IN THE MATTER OF the "Utilities Commission Act" S.B.C. 1980, Chapter 60

and

IN THE MATTER OF an Application by BC Gas Inc. To Amend its Schedule of Rates

Rate Design Phase B

Volume 1

Application

April 1993

BC Gas

BC Gas Inc.
1111 West Georgia Street
Vancouver, British Columbia
Canada V6E 4M4

Tel (604) 443-6607
Fax (604) 443-6789

David M. Masuhara
Vice President
Legal and Regulatory Affairs

BC Gas

VIA COURIER

April 15, 1993

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: R.J. Pellatt
Commission Secretary

Dear Sirs:

Re: 1993 Rate Design - Phase B Application Volumes 1 and 2

Pursuant to BCUC Order No. G-15-93, BC Gas files herewith 10 copies of its Rate Design Phase B Application Volumes 1 and 2. This application does not address issues raised in the recent Commission decision regarding the Review of Domestic Natural Gas Supply Rules. There has not been sufficient time to assess and analyze its impact on our rate design. It is our hope to be able to respond prior to the commencement of the hearing scheduled for July 5, 1993.

One copy of all materials will be filed upon registered intervenors and interested parties in the hearing.

Yours very truly,

BC GAS INC.

Per:

David M. Masuhara

Revised June 4, 1993

TABLE OF CONTENTS

Volume 1

Revised June 21, 1993

TABLE OF CONTENTS

Volume 2

BC GAS INC.

VOLUME 3

WRITTEN EVIDENCE

British Columbia Utilities Commission
Staff Information Request No. 1 - Part A
May 25, 1993

Volume Two Vol 4 Tab

Tab 2 FDC Studies

1. Ref: Page 4 A1

With regard to the assignment of the East Kootenay Link and the Lower Mainland LNG storage facilities to the Lower Mainland and Inland Divisions, how were the ratios of 79 percent and 21 percent derived?

What is the magnitude of this adjustment, i.e. how much does the adjustment increase the revenue requirement of each division?

2. Ref: Page 4 A2

Please explain in more detail, possibly with an example, how the demand allocators for the Inland Division industrial captive and bypass customers were weighted by transmission distance? Are these the only customers that were treated this way? If so, why was the method not applied to other customers within the Inland division or to customers within other Divisions?

3. Ref: Page 5 A3

Why did the company prepare a special study to annualize the Cranbrook lateral?

4. Ref: Page 6, Lines 28 - 29 A4

The Application seems to indicate that gas supply administration expenses are classified as commodity-related cost in the FDC studies. Are gas supply administration expenses included in the gas supply cost component of customer bills?

5. Ref: Page 7, Line 32 A5

Please confirm that the ex ante peak day refers to the forecasted peak day for the test year 1992 and not the actual peak day in 1992. How do the ex ante peak day demands (by customer class) compare with the actual demands on the peak day in 1992.

6. Ref: Page 5 A6

For accounting purposes, please describe the factors that would cause a plant expenditure to be defined as distribution rather than transmission.

7. Does BC Gas have a written policy that guides company staff in making gas supply purchase decisions? If so , please provide a copy of the policy. Please provide BC Gas's supply planning criteria for meeting gas demands of the various classes of service. A7

8. Ref: LM COS, Section 2, Page 2.2 A8

Please explain the allocation of Account 465, Mains.

9. Ref: LM COS, Section 2, page 6.0 A9

Please explain how cash working capital was estimated.

10. Ref: LM COS, Section 6.0, page 1.0 A10

Please explain how gas supply costs were segregated into demand, commodity, and customer components?

11. Ref: LM COS, Section 5, Page 2.2 A11

Please explain how administrative expenses were allocated.

12. Ref: LM COS, Section 1, page 1.1 A12

How do the revenue/cost relationships compare to the results of previous studies.

13. Ref: LM COS, Section 1, Page 1.1 A13

BC Gas has assumed that the rate of return on rate base is the same for all classes of customers. If BC Gas had assumed that the rate of return on rate base varied by customer class, for example to reflect differences in risk, how would this have changed the results of the FDC study?

Tab 3 LRIC Studies

1. Ref: Page 1 A14

Why has BC Gas focussed on the incremental cost of serving new customers rather than on the cost of providing existing customers with additional service.

2. How does BC Gas plan to use the LRIC study outside of this rate application? A15

3. Can the costs associated only with new customers be extracted from the study to determine costs applicable to existing customers. If so, what elements should be extracted? How do the graphs shown in Vol 1, Tab 8 change? A16

4. How are the results of the LRIC study used in evaluating DSM options. A17

5. Ref: Page 5 A18

   Is BC Gas asking the Commission to consider allocation to customer classes based on marginal costs? What is BC Gas's position on this issue?

6. Did BC Gas review any studies that estimated the marginal cost of peak day demands, seasonal demands, and gas supply (commodity)? If so, what led BC Gas to follow a different approach? A19

7. Ref: Vol 1. Tab 6, Page 2; Vol 2, Tab 3, Page 7: Summary Tables A20

   In the description of the LRIC study, the Application states that "Incremental Gas Supply costs for 1992 through 2006 were derived using the Gas Supply Planning model". Yet the Detailed LRIC Summary Tables found under Tabs 3A-3C indicate that the cost of gas was not used in the analysis. Moreover, at Tab 6, p.2, BC Gas states that the LRIC study indicates that residential margin costs are shown,

   Please explain where the incremental gas supply costs were used in the rate design process, if at all. If not, why were they were not used?

British Columbia Utilities Commission
Staff Information Request No. 1 - Part B
May 25, 1993

Vol. 4
Tab

General

1. Please explain how the withdrawal of the 1993 Revenue Requirements Application affects the Rate Design Application. B1

2. Please provide the revenue to cost relationships for each customer class which result from the proposed rate design changes. B2

3. How do the Cost of Service study (Peak Responsibility) results relate to the ultimate rate design proposal made for each rate schedule? If possible, please provide working papers relating the cost of service study results to the rate proposal. To the extent that the proposals are not precisely derived from the cost of service study, please explain why. B3

Volume 1

Tab 2 Application

1. Ref: Page 8

BC Gas states that it is seeking approval for a public process "to facilitate an understanding of the proposals, and to develop a specific list of issues and concerns to be more fully addressed in the public hearing". Where in the Application is this public process described? When does BC Gas plan to undertake such a process? How would this process be integrated with other public processes proposed by BC Gas? B4

Tab 3 Application Outline

1. Ref: Page 1, Lines 27 - 29

The implementation of basic monthly charges that improve the recovery of fixed costs will tend to make the commodity portion of the bill go down and decrease the incentive to conserve. Has this been considered? Have any social costs associated with the burning of gas (variable social costs) been considered? If so which ones? B5

2. Ref: Page 5, Lines 1 - 4

The Application states that while a speedy move to implement rate changes that improve revenue to cost ratios would be fair to those customers receiving the benefit, gradualism favours a phasing-in over time of any significant shifts. This would seem to imply that BC Gas sees the current proposals as a first step B6 towards future rate design changes or revenue shifts. Does BC Gas have plans in this regard? If so, what are they?

3. Ref: Page 6, Lines 22 - 28 and Page 13, Lines 25 - 29 B7

The Application states that the combination of the higher basic charge and uniform (i.e. flat) commodity charge will lead to more stable revenues.

For each customer class as appropriate, please indicate what percentage of revenues comes from basic charges under the current rate design and what percentage of revenues will come from basic charges under the proposed rate design.

Please indicate the typical pattern of revenues received by BC Gas under the current rate design and the expected pattern of revenues under the proposed rate design. If possible, please provide the information by customer class.

4. Ref: Page 7, Lines 1 - 8 B8

The Application states that over 90% of residential class revenues are consumption related and only 9% are related to the fixed portion of the rates while 92% of BC Gas's costs, exclusive of the gas costs, are fixed and the rest are variable.

(a) Please indicate the type of costs, exclusive of gas costs, that are fixed.

(b) How would the ratio of fixed to variable costs change if gas costs were included?

(c) Would BC Gas agree that over the long-run most of its costs are not fixed? If not, why not?

(d) If BC Gas agrees that over the long-run most of its costs are variable, does increasing the monthly charge to consumers send an inappropriate market signal?

5. Ref: Page 7, Lines 25 - 27 B9

The Application states that BC Gas reviewed the monthly charges of other gas utilities for residential customers and found that their proposed basic charge is in line with the others.

Please provide the basic monthly charges of the utilities which BC Gas reviewed.

Please indicate the block structure of these utilities as well i.e. single block, declining block, inverted block.

6. Ref: Page 7 and Tab 6, page.7 B10

Has BC Gas considered an inclining block structure for residential rates? If so why was this approach rejected? Has BC Gas considered the effect of load factor on gas supply costs in rejecting inverted block rates?

Has BC Gas examined whether inclining block or seasonal rates could be designed to reflect the seasonal variability of residential demand and the resulting differences in the demand portion of residential costs at different times of the year? If so, would BC Gas see this as an example of 'sending appropriate signals' (Tab 6, p.7, l.14)

7. Ref: Page 8, Lines 6 - 10 B11

Please explain how the proposed commercial rate design facilitates competitiveness through gas costs as opposed to utility margin.

8. Ref: Page 8, Lines 16 - 21 B12

When will a separate gas cost allocation for classes in the Columbia Division be available?

9. Ref: Page 8, Lines 21 - 27 B13

Please indicate how the proposed commercial rate structure compares to the commercial rate structures of other Canadian gas utilities with respect to size of basic charge, single block structure, division into over and under 2000 GJ

10. Ref: Page 9, Lines 8 - 12 B14

The Application states that most general service customers will see a lower overall price for gas under the proposal, due to the lower commodity cost of gas, but the delivery charge (excluding the cost of gas) in some instances is increasing.

