interim period, the Company is to maintain divisional rates.

The Commission is also concerned that any future intentions of the Company towards rate unification be made known to all customers before the Commission is asked to endorse consolidation. For example, postage-stamp rates could have significant policy consideration for all customers.

2.8 Divisional Accounts

BC Gas filed divisional information (Exhibit 4) as required by Commission Order No. G-115-91. Exhibit 4 indicates that if BC Gas were to apply for rate increase in 1992 on a divisional basis, it would require 3.04 percent for the Lower Mainland, 2.84 percent for Inland, 6.25 percent for Columbia and a decrease of 4.22 percent for Fort Nelson. The divisional information reflects the revenue requirements on a "stand-alone" basis, which means Lower Mainland and Inland adopt a common equity component and a rate of return on common equity of 37.5 percent and 13.5 percent respectively; Columbia uses 41.19 percent and 14.0 percent; and Fort Nelson is deemed 40 percent and 15.5 percent (based on deferred tax accounting).

There may be merit in the "stand-alone" approach if the Divisions were required to submit applications individually to support their revenue requirements. However, the evidence adduced in this hearing shows that no one would favour this approach. Instead, the Commission believes that an overall application with supporting divisional information is required to demonstrate the total and divisional revenue requirements. Different rate changes may then be contemplated and/or implemented. Examination of evidence will then be on a consolidated basis for joint costs, and on a divisional or operational basis for specific and identifiable costs. **Consolidation is not approved in this Decision, BC Gas is directed to adopt the above in its next revenue requirements application unless findings in the upcoming rate design hearing indicate other action.**

It is noted that in the acquisition applications of Columbia, Fort Nelson Gas and Squamish Gas, Inland, the predecessor of BC Gas, consistently stated that reduced financing costs and greater access to the capital market were two of the major benefits in the acquisitions. In order to achieve such benefits in the customer rates, the cost of capital in the subsidiaries must substantially reflect that of the parent. The Commission, in the past, accepted independent capital structures of the subsidiaries on the basis that they were separate legal entities with distinct sources of funds. However, once all the Divisions are amalgamated as one single company, the "stand-alone" capital structures are extinct. **The Commission directs BC Gas' Utility Divisions to adopt a common capital structure for regulatory purposes. However, it does not mean that divisional accounts for rate base, revenue and operating costs should also be terminated because there are other aspects and issues which must be addressed and satisfied before total consolidation can be approved.**

Examples of these issues are:

- The Applicant must address the equitable treatment of the deferred income tax carried in the books of the Divisions.

- Similarly, other distinct and separate accounts unique to any particular Division must be resolved, such as contribution in aid of construction, different depreciation rates currently existing in the Divisions, conflicts in terms and conditions in the tariffs (Exhibit 68).

3.0 RATE BASE

3.1 Plant In-Service - 1988-1991

Since rate base additions have long-term impacts on future customers rates, the Commission must review such additions to ensure that all items are used and useful. During the rate freeze period, BC Gas was required to file annual capital budgets with the LGIC pursuant to the Agreement. Mr. Kleven agreed that such filings were not assumed to be an approval by the LGIC for the expenditures (T. 464). With respect to the rate base for rate-making purposes after the transition period, the following dialogue was exchanged between Commission counsel and Mr. Kleven (T. 465):

> "Mr. Fulton: Q: Does this mean that — does this statement mean that these capital additions, if any of them are not found used and useful, should still be kept in rate base?
>
> Mr. Kleven: A: No."

Mr. Kleven further qualified (T. 466):

> "Because I think on capital that has an ongoing need for the customers. I think we think that all our expenditures were prudent and for the benefit of the customers in that period, and they will hopefully stand whatever test is necessary. It was never our intention to spend money in that period and arbitrarily expect that this Commission was going to accept it and the customers pay for it in rates."

That view of the Applicant is consistent with that of the Commission.

The Commission staff reviewed each year's capital budget as filed with the LGIC on an informal basis. BC Gas filed actual expenditures during this period in Tab 3 of Exhibit 1. Based on this information, the Commission has calculated that plant in-service increased by $236 million over the 3-year period, and that 80 percent of this increase or $188 million consisted of additions to distribution plant. These expenditures were mostly for mains, services, meters and related pressure control facilities which are customer growth related and largely non-discretionary since they are incurred in accordance with an approved mains extension policy. Further analysis of expenditures during this period showed that capacity-related plant additions for liquefied natural gas ("LNG") and transmission facilities amounted to only $12 million during the 3-year period. In contrast, for the test year 1992, comparative capacity-related expenses are $65 million.

The Commission concludes that the plant in-service additions made during the 1988/1992 period were primarily due to customer growth and were largely of a non-discretionary nature. On this basis, the Commission accepts that these plant additions are used and useful and in rate base.

3.2 1992 Plant Additions

The 1992 capital budget shows additions to plant in-service of $168 million and retirements of $8 million (Exhibit 1, Tab 3). The more significant or extraordinary plant additions are typically contained in the Engineering Capital Budget. For 1992, these amounted to about $71 million (Exhibit 2, Tab 12).

The Commission was not satisfied with the justifications contained in the Application in view of the magnitude of expenditures proposed. As a result, a number of Staff Information Requests were sent to BC Gas and the responses were filed in Exhibit 7, Tabs 1 and 6. With only a few exceptions, the 1992 capital budget was found to be justified by the information responses. However, the Commission incurred considerable expense in retaining an outside consultant to investigate the large capital projects.

Extraordinary Plant Additions

The Surrey-Langley pipeline represented the single largest expenditure for 1992 and $47 million of the $71 million for extraordinary plant additions [exclusive of overheads and Allowance for Funds Used During Construction ("AFUDC")]. It was a concern to a number of intervenors, notably the BCPIAC and the LMLVGUA. During the hearing, BC Gas clarified that since approval for this project was being sought separately under an Energy Project Certificate Application, the project justification did not require Commission approval under this Application (T. 1189-1191). On June 2, 1992 the project was referred by the Minister of Energy, Mines and Petroleum Resources to the Commission as an application for a Certificate of Public Convenience and Necessity ("CPCN"). The Commission granted the CPCN by Order No. C-5-92 and followed up with detailed Reasons for Decision on July 9, 1992.

With respect to the remaining $24 million of the $71 million, transmission system improvements in the Inland and Columbia regions, together with the transmission extension to serve Pacific Coast Energy Corporation ("PCEC"), accounted for $11 million; and $13 million covered new meter purchases ($6 million), regulator and meter set prefabrication ($1.5 million), natural gas for vehicles

("NGV") refuelling stations ($1.5 million), LNG plant improvements ($1 million) and a variety of mostly distribution related items ($3 million).

The BCPIAC questioned the need for the addition of more emergency generator capacity at the LNG plant. The need for this addition assumes that the plant will be used to send out 150 mmcf/d rather than its name-plate capacity of 100 mmcf/d. The Commission recognizes that such a method of operation would typically be required for only a few days a year and, hence, should be feasible. However, if this capacity increase is to be made reliable, the additional standby generator is required so that the plant can be relied upon regardless of power interruptions since existing standby generators only power 100 mmcf/d of send-out capacity. The ability to send out an additional 50 mmcf/d reliably enables long-term gas supplies to be reduced commensurately at an annual saving of $5 million (Exhibit 7, Tab 1).

The BCPIAC also questioned the expenditure of $6 million for new meter purchases along the general lines of whether the purchased meters might become technologically obsolete. The Company responded that technical upgrades were expected to be compatible with existing meters and have occurred slowly in the past (T. 1205-1206).

Other Plant Additions

With respect to the balance of $97 million for plant additions (i.e. $168 million total subtracting the $71 million discussed above) some $68 million of this is for system growth (including overheads charged to construction). In the coastal area, the forecast is for 13,308 service additions and 178 kilometres of new mains while in the interior area the forecast is for 5,879 new services and 111 kilometres of new mains. The other $29 million in plant additions is for general equipment of which $20 million is for computers associated with the MIS programs.

Commission Decision

The Commission accepts the 1992 plant additions, except for those specific adjustments identified in Appendix "H".

The Commission believes there is a need for the Company to file information on future rate base additions. This will be in the form of the 5-year capital plan required pursuant to Section 51.3 of the Act.

3.3 Plant Capitalization Policies

Although the physical requirement for major plant in-service has been discussed in the foregoing sections, the method of capitalizing these additions to plant in-service must be scrutinized to ensure prudency and consistency are maintained. In response to a Commission Staff Information Request, BC Gas filed a document to describe the Company's capitalization policy (Exhibit 5, Tab 9, item 1.9(b) and Exhibit 7, Tab 24, item 2). It was an extract from an internal Plant Accounting Policy Manual dated December 6, 1991.

In reviewing the plant capitalization policies, the Commission must confirm the actions taken during the rate freeze period to ensure that they are consistent with the agreements entered into in the purchase of the Lower Mainland Gas Division. The Commission determinations for the rate freeze period must preserve the essence of the agreements that rates were to remain frozen except for specific cost items identified, such as cost of gas. From October, 1991 forward, the Commission must determine and confirm plant capitalization policies that are consistent with the Commission's regulatory standards.

Mr. Besel, Vice President, Corporate Controller, in his direct testimony, provided the following statements (Exhibit 2, Tab 19, pages 7-8):

"Q: What can you tell us about the accounting policies and procedures of the new entity (BC Gas) particularly in terms of their consistency of application from 1987 through 1991 and into the 1992 test year?

A: In general, the accounts are kept in accordance with Generally Accepted Accounting Principles (GAAP) and the BCUC Uniform System of Accounts Prescribed For Gas Utilities.

However, it may be helpful if we first defined the "entity" which is adopting the accounting policies and procedures.

From an accounting, financial reporting and corporate structure point of view, the "new entity" (BC Gas Inc.) is really the old Inland augmented by the assets of another, albeit rather large, operating division which it acquired.

The Lower Mainland Division while part of B.C. Hydro was effectively regulated in the same manner as was B.C. Hydro - on an interest coverage methodology for determining income. Inland was, and the new entity is, regulated on the traditional rate of return on rate base methodology and is the Company of record for accounting, regulatory and financial reporting purposes.

> Being temporarily "out of normal regulation" for a three year period did not change the application of Generally Accepted Accounting Principles (GAAP) - the assumption being that what was approved by the BCUC before 1988 would continue on and only be changed, on a prospective basis, after a hearing.
>
> Q: So essentially, the new entity (BC Gas) adopted the old Inland accounting policies?
>
> A: That is correct. GAAP was followed throughout the entire period and reported on by our external auditors as being consistently applied.
>
> Q: Is there an inference here that the accounting policies followed by the Lower Mainland Division, while the accounting was being performed by B.C. Hydro, were different from the ones followed by Inland?
>
> A: No. Notwithstanding the fact that the costs were collected in different "pockets" and accounts, eg. Lower Mainland did not use the BCUC code of accounts, there was no net differential effect on cost of service or rate base except in the area of overhead costs charged to construction."

The following issues are discussed in the context of the foregoing.

3.3.1 Overhead Capitalized

Mr. Besel in his direct evidence (Exhibit 2, Tab 19, page 9) identified some inconsistency in overhead capitalization after Inland purchased the Lower Mainland Gas Division from B.C. Hydro. This was due to the fact that B.C. Hydro had a different overhead allocation methodology but continued to perform certain accounting functions on behalf of BC Gas. BC Gas also filed Exhibit 96 which documented the overhead capitalization methods for the period 1988 to 1991. The level of overhead capitalized and the circumstances which caused the continuing modification of the overhead allocation process were verified by Commission staff.

The Commission accepts the overhead capitalization numbers for the period from 1988. With the new Financial Information System ("FIS") in place, the Commission expects a full review and documentation of overhead capitalization policy be filed prior to the next revenue requirements application, or in any event by December 31, 1992.

3.3.2 Interest During Construction - Allowance for Funds Used During Construction

In May 1980, the Commission revised the Uniform System of Accounts prescribed for gas utilities. The title of Account 497 - *Interest During Construction* ("IDC"), was revised to AFUDC. The latter extends the allowance to include other funds such as equity used by a utility. However, the method of allocation and the rate used were left to the discretion of the utilities based on their individual circumstances. Most gas utilities continued to use the IDC methodology. Consistency, however, is the key criterion in determining the prudency of the allocation. The Uniform System of Accounts also specifies "The rate applied must receive prior approval of the Commission."

The Applicant, in Exhibit 7, Tab 5, item 5.4, explained the derivation of IDC/AFUDC rates between 1988 and 1992. Up to the end of 1990, the Inland Division adopted an IDC rate equal to the annual weighted average of the weighted daily prime lending rates actually used. For the same period, the Lower Mainland Gas Division adopted the B.C. Hydro methodology, that is, an IDC rate based on the prior year's actual bond interest payment. In 1991, all Divisions used an IDC rate based on the prior year's actual bond/debentures interest payments. Commencing 1992, the Company used the AFUDC rate equal to the cost of capital in the test year. While there may be some inconsistency among the methodologies used between 1988 and 1991, the derived rates were not significantly different whether the prime rate, bond rate or average cost of capital rate was used. However, in 1992, the average prime rate fell below 8 percent. This resulted in some 3 percentage points difference from the average cost of capital rate. Accordingly, the AFUDC method created an additional $1.5 million charge to capital (Exhibit 95 and T. 2551), although this charge had minimal impact on the 1992 revenue requirements.

On the issue of Commission approval, Mr. Kleven stated:

> "It is specified in the Commission's Code of Accounts that this is what we are to follow, is AFUDC but if we have to make application then I do so right now" (T.2543).

While the Applicant insisted that the change to AFUDC is merely in compliance with the Uniform System of Accounts, the Commission notes that the revision to the Uniform System of Accounts was made in 1980. It is difficult to understand why the Applicant waited 12 years to make the change. The Application incorporated the AFUDC method without indicating the change in treatment. Mr. Besel had stated in his direct evidence:

> "From an accounting, financial reporting and corporate structure point of view, the "new entity" (BC Gas Inc.) is really the old Inland augmented by the assets of another, albeit rather large, operating division which it acquired.
>
> ...the assumption being that what was approved by the BCUC before 1988 would continue on and only be changed, on a prospective basis, after a hearing." (Exhibit 2, Tab 19, page 8)

This issue of consistency was also raised with respect to the head office move and the MIS (T. 2552-2557). BC Gas applied AFUDC to the these projects in 1992 but did not do so when Inland undertook similar projects in 1978/79 (Exhibit 6, Tab 7, page 1). Mr. Kleven explained (T. 2556):

> "I am not aware of a distinct change in policy but that doesn't mean that — the practice was different but I am not aware of a, you know, of coming up with a new policy that says that we are going to do it even though we didn't do it before. Certainly this time around I stand by what I stated earlier that we are really doing what's provided for both in the practice of other companies and utilities and in the code of accounts. Whether the old Inland Division or Columbia followed that in the past, it may have or may not have for whatever reasons existed at the time but that, as I said, it didn't necessarily make it right."

The issue of consistent methodology through time is of concern to the Commission. It expects all utilities under its jurisdiction to explain or apply for approval of any significant change in accounting or regulatory methodologies when they are deemed necessary. In a rate application, if such changes are not clearly enunciated, extra hearing time and costs are incurred.

The Commission views AFUDC as the appropriate method to allow utilities to recover cost of funds used during plant construction periods and since it is prescribed in the Uniform System of Accounts, the Commission approves the adoption, by BC Gas, of an AFUDC rate which is based on the average cost of capital. The maximum rate will be determined at the beginning of each fiscal year and will comprise the embedded book-cost rates for the prior year debt and preferred stock, and the granted common equity rate in the last rate proceeding. This rate should be revised periodically during the year to reflect any major change in the cost of capital. For 1992, the approved average cost of capital contained in Schedule IV may be used.

3.3.3 Capital Leases

Long-term lease agreements, with respect to the FIS and vehicles, have been considered as capital leases and included as plant in-service in the Application. Ms. Lambert, Vice President, Treasury, explained that the interest associated with the FIS lease is 11.65 percent (Exhibit 2, Tab 21, page 7) and that the Lease was entered into when the Company had severe capital spending limitations due to the Acquisition Loan for purchase of the Lower Mainland Gas Division (see Section 7.3). If the Company had borrowed funds directly to finance the FIS project and capitalized the full amount as plant in-service, it would have been able to claim maximum Capital Cost Allowance ("CCA") for tax purposes in 1990 and 1991. CCA for software is 100 percent claimable in the first two years of expenditure. Ms. Lambert further stated:

> "The cost to the customer is lower for the year 1992 through to the end of the lease, by virtue of the fact that the CCA benefits were foregone prior to the Company's re-entry into regulation. The customer derives a net benefit in this regard without having suffered any loss of CCA benefits."

The Applicant provided an opinion from Peat Marwick Thorne, Chartered Accountants, stating that both the FIS and vehicle leases should be treated as capital leases for accounting purposes. To further justify the rate base treatment of capital leases, the Applicant responded (Exhibit 7, Tab 9, item 3, page 1.2):

> "The issue here is not whether the Company objects to the operating lease treatment. This is not a question of optional accounting treatment - the Company has purchased a capital asset (computer systems/software and vehicles) and financed it via the lease methodology as opposed to debt or equity financing. The only difference between this and any other rate base item is the form of financing that took place. This is precisely the reason why the CICA accounting guidelines were developed - to prevent companies from acquiring fixed assets and leaving both the asset and the related liability off of the balance sheet merely by restructuring the "paperwork" for the liability.
>
> In summary, the Company has acquired capital assets and has properly recorded same in its accounts. Accordingly, it would be totally inappropriate to exclude these assets from the Company's rate base."

Commission staff canvassed a third alternative which would provide consistent tax and regulatory treatments, namely, that BC Gas could have treated the leases as operating for both tax and regulatory purposes. BC Gas calculated that such a proposal would cause a $1.61 million reduction of the revenue deficiency in 1992 (Exhibit 7, Tab 9, item 3, page 1). BC Gas further compared the revenue requirements of the FIS lease over the 8-year life and concluded that customers were better off if it was treated as a capital lease. However, when the revenue requirement stream is subjected to a net present value calculation, the result indicated that the operating lease option would be more beneficial for the customers (T. 2563).

In the lease analysis for the FIS, BC Gas' assumptions were (Exhibit 5, Tab 10, item 1.10(a), Appendix "I"), among other things:

> "... - a lease will be treated as a capital lease for accounting and regulatory purposes, but will be an operating lease for tax purpose - the appropriate discount rate is BC Gas' marginal cost of debt financing, since leasing displaces debt only...".

In response to a Staff Information Request with respect to whether the FIS lease should require approval under Section 57 of the Act, the Applicant obtained a legal opinion (Exhibit 94-Appendix "G"). The opinion concluded that BC Gas should not be required to apply for approval because if the Lease is to be considered as an "other obligation", then it must be read in conjunction with the words "shares", "bonds, "debentures" and "notes". As "an obligation", it therefore, has to be "a security as a security is generally known". The Lease does not fit within this definition. It is not a security "issued" by the Company.

Based on the above evidence, the Commission accepts that BC Gas must include the leases as capital for accounting and financial statement purposes. They are, however, open for Commission consideration for regulatory purposes. The Commission finds that:

(i) If a lease is considered as operating for tax purposes, it would be preferable for it to be considered the same for regulatory purposes for the reason that BC Gas is on flow-through tax accounting. On that basis, the intention is to give the customers maximum tax benefits in the earlier years of the fixed asset.

(ii) The leases, if included in rate base, would be deemed to be financed by the average cost of capital, this is inconsistent with both the lease analysis and the FIS lease agreement which indicate that they are financed by debt.

(iii) The legal opinion cited in Exhibit 94 excludes the leases as debt obligations. They should, therefore, not be included as debt obligations in the capital structure; it follows that they cannot receive rate base treatment. As such, the lease payment which includes a component of debt interest and principal repayment should be treated as a normal operating cost.

The Commission therefore concludes that the FIS and vehicle leases should be treated as operating leases for regulatory purposes in this Application and future filings.

3.3.4 Mains Extensions

The Utility funding, in support of new mains extensions, is intended to reflect the benefits of new customers without causing a detriment to existing customers. The "test" is a simplified proxy for more detailed economic evaluations. Since mains extensions tests are not an exact science, the topic has frequently been a concern in hearings. A major issue is that if the test is not reasonable, existing customers may end up subsidizing the new customers. Another issue is whether the Utility has consistently applied the test.

The evidence indicated that BC Gas has different mains extensions tests for different divisions. For example, the Lower Mainland Division adopts a 5-year net revenue test, while the Inland Division uses a 6-year net revenue test [Exhibit 5, Tab 9, item 1.9(b)]. These tests have been inherent in the divisional tariff and appear to have been applied consistently.

BC Gas stated that it is currently reviewing alternate test methods with a view to a system-wide proposal to be made in late 1992 (Exhibit 7, Tab 5, item 5.6). The Commission directs that mains extensions test proposals be filed by BC Gas prior to, or concurrent with the Phase B Rate Design Application.

3.4 Management Information Systems

3.4.1 Background

After the purchase of the Lower Mainland Gas Division, it was found that the information systems of the different Divisions were incompatible, becoming obsolete and unusable. There was a need to enhance methods of communication with customers, employees, investors, government and the public at large. Internally, the Utility required systems to provide appropriate financial, accounting, budgeting, planning and work management. While B.C. Hydro was processing most of the information for BC Gas through service agreements, there was a desire to be independent, since B.C. Hydro was developing its own systems for electrical operations.

A process called "Business Approach to Technology" for the use of information technology in BC Gas was developed for decision making in regard to MIS. There were two parts to the process. The "Business System Strategies" contains a revolving 5-year Strategic Plan for technology use, an Organizational Plan for staffing, and a Delivery Strategy for implementation. The "Development Strategies" covers the ways in which systems are developed, operated and maintained. The 5-year Strategic Plan leads to the annual operational plan and budget, and individual systems are justified by a cost/benefit analysis.

The Company chose an "out-sourcing" strategy which involved the contracting out all systems development, maintenance, operations, network management and user support functions. A set of systems was identified for implementation and four were considered essential. These systems were: financial, work management, customer information and human resources. The FIS was determined to be a critical priority and was fully implemented in January, 1991 at a cost of $7 million. There was an additional enhancement of $2.5 million in 1991. The Work Management System ("WMS") is expected to be in use in 1992 at a cost of $4.2 million. The Human Resources Information System ("HRIS") was budgeted for 1991 and 1992 at approximately $1.1 million, and the Customer Information System ("CIS") is scheduled for 1993 at a cost of $15 million. The above are direct costs before allocation of overhead.

3.4.2 Costs

Based on the evidence provided under Exhibit 2, Tab 16 and Exhibit 127, it was estimated that the 5-year capital costs of the above systems will be approximately $50 million (T. 3562), of which $11 million was spent up to 1991, $17.7 million to be spent in 1992 and $15 million in 1993. Overhead is not included in the 1992 and 1993 costs. Operating costs for 1991 were $5.5 million (presumably before allocation to capital) and estimated at $8.3 million for 1992. The total capital and operating costs over a 5-year period could approach $100 million.

In view of the magnitude of above cost outlay, the complexity and the highly technical nature of the MIS in BC Gas, the Commission staff engaged the consulting firm of Deloitte & Touche to review the MIS.

3.4.3 The Deloitte & Touche Report

The Deloitte & Touche report was filed as Exhibit 66. It included their findings and conclusions with respect to the validity of the information technology strategy, out-sourcing effectiveness, vendor selection processes, effectiveness of the major systems and a value for money assessment. Due to the technical nature of this topic, Commission staff conducted a seminar for the benefit of the intervenors on March 24, 1992. The Applicant and the staff consultant gave their respective overviews on the MIS in BC Gas. The seminar shortened the hearing process.

While there were criticisms in various areas, the consultant generally found that the systems installed or to be implemented are at the high end of the product line for similar utilities; the expenditures and investment decisions were not unreasonable and were supported by a business case analysis. Notwithstanding this, they recommended more analyses and review of the out-sourcing and contracting process. Deloitte & Touche criticized BC Gas for implementing the out-sourcing policy on a very narrow analysis. In particular, very little risk had been transferred to the vendors. They also suggested that there is an on-going concern for the Commission regarding: "control/management of the business risks associated with the development of CIS; the desirability of increased transference of risk to vendors engaged under the out-sourcing program; and the emergence of a more rigorous business case analysis of on-going and future projects." (Exhibit 66, page 24)

3.4.4 Commission Decision

The Commission accepts the Deloitte & Touche conclusions in Exhibit 66. The FIS, WMS and HRIS are complete or near completion, while the CIS is still in early development. Due to the significant business risks associated with the CIS, BC Gas should exercise maximum caution in the control and development of this system. While the expenditure on this project is treated as Construction Work in Progress attracting AFUDC and has no impact on the 1992 revenue requirements, the significant capital investment together with future operating costs will have an impact on future customer rates. The CIS is an unusually sophisticated undertaking and BC Gas must keep costs within budget to justify this level of development. The Commission directs BC Gas to file a progress report on a quarterly basis to detail the variance of costs and plans for the CIS. The first report for the quarter ending September 30, 1992 should be filed by the end of October, 1992 and the format of the report should be established in advance with Commission staff. The Commission will further review expenditures on the CIS before they are allowed for rate base treatment in 1993.

With respect to the risk transference, the Commission recognizes higher costs have to be incurred in exchange for lower risk, but the Commission expects the Company to minimize any unacceptable business risks to the extent that cost effectiveness is achieved. The Applicant should also conduct more rigorous business case studies for all future projects. The Commission will continue to monitor all MIS in BC Gas to ensure value for money is attained. The value for money test requires that BC Gas canvass the range of options to find the optimum mix of services versus development cost. This does not mean that only the expensive, top-end products are to be reviewed.

3.5 Office Facilities

In February 1993, BC Gas plans to consolidate its Lower Mainland head office functions into one single, downtown location in Vancouver. The functions to be moved would be those generally described as providing support services to the corporation and operations centres in Burnaby, Surrey and in cities in the interior (Exhibit 2, Tab 14, page 7). The new corporate headquarters will take up 10 floors of leased space in a building to be known as BC Gas Centre ("Centre"). Staff will occupy floors 2 and 3 and 6 to 12, while the Senior Management group will occupy the 24th floor. During the hearing the Commission reviewed the justification for the move and the expenses involved.

In his testimony to the hearing, Mr. C.F. Hess, Vice President, Administration and Planning, gave the following account of BC Gas' decision to move into new premises (Exhibit 2, Tab 14, page 7):

> "A number of departments which interact frequently are located in different buildings and locations. That arrangement negatively impacts productivity and communications among those departments. Projected manpower over the next 10 years for departmental growth and repatriated B.C. Hydro service contracts indicated that up to eight separate building locations should be required to hold these head office and administrative groups. The problems associated with operating a fragmented work force would continue if arrangements were not made to consolidate certain departments at one location."

BC Gas provided the Commission with information to justify the move on the basis of cost savings over a 10-year period as a result of lower expenses due to consolidation of office space, elimination of redundant services and lower lease rates due to the renting of a large block of space [Exhibit 5, Tab 11, item 1.11(d), pages 2 and 3].

The Commission was surprised by the apparent lack of any identifiable decrease in staffing due to the proposed consolidation of various activities into one location. BC Gas clearly indicated that there were synergistic benefits to moving all of its staff into one headquarters. The Chairman remarked (T. 1439):

> "...the value of consolidation in moving together, particularly in one building, ... — should be quantifiable in terms of manpower in my view..."

The Company maintained, however, that there were no identifiable departments that would benefit from reductions in employees when brought together in one location (T. 1435).

The decision process regarding the Centre was also scrutinized by the Commission. The initial requests for tenders for leasing proposals indicated that the developers would be judged on the numbers as submitted. Mr. Hess stated:

> "The second component I wanted to mention was that when we went through our tendering process, we made it clear to the developers that we wanted firm hard dollars and we led them to believe that there would be no protracted negotiating process, that this was a tendering exercise and the numbers were the numbers.
>
> Schroeder in his presentation and his discussions with us, made it very, very clear that that in fact was his approach. At some point in the presentations, Manual Life, despite our instructions, indicated that there was some room for negotiating so we felt that there was a greater chance with Manual Life to reduce their low numbers even though they were -- their numbers even though they were not lower than Schroeder but we had a good idea that we would be able to negotiate lower prices and in fact that's what we did. And I am sure if you compare the final numbers that Manual Life presented to us in terms of a net present value, they would probably come very close to the Schroeder proposal." (T. 1364)

The successful bidder did not have the lowest cost. Other considerations were judged by the Utility's management to be an important offset. After the initial decision was made, there were some favourable alterations to the proposal by the successful bidder. The hearing was told that BC Gas did not approach any of the other candidates and request that they reconsider their proposals. BC Gas felt that the changes in the successful bid were:

> "...a function of a clarification that we made to them after they were selected as the company which had the overall best proposal." (T. 1368)

The question of location was also raised in the context of whether or not the downtown Vancouver location was the wisest choice from the point of view of employee morale. BC Gas indicated that it felt it was necessary to stay in the downtown location in order to be closer to its major customers, bankers and lawyers. However, it acknowledged that there was no survey of affected employees to determine any preference for a downtown or suburban location.

The value of a positive public perception of BC Gas was raised a number of times in the hearing. The Commission considers that perception to be at some risk due to the decision to establish executive offices on the 24th floor. This separation from the rest of the workforce does not seem to be compatible with BC Gas' corporate objective to instill teamwork.

Expenses relating to the cost of acquiring new furniture for the head office were reviewed. The Commission is concerned that the level of expenditures on new acquisitions may be in excess of what might be considered acceptable. It was informed that these costs have been placed in the Construction Work in Progress ("CWIP") account and will be examined for prudency when they are added to plant in-service.

The Commission was informed of office developments in Kelowna and other interior centres (Exhibit 2, Tab 10, page 7). The Commission is concerned that these decisions seem to have been made independent of any potential efficiency in organizational requirements.

In conclusion, although the Commission questioned the methodology employed in determining the consolidation of the head office and some of the management decisions made, it accepts the Utility's expectation of improved operating efficiency and that an acceptable level of expenditures will be achieved.

The hearing also heard evidence regarding the Lochburn facility in Burnaby. BC Gas indicated after an examination by consulting engineers that some sections of the Lochburn facility were not seismically sound and,

> "...more importantly there was a serious structural deficiency in the pile caps of the foundation and it was their strong recommendation that we take steps to house those people in another facility because the repair of both facilities wasn't practical." (T. 1461)

BC Gas indicated that their legal counsel believed there may be some possibility of recourse against B.C. Hydro who were the former owners of the building (Exhibit 121). The Commission is concerned for the safety of the employees in the building, as also indicated by

Mr. Kadlec (T. 3703), and urges BC Gas to address the Lochburn facility and remedy the situation as early as possible. However, BC Gas must demonstrate that in the solution to the problem it has pursued all avenues of cost recovery from B.C. Hydro or others, and the Commission will require BC Gas to obtain a CPCN for any new structures.

3.6 Aircraft

BC Gas has a corporate aircraft which is owned equally by it and Canadian Forest Products Ltd. This acquisition was not the subject of a business case analysis, nor were any alternatives examined. Mr. Burns, Executive Vice President, Finance and Administration stated:

> "The opportunity was presented to us and we accepted it." (T. 1499)

The aircraft is included in the test year rate base in the amount of $1,579,000 net of depreciation. Exhibit 80 indicated that the revenue requirement due to the aircraft was $246,000. The cost/benefit analysis, completed for the Application, indicated that the aircraft had an incremental cost of $174,000 in 1992 and that over a 15-year period the Net Present Value ("NPV") of the asset resulted in a cost to the Utility of $1,372,711.

BC Gas provided an analysis of the investment in the corporate aircraft (Exhibit 6, Tab 9) in response to a Staff Information Request. This included the assumptions used in the Company's cost/benefit analysis and a NPV calculation. The assumptions included the savings due to commercial airline costs not incurred, the imputed value of employee hours saved as a result of not having to wait in airports and the savings in hotel costs. Against these benefits were deducted the direct costs of operating the aircraft. The analysis also took into account the income tax benefits which result from the write-off of the aircraft's cost against taxable income.

Evidence indicated that the assumptions used in the cost/benefit analysis had not been rigorously scrutinized by the Company. On closer examination, BC Gas concluded that a $100/hour value attributed to employee time saved should actually have been halved to approximately $50/hour (T. 1759). Benefits were also counted for dead-head hours (Exhibit 122). Witnesses for the Company also indicated that an analysis had not been done recently nor was the analysis done on an annual basis. A revision of the cost/benefit analysis to take into account these deficiencies would in the Commission's view, result in an even greater NPV cost to the Utility and its customers. The aircraft does not appear to provide quantifiable benefits over its measurable costs. However, it would appear that the BC Gas valuation of this corporate facility is found more in subjective reasons.