How many general service customers are likely to see their total bills increase rather than decrease?

11. Ref: Page 9, Lines 16 - 35 B15

With respect to interruptible sales and interruptible service, please indicate why BC Gas is crediting $0.41 per gigajoule to a deferral account when the preceding text indicates the difference in margin between interruptible sales and service is $0.36 per gigajoule.

Please show the effect (either in percentage or in dollars) of the proposal to recover the revenue loss of $0.41 per gigajoule.

12. Ref: Page 10, Line 37 B16

This sentence appears to be incomplete. Please provide the missing words.

13. Ref: Page 12, Lines 3 - 5 B17

Please indicate the process BC Gas intends to follow to obtain customer input regarding industrial tariff terms and conditions.

Tab 5 Regulatory Consolidation

1. Ref: Page 1 B18

The Application states that "Consolidation does not seek to adjust the historical rate differentials...What is meant by consolidation is that the increases in the overall revenue requirement occurring as a result of changes since 1992 would be spread evenly to all customers as a percentage of gross margin."

(a) Please confirm that postage stamp margin is not a prerequisite for consolidation.

(b) Please demonstrate that historical differentials are maintained if rate increases are spread evenly to all customers as a percentage of gross margin.

(c) Please confirm that divisional rate base and cost of service can be reconstructed should they be required in future.

(d) Please elaborate on the following statement (Vol 1, Tab 5 Appendix C, page 5)

"Regulation on a consolidated basis would require the BCUC to approve all of the components for determination of the revenue requirement on the basis of consolidated data for the Company's utility operations."

(e) Please address the disadvantages of consolidation cited at Vol. 1, Tab 5, Appendix C, Pages 40 - 41.

2. Ref: Page 20 of the August, 1992 Decision B19

At page 20 of the August 5, 1992 Decision, the Commission stated that "the canvassing of the full impact (of consolidation) on all customers is more important" than the forecast financial benefits. "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."

Please explain in what respect your rate design application has canvassed the full impact of consolidation on all customers, and describe how your rate proposals, such as postage stamping, have been made known to all customers.

3. Ref: General B20

(a) Please explain why your proposed consolidation does not include Fort Nelson and other utility subsidiaries.

(b) Please provide a cost of service study for Fort Nelson, if one has been done, and show the rate design impacts as shown on Vol. 1, Tab 3, page 19 and Tab 5 Pages 5 and 6.

(c) If a postage stamp margin is not considered reasonable or workable for Fort Nelson and/or Columbia, please explain whether alternative solutions are available and acceptable to BC Gas, such as postage stamp margin only for Lower Mainland and Inland, separate margins for Fort Nelson and Columbia, but all the same general terms and conditions.

4. Ref: Page 10 B21

(a) Deferred income taxes were collected from all customer rates whereas franchise fees are collected only from customers within certain municipal boundaries. Please explain the fairness of offsetting the deferred tax credit with future franchise fees of selected customers.

(b) As an alternative, please consider the merit of deriving the gross margin on items of divisional attributes i.e. revenues, cost of gas, franchise fees and proposed deferred income tax offsets. The postage stamp or divisional gross margin will account for common and joint costs only.

5. Ref: Page 7 B22

Please explain whether the grants given to the Lower Mainland municipalities are in essence franchise fees, i.e. "grants in lieu" of franchise fees, and should be treated as separate charges.

6. Ref: Appendix B, Pages 1 and 2 B23

Has a depreciation study been conducted by BC Gas? On what basis do your proposed depreciation rates reflect the useful or expected life of the plant assets?

7. Ref: Page 11 B24

Given the sophistication of your Work Management System, why is a simplification of capitalization procedure necessary?

Tab 6 Proposal to Revise Residential Gas Rates

1. Ref: Page 6, Lines 19 - 23 B25

BC Gas states that "If there are drastic increases in residential rate levels or the price of 20 to 40 gigajoules of gas per month, residential customers may substitute wood or electric power as their fuel of choice".

(a) Doesn't the residential elasticity study filed by BC Gas indicate that residential demand is relatively inelastic, and therefore substitution of residential load away from gas will not occur in significant amounts? Does BC Gas have any other studies or evidence that would suggest such fuel substitution would occur?

(b) If substitution of residential load away from gas did occur as a result of price increases, wouldn't it be possible that consumers might turn to energy efficiency or conservation measures rather than to wood or electricity? Was this possibility considered in designing the BC Gas rates?

2. Ref: Page 6, Lines 29 - 36 B26

Please explain how rates that adequately recover the largely fixed cost of the natural gas infrastructure owned by BC Gas leads to environmental responsiveness.

3. Ref: Page 11, Lines 17 - 19 B27

The Application states that 80% of the residential customers in the Lower Mainland Division consume between 60 and 180 gigajoules per year. Please provide similar figures for the Inland and Columbia Divisions.

4. Ref: Page 12, Lines 11 - 40 B28

Please provide an update to the referenced table showing impacts without the January 1, 1993 interim increase. Please include an additional column showing the percentage increase (decrease) exclusive of the cost of gas.

5. Ref: Page 12, Lines 11 - 40 B29

Please provide a table showing the dollar and percentage increase (decrease) in bills for low, medium and high use customers, for each division, for a typical summer month and a typical winter month.

6. Ref: Page 15 B30

The methodology for allocating gas costs to the rate schedules is that approved in the February 21, 1992 Decision (Phase A Rate Design methodology) and summarized in the August 5 1992 Decision (p.61). Would BC Gas agree that although the gas cost allocation methodology may be appropriate for allocating gas costs to the rate class, it doesn't aid rate design within the rate class? Please explain.

7. Ref: Page 26 and Tab 7, Page 26 B31

Please explain the difference between bills and sales as shown in the top graph. Please confirm that this graph indicates that approximately 7.5% of residential bills are for sales of 2 gigajoules or less and that this represents approximately 20% of total residential sales. This appears to be the inverse of the small commercial class sales - bills relationship which seems to indicate that approximately 25% of small commercial bills are for sales of 2 gigajoules or less and that this represents approximately 6% of total commercial sales. Please explain.

8. Ref: Page 32 B32

The graph appears to suggest that approximately 29% of margin revenue is generated on sales of 2 gigajoules or less while 56% of margin costs are incurred on sales of 2 gigajoules or less. Please confirm that this understanding is correct. Please reconcile the cost curve to the statement made elsewhere that approximately 90% of BC Gas' residential margin costs are fixed (Tab 3, Page 7).

9. Ref: Page 37 B33

This graph compares LRIC to the proposed postage stamp margin and to the present rate margin at various levels of consumption. Given that the proposed postage stamp margin and present rate margin reflect historical costs of serving current customers while the LRIC value reflects the cost of serving an incremental or new customer, does BC Gas see any difficulty in making these comparisons?

Tab 7 Proposal to Revise Commercial Gas Rates

1. Ref: Page 13, Lines 1 - 31 B34

With respect to small commercial customers, please provide an update to the referenced table showing impacts without the January 1, 1993 interim increase. Please include an additional column showing the percentage increase (decrease) exclusive of the cost of gas.

2. Ref: Page 13, Lines 1 - 31 B35

With respect to small commercial customers, please provide a table showing the dollar and percentage increase (decrease) in bills for low, medium, high and very high use customers, for each division, for a typical summer month and a typical winter month.

3. Ref: Page 14, Lines 5 - 33 B36

With respect to large commercial customers, please provide an update to the referenced table showing impacts without the January 1, 1993 interim increase. Please include an additional column showing the percentage increase (decrease) exclusive of the cost of gas.

4. Ref: Page 14, Lines 5 - 33 B37

With respect to large commercial customers, please provide a table showing the dollar and percentage increase (decrease) in bills for low, medium, and high use customers, for each division, for a typical summer month and a typical winter month.

Tab 8 Proposed General Firm Service and General Firm Transportation

1. Ref: Page 2, Lines 14 17 B38

Does BC Gas have any plans to implement demand metering for General Firm Service and General Firm Transportation customers?

2. Ref: Page 4, Lines 19 - 24 B39

Please indicate where the average margin per gigajoule numbers shown are calculated in the Application. If not shown in the Application, please provide the backup calculations in support of these numbers.

3. Ref: Page 10, Lines 5 - 35 B40

With respect to Schedule 5 customers, please provide a table showing the dollar and percentage increase (decrease) in bills for low, medium, and high use customers, for each division, for a typical summer month and a typical winter month.

Tab 9 Proposal to Revise Industrial Gas Rates

1. Ref: General - The Auction Proposal B41

This matter continues to be outstanding from the Phase A Process. It was Commission Staff's understanding that BC Gas would be revising its proposals on this matter as part of the Phase B application. Please file the current BC Gas position in response to this information request.

2. Please provide blacklined copies of Schedules 10, 13, and 22 showing any proposed revisions (from filed tariffs) which arise from the Phase B application. B42

3. Ref: Page 16, Lines 16 - 26 B43

The Application states that Rate Schedule 7, General Interruptible Service, will track Rate Schedule 10, Level 2 commodity rates with a premium in winter months initially set at $0.30 per gigajoule. How was the $0.30 per gigajoule premium determined?

4. Ref: Pages 24 and 25 B44

(a) It is unclear as to whether this application seeks approval of Schedules 22 and 22B. Please clarify the roles of the Tolls and Tariff Committee versus the public hearing review process.

(b) Please explain why it is appropriate to cancel Schedule 7 on which the current interim transportation rates are based, prior to approval of Schedule 22B.

5. Ref: Pages 34 and 35 B45

If not already answered elsewhere, please provide a more detailed explanation, with reference where possible to the FDC studies, of how the various charges were developed for rate schedules 22 and 27.

In particular, if the interruptible rates are derived from the firm rates, how are the $1.64 and $0.82 seasonal delivery charges initially established and why are these numbers not set at some other level which provides the same forecast revenue? Explain how the various factors such as daily versus monthly balancing, grouping of customers and expected number of interruptions lead to the resulting level 1 and 2 pricing for the two schedules.

Tab 10 Proposal to Revise NGV Gas Service Rates

1. Ref: Pages 4 and 7 B46

On P.4 lines 30 - 34, it is suggested that high volume centrally located stations should support low volume outlying critical stations. Explain how this is consistent with the delivery charge reduction of 50 percent for loads above 4000 GJ/month detailed on P.7 which is designed to encourage building load. Rationalize this load building incentive in the context of IRP, and the flat delivery charges proposed elsewhere in the application.

Volume II

Tab 5 Proposed Industrial Tariffs

1. Ref: General B47

Recognizing that rate schedules 5, 25, 7, 27 are either new or extensively rewritten, please provide a summary of changes similar to that provided beginning on V.1, T.12, P.3 including a comparison table where appropriate.

In the case of Schedule 27, comparisons should also be made to Schedule 22 (as revised by this application).

2. Ref: Page 5.5, Page 25.6, Page 7.5, Page 27.6 B48

Explain the rationale for what is in effect a minimum 13 month notice period. In the event the Company was able to arrange firm gas supply in less than 13 months, why would it not offer a sales rate to the customer? Comment on the suitability of the following alternative wording:

"The Company will require sufficient notice period to permit arranging additional firm gas supply; depending on when notice is received, a firm gas sales rate may not be available for up to one year after receipt of notice."

(Note that Rule 1.6 of the Commission's March 16, 1993 Rules pursuant to Section 85.3, sets an upper limit of one year for this notice period.)

Integrated Resource Plan - April 30th Filing

1. On page 2 of the cover letter from P.D. Lloyd, the company states that delay in approvals of deferral accounts will delay filing of the 1993 IRP. What activities, if any, does the Company plan to pursue regardless of Commission action? B49

2. In what ways were the 1992 draft IRP and the revisions contained in this filing used in preparing the LRIC study, the Fully Distributed Cost study, and the company's rate design proposal? B50

3. With regard to the IRP objectives outlined in Tab 1, has the company identified any quantitative measures that will enable it to assess whether or not it has met B51

these objectives. If so please describe what ratios or other statistics the company plans to gather or calculate?

4. Ref: Tab 2, pages 1 and 2 B52

With respect to the GSR&R Objective 1, why does BC Gas intend to acquire only residential and commercial end-use models and use disaggregated econometric models for the industrial sector? What information can econometric and end-use models provide that may be of use in implementing DSM programs.

With respect to DSM Objective 1, why is BC Gas only studying the residential and commercial markets?

With respect to DSM Objective 3, why is conservation potential being determined for residential and commercial markets only?

5. Tab 3: Deferral Accounts B53

(a) Several DSM and IRP Deferral Account Applications have been filed with the Commission. Specifically, these are:

- the March 2, 1992 Commercial Water Heater and Commercial Booster Water Heater Program Application;
- the November 23, 1992, Revenue Requirements Application: Vol.1, Tab 3. p.1-03-14;
- the December 31, 1992 Commercial Marketing Program Deferral Account Application;
- the April 30, 1993 Deferral Account Application.

Please reconcile the DSM and IRP costs in the IRP with the program deferral accounts requested in the other applications noted above. For each individual marketing or DSM program or expenditure and each DSM or IRP project, please provide:

i) a brief description of the program or project, including the current status of the project and the proposed termination date, and whether the program is being undertaken in conjunction with another utility (such as B.C. Hydro).

ii) an estimate of the proposed before-tax and after-tax expenses for the calendar year 1993,

iii) the actual or committed before and after-tax expenditures up to December 31, 1992 and,

iv) the actual or committed before and after-tax expenditures for the first three months of 1993.

(b) The LNG Deferral Account Application included three stages of public consultation. How will this public consultation process be integrated with other BC Gas public consultation processes? Has BC Gas considered combining this with the more general Public consultation process described under tab 10 with respect to the IRP process, in order to determine if an LNG plant is the most logical alternative and, if it is, where it should be located?

6. Please describe the purpose and expected content of the WestCoast Line Three Avoided Cost Study and the Monitoring Study Strategy Document (Level 2) identified in the milestone schedule under Tab 4. B54

7. The milestone schedule (Tab 4) indicates that BC Gas plans to file its final IRP on December 17, 1993. Will the final IRP contain a long-run DSM plan? If so will this plan rely on draft results from the end-use survey, given that the final end-use report will not be completed until December 19, 1993? B55

8. Ref: Tab 5, Pages 2 and 3 B56

(a) What 'off-the shelf' models has BC Gas evaluated prior to choosing the REEPS/COMMEND models?

(b) Has BC Gas discussed with BC Hydro the question of how much data is available from BC Hydro for sharing and how much of that data is applicable to gas demand forecasting?

(c) Has BC Gas surveyed other gas utilities regarding their choices of end-use models.? Has BC Gas explored the possibility of data sharing with other Canadian gas utilities?

(d) Can BC Gas provide any examples of REEPS or COMMEND models that have been customized for other utilities in order to forecast peak day/peak hour demand and to accommodate different block rate structures?

9. Ref: Tab 5, Page 4 B57

BC Gas indicates that the long-term success of the end-use modelling effort depends on the execution of three ongoing projects:

- Extensive residential and commercial customers surveys
- A customer monitoring program
- A conditional demand analysis study based upon results from customer surveys and monitoring programs.

Are the costs for these three projects contained in deferral accounts for which BC Gas is requesting approval?

10. Ref: Tab 7, Page 9 B58

The company indicates that it plans to select DSM programs using the California Standard Practice tests. Of the five standard practice tests outlined in the California Standard Practice Manual, which one will BC Gas rely on?

11. Avoided costs are inputs to the standard practice tests. Has BC Gas developed avoided costs that it will use or has used in the past to evaluate DSM programs? If so, please provide a copy of the Company's most recent estimate of avoided costs. How do the avoided cost figures compare to the LRIC study results? B59

12. Ref: Tab 7, Page 7 B60

BC Gas describes four steps "to identify potentially viable DSM measures, screen out non-viable measures and package potentially viable measures into programs". Where within this process is the avoided cost of gas taken into account? Has BC Gas used any analysis using its avoided cost for screening the programs proposed in Tab 7, Section 4? If so what was the avoided cost used and what was it based on?

13. Has BC Gas given any consideration as to how it will allocate the cost of DSM programs to customer classes? If so, please explain the company's thoughts on this matter. B61

14. Ref: Tab 7, Pages 4 and 6 B62

BC Gas states that "For the purposes of this discussion a DSM program is considered to be synonymous with the term DSM Resource' and "A DSM measure is defined to be any measure which can impact demand". These two statements taken together imply that any measure that effects demand is a DSM resource. Does this imply that BC Gas views all marketing programs as a DSM Resource?

15. Ref: Tab 7, Page 6 B63

Has BC Gas done any preliminary studies to assist it in designing the DSM research it intends to carry out. If so, please provide copies of the reports.

16. Tab 7, Page 11. B64

BC Gas notes several alternative ways of proceeding after selecting potentially viable DSM resources in the draft IRP. The alternative that it is proposing involves (1) including the developed and selected DSM Programs in the December 1993 IRP, (2) proceeding with the DSM potential study, and (3) proceeding with three DSM programs in advance of a complete IRP or public consultation.

(a) One of the proposed programs for implementation is the Customer Energy Education and Information Program (Tab 7, p.17). Please explain if BC Gas has any studies or evidence that indicate that general education programs have any impact on customer energy use behavior. Please provide any copies of evidence or studies that BC Gas has relied on in designing this program? What particular energy use behavior changes is the program intended to bring about?

(b) Another of the proposed programs for implementation is the R2000 energy New Home Construction Program (Tab 7, P.19). Please explain the value of this program given new provincial standards for energy efficiency that include such gas-fired appliances as furnaces and water heaters (March 19, 1993 MEMPR Press Release)?

(c) Regarding the Hot Water Saver Program (Tab 7, p.17): What proportion of the shower head and aerator costs would be paid by BC Gas and what proportion of the costs would be paid by interested municipalities.

17. Ref: Tab 7, Page 12 B65

Please explain if BC Gas has any studies or evidence that indicate that Industrial Energy Audit programs have any impact on customer energy use behavior. Please provide any copies of evidence or studies that BC Gas has relied on in designing this program? What particular energy use behavior changes is the program intended to bring about?

18. Ref: Tab 7, Appendix 1 B66

At page 5, BC Gas notes that rate incentives to encourage conservation were discussed. Were such considerations made a part of the BC Gas Rate Design Application of April 15, 1993? Does BC Gas consider aligning rates and IRP objectives an important consideration in rate design?

19. Ref: Tab 8 B67

The discussion of alternatives considered to the development of the ROM model is limited to a list of the shortcomings of the existing Gas Supply Optimization Model, and a reiteration that BC Gas solicited proposals and is convinced that 'building on existing models...is a far quicker and cheaper way to integrate its Resource Optimization'. Did BC Gas study any alternatives to modification of the existing GSOM (e.g. other stand-alone ROM models? If so please describe them and provide estimates of their cost for comparison to the chosen alternative (modification of the GSOM). If not, what evidence did BC Gas rely on to support this assertion?