Mr. Burns enunciated BC Gas' corporate attitude toward the aircraft (T. 1501):

> "...there's been a consciousness ... that these are considered corporate toys, that's they're frivolous, that they're not usable pieces of equipment. They're there for the convenience of people and to support egos, and I don't think that's the case.
>
> We know where it works. We know that, at 250 hours or thereabouts, that it makes sense to us as a corporate facility and a tool. We have half an airplane, the use of half an airplane 250 hours of use annually in the largest gas utility territory in North America, and most of the other utilities that have airplanes have whole airplanes, that is full use, and much smaller territories, and they find them usable and they find justification for them.
>
> I think it is really not in the culture of our company to have something that can't survive the test of bad times, and this aircraft, you know, it's not a flashy airplane, it is not a fast airplane, it is an airplane that was fitted specifically to get into the places we work. It is a slow speed landing and take off airplane that gets into all these places.
>
> I think we have been very conscious of the cost and the facility of this airplane and I can tell you it really does make it possible to be in the field and get to places that you just would have to pass up and you couldn't participate in the community or with the employees. It is a tool that we think works hard for us and we don't think it's something to be jettisoned when times get tough."

BC Gas claims that the aircraft is a "tool" that is required to help run the Company efficiently and effectively and that it facilitates the job of training employees. This view was summarized by the Utility's counsel in his closing argument (T. 4336):

> "The aircraft is used for a lot of purposes. The evidence is that. It's used for training purposes, communications. It's not ... just an executive aircraft. Any employee can use it if they meet travel criteria. ... There are a lot of functions that now occur out of the Lower Mainland operations, the training functions, the transmission functions and such, which have a direct role to play in the Interior, and it's important for the aircraft to be available to assist in that. It's not in any way unique that a company have an aircraft.
>
> Again, we've heard a lot about productivity and efficiency and I repeat my comment as Mr. Kadlec said that it's important that everybody buy into this concept, that there be good communication, that people get out there into the field and talk with people and explain what is going on."

Several of the intervenors commented on the corporate aircraft. In general they felt that the plane was an unnecessary luxury. Mr. Wallace commented (T. 4141):

> "With respect to the aircraft, we have little to say other than its seems rich. ... It is hard to understand why a Company that had operations all over the province and hasn't added to those operations, and didn't need an aircraft to run them, suddenly needs an aircraft when it acquires a Gas Division in the Lower Mainland."

Mr. Weafer echoed this same sentiment with his comments (T. 4185):

> "...There is no doubt in my clients position that this is an unnecessary item for the Company."

The Commission was surprised by the fact that there was no signed agreement between the co-owners of the aircraft over the sharing of costs involved or its use. Mr. Burns did not feel that this was inappropriate, although Mr. Kleven testified that he could not recall any other agreement of similar financial implications that did not have a signed document.

The Commission agrees with the intervenors that it appears inappropriate that the Utility would acquire the aircraft after a large expansion in the Lower Mainland where its headquarters are located, and the fact that the Company now maintains a vice president in the Inland Division offices in Kelowna. The Commission is not satisfied that the benefits are sufficient to warrant the cost.

Accordingly, the Commission determines that the aircraft should not be included in the rate base of the Utility. An adequate allowance for travel costs to compensate for the loss of the aircraft in the rate base is already included in the Application by way of the operating costs of the aircraft at $122,000.

BC Gas may wish to enter into an arrangement with the non-utility side of the Company that would allow the Utility to charter the aircraft on a pay-per-use basis. If this develops, the Commission will require, annually, all details of aircraft use for utility purposes, including purpose of each trip, all individuals on the trip, allocated cost and alternative cost by scheduled airline service or alternate charter.

3.7 Working Capital

BC Gas retained a consultant, Mr. W. Krampl, to undertake a lead/lag study for the purpose of calculating the cash working capital component of the rate base. The study indicated a cash working capital requirement of $5,792,000. This amount was revised during the hearing by Exhibit 73 which increased the value by $8,509,000 to $14,301,000. The revision was due to changes in the Revenue Agreement between BC Gas and B.C. Hydro (Exhibits 59, 59A, and 59B) which resulted in the average collection period for accounts in the Lower Mainland Division increasing from 14.33 days to 22.8 days.

The Commission expressed concern with the revision because it resulted in a significant increase in the cash working capital. Concern arose due to the fact that subjective judgement had been used to determine the average collection period for the last two quarters of the test year. The consultant indicated that the first two quarters of the year were covered under the Revenue Agreement as to the number of days that would constitute the average collection period. However, an estimate was required to be made for the average collection days in the final two quarters of the year. It was reported by B.C. Hydro that the estimate, in fact, was not unreasonable (T. 1623).

A question was raised by the Commission staff as to whether or not the lag days fell within the parameters of the tariff. The answer indicated (T. 3455 and Exhibit 148) that the lag days did fall within the tariff for the Inland, Columbia and Fort Nelson Divisions, but it appeared that in the Lower Mainland Division, B.C. Hydro allowed a grace period on the collections which would probably cause the lag days to fall outside of the tariff.

The Commission recognizes that 22.8 days take into account the lag between the customer billing and the receipt of payment by the Utility. However, it appears that the grace period might extend too far beyond the due date that is allowed in the tariff. **The Commission directs BC Gas to verify this situation with B.C. Hydro. The Commission will not make an adjustment to the forecast working capital with respect to this item. However, the inconsistency between actual practice and tariff conditions must be resolved so that the Utility will have consistency with the tariff.**

Commission counsel questioned the methodology used in the study and, in particular, the changes in the procurement of the Company's long-term gas supplies after November 1, 1991. The consultant had no historical payment history upon which to rely for the purposes of determining the expense lag days pertaining to the gas purchases. The methodology used relied upon the contractual due dates contained in the various contracts. Commission counsel queried the extent of subsequent research into the actual payment dates as opposed to the contractual requirements and the consultant indicated that he had not reviewed the actual data.

Finally, the Commission examined why it was necessary for BC Gas to use a consultant for the lead/lag study rather than utilizing their own staff. The Company indicated that the consultant was retained since their employees were engaged in other activities and were unavailable. In addition, the consultant had previously worked for BC Gas and had been involved in preparation of previous lead/lag studies. The Company indicated that in the future the studies would be done in-house. The costs of the consultant will be discussed in Section 6.7.

3.8 Deferred Charges

A schedule of deferred charges, included in the Application (Exhibit 1, Tab 3, page 1-03-14), showed the Company's approved and requested deferral accounts and the proposed treatments in the test year. The general approach by BC Gas is that expenses such as hearing costs are claimed for income tax purposes in the year in which they are incurred. The net after tax costs are in rate base and amortized as non-tax deductible expenses over a number of years. The Applicant believes that this is the least expensive method.

Since BC Gas is on a flow-through or tax payable method of accounting, Commission staff put forth a position (Exhibit 97) that expenses, intended or expected by the Utility for deferral and future recovery, should provide the tax benefit to the customers in the year of approval by the Commission. The Commission staff option indicated that, although the Utility should claim the expense for tax purposes in the year of incidence to avoid exclusion as "representation costs", such tax savings should not be taken into income until the proposed recovery is approved by the Commission. This normally occurs in a test year.

Exhibit 98 was filed by the Applicant. It showed that, over the amortization period, the BC Gas approach would yield a lower total revenue requirement. However, that saving would be nullified if the revenue requirements were recalculated to a present value recognizing the time value of money. The Applicant was able to demonstrate that, over the amortization periods, the revenue requirements are relatively stable.

It was also noted that there were other deferred accounts such as the hot water heater grants which were already approved by the Commission on a net after tax basis. In order to avoid confusion and provide for rate stability, **the Commission believes that all deferred accounts in rate base (other than those with interest accrual provisions) should receive the same net after tax treatment unless otherwise directed by the Commission.**

In the schedule of deferred charges (Exhibit 1, Tab 3, page 1-03-14), the Applicant also included certain deferred accounts which had been set up under Order No. G-92-91 for rate base treatment.

This type of account is related to cost of gas, and is normally established for short-term purposes with a provision to attract interest charges until disposition is directed by the Commission. However, the interest accrual provision was not specified in both the Company's Application and Order No. G-92-91. **The Commission accordingly approves these deferred accounts in rate base until their expected removal after the Phase B Rate Design hearing.**

With respect to the assumption to deem all new deferrable costs as if they were incurred mid-year, the Commission has taken the position that the 13-month average for new plant additions is the preferred method (see Section 3.10). It follows, accordingly, that costs incurred prior to the beginning of the test year should be accepted as recorded. However, cost projections pertaining to the Phase B Rate Design hearing, Demand-Side Management ("DSM") and the Least-Cost Integrated Resource Plan ("LCIRP") are conjectural at this point and will be examined by the Commission on an independent basis in a future hearing. They are, therefore, excluded from the rate base in this Application.

3.9 Depreciation Rates

During the hearing and in the Application, BC Gas made the following request:

> "There are two specific rates that the Company is seeking the approval of the Commission. One relates to a new class of assets, training and display and documentation materials which the Company is incurring some costs on, and is requesting approval for depreciation rate of 20 percent ... In addition we are requesting a depreciation rate for the aircraft of 5 percent." (T. 2225)

Training, Display and Documentation Materials

This is the first time that the Company has requested that these expenditures be considered as assets for rate base treatment at an allowed depreciation rate. In the past, amounts expended on such materials have not been significant and were treated as current expenses. Exhibit 135 indicates that the Company is seeking approval for an account balance of $882,000 at the beginning of the test year and depreciation expense in the amount of $176,500.

The Application indicated that there had been a substantial increase in training and documentation materials as a result of the sudden growth in the size of the Company, the development of several new large in-house computer systems and the fact that employees must be trained with the new systems.

The Commission expressed some concern with the fact that the request could be construed as retroactive rate-making as the Company had treated such expenditures as capital in 1991, prior to having Commission approval.

This is particularly relevant given the Agreements between the Company and the Government. If the Company seeks to recover costs in the "freeze" period by changing accounting policy, then it would be fair for the government to review "synergies" and other savings by the Company in that period.

The Commission recognizes that there has been a substantial increase in the size and complexity of the Company both in terms of the number of employees and in the systems now being used by BC Gas. It is reasonable to expect training and documentation manuals to be produced. One example was:

> "The Gas Division had a number of Hydro manuals, we had a number of Inland manuals and we are now bringing together two divisions..." (T. 2590)

The point was also made that the new manuals would increase efficiency in the Company.

There was no discussion as to the reasonableness of including the display materials as capital items other than Mr. Kleven indicating that the displays were used for:

> "...presentations to interested groups on advertising..." (T. 2690)

and that the materials:

> "...certainly have a longer life than one year." (T. 2590)

The Commission believes that training, documentation and display materials have different useful life-cycles and often require continuous updates and revisions. These expenditures should be expensed as incurred. Adjustments based on Exhibit 171 are reflected in the Decision schedules.

<u>Aircraft</u>

As the Commission has concluded that the aircraft will not be included in the rate base, there will be no depreciation expense to be claimed.

3.10 Mid-Year versus 13-Month Averages

BC Gas calculated its 1992 plant additions for rate base using the mid-year average methodology. In their opinion, this was consistent with previously accepted filings by its predecessor companies. The possibility and the impact of using a 13-month average method for "special" projects, was raised in Commission Staff Information Request No. 6 (Exhibit 7, Tab 24, item 4, pages 1 and 2). The Utility's response indicated that if the 13-month average method was used for those projects scheduled to be in-service in 1992, the rate base would be reduced by $20 million.

BC Gas has no difficulty with either method provided that it is applied uniformly to all plant additions. It objected to any mixed method approach on the basis of consistency and its finding that no other utilities in Canada calculate their gas plants in-service additions based on two methodologies.

Mr. Kleven (T. 2614) agreed, however, that West Kootenay Power Ltd. does use an adjustment to reflect the quarterly major project impact on rate base. Also, while BC Gas was firm in its position on consistency, its attitude was markedly different in the matter of AFUDC. He said:

> "Whether the old Inland Division or Columbia followed that in the past, it may have or may not have for whatever reasons existed at the time but that, as I said it didn't necessarily make it right." (T. 2556)

The issue in this matter is which method reflects a just and reasonable impact of new plant additions on customer rates. The use of the mid-year approach assumes that new plants are added evenly throughout the year. BC Gas, however, plans significant and special capital expenditures, the impact of which, including the timing of capitalization to plant in-service, can have a dramatic effect on the rate base.

The issue of proper matching is an important concept in regulatory accounting. For example, if a year-end rate base is used, other components such as revenues and expenses must be adjusted to reflect the year-end conditions. While most utilities under the jurisdiction of the Commission adopt a forward looking test year, they frequently use the word "mid-year" to label the average rate base and capital structure. However, regulatory literature generally uses the term "average" which suggests that the impact of all the numbers in a given set of data is considered. This is different in practice from "mid-year" which takes into account only the beginning and ending numbers. The intent for regulatory purposes is the use of "average" of all data if possible, and the mid-year information is acceptable only if the data are considered evenly distributed when the derivation of the average is not cost effective.

In the case of BC Gas, it has forecast sales based on the effective billed accounts each month throughout the test year (Exhibit 1, Tab 7). Related cost of gas and operating expenses are also forecast in the same fashion. In addition, the Company has utilized the 13-month average in other rate base items such as inventory, bad debt reserve, etc. (Exhibit 1, pages 1-05-06 to -12). In the capital structure, the Company also showed the effective impact of forecast long-term debt issues rather than a simple mid-year number (Exhibit 1, Tab 14, page 1-14-02). If the rate base is on a 13-month average, the capital structure would logically be derived on the same basis. Consequently, the use of a 13-month average on new plant additions is consistent and properly matched with sales, expenses and all other components in the Application.

Mr. Kleven suggested that one could move the fiscal year-end (T. 2272) or re-schedule the in-service date to maximize the return on rate base in a test year, if the 13-month average is used. The Commission believes that moving the fiscal year-end will effectively change all the ingredients in a utility's revenue requirement, which will then be examined from a different vintage. The re-scheduling of in-service dates must pass the prudency and "used and useful" tests.

In order to alleviate the concern, Mr. Kleven proposed that one of the following two methods could be used: Following the National Energy Board ("NEB") treatment of a TransCanada Pipelines Limited project, the impact of the Surrey-Langley Project could be deferred for recovery over the next three years; or the Surrey-Langley Project could be removed from rate base with continued AFUDC treatment until the end of 1992 when it is deemed to be in-service for the full year of 1993. BC Gas preferred the latter treatment although this might be in conflict with the Uniform System of Accounts, which stipulates that CWIP must be closed to plant in-service when it is completed.

The Commission understands Mr. Kleven's concern that a previously accepted methodology should not be judgementally replaced just to fit certain unusual circumstances. However, if a certain methodology is considered obsolete or no longer represents the current and future conditions of the utility, then it should be amended or substituted by a more accurate methodology such that both the interests of the utility shareholders and customers are protected. In all rate cases, the examination of the reasonableness of the information presented by the applicants also includes a re-evaluation of the methodologies used. Meanwhile the applicants often propose new methods for consideration, such as the use of certain deferred accounts and the use of AFUDC in BC Gas' situation. Another example is that construction in the interior is likely to take place during the summer months, whereas it can be done throughout the year in the coastal area. **In order to ensure that the impact of these plant additions is properly matched with the related sales and expenses, the Commission finds that the 13-month average is a more accurate measurement than the simple mid-year approach.**

Since the Surrey-Langley Project has been approved for construction and will be in-service by the end of fiscal 1992, it should therefore be closed to plant, and the two alternatives proposed by Mr. Kleven are only temporary solutions. The Commission concludes that using the 13-month average on all new plant in-service is the proper methodology to match revenues and expenses as forecast by the Applicant. With the new WMS in place, the Applicant should have no difficulty in determining the monthly construction schedules and the impacts on rate base. Similarly, the new FIS will also forecast the precise cash requirements.

For the purpose of adjustment in the test year, the Surrey/Langley Project is re-instated as 1992 plant additions, and $20,103,000 (Exhibit 7, Tab 24, item 4, page 2) is removed from rate base. Adjustment is not necessary for other non-special projects which are deemed to be added evenly throughout 1992. Since the topic of depreciation has not been reviewed for some time in areas such as appropriate rates, new plant units, and depreciation base, the Commission will consider further measures to allow all parties to provide input to the matter of revising depreciation rates.

4.0 SALES VOLUME AND REVENUE

The 1991 and 1992 sales and revenue figures in the Application are essentially two-year forecasts since, at the time the Application was prepared, 1990 was the last full year for which gas sales data were available. Commission staff engaged independent consultants to examine BC Gas' forecasts. During the hearing the sales volumes and revenues forecasted were revised to reflect updated information (Exhibit 41).

The Commission has accepted the forecasts in this Decision. It notes, however, that the quality of the forecasts is less than those which will be required in future hearings. The apparent underestimation of sales volumes is accepted only because this is the first hearing for BC Gas.

4.1 Residential

The Applicant testified that residential forecasted volumes for 1992 were based on a projection of customer additions and normalized average use per account (normalization is discussed in Section 4.7).

BC Gas stated in the Application (Exhibit 2, Tab 5, page 5):

> "...separate use per account projections are done for each division and rate class, by considering the most recent historical use per account, the trend in use per account in preceding years and the estimated impact of marketing programs and demand side management programs over the forecast period ... The volume forecast is the product of the average monthly number of customers times the monthly average use per account for each division and rate class, plus or minus an adjustment for measurement equity programs."

Sales revenue was estimated by using the tariff rates applicable at October 31, 1991 and adjusted in a manner consistent with Commission Order No. G-92-91 which dealt with the Gas Cost Flow-Through Application. The revisions to the Application found in Exhibit 41 updated the actual closing 1991 figures which were not available when the Application was submitted.

There was concern that the forecast of 1992 account additions was low in comparison to the number of account additions actually experienced in 1991 and when considered in light of Canadian Mortgage and Housing Corporation housing starts forecasted for British Columbia. During the regional hearings evidence was given to indicate that the 1992 housing starts were significantly ahead of forecast particularly in Prince George, the East Kootenays and the Okanagan.

The Commission was told that much of the increase in new accounts in 1991 over the forecasts for that year was due to the introduction of the Provincial Power and Gas Extension Program ("PGEP") in mid-1991. This program was not extended into 1992 and therefore BC Gas did not feel that the 1992 forecasts should be revised, despite the apparent increases in the interior regions. In addition, BC Gas predicted lower capture rates in 1992 in the Lower Mainland than had been experienced in 1991.

The Commission accepts the revised residential account additions, normalized volume forecast and sales revenue projections. Even though the Commission anticipates that new accounts will be higher than projected, the added volume will not be material to 1992 projections.

4.2 Commercial

The projections for commercial sector sales volumes, revenues and numbers of accounts were calculated using the same methodology as for residential customers. A revision to the figures in the Application was made (Exhibit 41) due to the fact that:

> "The original application had built into the projection of volumes for 1992 a projected opening balance of accounts for 1992 and we now have updated the '92 volumes to reflect the actual opening balance of accounts that occurred in 1992." (T. 786)

Exhibit 41 also incorporates the pricing structure accepted in the Phase A Decision of the Commission.

BC Gas disclosed that since the Application was filed, they had become aware that the number of commercial accounts for the Lower Mainland had been under-reported. This problem was a result of reporting from B.C. Hydro, which administers the billing system for BC Gas. A number of commercial accounts billed on a bi-monthly basis were missed. However, the Utility stressed that:

> "...in a projection of sales and volumes and revenues, this has no effect at all with respect to the projections." (T. 806)

Commission counsel cross-examined the BC Gas panel on the reasons for the apparent drop in usage rates from 1990 to 1991 which necessitated the revisions to the opening 1992 numbers. The concern was that there may be a built-in fault in the BC Gas forecasting methodology which would be carried through to the 1992 projections. BC Gas responded that the bulk of the reduction was due to the slow-down in the economy and that 1991 actual sales had indeed been lower than predicted. However, they did not feel that this would be the case for the revised 1992 projections.

The Commission accepts the 1992 forecast for the commercial sales volumes, revenues and number of accounts. Even though the use per account may be reduced by the slow economy in 1991, it is evident that the recovery is advancing very slowly in 1992.

4.3 Industrial

Sales volume and revenue for industrial customers, both large and small, was forecasted using a different methodology than that used for the residential and commercial customers. As explained in the Application (Exhibit 2, Tab 5, page 6):

> "Industrial customers are canvassed annually and their own estimates of gas consumption are used.
>
> In early April each of the utility's larger industrial customers is contacted by letter requesting they provide their best estimate for gas consumption for the calendar year 1992. Their responses are analyzed against current and historic performance to identify anomalies, and when variations of a material nature are apparent, steps are taken to verify these against identifiable causes.
>
> Further consideration is then given to each customer forecast where alternative fuels or direct market options offer competitive choices which expose BC Gas to the risk of losing such sales. Each case is individually assessed and adjustments to forecasts made accordingly. In addition, allowances are also made for reduced gas load resulting from possible labour disruptions."

BC Gas indicated that the Utility was forecasting a significant drop in sales volume in the large industrial category (Exhibit 5, Tab 1, page 4). Mr. H. Dinter, Manager, Industrial Marketing testified that:

> "Somewhere between 70 to 80 per cent of that is one industrial customer on the Lower Mainland here who has switched to alternative fuel." (T. 918)

The rest of the decrease is essentially due to two other customers, one of whom switched to transportation service and a projection of reduced purchases by the other.

Examination of the detailed projections for the Inland Division revealed an anomaly (Exhibit 7, Tab 16, page 2), as BC Gas provided an analysis of industrial sector sales volumes comparing budget to actual for the years 1989-1991. In each year the Inland Division industrial customer consumptions were significantly over the Utility's budget, ranging from 54 percent in 1989, to 360 percent in 1990 and 107 percent in 1991. When questioned as to the consistent under-estimation by BC Gas of sales volumes for the Inland Division, Mr. Dinter replied that BC Gas had not under-estimated the forecasts but that the analysis "...shows that the customers have consistently under-forecast their actual consumptions" (T. 920).

The Commission recognizes that the methodology employed by BC Gas starts with the customers estimating their consumption. However, the evidence also indicates that BC Gas assesses the customer forecasts and adjusts them to account for historical anomalies such as curtailments and strike provisions. As indicated in response to a Commission Staff Information Request, BC Gas did not adjust any of the Inland Division industrial customers' forecasts despite the historical under-estimating problem which existed (Exhibit 6, Tab 13, page 4).

The Commission accepts these forecasts for this year since the Commission is sympathetic to the financial impacts that unusually warm weather and a recession are having on 1992 gas sales.

4.4 Transportation Services

Transportation services, or T-service as it is known in the industry, were estimated using the same methodology as for industrial sales. The individual customers provided estimates of their gas consumption for the coming year. Revenue was computed from this estimate by multiplying the monthly transportation volume by the applicable adjusted present rates (i.e. the tariff rates in effect October 31, 1991 adjusted in a manner consistent with Commission Order No. G-92-91).

The Application indicated an increase of 17.8 PJ in the T-service volumes in the 1992 test year over 1991. The bulk of this change was due to increased volumes by PCEC. The PCEC volume in 1991 was 2,569 TJ versus a projected volume of 18,700 TJ in 1992.

Commission counsel questioned the BC Gas panel regarding the apparent levelling out of new industrial/T-service account additions in the Lower Mainland. Between 1990 and 1991 there was an increase of 39 industrial and T-service accounts from 141 to 180 (Exhibit 5, Tab 2, item 1.2(a)(iii), page 18.3). Mr. Dinter attributed the increase to "approximately 30 to 40 Lower Mainland firm sales customers that have moved onto transportation." (T. 916) The 1992 projection indicated that there would be no increase in industrial accounts from 1991. Mr. Dinter testified that:

> "It's our belief that any customers that have had any real economic ability to move to transportation on the Lower Mainland have already done so with regard to firm sales customers moving to firm transportation." (T. 916)

The Commission accepts the T-service volumes and sales revenue estimates as filed.

4.5 Burrard Thermal Plant

Sales to the Burrard Thermal Plant by BC Gas are provided under agreements which cover firm, interruptible and swing gas. Under the agreements there is a take-or-pay requirement of 20 PJ per year. A review of previous years consumption indicated very large year-to-year swings ranging from 0.030 PJ in 1986 to 44 PJ in 1989. In the 1992 test year BC Gas included 20 PJ of interruptible sales which represented their contractual obligations under the agreements and 3.5 PJ of swing gas covering the winter months operations. The take-or-pay revenue of $5 million is included as "Other Income" in the Application.

In a response to a Staff Information Request, the Utility stated:

> "Burrard Thermal volumes are a function of the electric power needs of B.C. Hydro. B.C. Hydro is unable to provide BC Gas with a definitive forecast of Burrard Thermal use ... The majority of net revenues ($5 million) generated from the operation of the Burrard Thermal Plant is based on a take or pay level of 20 Petajoules annually. Thus the year over year fluctuation of volumes is effectively not translated into a similar year over year fluctuation in net revenues ... The present outlook for Burrard Thermal interruptible sales volumes for 1992 is minimal." (Exhibit 7, Tab 15)

The Commission accepts the position taken by BC Gas that the sales volumes for this customer will not likely be higher than the take-or-pay level. The Commission also notes that when sales do exceed 20 PJ the margin on incremental sales is minimal. Therefore, even though it is not possible to reasonably forecast utilization of the Burrard Thermal Plant, the financial impact of varying consumptions is modest.

4.6 Marketing Programs

The BC Gas marketing department is organized by market sectors: Residential; Commercial; Industrial; and NGV. Residential, Commercial and NGV programs are discussed below. Industrial marketing was not examined in detail, although BC Gas provided a summary of industrial marketing initiatives in Exhibit 28.

Residential Marketing

As indicated by Mr. Rich, Vice President Marketing, in his written testimony, BC Gas' residential marketing programs comprise the following categories:

> "promotion of customer additions (new and conversion), conversion of domestic hot water heaters to gas, promotion of non-traditional appliances, programs to decease peak loads and increase energy efficiency, financing and merchandising." (Exhibit 2, Tab 5, page 10)

The marketing programs were examined by both intervenors and the Commission. One concern that both groups had was the apparent contradiction between marketing programs which promoted increased use of gas and DSM objectives, which would promote conservation in the use of gas. It was noted that there were financial incentive programs which promoted gas use and alternative financial incentive programs which supported DSM. As stated by Mr. Doherty (T. 866), "I feel somewhat uncomfortable with this separation of marketing and DSM programs." The Commission was also uncomfortable with the apparent cross-purposes of the marketing department. Ms. Wier, Manager, Residential Markets, indicated the DSM projects for residential use (T. 866):

> "...There is incentives to consumers to replace log sets with heater fireplaces...also the demand side management area, for one, being energy audits."

The confusion was exacerbated in the following exchange:

> "Mr. Doherty: So would it be fair to say that the marketing of financial incentives are all to encourage people to use more gas and the ones that you've included under demand side management should have the effect of the use of less gas?
>
> Ms. Weir: I would have to agree with that, yes." (T. 866)

It was evident in the hearing and in the written testimony of witnesses that BC Gas did not feel there was a contradiction. Ms. Weir stated:

> "...we've got conservation programs on one hand and what look like load growth programs on the other. And yet, if you look at them together, it's really overall strategic load management. Natural gas is a preferred fuel environmentally, it's low cost. People are going to want it ... you've got to help those people use it as efficiently as possible." (T.870)

Mr. Rich stated in his testimony, when referring to appliance financing programs (Exhibit 2, Tab 5, page 12):

> "These appliances provide natural gas loads which are year round loads and help to fill the traditional summer valley period. Revenues from these volumes are purely incremental and will assist in offsetting future rate increases for all rate payers in this group."

However, in contradiction to this objective, the Commission learned that, under the Consumer Appliance Financing Plan, all efficiencies of appliances are available for financing, not just high efficiency products. Ms. Weir, when queried by Commission counsel as to whether or not high efficiency appliances were financed rather than low efficiency, stated:

> "At this time we are financing all efficiency appliances...however I would say that there's definite consideration that we would like to be able to finance people who would like to make their homes more efficient, the improvements required, whether that be insulation or windows or things of that nature. So that gets towards that but we have not actually said that there will be no financing for low efficiency appliances." (T. 973)

The Commission encourages BC Gas to evaluate this anomaly in their marketing programs. This matter will be canvassed further during the review of the LCIRP.

The appliance financing programs have been operating in the Inland division for several years with Commission approval. BC Gas recently requested approval for a program in the Lower Mainland. **The Commission has concerns regarding the compatibility of this program with the LCIRP and therefore defers consideration of the appliance financing plan until the Phase B Rate Design hearing. Costs for this program and revenues have been included in the Application. As the Lower Mainland program has yet to be approved, the Utility's activities will be confirmed or rejected at a later date. Although the costs and revenues of the programs are reflected in the test year figures, they may be removed if the program is not approved.**

Commercial Marketing

Mr. Rich testified that a Commercial Water Heater Incentive program, a Restaurant Booster Water Heater program, and a Destination Points Travel Incentive program were currently in place. In addition, the utility is planning on introducing a Commercial New Construction program and a Commercial Energy Audit program in 1992. Three programs under development are the Multi-family New Construction Incentive Pilot program, the Fuel Substitution program and the Commercial Finance program (Exhibit 2, Tab 5, page 15).

It was pointed out during the hearing that the Commercial Water Heater program appears to be at odds with the DSM objectives of the utility in that it covers both low and high efficiency products. However, it was noted that new government regulations expected in about a year regarding high efficiency water tanks will force a change in these parameters (T. 985).

The Commission notes that the Commercial Water Heater program and the Restaurant Booster Water Heater Incentive program were being operated as pilot projects and have not yet received approval. The applications for approval are before the Commission. Consequently, the Commission will treat these programs in the same way as the Lower Mainland appliance financing program.

Natural Gas for Vehicles ("NGV")

The NGV program is the responsibility of the marketing department. Mr. Rich stated:

> "The objective of NGV marketing programs is to increase the use of an alternative fuel to gasoline, by facilitating the conversion of public and private fleet vehicles to natural gas." (Exhibit 2, Tab 5, page 22)

There are two primary programs in the NGV strategy, the Conversion Support Program ("CSP") and the Vehicle Refuelling Appliance Program ("VRAP").

The CSP was introduced in 1989 with Commission approval and will be reviewed in detail in an annual report submitted by BC Gas. Consequently, the CSP was not reviewed by the Commission as part of this hearing.

The VRAP, which runs until July 31, 1992, was described by Mr. Rich as follows:

> "The VRA program is a pilot program to demonstrate the effectiveness of offering customers a vehicle refuelling service at their premises.
>
> The VRA is a small electrically driven compressor which compresses natural gas to 3000 psi and fills a vehicle's fuel storage cylinders. It is a "slow-fill" process which can fuel a vehicle overnight." (Exhibit 2, Tab 5, page 25)

The VRAP will also be reviewed by the Commission in detail at a later date.

The major impact of the NGV program in the Application of BC Gas is the inclusion in the rate base of capital costs of $1,539,082 for the construction of five new NGV stations. BC Gas believes that the NGV stations are required to ensure that the future anticipated growth of natural gas as a substitute for gasoline is realized. Commission counsel queried Mr. Rich on the possible impact on BC Gas' long-term NGV program of the stated intention by the Provincial Government to remove the current tax relief from natural gas on March 31, 1997. Mr. Rich responded that the announcement was too recent for a review to have taken place. The Utility still planned to move ahead with increasing the number of NGV stations in its Lower Mainland and Interior divisions. Mr. Rich stated:

> "...The immediate task is to get the fuelling infrastructure in place so that we can serve the OEM's when they come ..." (T. 991).

The Commission recognizes that there is an inherent difficulty in developing a mature NGV program when BC Gas must rely to some extent on the production of new vehicles with natural gas engines for success. The change-over of automobiles from gasoline to natural gas as a fuel is a long-term goal that the Commission has generally supported. A detailed review of this area, as indicated above, will be performed by the Commission in the review of the CSP and VRAP reports and the LCIRP. The capital costs for the new NGV stations are allowed.

4.7 Temperature Normalization

Temperature normalization is a method used to remove the uncertainty of weather on estimates of gas use for a test year. The Application is prepared on a forward looking basis, i.e. the volumes of gas sales for the 1992 year are forecasted based upon projections of customer growth and use. One of the factors which can impact gas use is the atmospheric temperature so that on a cold day heating load customers will use a greater quantity of gas than on a warm day. The forecast is therefore "normalized" to determine how much gas would have been sold in an historical year with average temperatures. As long-term future weather cannot be predicted, a reasonable assumption is that future years will be average, and therefore, the historical base years, normalized to average conditions, provide a reasonable base.

There are various normalization assumptions and techniques which can be used validly. The normalization methodology used in the Application is the same as that used by the Inland Division in prior filings, however, it differs from that used by the B.C. Hydro gas division, which is now the Lower Mainland Division of BC Gas. A BC Gas consultant, Mr. W. Eyers, provided an independent review of their sales normalization methods to determine the most appropriate method to use in the Application. The report by Mr. Eyers was filed as part of the Application (Exhibit 2, Tab 7, Appendix WWE.1).

The Utility's use of a 10-year moving average as the basis to calculate normal temperature was questioned. Some other utilities use longer periods of time. Mr. Eyers maintained that the shorter average tends to reflect more accurately the current weather patterns, which do change over periods of years, or decades (Exhibit 2, Tab 7, page 9 and T. 943-944).