20. Westcoast/BC Gas Public Involvement Process - Greenhouse Gas Stabilization B68

(a) Has Westcoast Energy, BC Gas or Greenspirit Consultants gathered any information regarding other public processes that relate to greenhouse gases and that may be occurring in BC or Canada that apply to BC? If so, please provide a list of other public processes that BC Gas is aware are taking place? If there are other public processes of which BC Gas is aware, what information will this study provide that will not be available through some other process?

(b) BC Gas notes that "a cooperative effort involving all Interested Parties will be the most effective way of addressing this issue in a comprehensive fashion". Please describe, at least as an initial list, who those interested parties are that BC Gas anticipates would be involved?

(c) Will all draft and final reports resulting from this project be made available to the public?

21. Ref: Tab 9 B69

According to the information contained in Tab 9, one aspect of the functions carried out by the System Planning Department involves working with groups within BC Gas to determine possible load shedding options in specific areas. Please provide an example of the type of load shedding options that are considered.

The System Planning Department also evaluates transmission system costs, gas supply costs, security of gas supply and system reliability and flexibility. How are system reliability, flexibility and security of gas supply measured?

How are the extreme cold days defined? Do they represent the coldest day in a year or the coldest day experienced over many years?

22. Ref: Tab 10 B70

With regard to public consultation, Tab 10 discusses an information campaign designed to encourage active participation by the "general public". What is the nature of the active participation envisioned? Will key stakeholders be involved in the selection of resources?

GLOSSARY OF TERMS

Alberta Natural Gas (ANG)
Alberta Natural Gas Company Ltd. The operator of a natural gas transmission line which runs from Alberta to the U.S.A. across the south east corner of British Columbia. Gas moving to the Columbia service area flows through the ANG pipeline. The East Kootenay Link running from Trail connects to the ANG pipeline at Yahk.

Alberta and Southern (A & S)
Alberta and Southern Gas Co. Ltd. A marketer of natural gas which purchases natural gas in Canada for sale in California. Most of the capacity on the ANG pipeline is under contract to A & S. A & S supplies peaking gas to BC Gas which is transported via the East Kootenay link. A & S also acts as agent in the transportation of gas via the ANG pipeline to Columbia.

Average and Excess Demand (AED)
A method of distributing utility capacity related costs whereby the costs are allocated to classes partially based on peak day consumption, and partially based on individual class total annual energy consumption.

Basic Charge
A fixed monthly fee charged regardless of the quantity of gas consumed by the customer. May also be half the bimonthly fee charged customers billed bimonthly.

BCUC
British Columbia Utilities Commission.

Burrard Thermal
Electric generating plant owned by B.C. Hydro and located on Burrard Inlet near Ioco.

Burrard Thermal Agreement
The amended and restated interruptible gas agreement made as of the 29th day of September 1988 and providing for the supply and delivery of gas to the Burrard Thermal plant on an interruptible basis.

Burnertip — A term used to refer to the price or other characteristic of natural gas delivered to the premises or facilities of a customer. A "burnertip" price includes all costs to the customer.

Bypass — See "non-captive".

Captive — A term used to describe customers situated far enough from a pipeline that bypassing the distribution system would result in a rate higher than the applicable utility rate. It is also used to describe certain customers whose rates are final and do not change with changes in the utility's revenue requirements.

Coincident Peak — Peak capacity demand of a customer class which coincides with the peak capacity demand established by a system.

Columbia (COL) — The portion of the BC Gas service area which formerly was Columbia Natural Gas Limited. It is located in the East Kootenays and serves customers with gas from the ANG pipeline.

Commercial — Customer group of BC Gas which includes businesses, institutions and large multifamily buildings.

Commission — British Columbia Utilities Commission.

Commodity Charge — A charge collected on a volumetric basis which represents a market based price for utility interruptible gas supplied to the W.E.I. interconnection with BC Gas.

Cost of Gas Recovery — The portion of the price paid by the customer to compensate BC Gas for its costs of acquiring gas supply.

Cost Margin	From the Fully Distributed Cost study, the cost of service associated with a particular rate class less the associated cost of gas supply.
Delivery Charge	A unit rate for gas service, excluding the cost of gas component. This charge is collected on a volume basis and is in addition to the basic charge.
Demand Charge	A fixed monthly amount charged under a rate schedule or a gas supply or service contract. The charge is effectively a reservation fee and is paid regardless of whether or not any gas flows in that month.
Direct Purchase Administration Charge	A charge designed to recover the incremental costs associated with providing transportation service.
Division	A term created by OIC 953/89 which arose as a result of the amalgamation of four companies, namely BC Gas Inc., Inland Natural Gas Co. Ltd., Columbia Natural Gas Limited, and Fort Nelson Gas Ltd. into BC Gas Inc. in 1989. Each of these entities upon amalgamation were to be referred to for regulatory purposes as the Lower Mainland, Inland, Columbia and Fort Nelson Divisions.
East Kootenay Link	A gas transmission pipeline running between Trail and Yahk. It connects the Inland service area with the ANG pipeline.
Firm	Service provided year round without curtailment.
Fort Nelson (FN)	The portion of the BC Gas service area which formerly was Fort Nelson Gas Ltd. It comprises the Fort Nelson and Prophet River areas of northern B.C.

Franchise Fee Charge	A charge collected from customers which reside or operate in a municipality or city to which BC Gas pays franchise fees.
Full Fixed Charge	A fixed monthly fee charged regardless of the quantity of gas consumed by the customer, and representing a majority of the utility cost-of-service, excluding the cost of gas.
Full Variable Charge	A unit toll paid on each unit comprised of Commodity, Demand and Customer Margins, and the Cost of Gas Commodity.
Fully Distributed Cost (FDC)	The distribution of all gas utility costs to classes of customers.
General Service	A class of larger volume firm service customers who may have a significant portion of their consumption dedicated to processing loads.
Gigajoule (GJ)	A metric measure of energy. A billion joules.
Hyperplot	A graphical representation of a utility rate that is displayed as a straight line as a result of using a hyperbolic scale on the horizontal axis.
Inland (INL)	The portion of the BC Gas service area which formerly was Inland Natural Gas Co. Ltd. It is located throughout much of the interior of the Province and serves customers with gas primarily taken from the Westcoast pipeline system.
Integrated Resource Plan (IRP)	Planning process, used by regulated energy utilities, that equally compares options that involve changes in supply resources and changes in energy demand. The outcome of the process is an "integrated resource plan" (usually covering 15 to 20 years) and an "action plan" (usually two years).

Interruptible	Service provided with customer curtailment due to supply or system capacity limitations.
Joule	A metric measure of energy equal to the amount of work done when the point of application of a force of one newton is displaced a distance of one metre in the direction of the force.
Liquified Natural Gas (LNG)	The Company owns and operates an LNG peak shaving facility located in Delta, B.C. where natural gas is liquified and stored during off-peak periods, then vapourized and used to help meet firm customer demands during peak periods.
Load Factor	Ratio of the average load over a designated period of time to the peak load occurring in that period.
Long Run Incremental Costs (LRIC)	The estimated cost of adding an additional customer today calculated recognizing the impact of future costs.
Lower Mainland (LM)	The portion of the BC Gas service area which formerly was the Lower Mainland Gas Division of B.C. Hydro. It is located in the Lower Mainland and Fraser Valley and serves customers with gas primarily taken from the Westcoast pipeline system.
Margin	Charge for utility services calculated as the burnertip rate less the gas cost recovery.
Megajoule (MJ)	A metric measure of energy. A million joules.
Minimum Charge	A minimum monthly bill assessed customers. It is composed of charges specific to the rates in each customer class e.g. Residential, it is the basic charge or for Generally Firm Transportation, it is the basic and administration charges.

National Energy Board (NEB)	The federal regulator of interprovincial and export energy transporters. The regulator of Westcoast Energy Inc.
Non-coincident demand (NCD)	Peak capacity demand of a customer class at any time irrespective of when the system peak capacity demand is established. A method of allocating utility capacity related costs whereby the peak capacity demands for all classes are added together irrespective of the time of occurrence.
Non-captive	Customers close enough to a pipeline that bypassing the distribution system would result in a rate lower than the applicable utility rate.
O & M	Operating & Maintenance expenses of the utility.
Ogive	A graphic that represents the profile of gas sales to a group or class of customers. The horizontal axis is logarithmic and the vertical axis is on a probability scale.
Pacific Coast Energy Corporation (PCEC)	A pipeline company with its starting point at the BC Gas station near Ioco and its terminus in Victoria. The company transports gas for distribution to the Sunshine Coast, Texada Island, Powell River and parts of Vancouver Island.
Peak Responsibility (PR)	A method of allocating utility capacity related costs according to the capacity demands imposed on the system by various classes of customers during peak day.
Petajoule (PJ)	A metric measure of energy. 10^{15} joules.

Phase A — A BC Gas rate design application and hearing dealing with methodology to allocate the gas supply costs for Inland and Lower Mainland. It resulted in the Phase A Decision of February 21, 1992 in which the Lower Mainland and Inland Division gas supply cost allocation methodology and class gas cost recovery were approved.

Postage stamping — Determination of common rates for utility services, excluding gas costs, for classes of customers throughout the BC Gas service territory.

Residential — Class of customers including single family residences and multi-family buildings with less than 4 units.

Seasonal Rate — A rate which varies on a seasonal basis. Typically, the application of higher rates during the winter months of November through March reflecting the greater demand for system capacity.