Another concern expressed was the derivation of some of the data relating to the Inland Division. The majority of the customers in the Inland Division have their meters read bi-monthly. Accordingly, the first month billing is an estimate and the second month billing provides an adjustment to the actual use over the two month period. As a result, a concern arose as to the inaccuracy of some of the data used in the normalization equations and that this inaccuracy could have a material effect on the results. However, the consultant concluded that although there appeared to be the possibility of inaccuracies in the data, there was no material bias in the results which would impact on the normalized values.

The Commission accepts the temperature normalization process used by BC Gas. This process works well for rate-making purposes when the temperatures are not significantly different from the base conditions. In these cases, the extra revenue in cold years is offset by reduced revenues in warm years. However, the temperature normalization process can cause great earnings volatility in extreme weather years like 1992 (to date). The Commission has been concerned that these extremes create too much risk for shareholders and customers. BC Gas was approached at least twice in the past six months by Commission staff with proposals to institute a weather normalization process, but BC Gas has rejected these proposals. The Commission remains concerned with the impact that warm weather will have on BC Gas' earnings this year, and may have on future financings.

5.0 OPERATING EXPENSES

Other than "Gas Purchases", which is also discussed under this section, BC Gas forecasted $90.2 million in O&M expenses after allocation to capital. This represents a 14.5 percent increase over 1991 (Exhibit 5, Tab 14, item 1.14, page 2.2 combined). Upon request, the Company also provided breakdowns of these costs on a divisional basis for the years 1988 to 1992. However, it qualified the filed information in that,

> "BC Gas is reluctant to provide the historic data by BCUC account for the years 1988, 1989 and 1990, since in that period the four former Companies were merged, changes in the organization took place, different accounting codes, procedures and financial information systems were in place and were changed during the period to bring operations and information systems together in one of the largest mergers in the history of British Columbia.... However, starting January 1, 1991 the systems in place and the resulting information are reliable and meaningful...and comparable." (Exhibit 5, Tab 14, item 1.14, pages 1.1 and 1.3)

The Applicant objected to any attempt to compare 1991 information with the test year on the grounds that 1991 could not be considered as a base year (T. 340-343). In justifying the O&M costs/customer from 1991 to 1992, BC Gas also asserted that,

> "analysis of historical data of BC Gas is difficult and reviewing overall trends is a much more meaningful approach." [Exhibit 7, Tab 17, item 11(c), page 1]

Extensive evidence was canvassed throughout the hearing. Information was requested and filed to explain variances in excess of 5 percent from 1991 to 1992 (Exhibit 7, Tab 17, item 11). Comparison was made between 1991 and 1992 by Commission account and area of operation (Exhibit 38) and detailed O&M variance analyses were also filed (Exhibits 39, 40, 45 to 48, 63 to 65). The matter was further confused by changes in BC Gas' accounting during the rate freeze period so comparisons to individual accounts were not always possible between years. The Commission recognizes this problem but believes that comparison of the aggregate costs of a group of accounts under a specified broad function, such as maintenance or administration, should provide a reasonable trend.

The reasons given by the Applicant for the cost variances from 1991 to 1992 relate in general to the following factors: inflation and cost escalation particularly in wages and salaries, manpower increases, and costs related to the MIS and increased marketing activities. The Commission's Decision will focus on these areas.

While various forms of analysis were performed, the schedule contained in Exhibit 5, Tab 2, item 1.2(a)(iv), page 26 (rev.) represents a typical summary of O&M expenses by Commission account codes before transfers to capital and other allocations. In that schedule, from 1991 to 1992, "Operating" expenses were forecast to increase from $65.5 million to $70.8 million - an increase of 8.1 percent; "Maintenance" expenses were to increase from $7.1 million to $8.1 million - an increase of 14.0 percent; "Administrative & General" expenses were to increase from $36.0 million to $44.7 million - an increase of 24.2 percent. Overall, after transfers, the total net increase was forecast at 14.5 percent. The above information was subsequently amended to a minor extent by the Applicant.

In the Application, BC Gas indicated that it would rely on a review by Price Waterhouse in the comparison of BC Gas statistics and other related information as a support for the reasonableness of its request for the 3 percent rate increase (Exhibit 1, Tab 1, page 8). **While the Commission will discuss the Price Waterhouse evidence under Section 6.1, it believes that a review of the trend and comparison of the test year changes with the prior year base is essential in determining whether the forecast increases are acceptable. The only credible alternative would be a zero base budget review which was not practicable to be undertaken.**

The following sections review each of the major O&M categories making up the 14.5 percent aggregate increase, and the Commission reaches specific conclusions in each section. In Section 5.10 the Commission considers the total of the appropriate adjustments and determines that a single adjustment to O&M cost per customer, is the most appropriate action.

5.1 Gas Purchases

Gas purchases are by far the greatest cost contributing to the revenue requirement. For 1992, total gas purchases are forecast to be $385 million or 59 percent of the $650 million total revenue requirement. Because of the significance of these costs to the rate application, the Commission will briefly review gas purchases in the following sections notwithstanding that their prudency and allocation has been previously determined by the Commission in the Phase A Decision.

5.1.1 Gas Supply Planning Criteria

The Company's gas supply planning criteria were detailed in evidence given by Mr. Bierlmeier, Vice President, Gas Supply (Exhibit 2, Tab 3, page 14). In summary, the Company planned to meet the coldest day in the past 20 years using a portfolio of supplies. The bulk of the supply is purchased for the Inland and Lower Mainland Divisions. The priority is generally established on the basis of lowest cost supplies used first. The curtailment of firm industrial customers is used as a last resort recognizing it is limited to five days only by contract. The long-term contracts represent about half of the peak day supply and are considered as base load contracts. BC Gas leases underground storage at Aitken Creek in northeastern B.C. and at Jackson Prairie in northern Washington State. Supply from this latter source is effected by exchanges with suppliers who would otherwise export their gas to Washington State. The LNG plant provides for supply during needle peaks and is limited to use for only four days at maximum send-out capacity. Because the LNG plant is located in the BC Gas coastal service area, close to major load centres, there are no Westcoast Energy Inc. ("WEI", "Westcoast") charges for LNG peaking deliveries, and since under certain circumstances it can also serve to augment system capacity, the Commission views this plant as being of key importance to serving coastal customers.

The selection of the coldest day in the past 20 years by BC Gas makes its criteria one of the least conservative amongst major utilities across Canada and on the Pacific Coast of the United States. This is illustrated in Appendix 1 to Mr. Bierlmeier's evidence. While this criteria places the supply to core market customers at some risk under extreme cold weather, the Company maintains that additional gas supplies will always be available if the Utility offers a sufficiently high price. The selection of this criteria does provide ongoing savings to the customers during normal weather years which exceed the cost of any additional supplies required during extreme cold weather.

On the other hand, the design criteria does not represent a business risk to BC Gas since the Commission has previously accepted the prudency of the Company's gas supply planning design criteria in approving the Company's gas supply portfolio pursuant to Section 85.3 of the Act and the Commission's Rules thereunder. There was no evidence presented in this hearing to suggest that there is a need to reconsider the prudency of the planning criteria.

5.1.2 Allocation of Gas Supply Costs

With respect to the allocation of costs arising from the approved gas supply arrangements, the Commission conducted a hearing into this matter commencing December 3, 1991 and ending

January 10, 1992. The Decision issued February 21, 1992 approved a specific flow-through methodology. In summary, this methodology provides for allocation of commodity costs on a volumetric basis and allocation of demand costs (whether WEI tolls, producer demand charges or fixed peaking and storage tolls) on a coincident peak basis. (The coincident peak method allocates demand costs based on each customer class' forecasted percentage use of demand during the peak day). Since interruptible customers receive no service at peak, demand charges are allocated to firm customers only.

The Commission's review of BC Gas' revenue requirements, confirms that the methodology approved by the Commission has been adhered to in allocating gas supply costs. The Commission is therefore satisfied that the revenue requirements attributable to gas supply have been accurately stated.

5.1.3 Unaccounted-For Gas

Considerable effort was required through information requests and questioning of witnesses at the hearing to clarify the treatment of unaccounted-for gas ("UAF"). Since the Company had, in effect, decided to change a long-standing policy of using 10-year averages, this decision should have been highlighted in the Application and justified.

In the case of the Lower Mainland Division, the Commission concludes that the UAF figures contained in the Application are correct, having properly considered the changes resulting from the introduction of more temperature compensated metering as confirmed by Exhibit 57. In the case of the Inland Division, the Company has agreed (T. 1113) that a 10-year average would be more appropriate but the Commission will not make that minor adjustment. For the Columbia and Fort Nelson Divisions, the Commission accepts the rationales offered by BC Gas (T. 1114-1118) and approves the UAF calculations contained in the Application as updated in the hearing.

The Commission is concerned, however, that the UAF is currently running at too high a value. This is particularly true in the Lower Mainland Division where the UAF for firm sales consistently exceeds 4 percent in contrast to almost zero in the Inland Division. While the Commission accepts that much of this discrepancy is attributable to a lack of temperature compensation on residential and commercial metering, the Commission encourages BC Gas to

move judiciously towards a target of less than 1 percent UAF for the Company as a whole. The check measurement investigations currently being conducted in the Columbia Division are a good start.

5.2 Operations and Maintenance Activities

Review of the detailed operations and maintenance variance explanations (Exhibits 45-48) revealed the high level of capital activity, particularly in the interior operations, in 1991 which diverted resources from more routine operations and maintenance activities. The reason for this extraordinary situation in 1991 was the late announcement of substantial PGEP grants by the Provincial Government. No such grants will be provided in 1992. The majority of the 1992 increases are attributable to increased salaries and wages and increased manpower.

Individually, the variance explanations for operations and maintenance activities presented by the Company appear to be reasonable. However, on an overall basis, even when net costs are compared, 1992 operations costs have increased by 12.4 percent and 1992 maintenance costs have increased by 14.4 percent from 1991.

While the Commission endorses the individual activities to be undertaken in operations and maintenance, it is concerned about the overall size of cost increases from 1991. Adjustments to these costs are considered in subsequent sections.

5.3 Administrative and General

As shown in Exhibit 5, Tab 2, item 1.2(a)(iv), page 26 (rev.), the gross increase of $8.7 million or 24.2 percent from 1991 to 1992 for administration and general, represents the largest change in operating costs, both in dollars and percentages. Almost all of the increases are in costs under Commission Accounts 721 and 728. By definition in the Uniform System of Accounts, Account 721 includes: "The cost of salaries, supplies and expenses incurred in connection with the general administration of the company, which are assignable to specific executive, administrative and general departments and are not chargeable to a specific operating function." Account 728 includes: "The expenses incurred in connection with the general management of the company not provided for elsewhere, even if not allowable as an operating expense for regulatory purposes." These expenses include office supplies, rents, travel, memberships, contributions and donations, and costs related to shareholder dividends, meetings and annual reports. The bulk of the increases can be attributed to: Management and Exempt compensation of $3 million, Office Technical Employees Union ("OTEU") compensation of $2 million, and a slight decrease in International Brotherhood Electrical Workers ("IBEW") compensation. The other major increases are $1 million in computer costs and $0.7 million for rental [Exhibit 5, Tab 2, item 1.2(a)(v), page 30.1 (rev.)]. While some portion of these costs will be transferred to capital or recovered through redistribution of costs from non-utility operations, the forecast 1992 net administration and general costs are $3.8 million or 14.5 percent higher than in 1991.

BC Gas has a duty to demonstrate the prudency of its costs and to reflect the synergistic cost reductions anticipated in the acquisition of the Lower Mainland Gas Division. The evidence demonstrates a total increase of 24.2 percent before allocation and 14.5 percent after allocations to capital or non-utility operations. The Commission cannot accept such a large increase without adequate justification by the Company. The Commission believes that the residual 14.5 percent escalation should be less than half that amount. Specific cost assessments are provided in Sections 5.6, 5.7 and 5.8.

5.4 B.C. Hydro Services

As a result of the purchase of the Lower Mainland Gas Division from B.C. Hydro, there were 56 agreements to cover various administrative and customer services which continued to be performed by B.C. Hydro. Exhibit 62 shows that the 45 functions covered by these agreements represent an equivalent of 311 to 324 full-time employees. While BC Gas has repatriated 75 percent of these functions, or an equivalent of 73 employees, and two of the functions were replaced by other contracts representing up to 93 employees, there are still nine functions with an equivalent of 158 employees which B.C. Hydro continues to perform in 1992.

The Company has been terminating these services "because BC Gas could perform the service more cost effectively in house, or because BC Gas wanted to maintain control over the particular service area" (Exhibit 5, Tab 6, 1991 Corporate Business Plan Synopsis, page 9). While the Utility is re-negotiating some of the contracts, it has made allowance in the Application for an increase of 9 percent in addition to inflation, but expects the final increase to be in the 20 percent range (T. 1071). It also made extra provision for increased bad debt expense and a delay in receipt of the revenue from B.C. Hydro (T. 24). These have been reflected in the Application as increased working capital. Exhibits 59A to C and 73 were filed subsequently to reflect these revised agreements.

The Company indicated that B.C. Hydro wanted BC Gas to repatriate all services except in the area of billing (T. 324). B.C. Hydro intention had prompted BC Gas to accelerate the provision of its own services including accounting, the MIS, marketing and human resources (T. 395).

The Commission encourages both BC Gas and B.C. Hydro to cooperate wherever possible when there are common areas of interest and service. In addition, cooperation should be cost-effective and fruitful in areas of DSM or customer oriented programs, since they share most of the same utility customers.

5.5 Inter-Company/Division Charges

Based on an information response provided in Exhibit 5, Tab 5, item 1.5, the Commission understands that the practices regarding inter-company/division charges since 1988 are as follows:

(i) In 1988 and 1989, a management fee was charged to subsidiary companies based on actual time spent by the Company's management.

(ii) In 1990, head office administrative and general costs were accumulated by function and re-allocated to the Divisions based on operating statistics, eg. number of customers.

(iii) In 1991, other than specific costs which were allocated to the identified Division, corporate costs were allocated again based on operating statistics.

(iv) In 1992, apart from the specific divisional costs, corporate costs were allocated on a single basis, i.e. volume of gas sold.

BC Gas attributed the above changes to the evolutionary processes of the new utility and progressive integration of certain administrative functions. Although OIC 953/89 required BC Gas to maintain divisional accounts, the Company was able to do so only "to the extent possible during 1988-1991" (Exhibit 6, Tab 3, page 7).

Since the Company's methodology for inter-company/division charges was different from year-to-year during the rate freeze period, the Commission had difficulty determining whether the allocated costs were reasonable. On the basis of the evidence provided, the Commission accepts the 1992 allocation of joint costs based on firm sales volumes. The matters of

"Divisional Accounts" and allocation to non-regulated businesses ("NRB") are discussed in separate sections of this Decision (see Section 2.8 and 6.2).

5.6 Manpower Requirements and Consultant Services

One of the key expectations in the acquisition of the B.C. Hydro gas division, was the positive potential for synergistic impact on manpower levels. A listing of new employee positions was filed under Exhibit 7, Tab 18, item 12. The summary of number of employees contained in Exhibit 5, Tab 2, item 1.2, page 4.2 (rev.) shows that the total number of employees has increased from 1,290 in 1989 to 1,583 in forecast 1992. The B.C. Hydro Service Agreements significantly influenced the manpower requirements in BC Gas. Originally, the Company estimated the B.C. Hydro agreements had an equivalent of 255 full-time employees (T. 336). The estimate was revised to between 311 and 424 to reflect the 1992 situation (Exhibit 62).

The evidence indicated that Inland acquired an extremely efficient utility in the purchase of the Lower Mainland Gas Division. The Commission has the impression that BC Gas reached saturation in customer satisfaction in 1990 and 1991 (Exhibit 2, Tab 13, page 11), and that the ratio of customers to employees was efficient in 1989 (T. 1873).

The Commission is extremely concerned with regard to the very large additions to manpower since 1989. However, it is important to recognize those elements which have contributed to increased manpower requirements. They include the repatriation of employees for services undertaken previously by B.C. Hydro and the increased number of employees required to meet customer growth. If one can adjust manpower for these items, then valid comparisons can be made between the number of customers per employee in 1989 and 1992. This view is supported by the testimony of Mr. Burns that manpower increases are mainly intended to meet customer growth and satisfaction (T. 1871).

The first step in making the 1992 manpower comparable with 1989 is to remove from the 1992 estimates those employees related to the B.C. Hydro services previously provided. Exhibit 62 (T. 1304) shows that in 1992 the equivalent of 73 employees will have been repatriated, and another 80 to 93 employees will have been replaced by contracts. The 73 BC Gas employees should be removed from the 1992 manpower for comparability with 1989 levels.

The second step in adjusting manpower levels is to account for customer growth. The average customer growth between 1989 and 1992 was approximately 10.86 percent (Exhibit 5, Tab 2, item 1.2(a)(x), page 60, Appendix "H"). Assuming the utility maintained the level of efficiency that existed in 1989, the manpower requirement would have been 1,430 employees compared with the actual employee count (net of B.C. Hydro employee equivalents) of 1,510 employees. This analysis is a summary of the exchanges between Commission counsel and BC Gas witnesses (T. 1870-1891). The difference of 80 employees represents approximately $4 million in salaries in 1992.

Although the Commission recognizes the limitations in the foregoing estimates, it has concern about the efficient and necessary level of employees required by BC Gas, particularly since economies of scale were expected.

Of the total increase of approximately 220 employees from 1989 to 1992, Mr. Lotochinski, Vice President, Human Resources, attributed 38 to marketing activities, 40 to gas supply and engineering, 85 to administrative and the balance of 57 due to customer growth (T. 1886).

Mr. Lotochinski stated:

> "From a human resource planning point of view on a corporate basis, our presumption is that in the field operations, the number of employees will grow at less than the rate of increase in customers, because there isn't a one-to-one relationship there, largely I think due to productivity." (T. 1763)

To measure productivity, Mr. Lotochinski suggested that one could use the number of employees per supervisor ratio; compare the number of employees performing a specific function with other utilities, or compare the number of customers per employee.

> "MR. JOHNSON: Q: Mr. Lotochinski, the Chairman raised several questions directed to Mr. Burns relating to the assignment of responsibility for productivity at BC Gas, and whether the company has or intends to have a pro-active plan to ensure productivity actually does increase, and I think some of it was left that you might be able to assist in answering the question.
>
> MR. LOTOCHINSKI: A: Yes. We -- I guess, as a company, we attack this issue of productivity from two standpoints, and from a human resources standpoint or number of employees standpoint, we make a basic assumption that, if we can do the same work with fewer employees, or do more work with the same number of employees, that we are improving productivity. And as a consequence, when department heads are seeking approval to add to their staff, they must pass a rigorous process of justifying those increases in staff through a business case, including a challenge as to why they might not be able to rearrange their existing staff duties to accomodate whatever it is that they're asking for increased people.

> However, there are other ways of measuring people productivity, and I think one of them was alluded to in one of the questions I saw in the transcript, and it had to do with the supervisory ratio. If we could somehow arrange it so that the number of employees supervised by a particular person was greater, that would help increase at least people productivity.
>
> I can tell you that we have about 220 executives, managers and supervisors at BC Gas. And if you look at our 1,583 manning level in 1992, that gives a supervisory ratio of about seven to one. Now, it doesn't take much to calculate that, if we had a supervisory ratio of eight to one, we could get by with about 25 less supervisors, and one of our corporate goals is to flatten the organization over time and to concentrate on improving our managerial productivity in that way." (T. 1774-1776)

Another measure is the O&M costs per customer. However, the Commission cannot ignore Exhibits 16 and 24 which demonstrate that the average number of customers per employee has continuously shrunk from 430 in 1989 to the forecast of 387 in 1992 (see Figure 5.6.1).

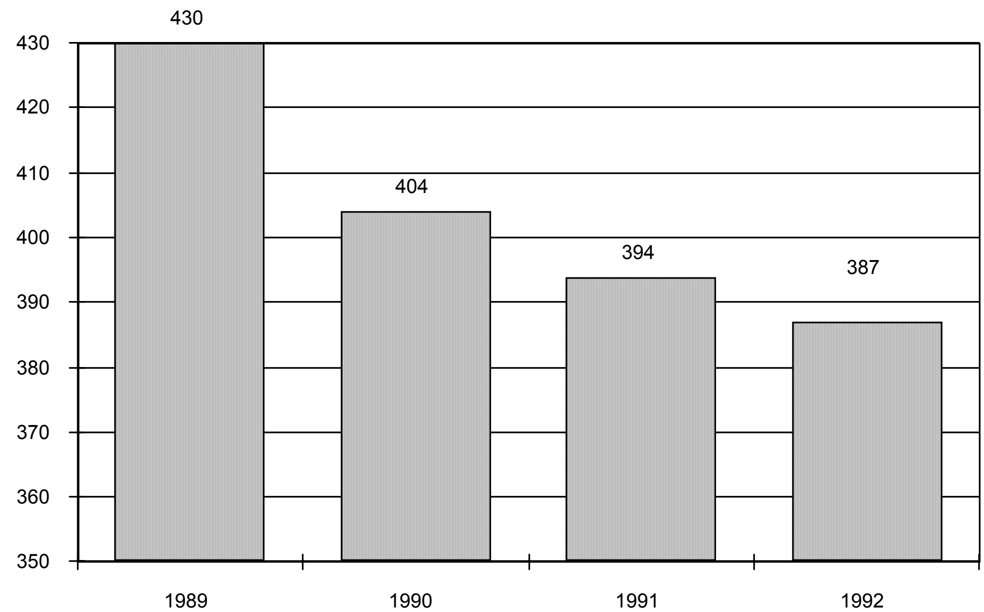
Mr. Lotochinski's allocation of 57 new employees to customer growth may indeed be reasonable if economies of scale and productivity are taken into consideration. But it is difficult to justify the employee increases in marketing, engineering, gas supply, legal, regulatory affairs and administrative services after customer growth and satisfaction, and repatriation of B.C. Hydro services have all been taken into account.

In addition to the manpower increases, the Company also relies on the services of outside consultants to augment its work force, such as the out-sourcing policy in MIS, gas supply and engineering, legal and regulatory matters. Some of these, services are provided by ex-employees. Mr. Lotochinski classified these consultants into three broad areas (T. 1768): consulting firm, non-exclusive and exclusive sole practitioners. These consultants are generally engaged for "peak shaving" and "specific knowledge" purposes. In addition, there are "dependent contractors" who are certified by the IBEW and independent contractors in the operations and construction activities. At the same time, the Utility is expanding administrative functions in the areas of taxation, marketing, legal and regulatory affairs departments.

The Commission concludes that the overall manpower level, inclusive of consultants, of BC Gas in 1992 exceeds the level of productivity attained in 1989. The data presented at the hearing is insufficient for the Commission to determine specific adjustments to manpower levels, and consequently the Commission has considered general adjustments to O&M costs in Section 5.10.

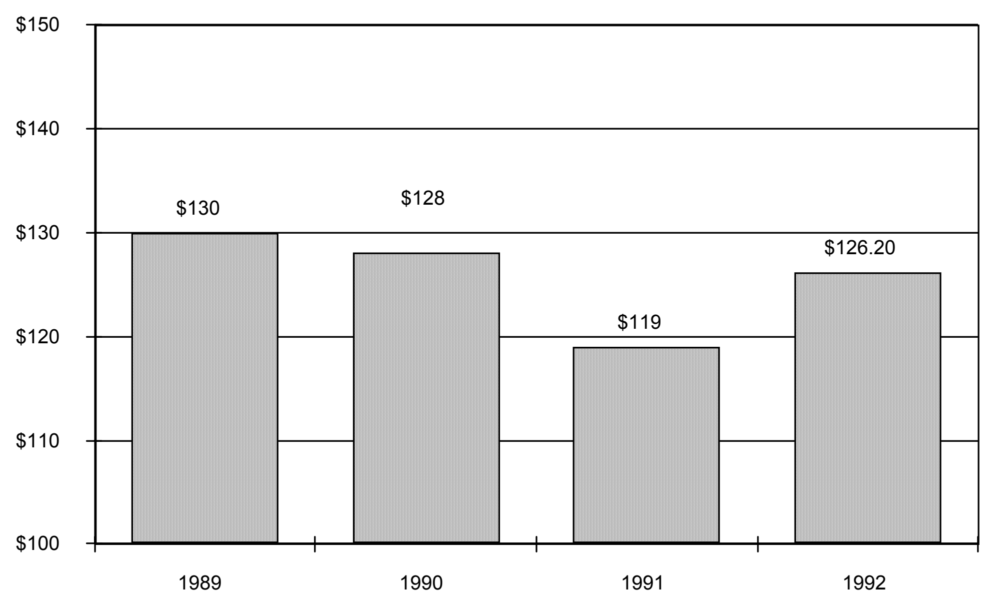
FIGURE 5.6.1

BC GAS INC.
CUSTOMERS PER EMPLOYEE



Ref: Volume 7, Tab 17, Item 11(b), Page 1

BC GAS INC.
O & M Costs per Avg. Number of Customers
(Inflation adjusted: 1989 Base Year)



Ref: Vol. 5, Tab 2, Item 1.2(a)(x), Pg.60

5.7 Salaries and Wages

Payroll costs of approximately $80 million in 1992 are the largest single expense for the Utility aside from the cost of gas [Exhibit 5, Tab 2, item 1.2, page 4.2 (rev.)]. The level of executive compensation is discussed in the following section in this Decision. This section provides a general review of the other groups of employees.

The Company negotiated separate three-year collective agreements with the IBEW and the OTEU in May, 1991 in which the increases effective each March 31 were 6 percent in 1991, 5 percent in 1992 and the annual increase in the Vancouver CPI in 1993.

> "In order to achieve that labour stability, as well as predictable labour costs, the Company agreed to structure its wage increases so they were weighted in the earlier years." (Exhibit 7, Tab 18, item 12)

In line with the foregoing union agreements, the Applicant made provision for a 5.5 percent increase for non-union employees in the Application. This was subsequently reduced at implementation to approximately 5 percent for management and 4 percent for executives, or a reduction of $75,000 as reflected in Exhibit 56A (T. 1780-1783). The increase includes a component for promotion and job reclassification.

Exhibit 82 entitled "1992 Salary Budget and Structure Update", as prepared by Towers Perrin, a compensation consulting firm retained by BC Gas, shows a 3 percent structural change for an average utility versus BC Gas' 3.5 percent for management employees, and a 2.4 percent change for an average utility versus BC Gas' 3.5 percent increase for the executives (T. 2139). The study stated in particular,

> "Of note is the dramatic increase in the percentage of companies which have chosen to freeze salary budgets, structures or both."

Mr. Lotochinski, in testimony and Mr. Johnson, in final argument (T. 3952) maintained that the above increases were in line with prevailing trends at the time of implementation and should be accepted by the Commission.

Mr. Kleven stated that the Company's policy is not to be a leader in wage increases (T. 410). The Commission believes that, by virtue of its size and economic influence, BC Gas is most likely seen to be a leader in wage and salary settlements by other utilities and labour unions both in and out of the Province. An example is that Pacific Northern Gas Ltd., in reaching a union agreement in 1991, used BC Gas as a benchmark. As the largest gas utility in the Province and the fourth in Canada, the Company's policy should not only address competitive compensation levels but also should consider them in the light of present and future economic conditions.

The union contracts were settled in May, 1991 during the rate freeze period, and are ongoing through 1993. Although the Commission believes they are in excess of current industry norms, they are approved for recovery. The non-union management employees are proposed to receive increases of 5 percent in 1992. The Commission believes that increases above 3.5 percent are unwarranted, and therefore a reduction of $349,000 (Exhibit 7, Tab 24, item 3, page 1.1) can be achieved (plus $75,000 from Exhibit 56A).

5.8 Executive Manpower and Compensation

5.8.1 Purpose of Compensation

The views of the Applicant and the intervenors with respect to executive manpower and compensation at BC Gas were polarized. This matter is very sensitive and therefore the Commission has deliberated carefully on all matters beginning with the basic purpose of compensation. Mr. Colbert, a partner with the management consulting firm of Deloitte & Touche, testified that:

> "...the purpose of compensation—you want the right compensation level to allow you to recruit the right people, in order to retain them in the organization and in order to motivate them as well." (T. 2001)

This premise went unchallenged by other parties in the process and was supported in part by the evidence of consultants retained by BC Gas.

The Commission accepts that the basic purpose of compensation is to recruit, retain and motivate employees. However, in the case of executive compensation, the Commission considers that the executive organization structure and compensation can set a theme for productivity throughout the whole of the Company. **To the extent that executive management is energetic, motivated, lean and paid in reasonable relationship to the management levels below it, then the whole organization will typically be energized as well. The converse can also be true. The Commission considers that management is a resource and, like other resources of the Company, should be capable of demonstrating value for money.**

5.8.2 Who Should be Responsible for Executive Compensation?

Regulatory tribunals have generally been reluctant to focus on the executive remuneration in utility companies. So long as executive pay in utilities was seen to be at reasonable levels, regulatory tribunals more often than not left the responsibility for review to boards of directors. In such instances, the utilities have the opportunity to operate like private enterprises in competition, where the board of directors determines executive compensation on behalf of the shareholders. BC Gas has established a similar structure and Mr. Kadlec spoke to the recent activities of the Management Resource Committee of the board of directors (T. 3577-3582). He read from the Minutes of the April 29, 1992 meeting of the committee which asserted their arms-length dealing with the executive and their objectivity. The committee rejected the findings of the Deloitte & Touche report presented at the hearing.

While BC Gas vigorously asserted that their executive review is equivalent to that in a competitive industry company, others at the hearing focused on the basic difference between a monopoly operation and competitive industry. In the case of a monopoly service, the public has determined that the greater public interest can be served by the institution of a single monopoly network exhibiting economies of scale for all consumers. In exchange for the exclusive right to transport natural gas in its service territories, the utility is required to provide all customers non-discriminatory service at rates reflecting the efficient operation of utility plant. The utility is provided sufficient revenue to cover its prudently incurred costs and sufficient to give the utility an opportunity to earn a fair return on its investments.

BC Gas proposed that all of its executive costs (except for NRB allocations) be covered by utility customers as an operating expense before the Commission considers the return to shareholders. This contrasts with a private competitive company where the executive compensation directly reduces shareholder returns. This notion was dwelt on by the counsel for BC Gas. In his closing argument, he stated:

> "The utility recovers its expenses only through the revenue requirement hearing process. There is only one enterprise from which all of the expenses must be paid. In my submission it is not appropriate to suggest that the shareholders benefit and therefore should directly pay a portion of the costs. The regulatory process is intended to ensure that all parties benefit. The customer should benefit, the shareholder should benefit, the employees should benefit, all persons should benefit from the process." (T. 4001-4002)

Commission counsel dealt with this issue in cross-examination of the Towers Perrin consultant (T. 2110-2111):

> "Mr. Fulton: Q: Okay, but the shareholders aren't going to be concerned about the level of compensation if the compensation is going to be recovered not out of their earnings per share, but out of the rates charged to the utilities customers, would you agree with me on that?
>
> Mr. Fox: A: I would think that they would have to be a blend. I don't think it can be from one or the other. I guess that's why I'm not really clear on the question. I think the base salaries should be recovered from both.
>
> Mr. Fulton: Q: The base salaries should be recovered from both the shareholders and the ratepayers.
>
> Mr. Fox: A: Well, the base salaries reflect how well the executives are growing and running the organization. Now that's to both the advantage of the shareholders and the customers.
>
> Mr. Fulton: Q: That's right and because it's to the advantage of both of them, both of them should have to contribute towards that, would you not agree?
>
> Mr. Fox: A: Certainly."

The Commission recognizes the basic difference in the nature of a regulated utility compared to a competitive industry company. The Province, on behalf of the customers of the utility has conferred a special monopoly right to the utility in exchange for the utility providing efficient cost based service. The utility customers fulfill their part of the pact by covering the prudently incurred costs of the utility. These include executive compensation like other resources of the company. The customers must be assured that they are receiving value for their money and

that the executives are providing efficient operations at the least cost. The Commission has a responsibility to ensure that this service is provided and that costs and organization size are contained and effective.

5.8.3 Executive Structure at BC Gas

The number of senior executives at BC Gas has grown from 14 in 1988 to 17 today (Figure 5.8.3). The increase in the number executives is even more pronounced when one considers that immediately below the executive level, the Company has created a new management level of directors. One now sees managers, directors, vice presidents, and senior/executive vice presidents reporting up to the president. The Company offered no evidence to indicate that the additional layers of management offered improved efficiency of operations. Meanwhile, intervenors pointed to the current trend towards flattened management structures so as to improve the timeliness and quality of corporate decision making.

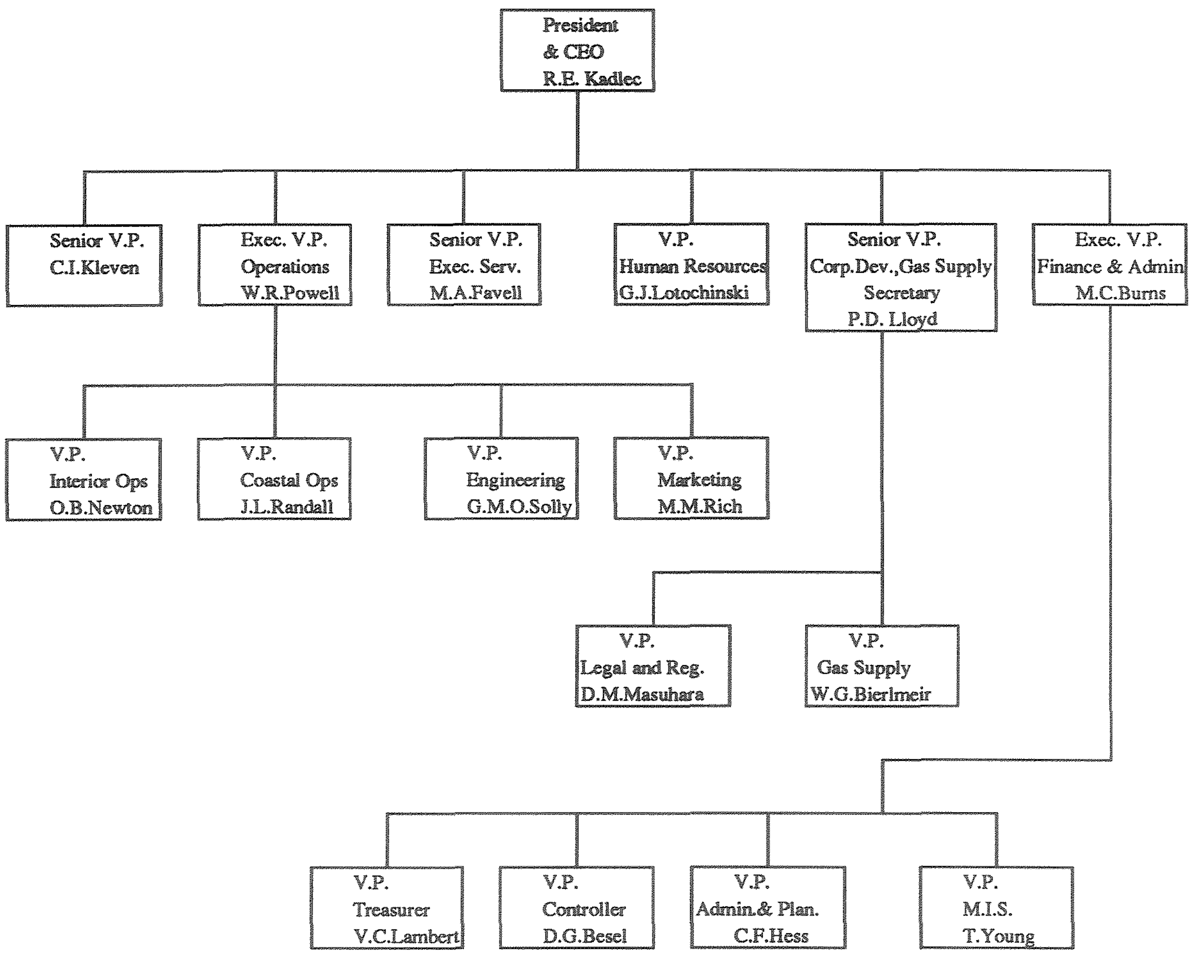
The Commission is concerned that the Utility has not demonstrated efficiency and effectiveness in its enlarged management structure. There are no apparent synergistic benefits developing from the acquisition of the Lower Mainland Gas Division with respect to management structure and efficiency. The Commission is also concerned that the quality of filings by the Utility have not been up to the standard that existed prior to the 3-year regulatory holiday. The Commission expects BC Gas to lead evidence at its next revenue requirements hearing to demonstrate the value of its executive organization.

5.8.4 Executive Compensation

The total cash compensation for the executive group has risen from $1,791,241 in 1988 to $3,226,000 in 1992. This represents an average compound growth of nearly 16 percent each year over the 4-year period. The total cash compensation per executive has increased from an average of $127,946 in 1988 to $189,745 in 1992 [Exhibit 5, Tab 2, item 1.2(b), page 4.2 (Rev.)]. This represents an average compound growth factor of about 10 percent per year. It should also be noted that this compound growth is understated as a result of the addition of executives below the senior vice president level.

FIGURE 5.8.3

BC GAS INC.
EXECUTIVE ORGANIZATION



Total cash compensation is taken to be the cash payment by way of salary plus bonus. In addition to the cash compensation, executives are given non-cash benefits including stock options, cars, club memberships, and accounting services. In addition the executives make no contributions to their pension plan. That pension plan is discussed in detail in Section 5.8.6.

The Commission has chosen to be selective in dealing with the most costly elements of executive compensation. However, just as the matter of perception was raised in relation to the Centre, the same concern exists with regard to such benefits as large stock options and a luxury vehicle for the President.

BC Gas Compensation Information

The Company's view with respect to executive compensation, is that it should pay within the norms of the utility industry. This view suggests that if the utility is not competitive with other utilities it will be unable to attract qualified people to executive positions and may see existing executives hired away from the Company.

A study by the consulting company of Towers Perrin was presented which indicated that BC Gas executives earn almost exactly the average of utility executives in the survey. Additional information was also recounted to indicate that utility executives earned slightly below private industry generally.

BC Gas stated that it would like to attract and pay executives in the third quartile of performance and pay. The BC Gas information was criticized as being superficial and potentially circular in its reasoning. Presumably there are not many utilities seeking to attract executives in the bottom quartiles. Therefore, one could find utilities "leap-frogging" on one another as they compare themselves in an attempt to boost salaries into the higher-than-average pay ranges.

The Deputy Chairman addressed this point in an exchange with counsel for BC Gas (T. 1993). He drew a comparison with the evidence of the Company with respect to return on equity, that returns for other sectors must be compared in conjunction with utility returns to avoid circularity. BC Gas responded that capital markets are universal while they believed that the pool of talent for utilities is contained largely within other utilities.

BC Gas presented two independent experts to address the issues of executive compensation. Mr. Jackson, of Caldwell Partners International, testified that it would be "highly unlikely" that he could find an executive for BC Gas within Crown Corporations or government agencies. He stated:

> "I think if you go fishing for salmon you look in a salmon stream, and I think that the most likely candidate to fit the bill, fit the qualifications as outlined in my earlier document because if you go through a process to build a Canada perspective or a job description and that person is more likely to come from the gas utility, gas, oil, or energy industry." (T. 2038)

Later in cross-examination Mr. Jackson acknowledged that he was not aware that none of the 17 BC Gas executives had been recruited to his or her executive level from another utility (T. 2119). He also admitted that he had not reviewed the hiring patterns of executives at BC Gas (T. 2114). Numerous other examples of senior executives hired from government or other industry groups were presented to Mr. Jackson.

<u>Deloitte & Touche Study</u>

Mr. Colbert of Deloitte & Touche was retained by Commission staff to prepare a study of executive compensation at BC Gas (Exhibit 54). The study was broken into two discrete evaluations. The first evaluation covered the BC Gas executive compensation in comparison with compensation at other utilities in Canada. Mr. Colbert relied on the information provided by BC Gas which indicated that the BC Gas executives were paid at about the average of executive compensation within other utilities in Canada.

The second evaluation compared the compensation at BC Gas with six other large British Columbia companies that were characterized as being customer oriented, low risk organizations as a result of either monopoly or a "safe" industry position. Those comparison companies were: University of British Columbia, British Columbia Ferry Corp., Insurance Corporation of British Columbia, Vancouver City Savings, University Hospital and Vancouver General Hospital. The positions chosen for comparison were: the President/Chief Executive Officer; Executive Vice President, Operations; Executive Vice President, Finance and Administration; and Vice President, Human Resources. Results were shown only in aggregate to avoid identification of specific remuneration. The results of the study showed such a large divergence between utility compensation and other low risk company compensation, that much debate ensued at the hearing. The results were as follows:

TABLE - 5.1

Comparison of Salaries and Total Cash Compensation

	BC Gas Inc. Survey	Survey Group Low Risk, Non-Utility
Average Salary	$210,798	$121,250
Average Total Cash Compensation	>$267,000*	>$125,000*

* Total Cash Compensation is estimated from the data and testimony. The estimates are slightly understated.

Mr. Colbert further testified that only one of the survey group companies paid bonuses and no stock options were available.

These results were criticized by BC Gas witnesses and their retained specialists. The matter of the fit between job classifications was discussed and Mr. Colbert stated that the fit between jobs was incomplete. The size of the sample was alleged to be too small and the number of government controlled companies was criticized. Mr. Fox concluded that the results of the Study were not strong enough to draw a conclusion about BC Gas compensation and that the information should be used only as "a minor market check" (T. 2053). Mr. Fox also testified that public sector companies often have salaries significantly below private industry because they may be "politically driven rather than free-market driven" (T. 2057).

Mr. Colbert also testified to certain parallels between utilities and other low risk companies. He stated:

> "BC Gas is a company that is not likely to go out of business as compared to somebody who makes bumpers for General Motors, they could be out of business next week. In other words, it has a monopoly to supply, therefore, there will be a continuity of employment for employees. It's not absolutely guarantied, but there's a very high level of continuity of employment opportunity as compared to private sector companies in competitive industries." (T. 2005)

He also responded to a question from Mr. Wallace by stating that :

> "And to the extent that we are seeing a new dimension with executives in terms of what they are looking for by way of career, that is they want to consider the trade-

> offs between rich compensation rewards and security of employment. When I say security of employment, that is employment in an organization which is secure. That raises this whole issue and it's a relatively new dimension. I think that up until about 1980 executives were not really particularly concerned about loss of employment. It's becoming an increasing issue through the '80s and I think a lot of executives today are prepared to trade-off high levels of compensation for work in a lower risk organization." (T. 1958-1959)

Mr. Colbert was examined with respect to a statement in his report that:

> "In regulated industries utility commissions are challenging what expenses can be allocated to the base rate." (Exhibit 54, p. 10)

In response to questioning from Mr. Wallace and the Deputy Chairman, Mr. Colbert testified that executive compensation is under increasing scrutiny although regulatory tribunals have not taken direct action as yet. He stated:

> "...there's a lot of smoke, but nothing's happened yet. But, we believe that there's an era right now wherein something's going to happen, and we think the Utility Commissions will probably have a new level of courage because of what's being said about compensation in the private competitive sector." (T. 1966-1967)

Mr. Colbert also testified that there are increasing challenges throughout industry about the levels of executive compensation. In terms of assessing value for money he stated:

> "It's occurring because the people who are responsible for making sure that the users of the service are getting the service at a reasonable price, are looking at compensation levels and saying, those numbers are too high. They're not fair. We should be able to have great management for less money. In other words the value for money is not what they think it should be." (T. 2019)

<u>Commission Views</u>

The Commission is concerned about the lack of justification by the Company for the levels of executive compensation. It relied solely on the argument that they must be competitive with other utilities to attract and retain staff. This argument is directly at odds with the historical facts. The Commission has not been given information to justify the salaries given. Moreover, even the expert presented by BC Gas testified that the premium for executive pay at BC Gas should be shared between the shareholders and the customers.

The Commission believes that executive compensation, prudently incurred to meet the requirements of service for utility customers should be included in the revenue requirement. However, BC Gas must be able to answer the concerns raised in the Deloitte & Touche Study and, in particular, the Utility must respond to the assertion that "We should be able to have great management for less money".

At the same time the Commission accepts that the Deloitte & Touche Study is not sufficiently complete to provide a benchmark for comparison with BC Gas. Even so, a situation where similar executives have a differential of well over two times the non-regulated executives' compensation remains unexplained. **Given the lack of complete evidence in this regard, the Commission directs BC Gas to provide full testimony on the value for money issue at the next revenue requirement hearing.** In addition, the Utility must realize that the burden of proof in these circumstances rests with the Company. The Company has increased total executive group costs by 80 percent in the four years.

The Commission recognizes that some positions have grown in responsibility and that the 1988 salaries included some recognition of the acquisition. However, the Commission cannot accept such continued large increases since 1988 without justification. The last opportunity to review compensation was in 1988 and therefore, salaries are adjusted for typical labour increases until 1992. **For the purposes of inclusion in the revenue requirement for this year, the Commission will accept the 1988 total cash compensation levels increased by 5 percent per year to 1991 and 3.5 percent for 1992, to be included in the utility revenue requirement before deductions for NRB activity. This provides a gross total cash compensation from utility customers of $153,300 per executive before NRB allocation.**

5.8.5 Executive Bonus

The Executive Bonus Plan is based upon achievement of earnings above those targetted by the Utility. For 1992 the incentive portion of the cash compensation is based on the 1992 Budget, which has built into it a 13.5 percent return on equity and a 35 percent common equity component. This would cause bonus payments at a performance level below that requested in this Rate Application. Counsel for BC Gas stated that the target would not be adjusted following the Commission's Decision. In response to questioning by Mr. Wallace, the Utility indicated that the incentive portion of the compensation contained in the forecast expenses for 1992 is approximately $600,000. The witness testified that this compensation is a reward by the shareholder for better than budgetted returns and that the calculation of earnings is not weather normalized (T. 3495-3496). The level of incentive increases from zero at 100 percent of the target return, to a full incentive at 105 percent of the target level. Mr. Lotochinski testified:

> "There would be correspondingly incremental adjustments made to that incentive remuneration pool until a maximum had been reached, which I think is so sky high that it might never be reached, but there would be a maximum level of 50 per cent beyond the base level beyond which it would remain fixed." (T. 2084)

Two-thirds of any bonus depends on corporate performance and, of that, 80 percent depends on earnings per share and 20 percent on O&M targets. The other third of the bonus relates to individually set matters (T. 2087).

The Commission recognizes that the major variant in earnings per share for the Company is the result of weather. The Commission determines the utility revenue requirement based on normal weather. In cold years the utility will over earn, while in warm years, sales will be less than forecast. On average, the normalized weather will occur. If the utility shareholders choose to pay a part of the extra earnings in cold years to executive bonuses, then the shareholders must be prepared to reduce salaries or take reduced returns in warm years.

Based on the philosophy of normalization, the Commission was disturbed by the testimony of Mr. Kadlec that he was considering cuts in training budgets and other costs provided for in the revenue requirement to boost shareholder earnings (T. 3603-3608). Such actions would penalize customers in both cold and warm years. The Company has readily accepted the increased revenues that came from additional sales in cold years, but under Mr. Kadlec's potential scenario the customers would receive reduced services in warm years without making up the pre-funded services later on. This would be inequitable in the Commission's view.

In focusing on the executive bonus the Commission agrees with the witnesses that its purpose is to motivate executives and provide a direct risk/reward opportunity. Mr. Colbert addressed the matter of "at risk" incentives as being a trend in industry (Exhibit 54, page 10). His recommendations that the Company move to a performance base, market-driven, compensation administration program were endorsed by BC Gas and the independent witnesses retained by them.

Mr. Colbert identified the following five examples of performance management criteria that may be appropriate for BC Gas:

(i) Cost of operations.
(ii) Reliability of service.
(iii) Safety.
(iv) Customer satisfaction.
(v) Return on equity that the performance of the Company and its executives is outstanding.

Discussion at the hearing recognized that certain performance criteria could be at odds with other objectives and that short-run maximizations of certain performance items could lead to long-term detriments. Mr. Colbert stated:

> "In other words I see executive compensation as relating to a combination of these elements in other words. A company can be doing well on the bottom line but it could be doing badly in other areas and I think that the executive of BC Gas and other companies have to be conscious of all of these elements." (T. 1974 - 1975)

Later (T. 2016) the Deputy Chairman focused on how a minimization of operating costs could potentially be undertaken by reducing services which might lead to safety or reliability problems at a later date. Mr. Colbert stated:

> "Well, you need to balance all of the different criteria. In other words you certainly don't want to take your cost of operations down to the point where you are running safety risks, if you like. So that what typically happens when you are establishing performance criteria, you do it on an annual basis and that's incorporated in the budget and the annual plan that supports the budget and from that flow performance targets for senior management and you are going to get some agreement between the management of the company and the board of directors in terms of what all those targets are and you have to balance up issues like cost of operation with customer satisfaction." (T. 2017)

The Commission recognizes that placing a part of the executives' total compensation "at risk" is a desirable motivational tool to encourage executives to meet the desires of the utility customers and the shareholders. The Commission agrees with the testimony of BC Gas' expert, Mr. Fox, when he stated (T. 2074), "The shareholders interest must be recognized, as well as the customer interest must be recognized." However, the Commission does not view

the bonus criterion established by BC Gas as being sufficiently responsive to the customers' interest of having safe, reliable, low-cost service.

As an example, the Utility may wish to take some part of the total compensation identified in Section 5.8.4 of this Decision and use it as an incentive for performance. In this regard, Mr. Lotochinski indicated (T. 2082) that approximately 20 percent of the planned total compensation was related to incentives. The average net total cash compensation from utility customers of $153,300 per executive could have the salary component making up 90 percent of the package with a potential incentive payment of up to 20 percent. On average, the performance criteria could be set so that the provision of fully satisfactory service to customers and shareholders would equal the 100 percent total cash compensation funded in the revenue requirement. The Company could administer the pool of incentive funding so that executives competed against one another to obtain more or less "at risk" compensation. The Company might also wish to consider dealing with performance criteria on a normalized basis so that the aberrations of weather on equity returns is minimized.

In any event, the Commission directs BC Gas to revamp its performance criterion to motivate its executive to fully meet the demands of customers as well as shareholders.

5.8.6 Executive Pension Plan

The executive pension plan was established in 1988 in connection with the formation of BC Gas (T. 2126). The Commission has not previously reviewed this plan or endorsed its funding.

The executive pension plan provides a pension of 2 percent of pensionable earnings for each year of service up to a maximum of 70 percent. Retirement, with full benefits, is possible at age 60. The pensionable earnings are based on the best three consecutive years' total cash compensation (T. 1813). This is inclusive of salary plus bonus. The pension plan is a defined benefit plan and is increased on an ad hoc basis at approximately one-half the rate of inflation. There is no provision to decrease benefits in deflationary periods or periods of poor earnings. The executives make no financial contribution to the plan.

The pension plan, as a defined benefit plan, may have tax consequences which could make the plan very costly for customers to fund in future. The pension plan was categorized as being "leading edge" by Mr. Colbert (T. 1935). The inclusion of the bonuses in the pension calculation was viewed as being "unusual". Countering this evidence were statements of Mr. Fox where he responded to questioning from the Chairman:

> "And the executive is logical if you think about it. The executive is living on salary, plus a bonus that's going to vary, depending on performance. But, the executive, throughout his career and as he approaches retirement, he or she approaches retirement, is living on that income.
>
> Is it not logical to have the pension based on that same income, which is in effect, what these companies are saying. So that, a number of the companies are saying that, we are going to base our pension and try and maintain a comparable cost of living to the executive as he or she retires." (T. 2061)

In other discussions related to the inclusion of the bonus in the pension, Mr. Colbert responded to cross-examination by counsel for BC Gas to state that even though the inclusion of the bonus in the pension is unusual at this time, it may become more normal to include the bonus at some future date when compensation packages become a bigger portion of the "at risk", incentive based remuneration (T. 1989).

In other testimony the liability to future ratepayers of the Utility was discussed in the context of rapidly rising salaries in the later years of employment resulting in a much larger pension liability than would have been thought earlier (T. 1937). This is exactly the scenario that has occurred for the executives of BC Gas during the last three years when the Utility operated in its partially unregulated state.

The Commission is concerned with the extent of the benefits offered in the executive pension plan. Further, the Commission is concerned that the full liability of the future pensions rests on future ratepayers. The Commission considers that it would be desirable if the existing executives funded a significant portion of their future benefits. By having the executives partially fund their pension plan they would become more attentive to the costs of individual benefits in the plan and may choose not to add increased benefits if the costs are not warranted.

The Commission has been made aware of the fact that non-contributory pensions have become normal in the utility industry. This is a significant executive benefit equal to roughly 10 percent of salary, all at the expense of future customers. Recognizing that the non-contributory nature of the plan is not abnormal for this industry, the Commission will allow it to continue. However, the Commission has taken account of its value in reviewing total compensation to executives.

The Commission has considered the matter of inclusion of the bonus in the pension plan. At this time the Commission recognizes that the bonus is triggered only when the Utility is in an "over-earning" mode. The current bonus is not responsive to executive performance in providing specific future benefits to customers. Therefore, it should not be placed in the pension plan where it will result in on-going future payments directly from the customers. At a future date when the executive compensation is structured so that it responds to customer-driven performance criteria, the Commission may consider inclusion of the bonus for recovery from the ratepayers.

The Commission is very concerned that rapid escalation in executive pay will create large funding costs for future customers. In particular, the compensation to the executives closest to retirement has gone up the most.

In summary the Commission concludes the following with respect to pensions:

(i) For rate-making purposes the bonus is not to be included in the pension costs to be passed on to customers.

(ii) The maximum amounts to be included in credits towards the pension plans are to be as identified in the total compensation projections at Section 5.8.4 (net of allocations to NRB). These average total compensation numbers will have to be allocated between executives for 1988 through 1992 in proportion to their actual salaries paid.

5.9 Donations

Donations are controversial as an accepted utility expense because it is often argued that customers are involuntarily charged for donations to certain organizations to which they may not wish to contribute. It may be more beneficial for most residential customers to make their own donations which are income tax deductible. Others suggest that donations likely only enhance the image of shareholders. The BC Gas donations budget for 1992 is $203,000, which, according to Mr. Burns, is low if the Company uses the nationally known "imagine" target, being 1 percent of the average pre-tax income for the previous three years. The Company stated that it would seek Commission comment on the appropriateness of that target (T. 2192).

The issue is not the size of the donations at this time. It is whether the utility customers should pay for the amount after an allocation to non-utility functions. Mr. Burns agreed that:

> "In speaking of donations, I think the shareholders benefit properly in proportion to the image of good corporate citizenship because I think today you can't do business or make money without being considered a good corporate citizen. So I think there is benefit on both sides and I think in the balance of our application both are properly rewarded but so both should bear the cost of operation." (T. 2199-2200)

Intervenors generally argued that donations should not be borne by the customers. Mr. Wallace in final argument stated:

> "The industrial customers in their communities already support charitable activities. The question becomes why should you take money from them to give it to someone else in the name of BC Gas. And I believe it's quite agruable that really the beneficiary of that is BC Gas. An alternative might be to have BC Gas make those contributions in the name of its customers." (T. 4142)

The Commission has considered the evidence and believes that a modest level of donations is expected from the Company and that donations to local communities may assist BC Gas in maintaining community goodwill. The Commission also believes that the shareholders benefit more from donations and may wish to augment funds at their expense. For this fiscal year the Commission establishes that $100,000 should be allowed as a utility expense.

5.10 Summary and Adjustments

The Commission has considered the potential adjustments from each section of Chapter 5.0. Rather than implementing individual adjustments, the Commission will make a lump sum adjustment based on the O&M costs per customer, and expects the Company to exercise its management responsibility and attain the efficiencies required by the Commission's Decision.

This approach was adopted on many occasions in the past, particularly in the case of Inland where the Commission in approving a 4 percent increase of operating and maintenance costs per customer stated on page 18 of the March 18, 1981 Decision that "... the Commission considers that an increase of 6.5 percent per customer is beyond a reasonable expectation of the cost to maintain safe and reasonable service to a greatly enlarged customer base where economics of scale should reflect some efficiencies." And on page 11 of the May 25, 1983 Inland Decision the Commission concluded that the same test of operating and maintenance cost per customer should be used and allowed a 6 percent increase.

This measurement takes into account inflation and efficiency and is advocated by Mr. Kadlec as the "most objective measure" of efficiency (Exhibit 2, Tab 22, page 5). The issues in the 1981 and 1983 hearings on operating and maintenance costs were mainly concerned with employee increases, prevailing economic conditions and efficiency. The Commission considers that circumstances and evidence presented in this hearing support the same test and treatment regarding operating and maintenance costs.

The Commission believes that in fairness to ratepayers and the utility, and based on the foregoing, it should set an overall increase in O&M costs based on its knowledge of actual activities, plus its general understanding of cost inflation in the industry and in the economy. On this assessment, the Commission finds that a 5 percent increase in O&M costs per customer above 1991 levels is appropriate. An attendant reduction in the proposed O&M budget of $3.28 million is incorporated in this Decision.

In addition, the Commission determines that a reduction of $1.1 million should be taken out of plant additions in rate base to reflect reduced overhead capitalized relative to the above O&M cost adjustment. See Appendix "H" for tabulations of Commission adjustments.

6.0 OTHER

6.1 Efficiency and Key Performance Index

BC Gas relied on the evidence of Price Waterhouse (Exhibit 1, Tab 1, page 8) to justify the 3 percent rate increase. Two studies were conducted; the first was a comparison of a set of Key Performance Indicators ("KPI") for BC Gas against other comparable utilities, and the second was a comparison of changes in BC Gas' residential rates over the 1988 to 1991 period versus changes of other regulated or public services. The conclusion of the KPI and rate studies was that "BC Gas is a relatively efficient utility" and it "has become more efficient during the last four years". And collectively, "BC Gas had a relatively efficient operation at the time of amalgamation, has improved on that level since amalgamation" (T. 1652).

Mr. R.J. Hull and Mr. J.R. Harrington, of Price Waterhouse, presented their evidence in Exhibit 3. Mr. Hull stated:

> "...our KPI study focuses not so much on the price, but rather on the costs - particularly those over which the utility has the greatest amount of control. These are the costs which should be of greatest concern to the regulators." (Exhibit 3, Tab 1, page 13)

They had reservations about the quality of their data by stating:

> "...we had to exercise caution in making comparisons because Canadian utilities have a fairly broad latitude in reporting and accounting for various costs." (Exhibit 3, Tab 1, page 12)

They also recognized that:

> "Isolating the results of one KPI can be misleading,"

and

> "Each utility is unique. To a greater or lessor extent unique features, such as customer mix, customer concentration, customer or system terrain, climate, geography, extent of its transmission system and even changes in accounting or reporting, can affect individual KPIs." (Exhibit 3, Tab 2, page 12)

In the KPI study, Price Waterhouse compared data from three periods: 1981, 1987 and 1992. The study indicated that BC Gas is relatively more efficient than other sampled utilities. This is encouraging but in itself is not sufficient to justify the 3 percent increase. The question as to whether BC Gas is more efficient in itself from year-to-year is unanswered, since the information for the period 1988 to 1991 was not provided. The rates study shows that with the 3 percent increase the real rates of BC Gas in the 1988 base are lower than most of the utilities in the study. Again, this could not be interpreted as an efficiency indicator and a basis for the rate increase. Mr. Harrington agreed with the Deputy Chairman that there is more consistency in the examination of a trend within a company than between companies (T. 1730) and that between 1981 and 1987, "B.C. Hydro was the top performer" of the 12 utilities in his sample (T. 1751).

The hearing heard criticism of BC Gas for not providing baseline data on the efficiency within BC Gas over the past three years. The general information provided was not adjusted to account for basic differences between utilities for age of assets, density of service territory, and range of service provided.

The Commission believes that there were unique circumstances to cause BC Gas to improve efficiency during the rate freeze period. Firstly, BC Gas purchased a dominant and efficient operation in the Lower Mainland Gas Division, the rates of which, as pointed out by the Applicant, were not established using the traditional "return on rate base methodology" and therefore might have been too high if converted to the traditional method (Exhibit 5, Tab 3, page 1). Secondly, the three year rate freeze provided a strong incentive to be efficient, otherwise there could be a negative impact on the shareholders. Thirdly, a set of factors, including unprecedented growth, normal to colder weather, lower tax rates and some synergies such as gas purchases and the results of amalgamation, all contributed to the success of the Company during the 3-year rate freeze period.

Both in its 1992 Business Plan and in Mr. Kadlec's direct evidence, BC Gas singled out O&M costs per customer as the most objective measure of its efficiency gains (T. 3720). Mr. Kadlec was unable to explain fully why the 1992 O&M costs per customer had increased some 10.5 percent over 1991. These increases are a concern to the Commission especially in the light of the evidence of Mr. Harrington that Inland acquired a very efficient utility in its purchase of the Lower Mainland Gas Division in 1988. The utility costs per customer have risen substantially in the past year.

The evidence adduced in this hearing does not convince the Commission of continued efficiency gains in the test year 1992, although there are references indicating that further efficiency may be achieved through consolidation of all Divisions, and with the full implementation of MIS. Mr. Johnson, in final argument, submitted that the Commission should look at the longer term efficiency (T. 4316).

The intervenors generally argued that the KPI and the comparison of rates to other services were irrelevant (T. 4170). However, the Commission believes that some of the KPI, if examined with caution, can provide a directional trend and can be utilized for comparison of BC Gas performance in future rate applications. **The Commission concludes that the KPI information indicates that BC Gas has been a relatively efficient utility, but the KPI is of limited use in validating the Utility's revenue requirement application for 1992.**

6.2 Non-Regulated Businesses

BC Gas and its predecessor companies have been involved in NRB activities for many years. These affiliated companies do not make up a significant portion of the corporate activities of the Company at this time. They are related businesses and the Commission has set a priority to ensure that the NRB operate at arms-length from the Utility and are not subsidized by utility ratepayers directly or indirectly.

Mr. Lloyd, in his opening comments related to NRB, stressed the small component of the NRB in the scheme of BC Gas operations (T. 2215). He stated that NRB activities represent only 1 percent of the gross revenues, 0.8 percent of employees, 1.8 percent of fixed assets and 3.9 percent of O&M expenses. He further stated that the way that BC Gas accounts for its NRB ensures that they provide "significant benefits to the utility's customers". The business purpose of the NRB was categorized as being:

> "...highly related to the needs of our customers, and in engaging in these activities, we thereby assist our customers without asking our customers to bear the cost or risk directly associated with developing those benefits." (T. 2216)

The direct financial benefit back to BC Gas was quantified as being $712,000 for this year (T. 2257).

The Commission and BC Gas have been working for several years to establish an acceptable level of arms-length relationship between the Utility and the NRB. Commission staff have also attempted to ensure that the utility customers receive full compensation for any and all assets of value utilized by the NRB. The culmination of these activities was the filing of the Stone & Webster Study on BC Gas, NRB/Utility Separation Study, dated December, 1991 [Exhibit 5, Tab 21, item 1.21(a)].

Flowing from the Stone & Webster Study was the development of a Code of Business Conduct with respect to the NRB of BC Gas, dated February, 1992 (Exhibit 6, Tab 5). BC Gas also filed a 1992 Annual NRB Information Report dated February, 1992. Page 18 of the study indicates the reporting structure of the various NRB companies back to BC Gas. It is shown here as Figure 6.2.1

As well as the above NRB, BC Gas intends to develop a holding company through which all the NRB would report. This concept of a holding company was proposed in the Stone & Webster Report and is under active development by BC Gas towards implementation by early 1993. With respect to the recommendation that BC Gas executives not have any voting rights on the board of the proposed BC Gas Development Corp., the evidence was that the recommendation had not yet been accepted by BC Gas (T. 2507).

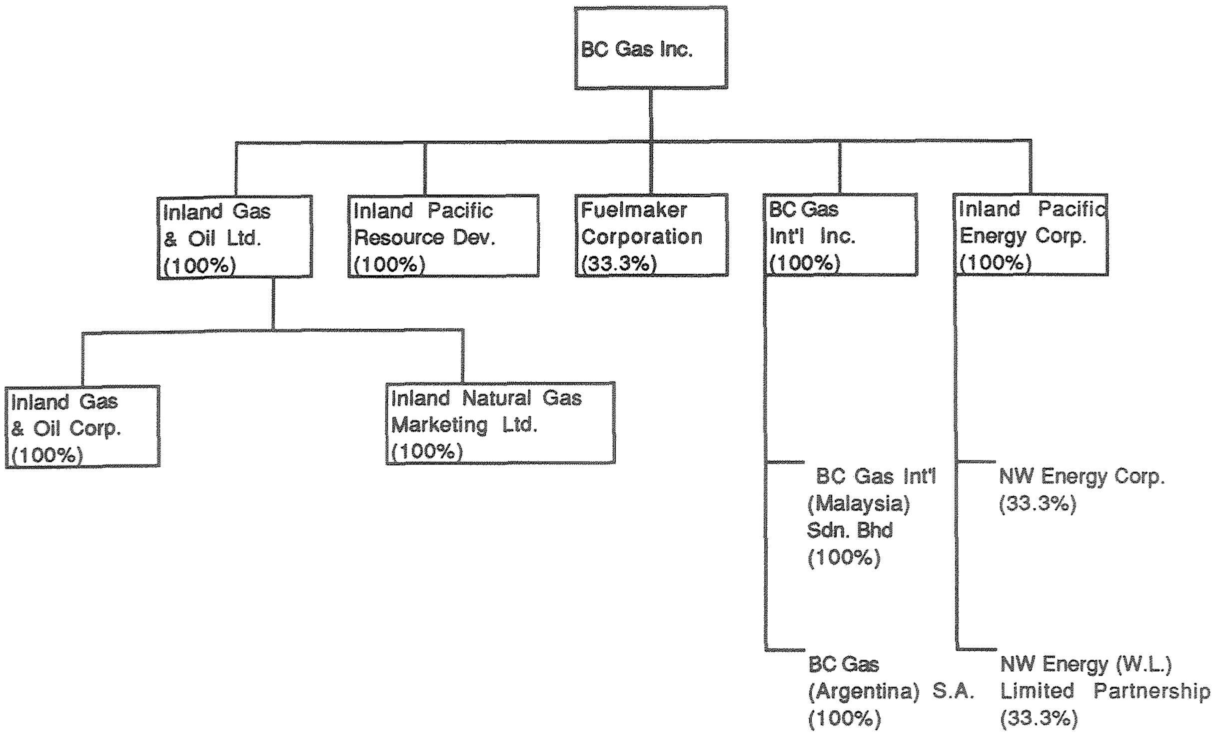
In considering the philosophy of the NRB separation, the Commission recognizes and commends BC Gas for the substantial progress it has made in the past year. The development of the Code of Ethics and the financial charges between organizations greatly assists in ensuring a substantial level of separation between utility and non-utility activities. In addition, the annual reporting structure to the Commission is helpful. With respect to the NRB holding company the Commission believes it would assist in maintaining separation particularly if the board of directors is structured as per the Stone & Webster report.