Terajoule (TJ) — A metric measure of heat. A thousand gigajoules.

Transportation service (T-service) — A gas delivery service provided by a pipeline or local distribution utility to customers who purchase natural gas from producers or marketers.

TY — Test year.

Valley — Pipeline and distribution system capacity available during off peak periods.

Westcoast (WEI) — Westcoast Energy Inc. The operator of natural gas gathering, processing and transmission pipeline facilities located primarily in the Fort Nelson and Fort St. John areas of the province. The transmission facilities are from those areas, and from Alberta, to the international boundary at Huntingdon in the Lower Mainland. The BC Gas facilities interconnect with the Westcoast facilities at many locations, with major interconnections at Savona and Huntingdon. Burrard Thermal Electric generating plant owned by B.C. Hydro and located onBurrard Inlet near IOCO.

IN THE MATTER OF the Utilities Commission Act SBC 1980, Chapter 60 and amendments thereto

and

IN THE MATTER OF an Application by BC Gas Inc. to implement certain rate design changes

To: British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, British Columbia
V6Z 2N3

APPLICATION

BC Gas Inc. ("BC Gas") hereby applies for approval of the various proposals set out in this Application and in the two volumes to which this Application pertains. These matters include:

CONSOLIDATION

1. An Order allowing BC Gas to consolidate for regulatory purposes the Lower Mainland Division, Inland Division and Columbia Division. That is, to have its revenue requirement (exclusive of gas supply costs) determined as one regulated entity and not on the basis of three separate divisions. The effective date sought for the Order is January 1, 1993 to accord with the BC Gas 1993 Revenue Requirement Application dated November 22, 1992 and Commission Order G-120-92.

2. An Order approving the elimination of divisional accounts and approving the specific accounting practices relating

to consolidation set out below:

(a) Depreciation and Amortization:
Common depreciation and amortization rates to be applicable to similar plant categories throughout the Company. Details of the proposed revisions are found in Appendix B of Volume 1, Tab 5.

(b) Deferred Income Tax Balances:
In order to dispose of the deferred income tax balances within the service area where the balance arose, BC Gas applies for Commission approval to draw down the accumulated deferred income tax balances in the following manner:

<u>Inland</u>:
The accumulated deferred tax balance of $11,031,000 will be drawn down in the Inland service area by a negative rider in lieu of franchise fee charges, to be applied at 3.09% on the billings calculated under Inland rates. The draw-down is to commence on January 1, 1994 and will cease when the balance is depleted, which is estimated to be between 2.5 and 3 years.

<u>Columbia</u>:
The accumulated deferred tax balance of $1,559,000 will be drawn down as follows:

i) A sufficient amount to be applied in 1993 to eliminate certain deferral account balances;

ii) A sufficient amount to be applied in 1994 to Residential, Commercial and General Service rates to offset 50% of the proposed 1994 margin increase for those customer classes;

iii) The balance as a Negative Rider in lieu of 1994 franchise fee charges, similar to that proposed above for the Inland Service Area. For greater detail see Volume 1, Tab 5, page 10.

(c) Other Deferred Charges:
Approval to dispose of the various balances as set out in the discussion on Consolidation at Volume 1, Tab 5.

(d) Franchise Fees:
Since municipal franchise fees are incurred only in the Inland and Columbia divisions, BC Gas seeks approval to:

i) remove the average franchise fee contained in the rates applicable to within the Inland and Columbia divisions, and

ii) collect the amount of franchise fees by way of a separate Franchise Fee Charge to customers who reside or operate within the boundaries of cities or municipalities to which BC Gas pays franchise fees.

RATE DESIGN - Rate Schedules

3. An Order approving the replacement of the residential rate schedules of Lower Mainland (existing schedules 2101 and 2102), Inland (existing Schedule 1), and Columbia (existing Schedule 1) with the proposed Rate Schedule 1.

4. An Order approving the replacement of the commercial and general service rate schedules of Lower Mainland (existing Schedules 2207, 2208, 2209), Inland (existing Schedules 2.1, 2.2) with the proposed Rate Schedules 2 and 3.

5. An Order approving the replacement of the existing commercial rate schedules 2.1 and 2.2 in Columbia with the proposed Rate Schedule 2.

6. An Order approving the replacement of the seasonal rate schedules of Lower Mainland (existing Schedules 2601, 2602), Inland (existing Schedules 4.1, 4.2) and Columbia (existing Schedule 4) with the proposed Rate Schedule 4.

7. An Order approving the replacement of rate schedules of Lower Mainland (Schedules 2006, 2007, 2207, 2208, 2209), Inland (Schedules 2.2, 5.1, 5.2, 5.3, 25), and Columbia (Schedules 2.2, 3, 25) with the proposed:

(a) Rate Schedule 5, General Firm Service, and

(b) Rate Schedule 25, General Firm Transportation

8. An Order approving the replacement of the rate schedules for the small interruptible service of Lower Mainland (Schedules 2501, 2502A and 2502B) and Inland (Schedule 7) with the proposed:

(a) Rate Schedule 7, General Interruptible Service, and

(b) Rate Schedule 27, General Interruptible Transportation

and offering these services in the Columbia service area.

9. An Order approving the replacement of the rate schedules for the large industrial service of Lower Mainland (Schedules 2501, 2502A, 2502B, 22) with the proposed Rate Schedule 22 Large Volume Firm & Interruptible Transportation.

10. An Order approving the renaming of Inland Division Schedule 22 as Rate Schedule 22A, modifying that schedule to accord with the proposed Rate Schedule 22 and closing that Rate Schedule 22A.

11. An Order approving the introduction of the proposed Rate Schedule 22 in the Inland service area.

12. An Order approving the modification of Rate Schedule 10.

13. An Order approving the renaming of Columbia Division Schedule 7 as Rate Schedule 22B and closing Rate Schedule 22B.

14. An Order approving the modification of Rate Schedule 13 and approving it becoming available to all service areas of BC Gas.

15. An Order approving the replacement of the rate schedules for NGV of Lower Mainland (Schedule 2206), Inland (Schedule 14), and Columbia (Schedule 5) with the proposed Rate Schedule 6.

16. An Order approving the renaming of Lower Mainland Vehicle Refuelling Service Schedule 2216 as Rate Schedule 6.1 Vehicle Refuelling Appliance Service.

COMMON GENERAL TERMS AND CONDITIONS

17. An Order approving the common general terms and conditions found at Volume 1, Tab 12 including the revised Application for Service Charges of $25.00 for existing installations and of $75.00 for new service installations.

18. An Order approving the incorporation of the common general terms and conditions into the existing tariff supplements.

INDUSTRIAL TARIFFS

19. An Order approving the proposed industrial tariffs found at Volume 2, Tab 5.

TERMINATING TARIFFS AND SCHEDULES

20. An Order approving the termination of the following tariff provisions and schedules and, if applicable, accompanying service agreements:

Lower Mainland:
- Schedules 2103, 2104 Residential Pension Service
- Schedules 2191, 2294 L.P. Gas Service
- General Terms and Conditions Applicable to Schedules 2006 and 2007
- General Terms and Conditions Applicable to Large Industrial Transportation

Inland:

- Schedule 30 Interruptible Transportation Service
- Westcoast/Inland Wheeling Agreement made January 17, 1977
- Schedule 6 Special Industrial Firm Sales
- General Terms and Conditions Applicable to Large Industrial Transportation
- General Terms and Conditions Applicable to Small Industrial Transportation Service.

RATE DESIGN IMPLEMENTATION DATE/DEFERRAL ACCOUNT

21. For classes affected by the rate proposals other than the industrial classes, the Company seeks an effective date of January 1, 1994 for the proposed rates and tariffs.

22. BC Gas seeks the proposed rates and tariffs for the industrial classes to be effective November 1, 1993. Since November 1 is the commencement of the gas year, practicality and convenience dictate that for industrial customers the rates and tariffs should be in place on that date. However, since the industrial classes are generally receiving a significant reduction, an immediate reduction would negatively impact the Company's 1993 financial results. BC Gas requests the creation of a deferral account with a balance equal to the reduction in total industrial revenue from proposed rates which would occur in November and December. This amount would then be taken into income by the Company during November and December. This would serve to keep the Company financially neutral. The deferral balance would be amortized by charges to the industrial class over the 12 months commencing November 1, 1993.

PUBLIC PROCESS

23. The Company seeks approval to adopt a public process to facilitate an understanding of the proposals, to receive comments, and to develop a specific list of issues and concerns to be more fully addressed in the public hearing.

CONCLUSION

In support of this Application, BC Gas has filed material in Volumes 1 and 2 demonstrating that the proposals contained herein are not unjust or unreasonable, unduly discriminatory, or unduly preferential.

All of which is respectfully submitted.

Dated at Vancouver, British Columbia, this 15th day of April, 1993.

BC GAS INC.
Per:

David M. Masuhara
Vice-President
Legal & Regulatory Affairs

All notices and communications with regard to this Application should be sent to:

BC Gas Inc.
Attention: D.M. Masuhara
1111 W. Georgia Street
Vancouver, B.C.
V6E 4M4
Phone: (604) 443-6607
Fax: (604) 443-6789

APPLICATION OUTLINE

1.0 INTRODUCTION

Since the creation of BC Gas in 1988, the structure of the Company's rates has not undergone a comprehensive review, apart from the determination of the appropriate methodology for the allocation of gas supply costs in 1992. Since 1988, parties such as industrial customers and the British Columbia Utilities Commission have expressed a desire for a review of the Company's rate design. Various matters relating to gas costs, regulatory consolidation, consideration of postage stamp rates, industrial complaints and tariffs have been referred to a rate design proceeding. The Company has now undertaken a review of the structure and design of its rates. It is proposing changes which are responsive to the above-mentioned issues and others which the Company views as appropriate. The proposals of the Company include:

1. The consolidation of the Lower Mainland, Inland and Columbia Divisions for future revenue requirement purposes.

2. The implementation of uniform postage stamp margins, excluding gas supply costs ("delivery rates" or "delivery charges"), for residential, commercial and general service customers.