Much discussion at the hearing focused on the transfer of financial charges between the Utility and the NRB. In response to a Staff Information Request, the Utility filed data for each NRB establishing a budget for services to be provided this fiscal year (Exhibit 5, Tab 21). This budget was incorporated into the Application so that the extent of the costs identified have been deleted from the revenue requirement of the Utility. Each allocation was reviewed in detail during the course of the hearing.

FIGURE 6.2.1

BC GAS INC.

NRB Subsidiaries and Affiliates



BC Gas has established several categories of charge-outs for utility services to ensure there is no cross-subsidization between the Utility and the NRB.

(i) Full Time Employees - The full time employees of the NRB are paid by the NRB and are, therefore, outside of the Utility accounts. These employees are participants in the BC Gas pension plan and the NRB is charged the full cost of that participation (T. 2410).

(ii) Specific Committed Services - These services (mostly accounting) are provided on a contract basis. The NRB must pay for the service whether the service is used actively or not. BC Gas showed by example that the Utility loading of costs for specific committed services are such that a mark-up of approximately 25 percent exists (T. 2421).

(iii) As Required Services - This category includes employees on the BC Gas payroll who, when their Utility duties permit, perform services for the NRB. These services are provided on an "as required" basis. The loading for these services are higher than for the Specified Committed Services. The premium is 10 percent general overhead, plus 20 percent supervision, plus 20 percent availability charge, plus $67.00 per day facilities charge. In an example the markup was shown to be approximately 66 percent above the daily loaded labour costs. Other variations exists for employment on an as required service off-site, or for extended periods.

The Commission is satisfied with the charge-out procedures adopted by BC Gas. Provided that all of the time spent related to NRB activities is identified, the markups will provide a significant benefit back to the Utility. A large portion of the expected costs have been identified in Volume 5, Tab 21 and are already removed from the applied for revenue requirement. However, to the extent that services are provided that have not yet been identified, Mr. Kleven stated:

> "...Mr. Lloyd had indicated that there may some potential additional revenues or contributions from the NRBs in excess of what's reflected in the application. If they draw on the utility's staff on an as-required services basis that if it exceeds what's reflected in the application and they intent was to set up those revenues in a deferral account and there, since that hasn't occurred yet, we are really seeking permission from the Commission to create such an account which would allow us to accumulate, but there aren't any additional revenues at this point in time or contributions." (T. 2232)

The Commission approves the above request.

The Commission has a continuing concern that not all of the time devoted to NRB activities will be recorded by utility employees for inclusion in cost recovery. Mr. Kleven spoke of his "below the line" allocation (T. 2429). These charges are not specific to any NRB and are to be recorded by the executive and passed on to accounting where they are to be coded as non-utility expense.

Mr. Kleven and Mr. Lloyd assured the Commission that they kept accurate accounts of their time allocations in their diaries. However, in response to a request from Commission counsel that the diary be provided, Mr. Kleven indicated he used codes to identify projects and the codes may not be identifiable by others (T. 2437-2438). **The Commission therefore requests that a detailed summary of these allocations be provided annually with a breakout by executive to each NRB, by month.**

In reviewing each NRB the Commission is most satisfied with the separation of the Williams Lake Woodwaste Project. That project with its project financing and distance from the Utility is easily able to demonstrate its arms-length performance.

During the course of the hearing it was stated repeatedly that FuelMaker Corporation was able to be separated entirely from the Utility. The Commission encourages this to happen in the near future. FuelMaker has been the subject of past complaints to the Commission. The Commission views this separation as a minimum action to ensure arms-length dealings.

The Commission is also aware that Inland Natural Gas Marketing Ltd. is a viable enterprise that can stand on its own. As such it should be physically separated from BC Gas and divorced from interaction with the Utility. In particular, the current reporting of the marketing company to the senior vice president for utility gas supply is not appropriate.

The Commission's greatest ongoing concern at this time relates to BC Gas International Inc. That Company is directly a result of the expertise of the Utility personnel. It is in this company that there is the greatest potential for misallocation of services and charges from the Utility to the NRB. **The Commission directs BC Gas to provide an annual summary of the activities of BC Gas International Inc. inclusive of the work done on various contracts involving the participation by BC Gas utility employees in each project. This accounting will assist as a cross-check to ensure that the full Utility services provided to this NRB are recovered.**

BC Gas proposed to recover the approximately $65,000 of cost for the Stone & Webster Study equally from utility shareholders and utility customers. This proposal was criticized in final argument by both Mr. Weafer and Mr. Wallace. However, the Commission agrees with BC Gas that the costs should be recovered equally from shareholders and ratepayers.

A final matter of NRB discussion was the potential drag on utility financing costs. The Company testified that lenders' interest in projects like the Williams Lake Woodwaste Project and FuelMaker may assist borrowings. However, the Commission is not convinced that there is no marginal negative impact on borrowings. The Commission will continue to review this issue. The negative impact of the limited NRB activity at this time is not likely to be a material drain on utility borrowing potential.

6.3 Other Revenue

The Applicant included in this category, revenue relating to the Burrard Thermal Plant interruptible margin and Swing Gas reservation fees, PCEC wheeling charges and marketing programs as offset to operating expenses (Exhibit 1, Tab 12). An update was made in Exhibit 56 to reduce the revenue by $498,000 mainly due to a decrease in appliance financing and loss of margin from the Chatterton Petrochemical plant. **The Commission accepts the forecast of other revenue as reasonable**.

6.4 Least-Cost Integrated Resource Plan

A LCIRP is a planning tool for creating sustainable energy strategies that address the need for increased resources to meet load growth by comparing both supply-side and demand-side resources on an equal basis. The output from this dynamic process includes an integrated supply schedule that sequences supply and demand alternatives according to a combined ranking of least-cost, environmental impact and security risk.

During the course of the proceedings, BC Gas indicated its level of commitment to the implementation of LCIRP and to the development of DSM as an alternative source of supply (T. 3639-3643 and Exhibit 5, Tab 6, item 1.6, pages 2-2.1). These commitments are, in part, an expression of the fourth corporate objective of the Company which was examined during the hearing (T. 3610-3614):

> "To operate BC Gas in an environmentally responsible manner and to position the Company as an environmental leader.
>
> In support of the corporate environmental policy and the fourth Corporate Objective, BC Gas is currently developing DSM pilot programs which encourage conservation of natural gas by promoting increased end use efficiencies. These programs will be included in the BC Gas Least Cost Integrated Resource Plan to be forwarded to the Commission later this year." (Exhibit 5, Tab 4, item 1.4)

DSM may include cost effective utility investment for the purpose of increasing customer purchases of energy efficient end-use appliances and for modifying the usage patterns of customers. Exhibit 22 provides a range of objectives, from fuel substitution to conservation, that a utility may seek to satisfy through DSM. Fuel substitution from other fossil fuels to natural gas recognizes that natural gas is the cleanest of the fossil fuels. Load shaping recognizes that additional pipeline investment can be deferred through more efficient utilization. And conservation recognizes that natural gas is a non-renewable resource that also draws upon the ability of the environment to carry greenhouse gases and ground-level ozone smog causing emissions. These incremental future costs and externalities can be valued to ensure that the proper decisions are made for future investments by the Utility.

Commitment to LCIRP and DSM may cause a utility to shift its strategic focus from being a commodity supplier to being a marketer of energy services. BC Gas' Chief Executive Officer referred to this in his remarks to the recent Globe '92 conference and, in testimony, summarized his comments as (T. 3634) "use natural gas, but use it wisely":

> "We should be leaders in Demand-Side Management programs, working to educate our customers, and to assist them in acquiring the energy efficient technologies that will trim our load and lower their monthly usage.
>
> We should mentally reconstitute ourselves as suppliers, not of energy commodities, but of energy services. If the best service we can provide is to show a customer how to use less energy, then that is the service we should provide." (Exhibit 159)

The foregoing policy statements of BC Gas are consistent with the applicable recommendations of the British Columbia Round Table on the environment and the economy contained in their report, "A Sustainability Strategy for Energy" (Exhibit 158). Specific recommendations that were discussed with Mr. Kadlec (T. 3616-3628) included:

(i) The importance of evaluating energy efficiency and conservation as a supply option.

(ii) Energy efficiency standards for new construction and appliances.

(iii) Reduction in greenhouse gases through improved energy efficiency and conservation, referred to by the Round Table as a "no-regrets" strategy.

The Commission has been a strong supporter of DSM and LCIRP. Any action to further encourage research or incentives is premature before a full review of the LCIRP is complete.

6.5 Fort Nelson Gas - Income Tax

The Applicant requested Commission approval to switch accounting for income tax in the Fort Nelson Division from a deferred to a flow-through basis (Exhibit 1, Tab 1). This request is denied at this time. The Commission expects to review this matter in the Phase B Rate Design hearing.

6.6 Disposition of Deferred Income Tax Balances

In order to offset the impact on the Fort Nelson Division due to the proposed across-the-board 3 percent increase, and to alleviate a concern that Fort Nelson should indeed receive a reduction of 4.22 percent, which was amended to a 0.04 percent increase in Exhibit 152, BC Gas proposed that the revenue deficiency could be taken away from the deferred income tax balance which had been accumulated for the Fort Nelson Division (T. 2566-2569). The deferred income taxes were ear-marked to provide a fund for the future payment of income taxes when the Utility adopted the deferred tax accounting method. Since Fort Nelson, along with the other BC Gas Divisions will be on flow-through income tax accounting (see Section 6.5), the Company believes that this fund can be used for other purposes. Moreover, if the Company is successful in its consolidation request, the Lower Mainland, in particular, will benefit from the use of the deferred taxes since this Division does not have a deferred tax balance.

However, Commission counsel suggested that it might be fair for this fund to be spent on long-term projects such that the system can derive longer term benefits because inter-generations of customers had contributed to this fund. The Commission has directed BC Gas to investigate this topic in Section 2.8.

6.7 Hearing Costs

In the Application, the Company made a provision for hearing costs of $650,000 exclusive of the Commission's portion. These costs were revised to $1.157 million in Exhibit 131. Again, the total costs, including an estimate of $200,000 for the Commission's costs were updated in Exhibit 171 to $1.392 million.

The Commission appreciates the effort of BC Gas in answering the unprecedented number of information requests prior to and during the course of the proceedings. However, a great number of these requests were due to the inadequate presentation of the Application which did

not provide the equivalent level of information as filed in previous rate reviews. In any event, the Commission observes that the information responses were generally prepared by the Applicant's own staff, whose time was largely not reflected in the hearing costs. The most significant costs of the Applicant are consultant and legal fees which account for over $1 million. The Commission makes the following adjustments to Exhibit 131 as revised in Exhibit 171:

- **The Commission believes that the engagement of A.E. Sharp and Associates Ltd. in the matter of consolidation was unwarranted in light of the fact that the Company's own witnesses had the intimate and broad knowledge of the related issues. The costs of $50,731 are disallowed.**

- **In the matter of the lead/lag studies, the Commission finds that this was a routine study normally performed by the employees of the Company's predecessor in many of the previous rate cases. The study itself does not require sophisticated technical knowledge once the methodology is established. The costs of Mr. Krampl of $101,192 are removed.**

- **The KPI studies prepared by Price Waterhouse were of limited use to measure the trends in performance and efficiency at BC Gas. However, the bench-marks established for 1992 in the studies will provide a basis for future comparisons. The expenditures of $270,000 are excessive and the Commission will allow the original estimate of $150,000.**

- **The evidence of Mr. Hall of RBC Dominion Securities, overlaps with the evidence of Dr. Morin, Utilities Research International Inc., in the matter of capital structure, and $30,000 is removed from their combined costs.**

- **Total legal costs of $316,000 appear to be excessive and are reduced to $250,000. Before determining whether to approve legal costs in excess of $250,000, the Commission will require a filing by BC Gas on all outside legal service in 1992 with details of activity, hours spent, rates and other charges. The Commission considers that legal costs incurred by outside counsel can be dramatically curtailed if the already enlarged Legal and Regulatory Affairs Department functions effectively.**

The allowed hearing costs are normally amortized over a number of years. In this hearing some of the investigations and determinations were aimed at establishing a basis for regulatory evaluations for many years to come. Other matters, such as return on equity evidence, have value only for the test period until the next revenue requirements hearing.

The Commission determines that $300,000 of the allowed total of $1.09 million hearing costs should be amortized over five years. The balance of the allowed costs should be written off this year, based on the view of BC Gas that it will return for a revenue requirement request in 1993. If BC Gas is able to avoid a hearing next year, it will realize an avoided cost equal to the non-recurring costs expensed this year.

The Commission's decision to write off hearing costs over one year catches within it other costs, in particular, gas supply negotiations and the Phase A Rate Design costs. The Commission considers these to be somewhat unique and, in these particular circumstances, should be written off as above.

7.0 CAPITAL STRUCTURE

7.1 Introduction

As part of its revised Application for rate relief, BC Gas applied for the following capital structure and costs of capital for the utility portion of its business.

Proposed Capital Structure - BC Gas Utility

	Capital Structure %	**Cost %**
Long-Term Debt	42.14	10.798
Unfunded Debt	10.68	7.1
Preference Shares	9.68	8.901
Common Equity	37.50	13.500
Total	100.00	11.23

Exhibit 171, page 1-02-04 (rev. 3)

This capital structure is derived from the Company's legal or non-consolidated financial statements. The appropriateness of this capital structure was supported by testimony from expert witnesses retained by the Applicant, namely, Dr. R.A. Morin, Utilities Research International Inc. and Mr. D.G. Hall, RBC Dominion Securities, as well as various Company witnesses.

An alternate view of the appropriate capital structure was put forth by Dr. W.R. Waters, W.R. Waters Ltd., an expert witness retained by Commission staff. Dr. Waters derived a capital structure based upon BC Gas' consolidated financial statements and recommended that the Utility's capital structure contain a 32.5 percent equity component.

7.2 Existing Equity

Discussion as to the appropriate capital structure for BC Gas was dominated by two major issues, namely, the extent to which the applied for utility equity component was supported by actual equity and the extent to which the applied for utility equity component was appropriate given the Utility's business and financial risks and financial outlooks. The first issue, regarding the existence of sufficient equity to justify the Utility's request for a 37.5 percent equity component, revolved around BC Gas' inter-corporate relationships.

7.2.1 Position of Applicant

BC Gas consists of the regulated utility, operating under a special Act of the legislature, a number of small, wholly-owned, non-regulated businesses and a majority investment in Trans Mountain Pipe Line Co. Ltd. ("TMPL"). In turn, TMPL has a minority investment in BC Gas [Exhibit 1, Tab 5, page 2; (T. 3445)]. The Company keeps two sets of financial statements: consolidated financial statements and non-consolidated or legal financial statements. Consolidated financial statements are defined in Section 1600.03 of the Canadian Institute of Chartered Accountants ("CICA") handbook as follows:

> "Consolidated financial statements are those produced by aggregating the financial statements of one or more subsidiary companies on a line-by-line basis (i.e. adding together corresponding items of assets, liabilities, revenues and expenses) with the financial statements of the parent company (related by common share ownership) eliminating intercompany balances and transactions, and providing for any minority interest in a subsidiary company. Consolidated financial statements recognize that the separate legal entities are components of one economic unit and are distinguishable from the separate parent and subsidiary company statements and from combined statements of affiliated companies. The distinction is based both on the nature of such statements and on the difference in circumstances justifying their use."

The accounting treatment for equity when consolidating companies with reciprocal shareholdings is presented in Sections 1600.70 and 1600.71 of the CICA handbook.

> "1600.70
>
> (a) Where a subsidiary company holds shares in the parent company, such shares should be presented on consolidation as if the parent company had purchased its own shares.
>
> 1600.71
>
> (a) Where a subsidiary company holds shares of the parent company, the issued share capital of the parent should be set out in full, with the cost of the shares held by the subsidiary shown as a deduction from shareholders' equity. (See Share Capital, Section 3240, April 1975)"

BC Gas' published consolidated financial statements are audited by Peat, Marwick and Thorne and were found to comply with these statements.

The non-consolidated or legal financial statements show BC Gas' investment in the subsidiary company at cost and are prepared for regulatory and other purposes and not for issuance to shareholders. These statements reflect the fact that the parent and subsidiary companies are separate entities under law.

The utility capital structure, presented by BC Gas in its Application, is derived from the non-consolidated statements adjusted for capital allocations to NRB and other categories as described in Exhibit 137 and as testified to by the Company witness (T. 3466-3468). These statements show that BC Gas contains 38.0 percent common equity. Under the Company's capital allocation methodology, non-utility investments, are deemed to be funded 45.7 percent through common equity. Specifically, this consists of a 40 percent equity funding of TMPL, a 60 percent equity funding of Inland Gas and Oil Ltd. and a 43 percent equity funding of all other subsidiaries. Another category of non-rate base assets called "Utility-Other Investments" by the Company, namely, the acquisition premium paid on the Lower Mainland gas assets of B.C. Hydro, other assets including underground storage development costs, deferred charges, long-term receivables and investments, and AFUDC were deemed by the Company to be financed 37.5 percent through equity. These adjustments resulted in the residual equity being used to fund rate base, giving rise to a 37.5 percent utility equity component.

Although some of the subsidiary companies have never earned a profit, Company witnesses rejected the suggestion that such companies should be 100 percent equity financed, even though their expert witness Dr. Morin agreed (T. 2709). Instead the witnesses differentiated between businesses which are losing money as a result of being in a declining industry and those which are losing money as a result of being in a start-up phase (T. 3429).

In choosing to use the non-consolidated statements, Company witnesses stated that:

> "Although the consolidated financial statements are those used by the investment community, the full consolidation of the Company's investments does not separately identify the assets being regulated. The assets and liabilities of Trans Mountain Pipeline and the minority interest component of shareholders' equity and the treatment of the reciprocal deduction are of no significance to the regulatory process." (Exhibit 2, Tab 21, page 22)

The Company's methodology in this hearing is consistent with that used by its predecessor company, Inland, during its last Revenue Requirement hearing in 1986.

7.2.2 Position of Dr. W.R. Waters

Dr. Waters took as his starting point the consolidated financial statements of the Company and determined the common equity position of the Utility after subtracting from the total consolidated common equity, the common equity needed to operate the other segments of the organization on a stand-alone basis (Exhibit 43, page 27). Dr. Waters stated that this process allows for the identification of any common equity inadequacies in the common equity ratio of the Utility (Exhibit 43, page 27).

Beginning with the consolidated financial statements, Dr. Waters specifically considered the equity needed to support BC Gas' investment in TMPL. Based on Exhibit 6, Tab 23(a), page 5, the witness determined that the provision made for funding TMPL, net of consolidating adjustments, i.e. the difference between the consolidated and non-consolidated capital structures reported by BC Gas was $13.1 million, including the minority interest in BC Gas held by TMPL. This implies that the BC Gas common equity associated with its investment in TMPL is 7.6 percent [Exhibit 43, page 28, (T. 3185-3186)]. Further, Dr. Waters stated that the "non-utility activities" identified in BC Gas' capital structure included a $19.2 million premium paid by Inland on the acquisition of TMPL shares in 1983 (Exhibit 43, page 29 and Table 15A).

As a result of the inter-corporate holdings between BC Gas and TMPL, Dr. Waters made the following adjustments:

> "(i) An adjustment in respect of the acquisition premium for the common shares of TMPL purchased by Inland;
>
> (ii) An adjustment for the common shares of BC Gas held by TMPL; and
>
> (iii) An adjustment to ensure that TMPL is allocated an amount of common equity consistent with the amount needed to support its pipeline operations." (Exhibit 43, page 30)

Dr. Waters stated that the premium paid on TMPL shares generates no earnings and is therefore "basically incapable of supporting debt" (Exhibit 43, page 31). Therefore, he maintained, it should be considered to be financed entirely through common equity. As a result, the witness stated that:

> "an equivalent amount of consolidated equity (i.e. $19.2 million) must be assigned to the TMPL premium section of the assets to reflect the funding of this portion of the acquired assets. This amount is additional to the common equity allocated to the earning assets of TMPL. "Non Utility" common equity has been reduced by a corresponding amount." (Exhibit 43, page 31)

In response to BC Gas counsel, Dr. Waters agreed that TMPL owned some non-regulated assets and that the non-utility assets of TMPL had the potential to offset the $19.2 million acquisition premium; however, he was unable to determine by what amount (T. 3215-3217).

With respect to the second adjustment, i.e. the treatment of the common shares of BC Gas held by TMPL, Dr. Waters stated that the acquisition of TMPL shares by BC Gas was tantamount to a buying of its own shares since TMPL owned the BC Gas shares (originally Inland shares) prior to the acquisition by Inland of TMPL shares. As a result, Dr. Waters suggested that the cost of the BC Gas shares held by TMPL:

> "...should be considered to have reduced the unconsolidated equity of Inland/BC Gas..." (Exhibit 43, page 33, updated T. 3110)

This results in a corresponding transfer of equity to TMPL.

Dr. Waters testified that with these two adjustments, the resulting common equity base of TMPL was 31.3 percent, an amount which he considered insufficient and which was less than the common equity component requested by TMPL from its regulator, the NEB. Therefore, he increased the equity supporting TMPL to give rise to a common equity ratio of 40 percent. However, since it was not possible for the equity to support TMPL and the non-consolidated capital structure of BC Gas, a corresponding reduction was made to the equity component of the non-consolidated capital structure.

As a result of his adjustments, Dr. Waters determined that the actual capital structure of the Utility was as follows:

Utility Capital Structure - Dr. Waters

	Percent
Unfunded Debt	15.8
Long-Term Debt	41.7
Preferred Shares	9.6
Common Equity	33.0
	100.0

(Exhibit 43, page 37)

With respect to the shares of TMPL held by BC Gas, Dr. Waters agreed that there had been an appreciation in the price of TMPL shares above the average price paid by BC Gas and that if BC Gas were to sell its shares in TMPL above the price at which it acquired the shares, there would be an increase in the equity reported in the BC Gas financial statements (T. 3228). However, Dr. Waters stated that:

> "...we haven't got this sale, and we're not going to have the sale, I would submit, except under very surprising circumstances that no one, I would imagine, is anticipating today." (T. 3229)

The witness agreed that in another hearing with respect to TMPL, he had taken unrealized capital gains on the BC Gas shares held by TMPL into account when looking at the common equity available to support TMPL's non-regulated activities (T. 3234). However, he stated that the circumstances were different in that the TMPL holdings of BC Gas were only 12 percent, and that:

> "...It is not a control block, it is a residual from yesteryear if I can put it that way. BC Gas shares held by Trans Mountain are not going to define the market price in the share. If they are sold it is not going to define the market price level, in my belief, at a level of anything significantly different from what they are trading at and it is a block that would not make, as far as I can tell anyway, a significant difference to the inter-relationship between BC Gas Inc. and Trans Mountain from an operating perspective, that is to say the two divisions, if it was decided to sell those shares." (T. 3235-3236)

Dr. Waters agreed that the investment in TMPL by BC Gas was approximately $56 million (Exhibit 69), substantially in excess of the $13 million of BC Gas equity he had originally found to be associated with TMPL. The witness indicated that he was trying to identify the common equity that BC Gas had committed to TMPL and not how much the investment was in total (T. 3188). However, the witness disagreed that the result of his adjustments was to assign $69 million of BC Gas equity to support a $56 million investment. Instead he stated:

> "The investment in Trans Mountain in the context of my Table 15B takes the consolidated circumstances of BC Gas, and its from that perspective where all the debt of Trans Mountain is also recognized, that I had the 56 million plus 13 million common equity requirement." (T. 3239)

Dr. Waters stated that the $69 million is inclusive of the minority interest (T. 3240).

Dr. Waters' position in this hearing is consistent with that held by him in the previously referenced 1986 Inland Revenue Requirements hearing. However, he rejected a suggestion by BC Gas counsel that his evidence had been rejected by the Commission at the previous hearing and stated events subsequent to the 1986 hearing, i.e. the sale of Inland shares by TMPL, had rendered his testimony "no longer on point" (T. 3174).

Dr. Waters agreed that if he had begun with the non-consolidated statements, he would not have had to make any of his adjustments, but rejected the notion that such an approach would have been correct.

> "...The reason for looking at the consolidated financial statements is to see what the implications are of the way in which the owner has financed itself, in this case BC Gas, and whether or not the way in which that financing has been undertaken will have some adverse implications for the ongoing financial integrity of the utility subsidiary that we're talking about.
>
> We don't have a ring fence around this non-consolidated public utility. We can't be absolutely sure that, should adverse circumstances due to adventures that probably aren't contemplated, and I can't contemplate either, but might occur in BC Gas Inc., would affect the financial capability of BC Gas Inc., which is the fund raising entity for the utility, to do this on reasonable terms and conditions." (T. 3192)

7.2.3 Lower Mainland Gas Assets Acquisition Premium

As indicated in Section 7.2.1, BC Gas has assumed that the acquisition premium paid on the Lower Mainland gas assets is funded by a mixture of debt, preferred shares and common equity. Exhibit 153, prepared by Commission staff, presented an alternate funding treatment for the Lower Mainland acquisition premium, showing the impact of funding the premium through preferred and common equity only and assuming the amount of the premium is reduced each year by a 5 percent Capital Cost Allowance. The allocation of a greater amount of common equity to the acquisition premium results in reduced equity to support the utility rate base. As a result, the utility rate base is seen to be funded 33.1 percent by common equity.

In presenting this exhibit, Commission counsel suggested that the acquisition premium was essentially like good will, in that it was an intangible asset, and questioned whether banks would accept the acquisition premium as a basis for loaning money to BC Gas (T. 3470). Both suggestions were rejected by Company witnesses who stated that the premium was allocated to assets at the time of acquisition and that the banks would accept the premium as a basis for raising money (T. 3470). Indeed, Mr. Kleven stated that:

> "They did in fact loan us $300 million, and they looked at the purchase of the assets. The regulators, being the Lieutenant-Governor-in-Council at the time, set the rate base at $583 million dollars. The purchase price, which went to Hydro and the province, was 741 million dollars, and that's the price of the assets. Those assets are depreciable. We claim capital cost allowance on the total value of the assets. It just so happens that the amount that was set for rate base was a lower amount. The whole amount had to financed by a combination of debt and equity..." (T. 3470)

However, the Company witness agreed that the acquisition premium generated income only through tax savings as long as there is excess capital cost allowance (T. 3472) and that the tax savings formed the principal benefit from the acquisition premium to the Company (T. 3506).

Although the acquisition premium is not in rate base and therefore is not recovering a return from customer rates, an examination of the evidence indicates two additional concerns. First, the acquisition premium of $176.8 million, shown in the Application, includes $35.8 million attributable to capitalized losses and a tax agreement adjustment not related to the acquisition financing of the Lower Mainland gas assets. BC Gas has shown this additional premium as partially financed through the acquisition funding.

Second, the Application indicates that the Purchase Money Mortgages ("PMM") used to fund the acquisition were all "secured by a first fixed mortgage on the assets of the Coastal Division" (Exhibit 1, Tab 7, page 14). With the acquisition premium proportionately financed by the PMM, BC Gas effectively uses the utility rate base assets to guarantee non-rate base activities. A similar issue with respect to a guarantee by Inland of an NRB agreement formed part of the 1986 Inland hearing.

7.3 Appropriateness of Applied for Capital Structure

In addition to the evidence as to whether sufficient common equity existed in BC Gas to support the requested utility capital structure, significant testimony was also given as to the appropriateness of the requested common equity component.

7.3.1 Position of Applicant

As previously indicated, BC Gas applied for a utility capital structure containing a common equity component of 37.5 percent, some 5 percentage points greater than the 32.5 percent allowed the much smaller predecessor company as a result of the last revenue requirements hearing. In written evidence, Company witnesses stated that the thicker equity component was needed due to increased volatility in natural gas and capital markets and the expected rapid growth in the Company (Exhibit 2, Tab 21, page 21).

Expert witnesses retained by the Company recommended a 40 percent common equity component (Exhibit 3, Tab 4 and Tab 5). However, the Company applied for a lesser common equity component, since an increase to 40 percent from the previous Inland equity component of 32.5 percent was felt to be too large (T. 231). The Company stated that it intends to work towards a 40 percent common equity component (Exhibit 2, Tab 21, page 22) and, assuming the 37.5 percent was allowed as a result of this hearing, to move to the 40 percent equity component within three years (T. 3416). Company witness, Mr. Kleven, stated:

> "...And it's our view that the LDCs, particularly in Canada as opposed to the States, and the electric utilities and the telephone utilities, have too thin an equity component and ideally they should be approaching 40 to 45 to 50 per cent common equity component." (T. 231)

Mr. Lloyd, also appearing for the Company, rejected the idea that the Agreement mandated a common equity component of no less than 35 percent (T. 226). Instead he, along with Mr. Kleven, indicated that the desire for a common equity component of no less than 35 percent expressed in the Agreement reflected concerns, at that time, about the financial strength of the new company and the possibility of a high degree of leverage after the acquisition of the Lower Mainland gas assets (T. 226-227). Mr. Kleven stated that the inclusion of a target equity component reflected the fact that the parties to the agreement:

> "...wanted to ensure that there was some expectation that we would have a capital structure more typical of a normal utility." (T. 227)

Dr. Morin, an expert witness retained by the Company, supported the Company's position and recommended that a common equity ratio of 40 percent be employed for rate-making purposes. Dr. Morin stated that his recommendation was based on a policy approach and so did not reflect an accounting point of view but rather what was "the appropriate capital structure, what's the right thing to do" (T. 2627).

In making this determination, the witness relied on the following factors. First, Dr. Morin testified that an examination of actual common equity ratios for Canadian utilities over the period 1986 to 1990 showed a clustering around 40 percent (Exhibit 3, Tab 5, page 58 and RAM-14, page 1).

However, he agreed that if gas distribution utilities only were considered, his 40 percent common equity component recommendation would exceed the next highest common equity component by 3-3/4 percentage points (T. 2646). Further, the witness agreed that telephone and electric utilities which were included in the exhibit were traditionally more equity-rich than gas utilities (T. 2715). The witness agreed that the table excluded several gas distribution utilities and gas pipelines for which the common equity component was below 40 percent (T. 2712-2715).

Dr. Morin agreed with Commission counsel that the common equity ratios presented in his exhibit, RAM-14, page 1, included the consolidated common equity ratios of diversified companies, such as TransCanada Pipelines Limited and WEI, and that it would be preferable to identify companies which were pure utilities. However, the witness stated that he did not adjust the data given in RAM-14, page 1 since it had been taken from another source and he did not want to contaminate the data by isolating utility and non-utility activities (T. 2711-2712).

As a second source of evidence supporting his recommendation, Dr. Morin undertook an examination of the common equity ratios deemed to be efficient by Canadian regulators. He stated that this showed:

> "...the average deemed common equity ratios for Canadian utilities is close to 40%. As a general observation, these ratios are for the most part located in the 35% to 40% range. For gas distribution utilities, the average is 34%. If Union Gas's unrepresentative low equity ratio is removed from the mean, the average is almost 40%." (Exhibit 3, Tab 4, page 59)

However, when referred to Exhibit 3, Tab 5, RAM-14, page 2 which contained this data, Dr. Morin agreed that the removal of Union Gas resulted in an average for gas distribution utilities of 34.6 percent. Further, Dr. Morin agreed that some of the data shown in RAM-14, page 2 was out-dated and that the appropriate common equity ratios were lower than that which he was indicating (T. 2717-2720).

As a third source of support, Dr. Morin testified that the optimal capital structure for a utility was one which minimized capital costs. He stated that the financial literature:

> "...suggests that utilities which are (bond) rated a strong A to AA enjoy lower capital costs and provide lower rates than utilities rated otherwise, especially in adverse capital market conditions." (Exhibit 3, Tab 5, pages 59, 60)

The witness stated that these findings were supported by his own studies which also showed the desirability of a strong A to AA bond rating from both the ratepayers' and investors' standpoint (Exhibit 3, Tab 5, page 61) and that a bond rating at this level minimized the cost of capital, inclusive of taxes (T. 2728-2729). To achieve a strong A rating, Dr. Morin testified that a common equity component in the range of 35 to 40 percent was needed, assuming a preferred stock ratio of 10 percent (Exhibit 3, Tab 5, page 60).

Finally, Dr. Morin stated that the Company's ambitious capital expenditures program for the next several years, which would result in the need for substantial external financing, increased the need for a strong common equity base in order to strengthen the Company's financial ratios (Exhibit 3, Tab 5, page 61). He stated:

> "...I am heavily influenced by the fact that this company has a B plus plus bond rating by CBRS, which is slightly below investment grade, and here's a company that's going to require funding from these capital markets.
>
> It certainly would be in our interest, meaning ratepayers and investors, to have a strong--at least a strong, A-rated company so as to minimize the cost of these future borrowings." (T. 2696)

Dr. Morin stated that he was comfortable with allowing a common equity ratio for rate setting purposes that exceeded the common equity actually in place (T. 2734), although he recognized that this would result in customers paying for a flexibility, associated with common equity, that did not exist (T. 2735), and would result in a rate of return on the actual equity in excess of that formally allowed (T. 2737). However the witness stated that customers would "...get the benefits through the Company borrowing at a lower rate down the road, under more advantageous terms." (T. 2735) A somewhat different position was held by Mr. D.G. Hall, another expert witness appearing for the Applicant, who stated that he would be distressed, as a customer, to pay for an equity component which was not in place (T. 2865). This view was also held by Company witness, Mr. Kleven, although he stated that such a scenario did not apply to BC Gas (T. 3437).

Mr. Hall assessed the way BC Gas (the consolidated company) is viewed by the capital markets and determined that a 40 percent common equity structure would be prudent (Exhibit 3, Tab 4, page DGH17). In arriving at this recommendation, the witness examined general economic and capital markets conditions, which he characterized as risky (Exhibit 3, Tab 4, page DGH9), as well as investors' perceptions of the attractiveness of BC Gas.

In assessing investors' perceptions of BC Gas, Mr. Hall examined the Company's business, financial and regulatory risks. With respect to business risk, he found the following major sources:

(i) The demand for gas is dependent on the health of the British Columbia economy which in turn is highly dependent on resource based activities such as pulp and paper and mining;

(ii) Over 90 percent of the Company's delivered gas supply comes from three large processing plants located in Northern B.C., exposing the Company to potential supply disruptions;

(iii) The Company does not enjoy legislative protection which would allow for the appropriation of export gas in emergency;

(iv) Restructuring of Westcoast system charges, so that demand charges now comprise in excess of 95 percent of total charges, has effectively shifted the burden of forecasting gas demand to the Company;

(v) The movement towards increased direct sales to large volume customers has led to a decline in the stability of the remaining base load; and

(vi) Unlike many other gas utilities BC Gas does not have access to underground storage facilities (Exhibit 3, Tab 4, pages DGH10/11).

However, under cross-examination, Mr. Hall agreed that BC Gas' revenue is not as volatile as the economic performance of the forest and mining industries and that he had not undertaken any statistical tests to determine the correlations between British Columbia Gross Domestic Product ("B.C. GDP") and the bottom line revenues of the Company (T. 2808-2809). With respect to legislative protection which would allow for appropriation of export gas in the event of an emergency, Mr. Hall indicated that he had relied on statements from Company officials and had not actually read any licenses to determine if "clawback" provisions existed (T. 2849-2852).

With respect to financial risk, Mr. Hall noted that BC Gas had operated with a high degree of leverage over the three-year transition period following the acquisition of the Lower Mainland gas assets of B.C. Hydro but stated that such leverage was not indicative of the Company's optimum risk pattern (Exhibit 3, Tab 4, pages DGH11, DGH12).

Company witnesses supported Mr. Hall's statement that the low common equity ratio enjoyed by the Company over the transition period was not indicative of the Company's optimal capital structure. Mr. Kleven stated that the Company had been able to survive on the low equity component for a number of reasons. First, a significant amount of the $741 million used to purchase the assets was provided by the Province and/or B.C. Hydro at favourable rates. Second, the $150 million exchangeable bond which was also used to finance the acquisition was guaranteed by the government. Third, the Company was able to arrange a $300 million credit facility with a syndicated group of bankers by undertaking "significant" repayment terms. And fourth, the Company was able to provide the bond rating agencies with sufficient information to assure investors that the Utility planned to revert to a more typical capital structure (T. 3343-3347).

Mr. Hall stated that the capital spending needs of the Company which would lead to a demand for external funding would increase the Company's financial exposure to volatile capital market conditions (Exhibit 3, Tab 4, page DGH12).

In addition to business and financial risks, the witness indicated that investors in the Company were exposed to a short-term regulatory risk as BC Gas moved back into regulation after a three-year hiatus (Exhibit 3, Tab 4, page DGH12).

After assessing these risks, he concluded that BC Gas faced slightly higher than average business risks, financial risk in excess of its peer group and a short-term regulatory uncertainty (Exhibit 3, Tab 4, page DGH12).

Mr. Hall stated that the Company needed an investment grade rating by external capital suppliers to ensure access to capital market at reasonable prices at virtually anytime, implying that the Company should try to achieve an A (high) or A+ credit rating. To achieve such a rating, the witness suggested the Company should be working towards an interest coverage of about 3.0 times, significantly higher than the 1.6 times achieved by the Company in 1991 and a prospective 2.1 times expected for 1992. Without an improvement in its interest coverage ratio, he suggested BC Gas would be unable to return to financing via unsecured debentures (Exhibit 3, Tab 4, pages DGH13/14). Mr. Hall stated that to achieve such a rating, BC Gas would require a solid equity component. A comparison with other Canadian utilities suggested to the witness that BC Gas should be moving towards a 40 percent common equity level (Exhibit 3, Tab 4, page DGH16).

However, Mr. Hall agreed that Table 12B, Exhibit 43 indicated that there was a wide variety of interest coverage ratios associated with A-rated bonds and debentures (T. 2889) with the averages for the 1982 to 1990 period ranging from 1.8 times to 4.4 times. Further, he agreed that coverage ratios for regulated utilities have been decreasing since 1987 (T. 2884) - a fact which he attributed to regulated rates of return declining more quickly than utility debt costs, since utilities tend to lock in debt rates for a long period of time (T. 2885). The witness indicated he knew of no cases where a utility was forced to curtail a capital expenditure program that was clearly in the public interest due to financial markets being inaccessible (T. 2857).

Mr. Hall stated that his capital structure recommendation of a 40 percent equity component and 3.0 times interest coverage had been influenced by the Company's aggressive capital expenditure plans but that they would not have changed if the plans had been a little less aggressive (T. 2893). Mr. Hall agreed that the market is comfortable with BC Gas as an investment because of the growth opportunities that the Company is in the process of achieving (T. 2838) and that, as a result, most brokerage research reports were recommending the purchase of BC Gas shares (T. 2843).

7.3.2 Position of Dr. W.R. Waters

Based on an examination of the common equity ratios approved for the major gas pipelines and other major gas distribution companies, an examination of the interest coverage ratios for those companies and a determination of the interest coverage which would result for BC Gas, Dr. Waters concluded that a common equity ratio of 32.5 percent would be appropriate for the utility portion of BC Gas and that this would enable the Utility to maintain its financial integrity (Exhibit 43, page 46).

Dr. Waters testified that the capital structures for the major Alberta and Ontario gas distribution utilities ranged from 29.0 percent to 36.3 percent, excluding customer contributions (Exhibit 43, page 37).

The witness examined before tax interest coverage ratios for Canadian utilities over the period 1982 to 1990. Grouping companies by bond quality rating, he found a wide range of ratios existed within any particular quality group. Table 12B (Exhibit 43) shows that the AA group includes companies with average coverage ratios ranging from 2.8 to 3.7 times. Similarly, average coverage ratios for the A group of companies ranged between 1.8 to 4.4 times while for companies in the BBB rating group, average coverage ratios ranged from 1.3 to 2.1 times, excluding Nova Corporation of Alberta. In his written testimony, Dr. Waters noted that "the range of the AA group is completely contained within the range of the A group." (Exhibit 43, page 41)

Dr. Waters testified that after tax interest coverage ratios are more relevant for regulated utilities since income tax is treated as an expense in the regulatory process and regulators are likely to approve a rate increase in response to an increase in tax liability. This implies that utilities which are not in a current tax payable position, or who only have a small tax liability have interest coverage ratios which are downward biased, a fact which has been recognized by the Dominion Bond Rating Service (Exhibit 43, page 43).

The witness stated that his capital structure and return on common equity recommendations would result in a before tax coverage ratio for the utility portion of BC Gas of 2.07 percent (Exhibt 43, page 44) which is sufficient to meet the terms for issuing unsecured debentures contained in BC Gas' trust indentures and in line with recent interest coverage ratios for Consumers Gas Co., Union Gas Limited, and Centra Gas Ontario (Exhibt 43, page 46).

Dr. Waters agreed with counsel for BC Gas that the significantly warmer than normal weather conditions experienced by BC Gas to date in 1992 could result in his recommendations resulting in a before tax interest coverage ratio of less than 2.0 times. However, Dr. Waters stated:

> "The circumstances that you've described are an unusual phenomenon, as the press release says. With the exception of one other year, this has been the warmest weather in the last 50." (T. 3075)

Dr. Waters suggested that the interest coverage ratios would also be affected by BC Gas' tax position.

> "The coverage ratios we're talking about here are before tax coverage ratios, which, I think it's clear from my testimony, are obviously a function of what the tax rate happens to be and the lower the tax rate, the lower in particular the effective tax rate that the company pays, the lower its interest coverages are going to be, simply because it's collecting less tax which goes not to service debt but to the government in its rates.
>
> With BC Gas on flow through and the large expansion program, then I imagine the effective tax rate is going to be considerably below the marginal tax rate of 43 or 44 percent.
>
> So you have, since Inland Gas, the predecessor of BC Gas was put on flow through, a situation where any growth of the type that is being anticipated by the firm today would reduce the coverages automatically, due to the tax component being lower." (T. 3075-3076)

The witness suggested that the Company might investigate having its indenture provisions revised, given the prospects for substantial expansion and the effect these would have on the tax rates that the Company could expect to pay (T. 3076). However, the Company witness stated that it was very unlikely that BC Gas would be able to negotiate a relaxation of the trust indenture provision since the Company had already issued a substantial amount of Purchase Money Mortgages which were not subject to the indenture provisions (T. 3335).

7.4 Impact of Financing Plans on Capital Structure

As indicated in the preceding sections, the capital expenditure plans of the Company appear to be one of the major forces behind the Company's request for an increased equity component (Exhibit 2, Tab 21, page 21). In fact, the Company currently plans capital expenditures in excess of $100 million per year over the next five years (Exhibit 5, Tab 12). Much of these funds will need to be obtained from external sources, with the Company planning to issue at least $200 million and perhaps as much as $275 million of unsecured debentures over the 5-year period commencing 1993 (Exhibit 2, Tab 21, page 12).

Similar to the evidence given by Mr. Hall, Company witnesses stated that to access these external sources:

> "BC Gas must continue to improve its credit quality as reflected by its credit rating. ... A strong "A" credit rating is needed to provide customers with cost effective service, appropriate risk adjusted returns to investors and finance prudent capital expenditures."

and

> "BC Gas must improve its current level of performance as measured by various financial indicators". (Exhibit 2, Tab 21, page 15)

As a result the Company applied for a common equity component of 37.5 percent.

Company witnesses, Mr. Kleven and Ms. Lambert, provided and spoke to Exhibit 141 which identified BC Gas' capacity to raise debt through debentures under a variety of conditions. Assuming normal weather conditions had prevailed in 1992 to date and continued to prevail for the remainder of the year and assuming that the Application was approved as submitted, the witnesses indicated that the Company would be able to raise between $168.5 million and $212.6 million of debentures, depending on the interest rate associated with debt. However, if the Commission allowed only a

33.0 percent common equity component, roughly equivalent to that recommended by Dr. Waters, and adopted his recommended rate of return on common equity of 12.125 percent, the Company's ability to issue debentures would be restricted to $109.3 million to $138.0 million depending on the cost of debt.

On the other hand, the Company witnesses indicated that weather in the BC Gas service area had been approximately 13 percent warmer than normal over the first four months of the year (T. 3329), substantially reducing the Company's ability to exceed its times interest coverage requirements and thus reducing the Company's ability to issue debentures. Assuming that the weather returned to normal temperatures for the remainder of the year, the Company indicated that under the Application as filed, the Company would be able to issue no more than $95.7 million and perhaps as little as $75.8 million depending on debt costs. Under the more restrictive scenario of a 33 percent common equity component and a 12.125 percent return thereon, the Company would be able to issue no more than $21.1 million and perhaps as little as $16.7 million.

Further, the exhibit indicated that if weather continued to be as much as 10 percent warmer than normal over the remainder of the year, the Company would be able to issue no more than $36.1 million of debentures if the Application were accepted as filed and no debt at all under the more restrictive scenario.

Mr. Kadlec testified that under Dr. Waters' proposal the combination of expected internally generated funds and the amount of debt the Company could expect to issue, given the substantially warmer than normal weather to date, would be insufficient to allow the Company to undertake its planned capital expenditures, leading to cuts. He stated:

> "...I would be amazed if we could make that kind of severe cut unless we were allowed by the Commission, or the Commission would have to understand that we can't provide full service.
>
> And full service, by that I mean reinforcing areas that, given a cold winter next year, that we may not be able to get gas to those customers, and also not supply certain customers within the current guidelines that we are required to supply. That would be a draconian cut." (T. 3709)

Exhibit 172 indicated that the major reductions in the proposed capital expenditures would be related to the provision for growth inclusive of mains, meters, service and required system reinforcements. The market demand for natural gas services would not be met.

In response to questioning by Mr. Wallace, the Company witnesses agreed that the shareholder should not get a higher return than otherwise appropriate because of adverse weather conditions (T. 3541) nor should the shareholder get a higher return than otherwise appropriate in order to increase interest coverage ratios (T. 3542).

The Company initially rejected the idea of selling TMPL shares to meet their capital program expenditures. Mr. Kleven equated such a move to using the proceeds to alleviate the debt obligation and suggested that this was not a very good return to the shareholder on an after tax basis so that sale of the TMPL shares would be a last resort (T. 3355).

However, upon further consideration, the witness indicated that using the proceeds to fund the Utility might be "a very good use" (T. 3374) and, in addition, would raise the equity component for the legal entity to 41.6 percent in line with that recommended by the Company's expert witnesses (T. 3375). As well, he indicated it would increase the common equity in the consolidated capital structure since it would remove the reciprocal deduction of $41 million associated with the inter-corporate holdings between TMPL and BC Gas and so address the concerns raised by Dr. Waters (T. 3376). In Exhibit 145, a statement made to TMPL's 1992 Annual General Meeting, Mr. R.L. Cliff, Chairman of the Board for both TMPL and BC Gas, indicated that TMPL would consider selling its shares in BC Gas under the appropriate conditions.

7.5 Debt

7.5.1 <u>Short-Term Debt</u>

BC Gas has applied for a 10.68 percent short-term debt component as part of its capital structure, which it proposes to fund at a forecast cost of 7.1 percent. The Company witnesses stated that short-term interest rates have tended to be more volatile than long-term rates, creating a substantial risk for equity investors for which they will wish to be compensated. To eliminate the shareholder risk associated with short-term debt, the Company applied for an interest rate deferral account into which any deviations from the forecast rate can be accrued (Exhibit 2, Tab 21, page 23). In establishing the rate to be associated with the deferral account, Mr. Kleven stated that:

> "...we would tend to err on the low side rather than the high side in coming up with a rate, because it has a negative impact on the overall revenue requirement. If we defer -- or sorry, if we record interest costs that aren't paid because we've pegged the rate too high, they're non-tax deductible, Revenue Canada won't allow them, so you're better to err on the low side so that at least you get the tax deduction." (T. 3325)

7.5.2 Long-Term Debt

BC Gas has applied for a long-term debt component of 42.14 percent of its capital structure at a cost of 10.798 percent. The long-term debt component includes $75 million of Purchase Money Mortgages and $100 million of unsecured debentures expected to be issued in 1992 at a cost of 10.3 percent (Exhibit 2, Tab 21, page 12 and Exhibit 1, Financial Tab 14, page 1-14-02).

The Company stated that the issue of the long-term debt was necessary and that:

> "...if the long-term financing is not undertaken in the test year, the actual short-term debt in the Company as at December 31, 1992 would increase to $280 million. It is the Company's position that this level is too high and the long-term financings should be undertaken prior to December 31, 1992." (Exhibit 5, Tab 19, item 1.19, page 1)

With respect to these issues, the Company stated that, for regulatory purposes, these long-term issues had been weighted into the capital structure based on their expected date of issue. BC Gas suggested that to the extent the actual achieved rate differed from that reflected in the Application, the difference be captured in a deferral account (Exhibit 5, Tab 19, item 1.19, page 1).

7.6 Commission Decision

The Commission agrees with the Applicant that any variation between the applied for interest rate and that actually paid by the utility for short-term debt should be accrued in a deferral account. Further, the Commission is sensitive to the Utility's concern with respect to the tax impact of setting a rate that exceeds that which is actually paid. Given the downward trend in short-term interest rates which occurred over the course of the hearing and the possibility that such a trend may continue, the Commission sets the short-term debt cost at 6.35 percent.

With respect to long-term debt, the Commission is concerned that allowing the utility to earn a long-term debt rate on the portion of the long-term debt component which is still to be issued will result in utility customers paying for the security of long-term debt before that security is in place. Therefore, the Commission determines that the portion of long-term debt still to be issued should be funded at the cost of short-term debt until it is actually issued. To the extent the cost of the long-term debt, while funded at short-term rates, differs from the allowed short-

term cost of debt, the difference shall be placed in the same deferral account as that outlined above with respect to short-term debt.

In determining the appropriate capital structure for the utility portion of BC Gas, the Commission's primary obligation is to determine the amounts of debt and equity which will result in an efficient capital structure. By "efficient" the Commission means a capital structure which will result in the utility being able to access capital markets at reasonable rates so as to minimize costs to customers. In addition to this primary issue, i.e. is the applied for capital structure appropriate, in this hearing the Commission was also asked to address two other issues. These are:

(i) Does sufficient equity exist in the Company to support its Application; and

(ii) To what extent should the special circumstances facing the Company affect the capital structure of the Utility?

Two approaches were adopted in the hearing to determine whether sufficient equity exists in the Company to support a utility common equity component of 37.5 percent. The Applicant began with the non-consolidated financial statements of the Company which presented the financial position of the legal entity, with investment in subsidiary companies shown at cost, and allocated the various sources of capital amongst non-utility, utility-other and rate base components as discussed above, to determine the capital structure of the Utility on a stand-alone basis. An argument may be made that commencing with the non-consolidated statements to determine the capital structure of the Utility is appropriate since it is the legal rather than the consolidated Company which issues debt and equity securities and to which creditors have recourse in the case of default.

The alternate approach, testified to by Dr. Waters, suggests that the determination of the utility capital structure should begin with the consolidated financial statements which are then adjusted to determine the capital structure of the utility on a stand-alone basis. The statements of one company are consolidated with those of another company in which it has an investment, whenever that investment results in the first company having effective control of the second company. When such control occurs, the two companies, while separate legal entities, form one economic unit. It is the financial ratios of the economic unit which are calculated and the health of which is assessed by capital suppliers in determining whether or not to make funds available to the company and at what costs since capital suppliers recognize that the effective control of the subsidiary by the parent implies that the subsidiary's assets can be managed to support the parent. The Commission believes that it should recognize this economic reality as well. **Therefore, the Commission determines that the appropriate starting point to determine the utility capital structure is the consolidated financial statements.**

The Commission recognizes that the use of non-consolidated financial statements was allowed previously. However, changes in the circumstances of the Company and the evolution of capital markets makes the use of the consolidated statements more appropriate now.

With respect to the specific adjustments to the consolidated statements adopted by Dr. Waters, the Commission accepts that the acquisition of a controlling interest in TMPL by BC Gas resulted in the effective re-purchase of its own shares and reduced the equity of BC Gas available to support rate base and other assets by $41 million. The Commission notes that such a finding is consistent with the intent of CICA Handbook Section 1600.70.

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 that 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 by 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.

As for Dr. Waters' third adjustment, i.e. the earmarking of sufficient equity to raise TMPL's equity component to 40 percent, the Commission believes that whatever amount is attributed to TMPL by the NEB should be allocated here. In making this determination, the Commission agrees with Dr. Waters when he states "equity cannot provide an equity base for TMPL and BC Gas utility at the same time" (Exhibit 43, page 35).

Subsequent to the hearing, the NEB has determined that the appropriate common equity component for TMPL is 47.5 percent, some 7.5 percentage points greater than that used by Dr. Waters in his testimony. Adjusting his Table 15B (Exhibit 43, Table 15B) to reflect the NEBs common equity determination suggests that BC Gas Utility has a common equity component of 32 percent.

However, the Commission recognizes that the complexity of BC Gas means that any allocation is, to a degree, arbitrary. Therefore, the Commission adopts a conservative approach and finds that the capital structure of the Utility contains approximately 33.0 percent common equity.

The issue of the amount of equity in existence to fund the Utility was addressed in a hearing concerning the predecessor company. In the Inland Decision, August 6, 1987, page 46, the Commission urged the Company to seek a solution to this problem. Events subsequent to that Decision prevented the Company from doing so. **The Commission reiterates its request that BC Gas seek to isolate its utility assets so that a clearer picture of the Utility's capital structure will be available at the time of the next hearing.**

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. With respect to the use of rate base assets to guarantee non-rate base activities, the Commission directs BC Gas to investigate the identified concern and provide a resolution in a timely manner.**

The second issue which must be addressed is the appropriateness of the applied for capital structure. The Commission agrees with the Applicant's position that the low common equity ratio enjoyed by the Company over the transition period does not reflect the Company's optimal capital structure. However, the Commission does not find that the Company has proven its case that a 40 percent common equity component is necessary to preserve the financial integrity of the utility. The Company's own evidence clearly showed that gas distribution companies do not have common equity components in the 40 percent range. Indeed when the Company's evidence was updated, it was shown that the common equity component more usually associated with gas distribution utilities was substantially below this level. Nor was a direct link between a 40 percent equity component, a high interest coverage ratio and a strong A to A+ bond rating clearly demonstrated. Table 12B, Exhibit 43 showed that there was a wide range of interest coverage ratios associated with A-rated bonds and debentures.

Finally, Exhibit 141, prepared by the Company, showed that a common equity component of 33 percent, substantially the same as that allowed the smaller predecessor company, was sufficient to allow the Company to access debt capital markets for substantial amounts in all but very unusual circumstances. In addition, the Commission notes that Exhibit 173 shows that utility income before interest and taxes is greater than that for the consolidated company, indicating that the Utility's ability to issue debt has been negatively affected by the NRB.

Regarding the third issue, namely the impact of the Company's capital expenditures plans, the Commission is aware that the Company requires a financial profile which will permit it to access capital markets under adverse conditions. This fact was recognized by all witnesses to the hearing, including Dr. Waters who testified that:

> "... the regulated utility's obligation to provide service may require it to raise capital regardless of capital market conditions. At such a time the fairness standard is rendered irrelevant by the imperatives of the capital attraction and financial integrity standards. These standards require that utilities be able to attract capital, under all but the most adverse of circumstances, on terms and conditions which do not impair the credit worthiness of the utility's outstanding senior securities and do not dilute the earning power of the existing common shareholders." (Exhibit 43, page 14)

However, the Commission does not believe that this requirement is one which it must fulfill blindly.

In this hearing substantial time was spent on the impact of weather on the expected 1992 earnings of the Utility and the resulting impact on interest coverages and the ability to raise debt capital in 1993. The new gas supply contracts entered into by the Utility, which have a significant fixed charge component, have exacerbated these weather-related effects. Although the Commission recognizes the impact of the warm weather faced by the Utility, it does not believe the correct course of action would be to allow the Utility a capital structure which the Commission would not otherwise find appropriate. The temperature normalization process undertaken as part of the regulatory process addresses this problem in part. To set the capital structure at a level higher than would otherwise be appropriate, to preserve the Utility from likely short-term adverse weather, would have the effect of penalizing customers.

The Commission concurs that the impairment of BC Gas revenues due to abnormal weather might have an unfavourable impact on the Utility's ability to raise debt as demonstrated by Exhibit 141. However, the Commission believes there are options open to the Company to meet necessary capital expenditures and preserve the quality of service to customers. Such options might include deferral of non-critical capital projects and maintenance expenditures to a subsequent year or the sale of TMPL shares. It is the Commission's belief that the weather constitutes a special circumstance. If a genuine difficulty develops the Commission will consider interim actions to ensure the Utility will be capable of serving the public interest.

Therefore, the Commission finds the appropriate common equity component for the utility component of BC Gas to be 33.0 percent.

8.0 RETURN ON COMMON EQUITY

8.1 Introduction

BC Gas applied for a rate of return of 13.5 percent on a common equity component of 37.5 percent, as discussed in Section 7.0 of this Decision. The Application was supported by Dr. R.A. Morin, an expert witness, who recommended 13.5 percent, within a range of 13.25 percent to 13.75 percent. This recommendation was based on his assessment of the business and financial risks and capital requirements outlook of the Utility. Dr. Morin stated that such a return would allow BC Gas:

> "to attract capital on reasonable terms, maintain its financial integrity, and it is commensurate with returns on investments of comparable risk." (Exhibit 3, Tab 5, page 7)

In addition to the evidence provided by the Applicant, the Commission also heard evidence from Dr. W.R. Waters, an expert witness retained by Commission staff who provided his view as to the appropriate rate of return on common equity for the utility portion of BC Gas. As a result of his assessment of the risks and financing issues facing BC Gas, Dr. Waters concluded that:

> "the financial integrity of BC Gas utility would be adequately maintained if its common equity rate of return were set within the range of 12 - 12 1/4 percent for the the 1992 test year." (Exhibit 43, page 2)

8.2 Economic Environment

Dr. Morin stated that he expected the Canadian economy to grow by about 2.0 percent in 1992 (T. 2742) and the inflation rate to decrease, but the British Columbia economy to lag behind that of the nation (Exhibit 3, Tab 5, page 15). He indicated that long-term bond markets have been volatile and that utility debenture yield spreads over long Canada bonds were in the order of 100 - 125 basis points (Exhibit 3, Tab 5, page 16). In his written evidence, filed in October 1991, Dr. Morin stated that he didn't expect the interest rate of long Canada bonds to decline significantly from then current levels of 9.25 percent and could increase with economic recovery (Exhibit 3, Tab 5, page 16). He confirmed this view with respect to interest rates during the course of the hearing (T. 2624).

Dr. Waters provided a similar view with respect to long-term interest rates, indicating that he expected the rate of long Canada bonds to average between 9.25 percent and 9.5 percent in 1992, for a spot rate of 9 and 3/8 rounded to 9.4 percent (Exhibit 43, page 2 and page 71).

However, by the time the hearing ended, long-term Government of Canada bonds yields had begun to trend downward.

8.3 Business, Financial and Regulatory Risks

8.3.1 Position of Applicant

Dr. Morin stated that BC Gas' current risk environment could be separated into two broad components: business risk and financial risk. He stated that business risk related to variability of operating profits induced by external forces which affect the demand for and supply of the firm's products (demand and supply risks), the presence of fixed costs (operating leverage), the extent of or lack of diversification of services and the character of the regulation experienced by the firm (regulatory risk) (Exhibit 3, Tab 5, page 18).

With respect to the demand risk faced by BC Gas, Dr. Morin identified increased competition from alternative energy sources; reliance on an industrial customer base dominated by forest, pulp and paper and resource industries; a potential for industrial customers to leave the BC Gas system and seek alternative sources of energy and a residential and commercial load which is highly weather sensitive (Exhibit 3, Tab 5, pages 19-21).

With respect to the supply risk, Dr. Morin identified the move to fragmented sources of gas supply, some of which is short-term in nature; a high degree of dependency on the gathering, processing and transmission facilities of WEI; the lack of storage close to markets; market set prices which may be less readily accepted by regulatory authorities, and a potential for movement by large customers to direct sales (Exhibit 3, Tab 5, pages 21-24). Many of these risks were supported by the testimony of Company witnesses with respect to the effects of deregulation (Exhibit 2, Tab 2, pages 6-9).

With respect to regulatory risk, Dr. Morin stated that the termination of BC Gas' regulatory "holiday" and the resumption of normal regulation has increased investor uncertainty, although he noted that the Commission's past rate orders and policies had generally been perceived by the investment community as fair (Exhibit 3, Tab 5, pages 24-25).

The second major source of risk identified by Dr. Morin is financial risk and is defined as the additional variability of earnings caused by the way in which the company is financed (Exhibit 3, Tab 5, pages 18-19). After examining the bond rating and selected financial ratios of BC Gas and comparing them to those of its industry peers (Exhibit 3, Tab 5, page RAM-14), Dr. Morin concluded that BC Gas was subject to higher financial risk than other utilities (Exhibit 3, Tab 5, page 26).

Dr. Morin stated that BC Gas' financial risks were exacerbated by its large construction program:

> "...I believe that the company's financial risks exceed the average and I looked at that not so much in terms of their capital structure or coverage ratios, although that's crucial, but in terms of their construction program. Now, here is a company who is going to be making repeated access to the capital markets for the next four to five years. There's a certain amount of construction risk, certain amount of capital market exposure for this company, and it's absolutely crucial that a financial profile be awarded to this company that enables it to compete effectively on capital markets and at reasonable costs." (T. 2625-2626)

Dr. Morin indicated that the doctrine of capital attraction, as it applies to determining the appropriate return on equity, was "crucial at this juncture for BC Gas" and that:

> "The return allowed on common equity will play a crucial role in determining the terms and conditions under which the company can raise funds." (Exhibit 3, Tab 5, page 28)

In response to a question by the Chairman, Dr. Morin ranked the financial risks attributed to the capital expenditure program as being the greatest of the risks faced by BC Gas and that he expected rate base to increase by 65 percent over the next five years (T. 2691). Dr. Morin identified the next highest group of risks to be that associated with gas supply, while a distant third would be demand risks (T. 2692).

In summary, the witness stated that BC Gas' demand risks were slightly below average, its supply risks were above average, its regulatory risk was above average in the short-term and its financial risks, including those associated with capital expenditures, were well above average. In total, Dr. Morin stated that BC Gas' overall risk was above average relative to other regulated utilities (Exhibit 3, Tab 5, page 29).

However, in cross-examination, Dr. Morin agreed that the competitive position of natural gas in British Columbia at this point in time is very advantageous and that government policies favoured natural gas as a fuel of choice for environmental reasons (T. 2634). In addition, he agreed that the recent recession had had only a minor impact on BC Gas' revenues (T. 2636) and that the Commission's position with respect to customers leaving the system had reduced the possibility of by-pass. As well, since the margins associated with industrial customers were thin, Dr. Morin concluded that their loss would not have a big impact on the Company (T. 2639).

With respect to market set prices, Dr. Morin stated that he had been unaware of a clause within the *Utilities Commission Act* that encourages the Commission to approve pass-throughs on increased prices and that the Commission acts upon this clause. He agreed that such a clause would dissipate the supply risk associated with negotiated prices which he had identified previously (T. 2706).

Company witnesses also addressed the risks faced by BC Gas. Exhibit 142 was produced to show that approximately 72 percent of the utility costs are fixed, compared with 37 percent for the old Inland utility, while only 9 percent of revenues were fixed compared with 13.9 percent for the previous Inland utility. Approximately 44 percent of the fixed costs are associated with the gas purchase costs. The Company indicated that the high proportion of fixed costs has a direct impact on the Company's ability to earn its rate of return on equity. Exhibit 143 showed that if the weather were 15 percent warmer than normal, revenues would drop 8.9 percent, total margin would decline by 16.1 percent and the actual rate of return on equity, assuming an allowed rate of 13.5 percent, would be 6.59 percent.

8.3.2 Position of Dr. W.R. Waters

Dr. Waters stated that the business risks faced by investors in BC Gas could be divided into three categories:

> "(i) The risk that rates will not be set at a level sufficient to provide a fair rate of return on total capital invested;
>
> (ii) The risk that a particular period's operating and or financial costs will exceeded those utilized in setting rates, or that the revenues will fall short of those projected;
>
> (iii) The risk that the utility will become uneconomic and will be shut down completely or will be unable to recover fully its fixed costs, including those relating to financing." (Exhibit 43, page 17)

More specifically, Dr. Waters stated that the business risks faced by the Utility flowed from the basic technology and capital intensity of its operations, its obligation to provide service, and its inability to change the prices of its service at will (Exhibit 43, page 18). While recognizing that gas distributors are not guaranteed that their fixed costs will be recovered, Dr. Waters stated that they benefit from "the strong consumer acceptance of natural gas and its competitive position relative to other fuels" (Exhibit 43, page 19).