3. The implementation of basic monthly charges that improve the recovery of the fixed costs incurred by BC Gas in providing gas service.

4. Rates that improve the revenue to cost ratio imbalances between rate classes.

5. Revised industrial rates and tariffs.

6. Common general terms and conditions, with new fees for certain company services.

2.0 HISTORY

BC Gas Inc. was formed in 1988 as a result of the acquisition by Inland Natural Gas Co. Ltd. ("Inland") of the B.C. Hydro and Power Authority Lower Mainland Gas Division. Following the acquisition, the four separate gas distribution companies, Inland, Columbia Natural Gas Limited ("Columbia"), Fort Nelson Gas Ltd. ("Fort Nelson") and B.C. Gas Inc. (the "Lower Mainland Division") were amalgamated in 1989 pursuant to the Company Act and the Hydro and Power Authority Privatization Act to constitute BC Gas Inc.

The service area extends from Fort Nelson south through the Northern Interior, the Cariboo, the Okanagan, the West and East Kootenay regions and the Lower Mainland. BC Gas serves over 100 communities throughout British Columbia and approximately 635,000 customers of which there are approximately 570,000 residential, 66,000 commercial, and 700 industrial and other. This represents over 90% of natural gas consumers in the Province.

Notwithstanding the amalgamation and the unified nature of the management and operations of Inland, Columbia, Fort Nelson and Lower Mainland, BC Gas has been required to maintain those separate regulatory divisions until such time as there was an opportunity for a public hearing into this issue. That is, while the corporate entity, the management, operations and the supporting systems of BC Gas operate as one unit, until otherwise determined in a public hearing, the rates for the divisions were to be maintained as though the divisions were separate utility entities. This divisional approach to rates has been maintained despite the new Company's need to merge the various cultures, employees and systems of the four separate entities to achieve the optimum benefits and efficiencies.

Since the creation of BC Gas, its rates have only been reviewed by the Commission in the context of the appropriate cost allocation for gas supply costs to various customer classes (the "Phase A" Rate Design hearing) and in terms of the appropriate overall revenue levels for BC Gas. A review of the appropriate structure and design of the rates of BC Gas has not been conducted. Furthermore, the structure of rates for the Lower Mainland Division had not been reviewed in a comprehensive manner by the Commission while that division was operated by B.C. Hydro. With regard to the Inland and Columbia Divisions, the structure of the rates was reviewed by the Commission in 1987 and rate design decisions were issued.

In terms of the appropriate methodology for the allocation of gas supply costs for the Inland and Lower Mainland Divisions, the Commission reviewed this matter in December 1991 and January 1992 in a public hearing and issued its Decision in February 1992. The Decision recognized the integrated nature of the gas supply for the two divisions. The methodology for the allocation of gas supply costs approved in the Phase A Decision is used in this application to allocate gas supply costs for the Inland and Lower Mainland service areas.

In its 1992 Revenue Requirement Application, BC Gas sought a uniform rate increase equally from all customers. This approach retained the historic rate differentials between the divisions while spreading future increases equally to all customers. The Commission approved this approach on an interim refundable basis. This matter was considered by the Commission in its August 1992 Decision. The final determination of this matter was left to a future rate design hearing.

3.0 RATE DESIGN OBJECTIVES

A review of the appropriate level and structure of each class of rates related to the utility's margins has been undertaken. BC Gas has considered amongst other matters the fair allocation of costs to rate classes, the long run incremental costs for customer classes and the rate imbalance between interruptible sales and service rates in the Lower Mainland. Rates which include "postage stamp" margins (exclusive of gas supply costs) for the Lower Mainland, Inland, and Columbia residential and commercial classes, and uniform rate structures, have been reviewed.

4.0 STUDIES

In considering the appropriate rate design for BC Gas, the following studies were undertaken to assist in determining an appropriate rate level and structure for customer classes.

1. A long-run incremental cost study on a divisional basis and by customer class (Volume 2, Tab 3).

2. A fully distributed cost of service ("FDC") study for each of the three divisions (Volume 2, Tab 2).

3. Price of competitive energy and elasticity studies (Volume 2, Tab 4).

4. Detailed revenue models which illustrate the impact of proposed rates on utility revenues.

Each of these studies have been used as a tool to assist in the determination of an appropriate level and structure of each class of rates for BC Gas.

While a speedy move to implement rate changes that improve revenue to cost ratios would be fair to those customers receiving this benefit, gradualism favours a phasing-in over time of any significant shift.

5.0 RATE DESIGN PROPOSALS

The review of the rates of BC Gas was conducted using the conventional approaches of analyzing rates through fully distributed cost of service studies ("FDC"), long run incremental cost studies ("LRIC"), price of competitive energy and elasticity studies, and revenue model analyses. The thrust of the review has been to determine if cost burdens are properly borne by each class; if rates reflect the proper economic signals; if rates will provide for stability both for the customer and for the utility; and if the rates retain simplicity. Table 1 provides a comparative summary of the existing rates with the rate proposals.

The FDC studies were conducted utilizing peak responsibilities, non-coincident peak, and average and excess demand methodologies. These all indicate that there is a substantial under-recovery of costs in the residential class in all divisions. While test year 1992 embedded cost studies are not a sufficient basis to serve as the sole or exclusive element for the determination of rates, they are an important consideration. Any significant departure in the setting of firm rates to customers from the costs to serve them may serve to create the appearance of unfairness or inequity. Accordingly, to overcome unfairness or inequity the rates proposed have sought to bring a closer relationship between revenue to cost relationship in the residential sector.

The LRIC studies also indicate that in the long run there is an under recovery of costs from the residential customers. With the LRIC costs pro rated to match the revenue requirement the studies indicate an under recovery of costs in the residential class in each of the Lower Mainland, Inland and Columbia Divisions. The directional results of the FDC and LRIC are the same, namely, that insufficient revenue is recovered from the residential classes.

The price of competitive energy studies indicate there are no competitive reasons which would prevent the rate adjustments that the FDC and LRIC studies suggest.

For customers who require firm gas service, BC Gas proposes a two-part rate structure consisting of a higher basic charge and commodity charge for each gigajoule of gas. The price elasticities of demand study shows only limited demand response to changes in price. BC Gas believes that Demand Side Management (DSM) programs should be the primary means for achieving conservation and increased consumption efficiency. The rate design is intended to supplement DSM programs by removing pricing signals, such as declining block rates, which could present barriers to energy conservation measures.

A uniform commodity charge strikes a compromise between sending consistent pricing signals to the customer regarding energy conservation and stable revenue for the utility. By generating a greater portion of the revenue through a higher basic charge, the revenue becomes more stable and less dependent on energy sales that vary when actual weather is different from forecast normal. The implementation of Demand Side Management programs will be less expensive by having less revenue impact as average consumption declines.

Postage stamping the margin will be achieved through a process of initially establishing a standard basic charge for each rate class across the Lower Mainland, Inland and Columbia divisions. A delivery charge, which excludes gas cost, will then be adjusted to a standard level.

5.1 Residential Rate Design

i) Structure: An analysis of the residential rates indicates that over 90% of revenues from this class are consumption related and only about 9% relates to the fixed portion of the rates, such as the customer/basic charge. Further, the costs of BC Gas (exclusive of gas costs) are about 92% fixed and the rest variable. This inverse relationship between the fixed nature of the utility's costs and the variable nature of revenues to recover these costs is an indicator that existing rates are a contributor to the instability of the utility's earnings.

The FDC studies indicate that the customer-related costs are significantly above the current basic monthly charges. The FDC customer-related costs are $11.33 for Lower Mainland (LM COS, p. 1.2, ln. 25), $12.11 for Inland (INL COS, p. 1.2, ln. 17) and $13.62 for Columbia (COL COS, p. 1.2, ln. 17), compared respectively with the current monthly fixed charges of $4.64, $3.52 and $3.90.

BC Gas proposes to increase the basic monthly charge of the residential rates to $7.00 per month to close the gap between the current charge and the basic costs of gas service. A review of monthly charges with other gas utilities indicates that this revised charge is in line with others.

In addition, the Company seeks to establish a uniform rate structure with a single block rate, rather than a rate structure with several declining blocks.

ii) Level of Rates: The Company is proposing to increase Lower Mainland and Columbia residential rates since the revenue margin to cost margin ratios are not reasonable, with respect to the Lower Mainland and Columbia Divisions.

Currently, the ratios are 76.88% (Lower Mainland), 92.04% (Inland), and 74.13% (Columbia).

5.2 Commercial Rate Design

i) Structure: With regard to the commercial class, BC Gas has sought to create a refinement in this category to facilitate competitiveness through gas costs, as opposed to utility margin, and to more appropriately allocate those gas supply costs. The Company proposes to divide this group into two; one which is 0 to 2,000 gigajoules per year, and the other 2,000 gigajoules per year and greater; and, in the allocation of gas costs to the two commercial classes, take into account the load characteristics of each of the classes consistent with the Phase A allocation methodology. In the present Columbia Division BC Gas does not separately allocate gas costs between commercial classes and the commercial class in the area served with the Columbia gas supply will continue as one class until a separate gas cost allocation between classes is available. The commercial class cost studies indicate a significant under-recovery of customer-related costs, thus the Company proposes a basic monthly charge of $14.00. Further, similar to the residential rate proposal, a uniform single block structure is being proposed for each of the two commercial customer groups.

ii) Level of Rates: BC Gas proposes to reduce the commercial rates in the Inland Division to bring the revenue closer to cost. Rates in the Lower Mainland and Columbia areas will increase with the proposed rates for the commercial customers in all three divisions being equal.

5.3 General Service Rate Design

i) Structure: Firm sales and transportation service is proposed for the general service customers. A basic charge of $300.00 per month is proposed with commodity charges for the delivery of the gas that are seasonal.

ii) Level: The proposed changes will see most general service customers receiving a lower overall price for gas, with the commodity cost of gas decreasing, but the delivery charge (excluding cost of gas) in some instances increasing.

5.4 Interruptible Rate Design

With regard to interruptible rates, the focus has been to remedy the historic rate margin difference between the interruptible sales and interruptible T-service margins in the Lower Mainland and to determine the appropriate rates for interruptible margins. The anomaly resulting from a higher interruptible sales margin of $1.25 per gigajoule versus $0.90 per gigajoule for T-service has created a revenue drain for BC Gas through the migration of interruptible customers to the lower transportation service rate. To remedy this a temporary mechanism had been implemented whereby any migration of interruptible sales customers to interruptible T-service customers has led to a crediting of $0.41 of the margin loss to a deferral account to keep the company whole. This differential is inconsistent with the concept of revenue neutrality as between sales and transportation rates when the services are of a comparable nature. Thus, in the exercise of determining the appropriate rates for the Lower Mainland interruptible group the Company has viewed sales and transportation as similar and has set rates treating this group as one.

With regard to interruptible rates, BC Gas seeks to create two categories under this type of service. They are:

(i) Small volume interruptible service for customers who consume less than 20,000 gigajoules per month.

(iii) Large industrial interruptible rate for customers who consume greater than 20,000 gigajoules per month.

The delivery charges proposed are set out in the tables attached to this outline. The interruptible delivery charges must be sufficiently below firm rates to prevent migration to firm service. The proposed delivery charges will provide a material reduction in rates to the interruptible customers. The proposed interruptible sales and transportation services:

(a) enhance system efficiency as they will encourage interruptible customers to stay interruptible and not switch to firm service, and forestall the need to construct additional capacity or obtain additional transportation pipeline capacity during firm peak periods;

(b) recognize that the BC Gas interruptible service has a relatively low level of curtailment;

(c) balance the need for proper allocation of resources with the aspect of fairness to the core market; and

(d) meet the object of simplicity and neutrality insofar as there would be no rate bias for sales service over T-service or for T-service over sales service.

5.5 Large Firm Industrial Rate Design

i) Structure: With regard to the existing large industrial firm customers, BC gas proposes to close this service. Existing customers will be permitted to remain on the existing rate, subject to incorporation of appropriate basic charges and general rate increases. New customers will be expected to negotiate rates which reflect the costs of providing service to that customer, or to select interruptible rates.

ii) Level: Rates for existing large firm industrials are not significantly changed, although some of the current variable rates have been reduced in favour of customer-related charges.

5.6 NGV Rate Design

i) Structure: A uniform monthly basic charge is proposed. Delivery charges and gas commodity charges will be volumetric.

ii) Level: A basic charge of $35.00 per month and a delivery charge of $2.00 per GJ for the first 4,000 GJ per month. For loads above 4,000 GJ per month the delivery charge will be reduced by 50%. Gas costs will be in addition to these charges.

5.7 Seasonal Rate Design

i) Structure: A uniform basic monthly charge and delivery margin is proposed. The pricing is intended to attract summer loads.

ii) Level: A basic charge of $300.00 per month with rates that reflect a $0.60 delivery charge in summer plus gas cost recovery. The rate in winter is to be set at two times the residential block rate to discourage winter use under this schedule.

5.8 Industrial Tariffs

New industrial tariffs have been drafted. BC Gas, through a pre-hearing process, proposes to seek input from its customers regarding these terms and conditions. Additional tariffs are to be developed on a basis consistent with those found under Tab 5 of Volume 2.

5.9 Franchise Fees

Customers in the present Inland and Columbia divisions pay franchise fees as part of the margin component of their rates. BC Gas proposes to remove the franchise fees from the margin and identify the franchise fees as a separate item to be charged only to customers within cities or municipalities where franchise fees are levied. In this manner, customers of BC Gas who live or operate outside areas which levy franchise fees will not carry the burden of franchise fees as part of their rates.

5.10 Common Terms and Conditions

A comprehensive review of the general terms and conditions of the divisions has never been conducted. Given the desire for consolidation, postage stamping, and operating simplicity, integrated common terms and conditions were necessary. BC Gas has drafted new common general terms and conditions which can be found in Volume 1, Tab 12.

5.11 Deferred Income Tax Balances

During the mid-1970's to the early 1980's, BC Gas included in its rates tax calculated on a "normalized" basis and accumulated deferred tax balances of $11,031,000 in the Inland Division and $1,559,000 in the Columbia Division. In 1983, the Commission directed that this method be changed to a "flow through" method. As a consequence, the deferred tax balances were frozen. In the BC Gas 1992 Revenue Requirement Decision, the Commission requested BC Gas to propose a method to deal with these balances, given the desire of BC Gas to consolidate its revenue requirement. The proposal of BC Gas with regard to the Inland Division is to draw down its deferred tax balance by matching and offsetting the franchise fees to be collected from customers in the Inland Division. Once the balance has been exhausted the franchise fees would again be payable by the customer.

With regard to the Columbia Division balance, BC Gas seeks to utilize the balance to assist in the phase-in of the postage stamp rates for the residential, commercial and small industrial customers over two years. In addition, a portion of the balance will be used to offset certain deferred charges applicable to the division and the balance remaining will be used to offset franchise fees otherwise payable.

6.0 POSTAGE STAMP MARGINS

In addition to the rate proposals outlined above, and that of Consolidation, the Company is seeking approval for "postage stamp" rates (exclusive of gas costs) in its residential, commercial and small industrial classes across the Lower Mainland, Inland and Columbia divisions. The Company's cost reviews indicate that it is appropriate to make its schedules available at a uniform level to all customers in each of these customer classes.

Similar to the discussion following under Consolidation, a review of the existing margin differentials between the divisions arises out of historic reasons and are not necessarily related to present costs, nor future costs. The differentials arose at a time prior to the creation of BC Gas and following amalgamation of its underlying gas distribution companies.

The Company seeks to maintain the differential in rates insofar as they relate to gas supply costs. In the Lower Mainland and Inland divisions the differential in gas supply costs was recognized in the Phase A Gas hearing. With regard to the Columbia Division, the gas is supplied via sources quite distinct from that of the Lower Mainland and Inland divisions. The Columbia gas supply is predominantly delivered from the Alberta Natural Gas and NOVA pipeline systems, whereas the Inland and Lower Mainland divisions gas is delivered predominantly from the Westcoast Energy pipeline system. Since the gas cost aspect is not one over which the Company has significant control, it is the position of BC Gas that these gas costs should be considered as separate and distinct. It is the remaining costs that the Company seeks to reflect in its postage stamp rates.

As mentioned above, the historic margin differentials arise in part as a result of the fact that the three underlying divisions were three separate companies prior to being amalgamated into BC Gas. In the past, cities, towns and other communities were added to each of the separate divisions on a "rolled-in" basis. That is, their rates were not based on the specific cost to add them. Rather, they were added to the overall costs and revenues of the existing division's cost of service and the new customers in the added community were charged the "postage stamp" rate in that division. Given that the level of service was similar, to do otherwise would have been discriminatory. The amalgamation of the Lower Mainland, Inland and Columbia divisions into one company, and the similarities which are discussed below, lead the Company to seek a common margin.

In addition to the fact that the three divisions are now one corporate entity, the factors that lead the Company to seek postage stamp margins for the residential, commercial and general service classes include:

1) similar system design standards;

2) similar main extension policies;

3) similar policy with respect to the ownership of services and connections;

4) similar costs for each of the entities;

5) the same regulator, namely the British Columbia Utilities Commission;

6) the service areas all existing within the Province of British Columbia;

7) operational and administrative management from one single management group;

8) the identical cost of capital;

9) the same capital structure;

10) the same test year;

11) the same accounting methodologies;

12) similar depreciation rates;

13) natural gas service originated at about the same time period for the three divisions;

14) similar long run incremental costs;

15) economies of scale are being achieved and reflected to all divisions (e.g. cost of capital,

purchasing, human resources. See further discussion on Consolidation at Volume 1, Tab 5);

16) load characteristics of residential and commercial customers in the three divisions are similar; and

17) the difficulty in allocating operational and administrative costs and related capital overheads by division.

BC Gas is proposing in this application to introduce common General Terms and Conditions applicable to all rate classes, common depreciation rates applicable to all classes, and a common mains extension policy. A common utility margin would allow for economic neutrality (aside from gas costs). It is a view of BC Gas that fairness and equity in respect to present costs and future costs and the similarities outlined above lead the Company to the conclusion that a postage stamp margin is appropriate and meets the criterion of providing just and reasonable rates that are not unduly discriminatory, throughout its system. A review of other major utilities indicates that following a significant level of acquisitions and mergers of various utility entities requires integration and the creation of uniform rates.