Dr. Waters identified five factors affecting the business risk of the utility operations of BC Gas. These are :

(i) The characteristics of the B.C. economy;
(ii) The Utility's growth rate;
(iii) The Utility's competitive position;
(iv) The Utility's productivity performance; and
(v) Its income tax status (Exhibit 43, page 19).

With respect to these factors, Dr. Waters stated that while the B.C. economy is usually viewed as being more concentrated and more dependent on resource industries than the provincial economies in central Canada, the B.C. economy has benefited from growth in the Pacific Rim countries and a high underlying growth trend in the local economy. In addition, he testified that the Company's high expected growth rate, while meaning that distribution capacity must continually be added, also meant quick absorption of any excess capacity created by forecasting errors and a more up to date plant which would strengthen the Company's competitive position. Further, Dr. Waters maintained that the Application showed that the Utility has a record of strong productivity growth which would allow it to penetrate new markets and defend current markets from competitors.

Dr. Waters noted that the risks borne by investors in BC Gas are not restricted to those associated with the Utility (Exhibit 43, page 16). He stated that the other business segments of the Company involved greater business risk than the utility segment (Exhibit 43, page 23). Company witness, Ms. Lambert, agreed with this statement (T. 3439), although she indicated that it had no impact on how the Company's bonds were priced.

Dr. Waters defined financial risk as "the amplification of business risk which results when debt, preferred shares, and other claims senior to those of the common stockholders are used to finance a company's activities" (Exhibit 43, page 25). A common method of measuring financial risks is through financial ratios, particularly interest coverage ratios. Dr. Waters provided evidence to show that his recommendations with respect to common equity and return on common equity would place BC Gas' interest coverage ratio for 1992 within the range for central Canadian gas distributors (Exhibit 43, page 46).

Dr. Waters stated that he had not examined what portion of BC Gas' revenues could be considered fixed or assured but he had examined the extent to which the Utility's actual rate of return had deviated from its allowed rate of return when it was functioning as Inland (T. 3101).

8.4 Return on Equity ("ROE") - Methodologies

8.4.1 Position of Applicant

Dr. Morin established his estimate of the appropriate rate of return on common equity for BC Gas using three types of tests:

(i) The Comparable Earnings test which estimates the investors required rate of return by measuring the return on book equity achieved by a group of unregulated industrial companies, with the same risk characteristics as the subject utility, over a selected time period;

(ii) Discounted Cash Flow ("DCF") tests which estimate the prospective rate of return on market valued common equity for similar risk companies using a dividend yield plus growth model; and

(iii) Risk Premium tests which estimate the necessary premium over and above the risk free interest rate, as measured by long-term government bonds, which must be paid by the utility to attract investors.

The first two methods calculate ROE by reference to selected groups of companies judged to be of similar risk to the subject utility while the third method relies on estimates of the premium equity capital commands over debt capital in the capital market as a whole, adjusted to reflect the particular risk characteristics of the subject utility.

Comparable Earnings Test

In undertaking the Comparable Earnings test, Dr. Morin used four measures of risk to develop a sample of 27 Canadian industrial companies which he believed to be of similar risk to the utility portion of BC Gas (Exhibit 3, Tab 5, pages 30-31). Based on the period 1980-1989, he determined that the 27 low risk companies earned a mean return of 12.96 percent. In his written testimony, the witness indicated that his estimate might be upward biased since he had not included data for the years 1990 and 1991. However, Dr. Morin indicated that such bias would likely be offset to the extent that real estate companies and financial institutions, which are highly levered relative to utilities, were included in the sample (Exhibit 3, Tab 5, page 31). Dr. Morin stated that he did not suggest the removal of real estate and financial institutions from the sample on the grounds that these companies earned a low return on common equity (T. 2657) but agreed that he had only suggested their removal over the last three to four years when returns have been disastrous (T. 2657-2658).

The witness agreed that his sample could have been updated to include 1990 data but stated that he couldn't have used 1991 data since there was insufficient data on which to run his risk "filter", i.e. his four measures of risk. Dr. Morin indicated that it would be inappropriate to simply update the data for the 27 companies since there was uncertainty as to whether the same companies would survive the risk filter for the 1990 and 1991 periods (T. 2658, 2748). He stated that when he applied his risk filter to 1990 data, the sample of comparable risk companies declined to about 19 companies and he obtained an average return on equity for the 10-year period ending 1990 of 12.87 percent (T. 2754-2755). For the 27 company sample, the average return on equity for the period ending 1990 was 12.65 percent (Exhibit 149).

Dr. Morin agreed that based on the four risk measures which he used to construct his sample, the industrial sample appeared to be of higher risk than utilities; however, he stated that the industrial sample was still within the utility risk class (T. 2652-2655). However, Mr. Hall, also appearing for the Company, stated that he did not expect that the companies that Dr. Morin referred to in his report as being of comparable risk to BC Gas would do as well as BC Gas in the current economic environment (T. 2814-2816).

The witness agreed that there were a number of conceptual problems with the comparable earnings tests, that he no longer used it when preparing testimony for use in the U.S. and that he had recently characterized it as a dinosaur (T. 2660-2661). Dr. Morin stated he used the test in Canada where it has been a hallmark and because the other tests were not easy to implement here (T. 2661).

Finally, Dr. Morin agreed that reductions in inflation would tend to lower nominal rates of return on book equity (T. 2759).

Discounted Cash Flow Test

Dr. Morin applied the DCF test to four groups of comparable companies to produce estimates of the investors' required rate of return over the period 1980-1989. These were: a sample of comparable (i.e. low) risk energy utilities, a sample of Canadian telephone utilities, a group of low risk Canadian industrials and a group of U.S. natural gas distributors. For each of the samples, companies which paid no current dividends, for which dividend growth was not available or with negative growth rates were excluded. Dr. Morin stated he believed it was reasonable to exclude utilities which had a negative growth rate since nobody would buy a stock expected to grow negatively, forever (T. 2674).

Based on the group of energy utilities, Dr. Morin found the investors' required rate of return was 15.7 percent if growth was estimated using a 10-year historical dividends per share growth rate for the period 1980-1989 and 11.82 percent if historical earnings growth were used instead, for an average of 13.76 percent (Exhibit 3, Tab 5, page 47). Based on the sample of telephone utilities, Dr. Morin found the investors' required rate of return to be 12.18 percent when using dividend growth rates and 10.5 percent if using earnings growth rates. As the earnings based result approximates the Company's current cost of debt, Dr. Morin eliminated this result and retained the 12.18 percent (Exhibit 3, Tab 5, page 48).

In applying the DCF test to low risk industrials, Dr. Morin began with the sample he had used for the comparable earnings test and then eliminated those companies which did not meet his dividend and earnings criteria. For the 14 surviving companies, the investors' required rate of return was estimated at 12.76 percent, if using dividend growth rates and 12.50 percent, if using earnings growth (Exhibit 3, Tab 5, page 49). However, because of concerns about the sample's reliability, Dr. Morin chose to ignore these results. Instead, Dr. Morin relaxed the risk filters used to obtain the original sample and re-performed the test on an expanded sample. Using 29 companies (the original 14 plus 15 more), he estimated the investors' required return to be 13.62 percent if using dividend growth rates and 13.50 percent if using earnings growth rates for an average of 13.56 percent (Exhibit 3, Tab 5, page 50).

The witness agreed that it was unlikely that the average estimated cost of capital for the expanded sample would be almost 95 basis points higher than for the original sample if the newly included companies were really of the same risk as the original group (T. 2769). Further, Dr. Morin agreed that the growth rate for 1991, which had been excluded in his application of the DCF test, was likely to be less than the growth rate for 1990 by approximately 40 basis points (T. 2766).

Finally, Dr. Morin applied the DCF test to a sample of comparable risk U.S. natural gas distributors and found the the investors' required return was 12.81 percent if using earnings growth rates and 13.10 percent if using dividend growth rates for an average of 12.96 percent (Exhibit 3, Tab 5, pages 53-54).

Risk Premium Test

Dr. Morin relied on four risk premium studies to determine the appropriate risk premium for BC Gas. In his first study, Dr. Morin used time series analysis applied to a group of Canadian telephone utilities over the period 1984 to 1989 and determined that the appropriate risk premium for A+ utility bonds over long-term debt is 3.12 percent (Exhibit 3, Tab 5, page 33). Assuming that BC Gas's cost of debt is 10.35 percent, this suggests that the appropriate rate of return on common equity is 13.47 percent. Dr. Morin agreed that if he had included 1990 data, he would have found a risk premium of 2.72 percent some 40 basis points lower than the estimate he used. However, he stated that he had excluded the 1990 results because some of the companies had negative earnings growth leading to results which he considered to be "not reasonable" (T. 2663) and that he also would have excluded the 1990 data if the measured risk premium had been unreasonably high (T. 2664).

A similar study using Moody's Gas Distribution Utility Index as an industry proxy indicated a risk premium of 3.54 percent, suggesting that BC Gas' required rate of return on common equity is 13.89 percent (Exhibit 3, Tab 5, pages 34-35).

Two additional risk premium estimates were developed based on the Capital Asset Pricing Model ("CAPM") and the empirical approximation to the CAPM ("ECAPM"). The CAPM estimates the investors required rate of return as equal to the risk-free rate of return, usually measured by the rate on long-term bonds, plus the market risk premium adjusted for utilities' beta, where beta is a measure of the degree to which a stock or group of stocks moves with the market. Dr. Morin testified that he used adjusted rather than raw betas to account for the tendency of betas to move towards a value of 1 over time. The ECAPM is similar but relaxes some of the more restrictive assumptions underlying the CAPM, producing a somewhat flatter "risk-return" relationship (Exhibit 3, Tab 5, pages 36-41).

Using three well known studies, as well as Value Line data (Exhibit 3, Tab 5, pages 37-39), Dr. Morin determined the average market risk premium to be in the order of 6.0-7.0 percentage points. Applying this to the CAPM model and using an adjusted utility beta of .57, he determined the investors' required rate of return to be 13.26 percent. A result of 13.95 percent was obtained from using the ECAPM model.

Dr. Morin agreed that his estimate of the market risk premium had been found by other Boards to be too high (T. 2668). Further, he agreed that he was not using the most up-to-date edition of one of the studies on which he was relying (T. 2771). In addition, he stated that there were no Canadian studies to support his contention that utility betas were moving towards one over time, but argued that:

> "...it makes sense to think, just intuitively, that utilities are about 50, 60 percent as volatile as the average stock in Canada." (T. 2670)

Together the comparable earnings, DCF and risk premium tests yielded an average investors' required rate of return on 13.33 percent. After removing the high and low estimates from the average, Dr. Morin found a truncated mean of 13.41 percent. On this basis, he recommended a return on equity of 13.50 percent for the utility portion of BC Gas.

8.4.2 Position of Dr. W.R. Waters

Dr. Waters estimated the required return on equity for the utility portion of BC Gas using the DCF and Risk Premium methods. He rejected the use of the Comparable Earnings method since he had concerns that:

> "(i) the concept of comparable earnings does not necessarily have any relationship with the concept of a fair return;
>
> (ii) the measurement of comparable earnings (based on accounting data) provides results which are difficult to compare meaningfully across companies and across time." (Exhibit 43, page 75)

Discounted Cash Flow Test

Dr. Waters used five measures of risk to develop a sample of low risk Canadian industrials which he then used to calculate the investor's required rate of return using the DCF model. This model requires the estimation of the next period's dividend yield and expected dividend growth rates. Five, eight and ten year period dividend growth rates were calculated, based on historical dividend data aggregated in such a way as to give each company in the sample equal weight in a "dividend index", i.e. the same dollar amount is assumed to be invested in each of the sample companies. Since share prices for each company differ, the assumed amount of stock held in each company will also differ. The witness stated that if prices from periods other than the most recent were used to weight the stocks held, this method would result in stocks which subsequently had higher rates of price appreciation being given relatively more weight than stocks which had relatively low price appreciation. If the portfolio contained more stocks which had relatively high levels of price appreciation than low levels of price appreciation, this method would result in an overestimate of the investors required rate of return. Similarly, if the portfolio contained more stocks with relatively low price appreciation, the investors' required rate of return would be underestimated. To avoid this potential for bias, the witness used three different price periods to weight his sample stocks (Exhibit 43, pages 51-52). As a result of the various combinations of historical time periods, index weighting base periods and measurement techniques, a total of 27 growth rate estimates were generated, which, when combined with the estimated dividend yield, gave rise to investors' required rate of return estimates in the range of 9.7 percent to 10.9 percent. The witness concluded that the required rate of return for low risk industrials would be no higher than 11 percent.

However, based on information developed as part of the risk premium test, Dr. Waters stated that the low risk industrials were riskier than the lowest risk utilities and had an investors' required rate of return some 60 to 80 basis points greater than that for lowest risk utilities. Therefore he deducted this difference from the 11 percent value determined above to obtain his estimate for low risk utilities (Exhibit 43, page 73).

Two supplementary samples of somewhat higher risk were also used to estimate the investors' required rate of return. These samples gave rise to estimates approximately 45 basis points greater than the primary sample.

Dr. Waters agreed with Counsel for the Utility that his method of aggregating dividend growth rates could result in his estimate of the investors' required rate of return having a downward bias, as explained above. However, the witness reiterated his testimony that his use of three different period weights guards against such an eventuality and that if his results were examined they could be seen to be free of bias (T. 3047).

Dr. Waters agreed that the estimates of the investors' required rate of return for low risk industrials generated by this test were substantially the same as the bond yields for these companies and that:

> "It doesn't make sense to say that the mean values and the median values for those 27 estimates are the appropriate values to utilize and I do not utilize them." (T. 3048)

Risk Premium Test

Dr. Waters also undertook to estimate the required risk premium for the Canadian equity market as a whole, his sample of low risk industrials and for lowest risk utilities. Using historical data from five different sources, he concluded that the equity market risk premium was 5.7 percentage points for the 1926-1987 period and 5.9 percentage points for the 1950-1987 period. However, Dr. Waters stated that the historically achieved values were likely to overstate the equity risk premiums which were prospectively anticipated by approximately 1.4 percentage points (Exhibit 43, page 61). Therefore, he concluded that an initial estimate of the risk premium required by equity market investors would be 4.5 to 5.7 percentage points. A further 1 percentage point downward adjustment was made to both numbers to reflect a purchasing power risk premium which the witness maintained was included in long-term Government of Canada bond yields (Exhibit 43, pages 60-63).

Based on three measures of share price volatility and two measures of per share earnings volatility, Dr. Waters determined that his sample of low risk industrials had approximately two-thirds of the risk of the equity market as a whole (Exhibit 43, page 64) while low risk high grade utilities were only one-half as risky as the market (Exhibit 43, page 66) giving rise to premiums of 2.4 to 3.2 and 1.8 to 2.4 percentage points respectively. As a result, the witness estimated that the appropriate return on equity for the utility portion of BC Gas would be 1.8 to 2.4 percentage points above the long-term government bond rate of 9.4 percent or 11.2 to 11.8 percent.

In discussion with counsel for the Utility, Dr. Waters agreed that fear of inflation permeates all types of investments but indicated that this did not negate the necessity for the purchasing power risk premium since equity investors would be more likely to recover inflation induced costs than would fixed income securities investors (T. 3162-3166). The witness also rejected the suggestion that the two adjustments resulted in double counting, stating that the one adjustment related to an observed relationship between what was required by investors in the past and what they achieved and the other related to prospective inflation (T. 3165-3166). The witness agreed that he had not always included these adjustments in his testimony as he "had not thought of a way of estimating it until, I think, about 1988" (T. 3167).

Dr. Waters stated that the unsettled conditions in financial markets caused him to give greater emphasis to the results of the risk premium test than the DCF test. Therefore, he concluded that the investors' required rate of return for the lowest risk utilities is 11.25 percent to 11.75 percent (Exhibit 43, page 73). To this recommendation, he added 50 basis points as a margin of safety of allowance for "flotation costs" which is intended to cover costs associated with the issue of new common equity and minimize the possibility of diluting shareholder equity if issues of new equity need to be made into unfavourable markets (Exhibit 43, page 4).

8.5 Commission Decision

Based on the evidence the Commission agrees with Dr. Morin that the most significant risks facing BC Gas are those associated with financing its aggressive capital expenditures program. While a number of business risks faced by the Utility were shown to exist, a substantial number of offsets were also identified. However, although the Commission agrees that the major risks facing the Utility are those associated with financing, the Commission notes that the financing is associated with substantial expected growth which has the potential to bring to the Utility substantial rewards. Moreover some planned capital cost items, such as the East Kootenay Link and the transmission system in the interior, will require the Commission's careful scrutiny before they are allowed to proceed.

With respect to the tests used by the Applicant to determine the appropriate rate of return on common equity, the Commission had several concerns. As was shown during cross-examination, the data used by the witness in undertaking the Comparable Earnings test was out of date. While the Commission recognizes that the 1991 data was not available to allow the witness to repeat the test from "scratch", the 1990 data was available. Further, the indications during the course of the hearing were such as to indicate that inclusion of the more recent data would have led to a more representative estimate of the fair rate of return.

Several concerns exist with respect to the application of the DCF tests. First, the Commission is concerned that the decision to exclude companies with negative growth rates which would otherwise be seen as comparable to the utility portion of BC Gas results in an upward bias to all Dr. Morin's DCF based estimates. Second, the Commission is concerned that the exclusion of 1990 and 1991 data from the DCF test applied to the sample of low risk industrials leads to a further upward bias in the estimate of the investors' required rate of return. Finally, the expansion of the sample used in this test, which raised the resulting estimate by approximately 95 basis points, also draws into question the comparability of the risk of the sample to the risk of the utility portion of BC Gas.

There are also concerns with respect to the estimates based on the risk premium tests. The exclusion of 1990 data from the application of the risk premium test to telephone utilities results in an estimate of the risk premium some 40 basis points higher than if the 1990 data had been included.

With respect to the evidence presented by Dr. Waters, the Commission recognizes there is a potential for bias in the portfolio he developed for the application of the DCF test. However, the Commission does not find that such bias was shown to exist.

The Commission is cognizant that the unseasonably warm winter has had a material impact on the revenues of the Utility and thus on its ability to earn its allowed rate of return in this year. The Commission is sympathetic to the Utility's plight and has reflected this in the Decision. However, as indicated in Section 7.0 dealing with the capital structure, weather variations, while unfortunate, are not unexpected. In fact, it is a normal risk faced by the Utility. Indeed, it is precisely because variations in the weather are expected that the Utility undertakes temperature normalization in putting together its Application. To award the Utility a greater rate of return on equity than the Commission would otherwise judge to be fair, just and reasonable, because of the potential effects of the weather in this year, would be unfair.

The Commission finds that the appropriate rate of return on equity for the utility portion of BC Gas is 12.25 percent, within a range of 12.0 percent to 12.5 percent.

9.0 THE DECISION

The Commission has concluded that BC Gas, based on a fiscal 1992 test year, will be allowed an opportunity to earn a rate of return on common equity of 12.25 percent on a common equity component of 33 percent for all Divisions as shown in the Decision schedules. The resulting revenue requirement of approximately $630 million will enable BC Gas to achieve a return of 10.31 percent on a rate base of approximately $1,008 million.

The Commission hereby confirms the following:

(i) The request for interim and permanent increase of 3 percent as amended to 2.9 percent effective January 1, 1992 is denied.

(ii) The existing tariff rate schedules of all Divisions will remain in effect pending a rate design review.

(iii) The interim increase of 3 percent in effect since January 1, 1992, is to be refunded with interest to customers in accordance with the terms contained in Order No. G-115-91.

(iv) BC Gas is to implement the directions and conditions as detailed in various parts of this Decision and file tariff schedules to reflect the above, effective October 1, 1992.

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of August, 1992.

Original signed by:

John G. McIntyre, Chairman

Original signed by:

J.D.V. Newlands, Deputy Chairman

Original signed by:

N. Martin, Commissioner

BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-63-92

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

and

IN THE MATTER OF an Application by BC Gas Inc.

BEFORE:	J.G. McIntyre Chairman,	)	
	J.D.V. Newlands, Deputy Chairman; and	)	August 5, 1992
	N. Martin, Commissioner	)	

O R D E R

WHEREAS:

A. On November 20, 1991 BC Gas Inc. - Lower Mainland, Inland, Columbia and Fort Nelson Divisions ("BC Gas"), pursuant to Sections 64, 67 and 106 of the Utilities Commission Act, filed a Revenue Requirements Application and applied for an Order granting an interim and permanent rate increase of 3 percent, effective with consumption on and after January 1, 1992; and

B. By Order No. G-115-91 dated December 2, 1991, the Commission approved an across-the-board interim increase in rates of 3.0 percent except those in the Fort Nelson Division, effective with consumption January 1, 1992; and

C. By Order No. G-122-91 the Commission set the Application down for a public hearing to commence March 24, 1992; and

D. The public hearing into the BC Gas Application commenced on March 30, 1992 and concluded June 4, 1992; and

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

NOW THEREFORE the Commission hereby orders BC Gas as follows:

1. The Rate Base and Revenue Requirements for the test year 1992 are as set out in the Schedules contained in the Decision.

2. The interim rates, approved by Order No. G-115-91, for the Lower Mainland, Inland and Columbia Divisions, are hereby denied and are required to be refunded with appropriate

BOX 250 #600. 900 HOWE STREET VANCOUVER. B.C. V6Z 2N3 CANADA. TELEPHONE (604) 660-4700. TOLL FREE. B.C. 1-800-663-1385 FAX: (604) 660-1102

interest to customers from January 1, 1992 to the date upon which the new Tariff Schedules come into effect, October 1, 1992.

3. BC Gas will comply with the directions and conditions incorporated in the Commission's August 5, 1992 Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of August, 1992.

BY ORDER

John G. McIntyre
Chairman

/ssc

Schedule I

BC GAS INC.

UTILITY INCOME AND EARNED RETURN
for the year ending December 31, 1992

($000)

	Application P. 1-02-02	Difference	1992 Amended Exh. 171	Adjustments	Adjusted Balances
ENERGY VOLUME (TJ)					
Sales	170,522	(379)	170,143		170,143
Transportation	49,511	(376)	49,135		49,135
	220,033	(755)	219,278		219,278
Rate Increase %	3.00%		2.86%		-0.00%
UTILITY REVENUE					
Gas sales - Present rates	$618,131	($612)	$617,519		$617,519
Gas sales - Increase	17,645	(787)	16,858		16,858
Transportation - Pre. rates	12,724	(405)	12,319		12,319
Transportation - Increase	1,260		1,182		1,182
Additional deficiency					(18,063)
Total	649,760	(1,882)	647,878		629,815
Cost of Gas (inc. Gas Lost)	385,151	(234)	384,917		384,917
GROSS MARGIN	264,609	(1,648)	262,961		244,898
Operating and Maintenance	90,167	(701)	89,466		89,466
Property/ Fran./Sundry Tax	23,173	3	23,176	(107) [2]	23,069
Depreciation & Amortization	29,772	1,446	31,218	1,552 [3]	32,770
Other Operating Revenue	(15,017)	434	(14,583)		(14,583)
Commission Adjustments				(2,731) [1]	(2,731)
Total	128,095	1,182	129,277		127,991
Utility Income before Taxes	136,514	(2,830)	133,684		116,907
Income Tax - current	17,094	390	17,484		11,040
- deferred					33
- Lge Corp Tax	1,935	(158)	1,777		1,927
EARNED RETURN	$117,485	($3,062)	$114,423		$103,907
AVERAGE UTILITY RATE BASE	$1,030,567	($11,661)	$1,018,907		$1,007,826
RETURN ON RATE BASE %	11.40		11.23		10.31

[1] Adjustments per Appendix H $(549-3,280).
[2] Related Franchise Fee reduction to all adjustments at 0.593%.
[3] Additional amortization of deferred charges ($2,705-1,153) [Exh. 56A].

Schedule II

BC GAS INC.
Utility Rate Base for the Year Ending December 31, 1992

($000)

	Application P. 1-02-01	Difference	1992 Amended Exh. 171	Adjustments	Adjusted Balances
Plant in Service-Beginning	$1,079,981	$2,913	$1,082,894		$1,082,894
Additions	168,328	(44,296)	124,032	49,045 [2]	$173,077
Disposals	(8,026)	(364)	(8,390)		(8,390)
Plant in Service-Ending	1,240,283	(41,747)	1,198,536		1,247,581
Add - Intangible Plant	987	(150)	837		837
	1,241,270	(41,897)	1,199,373		1,248,418
Less - CIAC	(35,652)	832	(34,820)		(34,820)
- Acc. Depreciation	(132,100)	(1,074)	(133,174)		(133,174)
Net Plant in Service-End.	1,073,518	(42,139)	1,031,379		1,080,424
Net Plant in Service-Beg.	935,228	5,580	940,808		940,808
AVERAGE NET PLANT IN SERVICE	1,004,373	(18,280)	986,094		1,010,616
Less- Average Plant Adjustments				(34,248) [1]	(34,248)
Construction Advances	(1,690)		(1,690)		(1,690)
Work in Progress, No AFUDC	8,200		8,200		8,200
Unamortized Def. Charges	3,261	(1,057)	2,204	(1,723) [3]	481
Cash Working Capital	2,684	8,641	11,325		11,325
Other Working Capital	26,697	(965)	25,732		25,732
Deferred Income Tax	(12,958)		(12,958)	(368) [4]	(12,590)
AVERAGE UTILITY RATE BASE	$1,030,567	(11,661)	$1,018,907		$1,007,826

[1] Adjustment to average plant balances - Appendix H.
[2] Reinstate Surrey/Langley Proj. plus other adjustments $(50,145-1,100) - Appendix H.
[3] Revised average deferred charges per attached schedule.
[4] Deferred tax of Fort Nelson in Capital Structure.

BC Gas Inc. Summary of Unamortized Deferred Amounts

	A	B	C	D	E	F	G	H	I
1		Account	Recorded Bal.	Gross Additions	Less-Taxes	Net Additions	Amortization	Balance	Mid-Year Avg.
2			(12/31/91)					(12/31/92)	1992
3									
4	Metering Stations	179-45	18	0	0	0	-18	0	9
5	Furnace Grants	179-02	856	0	0	0	-856	0	428
6	Market Rebate Incentive								
7	Water Heater Grants	179-52	603	390	-171	219	-78	744	674
8	Commercial	179-13	0	178	-78	100	0	100	50
9	Space/Water Heating	179-13	0	45	-20	25	0	25	13
10									
11	NGV Conversion Grants	179-18/42	805	840	-368	472	-379	898	852
12	NGV Deferred Margin	279-08	-74	0	0	0	74	0	-37
13	Appliance Insurance Program	179-57	221	0	0	0	-221	0	110
14									
15	Revelstoke Deferred Fuel Cost	279-24	58	0	0	0	0	58	58
16	Conversion Grants-Revelstoke	179-42	-290	260	0	260	0	-30	-160
17	S.S.Tax on Aircraft	279-20	0	0	0	0	0	0	0
18									
19	Rate Design Costs-Phase A	179-58	125	162	-71	91	-216	0	63
20	Rate Design Costs-Phase B	179-58	0	0	0	0	0	0	0
21	Revenue Requirement Hearing	179-30	293	268	-117	151	-444	0	147
22	-amortized over five years			300	-132	168	-34	134	67
23									
24	Demand Side Management	179-63	0	0	0	0	0	0	0
25	Integrated Resource Planning	179-64	0	0	0	0	0	0	0
26	Gas Purchase Negotiation Cost	179-30	851	0	0	0	-851	0	425
27									
28	$0.41 Deferral	G-92-91	28	198	0	198	0	226	127
29	Deferred Cost of Gas-B.C.U.C.	G-92-91	578	1232	0	1232	0	1810	1193
30	Cost of Gas Rate 2501-B.C.U.C.	G-92-91	-495	-2435	0	-2435	0	-2930	-1713
31	Deferred COG Rate 10/12-B.C.U.C.	G-92-91	-217	-556	0	-556	0	-773	-495
32									0
33	VIA Credits		0	-1500	0	-1500	0	-1500	-750
34	Burrard Interruptible		0	-1160	0	-1160	0	-1160	-580
35	Deferred Capital Gain		0	-523	205	-318	318	0	0
36									
37	**Total Deferred Charges in Rate Base**		**3360**	**-2301**	**-752**	**-3053**	**-2705**	**-2398**	**481**
38									
39									
40	**Reference: Exhibit 56A**								

BC GAS INC.

Schedule III

CALCULATION OF INCOME TAXES ON UTILITY INCOME
FOR THE YEAR ENDING DECEMBER 31, 1992

($000)	Application P. 1-02-03	Difference	1992 Amended Exh. 171	Adjustments	Adjusted Balances
Earned return	$117,485	($3,062)	$114,423		$103,907
Deduct: interest on debt	(56,475)	2,371	(54,104)		(54,423)
Add:non tax deductible exp.	(628)	286	(342)	(669)[2]	327
Accounting income aft. tax	60,382	(405)	59,977		49,811
Deduct: timing differences	(39,657)	300	(39,357)	1,729 [1]	(37,628)
Add: Large Corporation Tax	1,935	(158)	1,777	150 [3]	1,927
Taxable income after tax	22,660	(263)	22,397		14,110
Income tax rate %(current)	43.000		43.840		43.840
1-current income tax rate	57.000		56.160		56.160
Deferred income tax rate					
Taxable income before income tax	39,754	127	39,881		25,124
Add: amount required to provide for deferred tax				59 [4]	59
TAXABLE INCOME	39,754	127	39,881		25,183
Income tax - current	17,094	390	17,484		11,040
- deferred				33 [4]	33
- Large Corp. Tax	1,935	(158)	1,777		1,927
TOTAL INCOME TAX	$19,029	232	$19,261		$13,000

[1] Per Appendix H.
[2] Per revised amortization of deferred accounts.
[3]

Net Plant in service	Sch. II	$1,080,424	
Other Rate Base items	Sch. II	(2,790)	
Total utility capital		1,077,634	$1,077,634
Non rate base items	P.1-13-05 rev.	200,520	
Total Capital		1,278,154	
Utility portion %		84.31%	
Utility portion deductible			(8,431)
Taxable Capitalization			1,069,203
Large Corp. Tax 0.2%			2,138
Less Surtax 0.84%			(211)
Net Large Corp. Tax			$1,927

[4] Fort Nelson remains on deferred income tax[Exh.4 T.5 P.4-02-03].
Timing difference = $75,000.

BC GAS INC.

Schedule IV

RETURN ON CAPITAL FOR THE YEAR ENDING DECEMBER 31, 1992

($000)

APPLICATION PAGE 1-02-04	Capitalization Amount	Adjustments	Capitalization Amount	Percentage %	% Average Embedded Cost	Cost Component %
Deferred Income Tax						
Long Term debt	429,317		429,317	41.66	10.798	4.50
Unfunded Short-term Debt	116,150		116,150	11.27	8.690	0.98
Preference Shares	98,637		98,637	9.57	8.967	0.86
Common Equity	386,463		386,463	37.50	13.493	5.06
	$1,030,567		$1,030,567	100.00		11.40

1992 AMENDED (Exh. 171)	Capitalization Amount	Adjustments	Capitalization Amount	Percentage %	% Average Embedded Cost	Cost Component %
Deferred Income Tax						
Long Term Debt	429,317		$429,317	42.14	10.798	4.55
Unfunded Short-term Debt	108,863		108,863	10.68	7.100	0.76
Preference Shares	98,637		98,637	9.68	8.901	0.86
Common Equity	382,090		382,090	37.50	13.493	5.06
	$1,018,907		$1,018,907	100.00		11.23

BCUC ADJUSTED BALANCES	Capitalization Amount	Adjustments	Capitalization Amount	Percentage %	% Average Embedded Cost	Cost Component %
Deferred Income Tax		$368	$368	0.04 [4]		
Long Term Debt	429,317	(29,337)	399,980	39.69 [3]	10.807	4.29
Unfunded Short-term Debt	108,863	67,395	176,258	17.49 [1]	6.350	1.11
Preference Shares	98,637		98,637	9.79	8.901	0.87
Common Equity	382,090	(49,507)	332,583	33.00 [2]	12.250	4.04
	$1,018,907		$1,007,826	100.00		10.31

[1] Short term debt rate reduced to 6.350%.
[2] Common equity component deemed at 33% and ROE at 12.250%.
Difference of 37.5 and 33% equity deemed as short debt.
[3] Forecast long term debt issues are treated as s/t debt and capital lease is excluded.
[4] Fort Nelson deferred income tax balance treated as no cost capital.

THIS AGREEMENT entered into as of the 1st day of July, 1989

BETWEEN:

HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF BRITISH COLUMBIA, represented by the Minister of Energy, Mines and Petroleum Resources

(the "**Province**")

OF THE FIRST PART

AND:

BC GAS INC., a body corporate amalgamated under the laws of the Province of British Columbia

("**BC Gas**")

OF THE SECOND PART

W H E R E A S:

A. BC Gas was formed by the amalgamation (the "Amalgamation") of Inland Natural Gas Co. Ltd. ("Inland"), B.C. Gas Inc. ("Mainland Gas"), Columbia Natural Gas Limited ("Columbia") and Fort Nelson Gas Ltd. ("Fort Nelson");

B. Prior to the Amalgamation, Mainland Gas was a "special company", as defined in the Hydro and Power Authority Privatization Act, S.B.C. 1988, (the "Privatization Act");

C. Pursuant to Section 33(2) of the Privatization Act and Order in Council 684, BC Gas is a "special company";

D. Prior to the Amalgamation, Inland held all of the issued and outstanding shares in the capital stock of Mainland Gas, and the Province and Inland entered into an agreement as of the 29th day of September, 1988 (the "Former Agreement"), pursuant to Section 38(3) of the Privatization Act;

E. The Minister of Energy, Mines and Petroleum Resources (the "Minister") desires that certain covenants of Inland in the Former Agreement be made, and carried out, by BC Gas;

F. The Minister has indicated a desire that the common equity component of the capital structure of the utility operations be not less than 35% (the "Equity Component") on or about October 1, 1991 and to achieve the Equity Component, a financing plan as set forth on Schedule A hereto, which was a schedule to the Former Agreement, was developed and is continuing to be implemented;

G. BC Gas intends that the customers of each of the former companies, namely Mainland Gas, Inland, Columbia and Fort Nelson (the "Former Companies") will, after the Amalgamation, continue to be charged separate natural gas rates;

H. It is the intention of the parties hereto that the natural gas rates of the divisions of BC Gas which were the Former Companies (the "Divisions") and of BC Gas will not be increased or altered in form until the end of September, 1991, except in the manner provided in an Order-in-Council No. 953/89 (the "Order-in-Council") granted under the Privatization Act and the Utilities Commission Act S.B.C. 1980, Chapter 60, (the "Utilities Commission Act") on the 28th day of June, 1989;

I. BC Gas expects that its revenue requirements included in natural gas rates for the customers of each of the Divisions will increase by less than three percent in the twelve month period following the end of September, 1991; and

J. BC Gas has identified various economic development initiatives in the Province of British Columbia, which it has indicated a desire to pursue, which initiatives are listed in

Schedule "B" attached hereto, which Schedule "B" was a schedule to the Former Agreement.

NOW THEREFORE, in consideration of the premises and mutual covenants and agreements contained herein, the parties hereto represent, warrant, covenant and agree as follows:

1.0 **RATE FREEZE**

BC Gas will not apply under the Utilities Commission Act or the Privatization Act to have the natural gas rates in the areas served by the Divisions increased or altered in form until October 1, 1991, except in the manner provided in the Order in Council.

2.0 **FEASIBILITY STUDIES**

On or before October 1, 1991, BC Gas will complete the feasibilities studies listed in Schedule "C" attached hereto, which Schedule "C" was a schedule to the Former Agreement, and will advise the Minister with respect to its conclusions relating to those studies.

3.0 **MANAGEMENT REVIEW**

3.01 On or about October 1, 1992 and every four years thereafter, the Board of Directors of BC Gas will appoint an independent consultant (the "Consultant") to review and report on the management of BC Gas.

3.02 BC Gas will permit the Consultant to review such documents and interview its employees, officers and auditors, to the extent reasonably required, to allow the Consultant to prepare its report properly.

3.03 BC Gas will permit the Consultant to prepare a summary of its report for inclusion in the annual report to shareholders of BC Gas, which summary will state that shareholders may obtain a copy of the report at BC Gas' reproduction costs therefor, from the offices of BC Gas.

4.0 NOTICES

Any notice or other communication provided for herein or given hereunder to a party hereto shall be in writing and shall be delivered by double registered mail, or in person to the individual listed below:

(a) to the Minister:

Minister of Energy, Mines and Petroleum Resources
Parliament Buildings
Victoria, B.C.

(b) to BC Gas:

23rd Floor
1066 West Hastings Street
Vancouver, B.C.
V6E 3G3

Attention: President

or such other address with respect to a party as such party shall notify the other in writing as above provided. All notices shall be deemed made upon actual notification or mailing as provided for above, whichever shall occur earlier; provided, however, that notice by mailing shall not be deemed to have been made until delivered.

5.0 COMPLETE AGREEMENT

This Agreement and the schedules attached hereto contain the complete agreement between the parties hereto with respect to the transaction contemplated hereby and supersede all prior agreements among the parties with respect to such transactions, but does not affect any Orders in Council of the Lieutenant Governor in Council. There are no restrictions, promises, representations, warranties, covenants, indemnities, or undertakings by the parties other than those expressly set forth in this Agreement and the Schedules. This Agreement may be amended, modified or terminated only by written instrument signed by all parties hereto and subject to the requirements of the Privatization Act.

6.0 GOVERNING LAW

This Agreement shall be construed and enforced in accordance with the laws of the P·ovince of British Columbia.

7.0 GRAMMATICAL

All necessary changes required to make the provisions of this Agreement apply in the plural sense where necessary will in all instances be construed.

8.0 HEADINGS

The descriptive headings of the paragraphs and subparagraphs hereof are inserted for convenience only and do not constitute a part of this Agreement.

9.0 COUNTERPARTS

This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which shall constitute but one instrument.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the date and year first above written.

SIGNED on behalf of **HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF BRITISH COLUMBIA** by the Minister of Energy, Mines and Petroleum in the presence of:

Witness

Minister of Energy, Mines and Petroleum Resources

THE CORPORATE SEAL OF **BC GAS INC.** was hereunto affixed in the presence of:

C/S

Authorized Signatory

Authorized Signatory

WPD-H/MG/8A-4

SCHEDULE A

PROPOSED FINANCING PROGRAM 1988 - 1993

		Short-term Debt	Vendor Debt	Long-Term Debt	Vendor Equity	Preferred Shares	Common Equity
1988	July	$ 25					
	October	175	$300		$150		$ 75
1989	April	(100)				$100 (1)	
1990	October		(75)	$ 75			
1991	October		(75)	75	(150)		(150)
1992	October		(75)	75			
1993	October		(75)	75			
		$100	$ -	$300	$ -	$100	$225

(1) The Preferred Shares may be issued in two tranches:

$50 million on or about July 30, 1989, and
$50 million no later than March 31, 1990.

SCHEDULE "B"

ECONOMIC DEVELOPMENT INITIATIVES WHICH INLAND (NOW BC GAS INC.) HAS IDENTIFIED AND WISHES TO PURSUE SUBJECT TO ECONOMIC AND FINANCIAL VIABILITY.

Project	Capital Expenditures (1988 - 1993)	Status
Underground Gas Storage Fraser Delta	$75 million	- drilling and testing ongoing
East Kootenay Link Expansion	$83-168 million	- construction planned for 1990/91
Petrochemical Plant in Southwestern B.C.	$250 million	- major feasibility study to commence with partners
NGV Cylinders	$3.2 million	- joint venture agreement pending
Flexible House Gas Piping	$2.2 million	- agreement with sponsor
NGV Home Compressors	$5 million	- market research completed - joint venture agreement pending
Gas Fireplace Assembly Plant	$2 million	- feasibility study ongoing

SCHEDULE "C"

INITIATIVES WHICH INLAND (NOW BC GAS INC.) HAS IDENTIFIED AND IS COMMITTED TO UNDERTAKE.

Initiative/Project	Commitment
Feasibility Study for Petrochemical Plant (Southwestern B.C.)	$500,000
Feasibility Study for Locating Gas Fireplace Assembly Plant in B.C.	$500,000
Promotion of B.C. as Location for Gas Consuming Industries	$250,000 (subject to matching formula of Ministry of Economic Development, and major Government)
Local Supplier Preference	5 year goal to increase purchases from B.C. based suppliers to 80% of requirements of B.C. Gas Institute a purchasing awareness program for B.C. suppliers
Local Professional/Consulting Community	Preferentially utilize B.C. based professional and consulting services.

BC Gas Inc.
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Vancouver, British Columbia
Canada V6E 3G3

Tel (604) 443-6607
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DAVID M. MASUHARA
VICE PRESIDENT
LEGAL AND REGULATORY AFFAIRS

June 10, 1992

BC Gas

BRITISH COLUMBIA UTILITIES COMMISSION
RECEIVED
JUN 11 1992
COMMISSION SECRETARY'S OFFICE

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: R.J. Pellatt
Commission Secretary

Dear Sirs:

Re: Information Request - Revenue Requirement Application

At transcript page 3685 Mr. Fulton asked Mr. Kadlec if he was prepared to file the update report by BC Gas to the Ministry of Energy Mines & Petroleum Resources on economic development initiatives referred to in Schedule B of the Resale Restriction Agreement. Mr. Kadlec indicated that BC Gas would. In reviewing this matter, BC Gas discovered that the report contained confidential commercial information including references to material transactions involving other publicly traded companies. The report was submitted on that basis to the Ministry.

In discussing this fact with Mr. Kadlec, he advised the writer that he had forgotten that the report had been submitted on a confidential basis and that the report did contain sensitive and confidential information. Since the Ministry in its letter of June 3, 1992 has indicated that it is leaving the level of disclosure of the report to BC Gas, we are submitting a summary of the report in respect of the Schedule B items. We believe this provides the information requested by Commission Counsel as it provides a status report and preserves the confidentiality which companies require if they are to maintain frank communications with the Ministry on commercial matters.

Yours very truly

BC GAS INC.

Per:

David M. Masuhara

cc: P. Ostergaard, Assistant Deputy Minister
J241 C. Weafer, Owen, Bird

BC Gas Inc.

ECONOMIC DEVELOPMENT INITIATIVES

S U M M A R Y

BC GAS INC. - ECONOMIC DEVELOPMENT INITIATIVES REPORT SUMMARY

INITIATIVE #1: Underground Gas Storage/Local Gas Supply

- BC Gas participated in the Anderson Inquiry into Fraser Valley Petroleum Exploration which had been established by Order in Council No. 695/90. The report stated: "The conclusions that emerge from the investigation are that the risks of exploratory drilling are slight, and the benefits, from the energy security and environmental points of view may be considerable." *(Source: Report of the Commission of Inquiry into Fraser Valley Petroleum Exploration - January 1991, page 1).*

- On February 1, 1991, the Energy Minister announced that there would be "no drilling for underground gas storage in the Fraser Valley".

- On July 4, 1991, the Energy Minister announced that a gas exploration well would be allowed in East Delta.

- On July 5, 1991, Order in Council No. 1223/89 was revoked and the responsibility for approval of future exploration work by BC Gas was transferred to the British Columbia Utilities Commission (BCUC).

- In September 1991, the Conoco/Dynamic/BC Gas consortium drilled the Mud Bay well in East Delta. This well was drilled to the depth of 1701 m and failed to encounter significant volumes of natural gas.

  Conoco, the operator of the well, noted that approximately $250,000 was spent on local contractors and services associated with that well. BC Gas estimates that others have spent approximately $4.5 Million on exploration in the Fraser Valley in addition to the funds expended by BC Gas.

- In October 1991, Inland Gas & Oil Corp. (a wholly owned subsidiary of BC Gas Inc.) participated with a consortium that includes Cascade Natural Gas, the nearest Washington State gas utility, in the Terrell well spud near Ferndale, Washington. The well was completed in early November 1991 and was drilled to a depth of 6010 feet.

INITIATIVE #2: East Kootenay Link Expansion

- BC Gas has performed a detailed feasibility study of the East Kootenay Link (EKL) expansion project. The analysis was done by BC Gas, Alberta Natural Gas Company and outside Consultants.

- Indications are that the EKL expansion option is technically feasible and economically viable but not as attractive as underground storage in the lower Fraser Valley.

INITIATIVE #3: Petrochemical Plant

- On March 22, 1990, BC Gas made a presentation to B.C. Government on its role in the development of a petrochemical industry in B.C..

INITIATIVE #4: NGV Cylinder Plant

- BC Gas pursued a joint venture arrangement with an Italian cylinder manufacturer for manufacturing and distribution of NGV cylinders in Canada & United States and was unsuccessful at developing a mutually acceptable arrangement.

- BC Gas was approached by a B.C. based company to join a consortium to manufacture a fibre wrapped aluminum cylinder. In response, BC Gas engaged Price Waterhouse Management Consultants to review the proposed business plan and perform a general feasibility study on NGV Cylinder manufacture in B.C.

  The study recommended not proceeding in the joint venture due to insufficient local infrastructure for fibre wrapped aluminum cylinders. The report did assist in revealing a California based company that had the ability to supply competitively priced cylinders for the utility's NGV conversion program. This resulted in BC Gas entering into a NGV cylinder purchase arrangement which meets the utility's needs, in the near term.

  The Price Waterhouse study indicated that a B.C. based all-composite manufacturer could be viable but did not perform a detailed analysis of such a venture.

- BC Gas continued testing of ABB Plast cylinders at the Powertech laboratory. The program was expanded to include cylinders from H.M. International of France. The testing program is scheduled to be completed in March 1992. The results of these tests to date indicate that all-composite cylinder technology is promising but has not yet reached the stage of commercial production. As a result BC Gas is no longer intending to take these cylinders through to Canadian certification, at this time.

- BC Gas has had several discussions with a local industrial plastics company that is interested in pursuing the all-composite cylinder design. This company is interested in developing a commercially viable technology and has the necessary manufacturing equipment.

INITIATIVE #5: Flexible House Piping

- The future for this product remains uncertain for several reasons.

  - Existing substitutes, such as copper tubing, have managed to penetrate the market despite their inherent disadvantages (ie. work hardening and difficulty in being pulled long distances through floors and walls).

- Existing piping technology has not appeared to be a significant barrier to natural gas appliance installation. Furthermore, the cost of the natural gas piping has not been significant enough to deter investment in additional appliances relative to other considerations (such as the relative cost of gas or other costs associated with installation).

- Corrugated Stainless Steel Tubing (CSST) has evolved as another substitute for house piping. Gaz Metro in Quebec has been a leader in promoting the use of this product.

- BC Gas Inc. continues to monitor the status of current house piping technology through involvement with industry associations such as the Canadian Gas Research Institute (CGRI) and the Canadian Gas Association (CGA).

<u>INITIATIVE #6: NGV Home Compressors</u>

- FuelMaker Corporation (one-third owned by BC Gas Inc.) has sold over 1,500 Vehicle Refuelling Appliances (VRAs) worldwide. FuelMaker has established itself as the world leader in home VRA market as well as in small commercial fleet applications.

- VRA sales have been made to nine utilities in Canada, ten utilities in the United States as well as to utilities in Europe and Australia. In addition, approximately 50 other utilities have purchased VRAs as demonstration models in anticipation of further purchases.

- Research and development is on-going with this activity focused on lowering production costs as well as technical improvements to the C-3 model.

- In September 1990, the decision was made to expand the production/assembly facility at Sulzer Canada's facility in Rexdale, Ontario. This decision was taken in order to minimize distribution costs as eastern Canadian Utilities represent the largest buying group of VRAs.

- In August 1991, the Minister of Energy Mines and Petroleum Resources wrote BC Gas to inform that the Provincial Government "wishes to remain neutral towards various alternate transportation fuels (ATFs)" indicating that subsidies for NGV related activities in B.C. would not be forthcoming.

- In October 1991, the Federal Ministry of Energy Mines and Resources (EMR) announced a continuation of the Marketing Development Incentive Program (MDIP) for all provinces <u>except</u> British Columbia. This program effectively reduces the cost of a VRA to the consumer by $1,000 as well as provides $500 for vehicle conversion to natural gas.

INITIATIVE #7: Gas Fireplace Assembly Plant

- BC Gas ended negotiations with the Dutch gas fireplace manufacturer mentioned in the last report. The Dutch firm was not comfortable with setting up a North American assembly plant that may have the potential of taking jobs from their main facility in Holland. They were particularly concerned with the Dutch government's reaction and with quality control issues.

- BC Gas examined a local fireplace manufacturer for possible equity investment and concluded that this may not be the most beneficial means to participate in natural gas fireplace manufacturing.

- During this period, it became evident that a viable gas fireplace industry was developing in British Columbia with increased availability of products and increased competition amongst industry participants, both local and out of province. This led BC Gas to conclude that direct participation in this industry is not appropriate at this time.

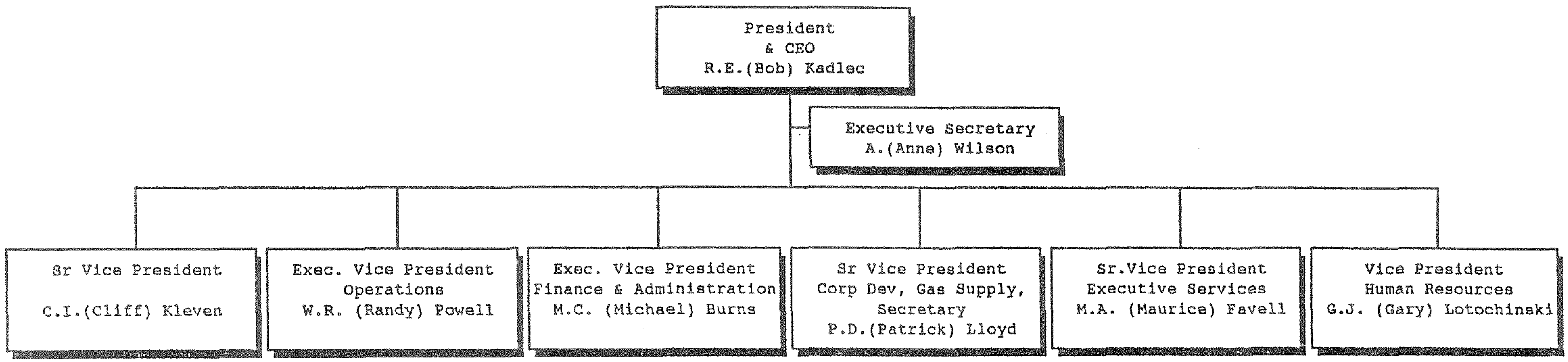
  Existing wood burning appliance manufacturers are now investing into gas burning appliance technology ensuring that the industry will continue to develop over the near term.

BC GAS INC. - ECONOMIC DEVELOPMENT INITIATIVES REPORT SUMMARY

1988 - 1993 ESTIMATED CAPITAL EXPENDITURES ($ Million)

	1 Original Objective	2 Last Report	3 This Report	4 Total to Date	5 Anticipated Future
#1 Underground Gas Storage/ Local Gas Supply	75	1.73	5.33	7.06	3.3
#2 East Kootenay Link Expansion	83 to 168	nil	nil	nil	uncertain
#3 Petrochemical Plant	250	nil	nil	nil	uncertain
#4 NGV Cylinders	3.2	nil	nil	nil	uncertain
#5 Flexible House Gas Piping	2.2	nil	nil	nil	uncertain
#6 NGV Home Compressors	5.0	3.5	2.0	5.5	1.0
#7 Gas Fireplace Assembly Plant	2.0	nil	nil	nil	uncertain

BC GAS
EXECUTIVE



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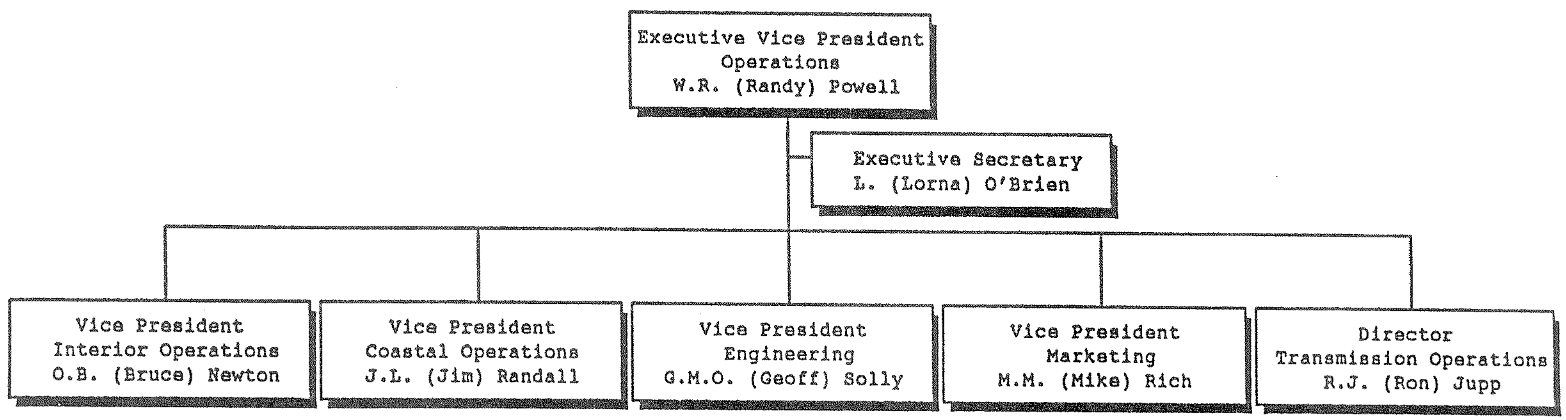
APPENDIX C

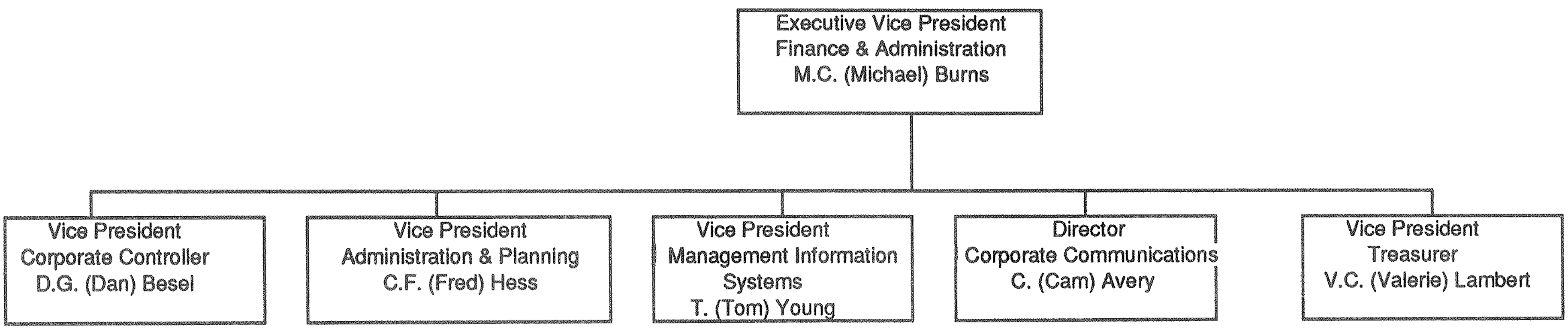
APPENDIX D

BC GAS
UTILITY EXECUTIVE



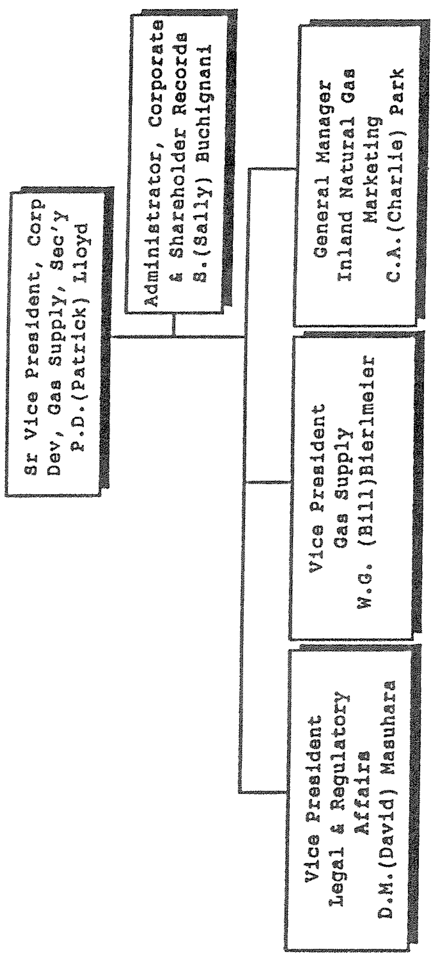
APPENDIX E

BC GAS
FINANCE & ADMINISTRATION



APPENDIX F

BC GAS
CORPORATE DEVELOPMENT AND GAS SUPPLY



FARRIS, VAUGHAN, WILLS & MURPHY

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700 WEST GEORGIA STREET
VANCOUVER, B. C.
V7Y 1B3

REPLY ATTENTION OF: Elizabeth J. Harrison

DIRECT DIAL NO. (604) 661-9367

OUR FILE NO. 00019-630

March 11, 1992

BC Gas Inc.
P.O. Box 12503
23rd Floor
1066 West Hastings Street
Vancouver, B.C.
V6E 3G3

Attention: Mr. David Masuhara

Dear Sirs:

Re: Utilities Commission Act (British Columbia) - Section 57 and Commercial Installment Lease Agreement with Toronto Dominion Leasing Ltd. dated May 30, 1990

You have asked our advice as to whether or not BC Gas Inc. (the "Company") is required pursuant to Section 57 of the Utilities Commission Act (the "Act") to request the approval of the British Columbia Utilities Commission (the "Commission") with respect to the entering into by the Company of a commercial lease agreement with Toronto-Dominion Leasing Ltd. dated May 30, 1990 (the "Lease").

Pursuant to the Lease the Company has agreed to lease computer software programs from Toronto Dominion Leasing Ltd. for a period of 96 months upon payment of $111,229.00 per month. The Lease provides that the Company has the right to purchase the leased equipment at the end of 96 months for $100.00. There are provisions contained in the Lease relating to the events of default and the consequences thereof. We also understand that Peat Marwick Thorne has opined that the Lease is a capital Lease for the purposes of the consequences thereof and financial statement disclosure of the Company.

LETTE664.EJH
31192/1202

Section 57(1) of the Act reads as follows:

> "1. In this section, "security" means any share of any class of shares of a public utility or any bond, debenture, note or other obligation of a public utility, whether secured or unsecured."

The first issue to be considered is whether or not the Lease qualifies as a security. Clearly the Lease is not a share, bond, debenture or note. Therefore the question is: "Is the Lease an "other obligation"?"

Initially, the operative words to be looked at is the word **"means"** in the definition. The use of the word "means" as opposed to "includes" makes the definition more restrictive than it would otherwise be. Therefore the definition merely encompasses those items defined as a security specifically in Section 57(1).

In interpreting this statute and in particular this section, the *ejusdem generis* rule must be applied. The description of the rule contained in Cote's - The Interpretation of Legislation in Canada states that "a generic or collective term that completes an enumeration of terms should be restricted to the same generis as those words, even though the generic or collective term may ordinarily have a much broader meaning". Certain conditions to the application of the rule are required to be satisfied as follows:

1. The general expression must be preceded by several specific terms;
2. The general term should usually follow rather than precede the specific term; and
3. The specific terms must have a significant common denominator to be considered within one given category.

Based on the foregoing, one must look to the words in Section 57(1) which states that a security means "any share, bond, debenture, note or other obligation". Shares, bonds, debentures and notes are all very specific terms, and they are specific terms that have a common denomination -- that is they are all instruments commonly known as securities which are issued to evidence an equity interest or an interest in debt or evidence of indebtedness and are usually tradeable or negotiable. The phrase "other obligations" obviously has to refer to obligations of like character to shares, bonds, debentures or notes and could be read to be **other obligations which would generally be considered a security.** The words "other obligations" is very broad and can include any contractual commitment made by the utility. As this would cover all obligations and all liabilities of the Company the very general character of other obligations must and is required to be read in conjunction with the words "shares, bonds, debentures and notes". On this basis, the term "other obligations" has to be given a narrower meaning and be applied to obligations in the nature of a security intended for sale to the public, even if the public is a smaller group of public and the term does not include a transaction which may be of a private character.

It has also been stated that the use of the *ejusdem generis* rule is ancillary and is subject to yield to contrary indications of legislative intent. In this regard we reviewed the prior history of Section 57. Prior to 1982 the relevant provision of the Act was as follows:

> "A public utility shall not issue a **security or other evidence of indebtedness** payable more than one year from its date, without first obtaining the approval of the Commission".

In the 1982 the stated purpose for the amendment to Section 57 and the extension provided therein was "to apply to all securities of a public utility". Although we have reviewed the Hansard materials on the bill relating to this amendment we find no further information in this regard. Clearly the legislature intended to cover "securities only" by the amendment.

Therefore it is our opinion that the words "other obligations" must be read in context of the definition of Section 57(1) and not in the broadest sense. As "an obligation" therefore has to be "a security as a security is generally known", the Lease does not fit within this definition.

In addition Section 57(1) is a definitional section. The operative provisions relating to Section 57 are contained in Section 57(2) which reads as follows:

> "(2) Except in the case of a security evidencing indebtedness payable less than one year from its date, a public utility shall not **issue** a security without first obtaining approval of the Commission under this Section and whereas Section 61 applies, under that Section."

The operative word in this Section which is the limiting section on the Company is the word "issue". The restriction is that the Company may not issue a security except upon compliance with this Section. While there has not been any judicial interpretation of the word "issue" which is on point, a review of the following definitions should be noted:

- in Black's *Law Dictionary* (5th ed.) "issue", with respect to securities, is defined as referring "to the act or process of offering stocks or bonds for sale to public or institutional investors"

- in Webster's *Third New International Dictionary*, "issue", among other ways, is defined as "to cause to appear or become available by officially putting forth or distributing or granting or proclaiming or promulgating"

- in *The Shorter Oxford English Dictionary*, "issue", among other ways, is defined as "the action of sending or giving out officially or publicly; an emission of bills of exchange, notes, bonds, shares, postage-stamps, etc."

The Lease in question is a lease of and on the form of Toronto Dominion Leasing Ltd. It is not a security "issued" by the Company. It is a contract which has been entered into by the Company but the Company has not created the instrument or taken any act to cause the issuance of the Lease document. The Toronto Dominion Leasing Ltd. is the "lessor" or "grantor" and is the party issuing same.

Accordingly based on the definition of security and on the operative words of Section 57(2) we are of the opinion that the entering into by the Company of the Lease did not require the prior approval of the Commission pursuant to the Section 57 of the Utilities Commission Act.

Yours truly,

FARRIS, VAUGHAN, WILLS & MURPHY

Per:

Elizabeth J. Harrison

EJH
Encl.

LETTE664.EJH
31192/1202

BC GAS INC.
1992 Revenue Requirement Adjustments *
$(000)

Appendix H (Page 1)

Particulars	Reference	Rate Base Average	Rate Base Additions	Oper. Costs	CCA	Cap. Struct.
	(Section/Exh.)	Average	Additions			
RATE BASE						
Inflation at 3.5%	2.5					
Material & services	Exh.7 T.24 I.3		(647)			
Capital leases	3.3.3					
GMS lease FIS	Exh. 171	(7,000)		1,336		(7,000)
Depreciation		875	875	(875)		
Vehicles		(7,933)	(2,142)	865		
Depreciation		2,252	1,091	(1,091)	(1,173)	
Aircraft	3.6					
Capital cost	Exh. 171	(1,619)				
Depreciation		162	81	(81)	(285)	
Training, Display Materials	3.9					
Capital cost	Exh. 171	(882)	(572)	572		
Depreciation/CCA			177	(177)	(271)	
Plant Additions -13 month average (Exh.7, T.24, P.2)	3.10	(20,103)	51,282			
Total Rate Base Related Adjustments		($34,248)	$50,145	$549	($1,729)	($7,000)
OPERATING COSTS						
Inflation at 2.5%	2.5					
Material and contracts $(542,293-361,529)	Exh.7 T.24 I.3			(180)		
Manpower	5.6					
80*$50,000=$4 million	Exh. 5 T.2					
70% expense 30% capital (% derived from Exh.5 T.2 I.1.2(a)(iv) P.26.1)	P.4.2 Rev.		(1,200)	(2,800)		
Management Salaries	5.7					
Increase at 3.5% $(164,655+258,996-75,000) = $349,000	Exh.7 T.24 I.3		(165)	(184)		
Executive Compensation	5.8.4					
$(189,745-153,300)*17=620,000	Exh.5 Tab 2					
70% expense 30% capital	P. 4.2 Rev.		(186)	(434)		
Donations allowed $100,000	5.9			(103)		
Total			(1,551)	(3,701)		
Actual Operating Cost Related Adjustments			($1,100)	($3,280)		

* Other than deferred charges and capital structure adjustments.

BC GAS INC.
1992 Revenue Requirements

Appendix H (Page 2)

MANPOWER

	1989	1992	CHANGE
Customer Growth [Exh. 5 T.2 I.1.2(a), Exh.41]	554,859	615,131	10.86%
Employee growth [Exh. 5 T.2 I.1.2(b) P.4.2 Rev]	1,290	1,583	
Repatriated Service[Exh. 62]	--	(73)	
Equivalent # of employees - no repatriation	1,290	1,510	
Increase as customer growth at 10.86% (1,290*1.1086)		1,430	
Excess No. of employees		80	

O & M COSTS PER CUSTOMER

	1991	1992
O & M Costs Exh. 38/171	$79,474,000	$89,466,000
Number of Customers Exh.5 T.2,I.1.2(a) P.18.3/Exh. 41	595,588	615,131
O & M costs/customer	$133.44	$145.44
Increase at 5%		$140.11
Excess O & M costs/customer		$5.33
Excess O & M costs (615,131*5.33)		$3,278,648