7.0 CONSOLIDATION OF REVENUE REQUIREMENT

BC Gas is seeking approval for the consolidation of the Lower Mainland, Inland and Columbia divisions for revenue requirement purposes (Fort Nelson will continue to be treated separately). Consolidation is required for the regulatory regime to be cost effective, to simplify the revenue requirement applications of BC Gas and to capture further efficiencies. Consolidation would eliminate the need for three separate revenue requirements, three separate rate designs, three separate accounting practices and three separate Least Cost Integrated Resource Plans. The challenges of allocating common costs would also be eliminated. To affect its objectives of simplicity and administrative ease, a consolidated tariff including general terms and conditions as well as standardized rate schedules are proposed. This will significantly reduce the number of tariffs and the number of rate schedules.

Consolidation will recognize the economic reality that BC Gas is one corporate entity which manages its affairs in a consolidated manner. Consolidation reconciles the managerial conflicts which arise as a result of divisionalizing BC Gas. That is, on a divisional basis management would be required to make decisions on the basis of optimizing for a specific division irrespective of the concerns of the others. This can be illustrated through the difficulties in assessing the appropriateness of the company's integrated resource plan (IRP). The efficiency of the plan would be uncertain unless the IRP were reviewed in the context of each individual division. This is clearly neither feasible nor desirable.

Consolidation enhances the efficiencies and stability in the rates as between all the divisions. The area of stability was discussed at some length in the 1992 Revenue Requirement hearing and is graphically illustrated when Columbia is considered on a divisional and consolidated revenue requirement basis. On a consolidated basis the rate increase requested for 1993 would be 11%, while on a divisional basis the increase for the Columbia Division would be 30% (expressed as a percentage of margin).

The Commission in its August 1992 BC Gas revenue requirement decision recognized "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."

8.0 IMPLEMENTATION

For classes affected by the rate proposals other than the industrial classes, the effective date of January 1, 1994 for rates and tariffs is requested.

BC Gas seeks the proposed rates and tariffs for the industrial classes to be effective November 1, 1993. Since November 1 is the commencement of the gas year, practicality and convenience dictate that for industrial customers the rates and tariffs should be in place on that date. However, since the industrial classes are generally receiving a significant reduction, an immediate reduction would negatively impact the Company's 1993 financial results. BC Gas requests the creation of a deferral account with a balance equal to the reduction in total industrial revenue from proposed rates which would occur in November and December. This amount would then be taken into income by the Company during November and December. This would serve to keep the Company financially neutral. The deferral balance will be amortized by charges to the industrial classes over the 12 months commencing November 1, 1993.

9.0 RATE DESIGN IMPACTS

The impacts of the rate design proposals on the various classes in 1994 after the adjustments of the deferred charges, credits, and other amounts as set out in the discussion on impacts for each of the rate classes are estimated as follows:

(a) Residential

Increase (Decrease)

Lower Mainland	Inland	Columbia
3.28%	(3.91%)	2.96%

(b) Commercial

Increase (Decrease)

	Lower Mainland	Inland	Columbia
< 2,000 GJ/yr	6.3%	(14.5%)	3.1%
> 2,000 GJ/yr	(6.9%)	(12.8%)	N/A

(c) Industrial

As a result of the proposed rate design, the revenue requirement from the services applicable to the industrial classes has been reduced by approximately $10.8 million. Approximately $10.2 million is a reduction in revenue requirement from the large interruptible class in the Lower Mainland. $1.1 million is a reduction from Lower Mainland firm industrials, with other industrial customer classes receiving relatively minor increases or decreases.

10.0 PUBLIC PROCESS

The Company, in this application, has put forward proposals which, in its view, are in the interest of each of its customer groups, while at the same time embracing broader societal goals and objectives.

However, from another perspective the application forms a focal point to encourage an expanded dialogue and understanding with its customers and governments at the provincial, municipal and regional levels.

The economic environment in which the Company provides service is both dynamic and evolving and, accordingly, processes which promote and facilitate understanding, while at the same time providing flexibility, are required.

The Company proposes to adopt an interactive public process which will promote and facilitate an enhanced public understanding while at the same time encourage the development of a specific list of issues or concerns to be more fully addressed at the Public Hearing commencing on July 5, 1993.

BC Gas requests that the Commission give consideration to a pre-hearing conference, at which time issues and concerns, if any, can be reviewed and at which consideration can be given to the best means of resolving those issues or concerns. From a practical perspective it may be that certain matters should be considered at the hearing, whereas others would be more appropriately resolved by a less formal process.

11.0 CONCLUSION

The rate design proposals in this application are the result of consideration and analyses of numerous factors. They include detailed cost studies, competitive price studies, industrial complaints, tariff reviews and Commission comments. The proposals seek to balance the numerous factors which go into establishing just and reasonable rates.

LOWER MAINLAND
SALES & TRANSPORTATION SERVICES
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES

PRESENT RATE CLASSES				PROPOSED RATE CLASSES			
Schedule	**Type of Service**	**Rate Block**	**Rate**	**Schedule**	**Type of Service**	**Rate Block**	**Rate**
2101,2102, 2207,2208, 2209	Residential & General Service	Basic Charge/2 mo.period First 1,000 GJ/period Next 15,000 GJ/period Next 34,000 GJ/period All Additional GJ/period	$9.28/2 mo. $4.392/GJ $3.902/GJ $3.652/GJ $3.432/GJ	1	Residential	Basic Charge/2 mo. All gigajoules	$14.00 $ 4.47
				2	Small Commercial (0-2,000 GJ per year)	Basic Charge/2 mo. All gigajoules	$28.00 $ 4.41
				3	Large Commercial (over 2,000 GJ per year)	Basic Charge/2 mo. All gigajoules	$28.00 $ 4.03
2601, 2602	Seasonal Off-Peak Service	<u>During Off-Peak Period</u> First 200 GJ or less Next 300 GJs All additional GJs <u>During the Peak Period</u> First 5 GJs All additional GJs MINIMUM CHARGE	 $517.96/mo $2.590/GJ $2.170/GJ $3.450/GJ $7.740/GJ $517.96/mo/off-peak $10.00/mo/peak period	4	Seasonal Service	Basic Charge/mo. Each Gigajoule MINIMUM CHARGE	$300.00 Summer $1.98 Winter $8.94 $300.00/mo (when gas is consumed)
				5	General Firm Service (greater than 50% non-space heating)	Basic Charge/mo. Delivery Charge/GJ Gas Cost Recovery/GJ MINIMUM CHARGE	$300.00 Summer $0.75 Winter $1.50 $2.291 $300.00/mo.
2206	General Service Transportation	Basic Charge All gigajoules	$9.28/2 mo. $3.476/GJ	6	NGV	Basic Charge/mo. Delivery Charge/GJ Gas Cost Recovery/GJ MINIMUM CHARGE	$35.00 (0-4,000 GJ) $2.00 (>4,000 GJ) $1.00 $1.576 $35.00/mo.

LOWER MAINLAND
SALES & TRANSPORTATION SERVICES
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES

PRESENT RATE CLASSES				PROPOSED RATE CLASSES			
Schedule	**Type of Service**	**Rate Block**	**Rate**	**Schedule**	**Type of Service**	**Rate Block**	**Rate**
2501	Interrup. Sales	First 1,500 GJ/mo Next 6,500 GJ/mo Next 17,000 GJ/mo All Additional GJ/mo Unauthorized gas/GJ MINIMUM CHARGE	$4,176.15 $2.588/GJ $2.358/GJ $2.328/GJ $18.840/GJ $4,176.15/mo	7	General Interruptible Service	Basic Charge/mo. Delivery Charge/GJ Level 1 Level 2 Commodity Charge/GJ MINIMUM CHARGE	$700.00 Summer $0.75 Winter $1.20 Summer $0.70 Winter $0.95 Summer $1.10 Winter $1.90 $700.00/mo.
2502	Interrup. Sales	First 1,500 GJ/mo Next 6,500 GJ/mo Next 17,000 GJ/mo All Additional GJ/mo OPTION A: Rate above plus OPTION B: Rate above plus Unauthorized gas/GJ MINIMUM CHARGE Apr - Oct Nov - Mar	$4,176.15 $2.588/GJ $2.358/GJ $2.328/GJ $0.30/GJ $0.60/GJ $18.840/GJ $4,176.15/mo $4,626.15/mo				
2006/2007	Firm Transportation Service	Basic Charge All gas transported/mo.	$500.00/mo $1.687/GJ	25	General Firm Transportation	Basic Charge/mo Delivery Charge/GJ Admin. Charge/mo. MINIMUM CHARGE	$300.00 Summer $0.75 Winter $1.50 $175.00 $475.00/mo.
				27	General Interruptible Transportation	Basic Charge/mo. Delivery Charge/GJ Level 1 Level 2 Admin. Charge/mo. MINIMUM CHARGE	$700.00 Summer $0.75 Winter $1.20 Summer $0.70 Winter $0.95 $175.00 $875.00/mo.

LOWER MAINLAND
SALES & TRANSPORTATION SERVICES
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES

PRESENT RATE CLASSES				PROPOSED RATE CLASSES			
Schedule	**Type of Service**	**Rate Block**	**Rate**	**Schedule**	**Type of Service**	**Rate Block**	**Rate**
10	Large Volume Interruptible Sales	Mo. Reservation Charge/10^3M^3 of MDSV - Level 1 Commodity Charge/GJ Level 1 Level 2 MIN. CHARGE for LEVEL 1 MIN. CHARGE for LEVEL 2	$290.00 $1.15 -Winter $1.00 - Summer $1.60 -Winter $1.10 - Summer Reserv. Charge times MDSV No minimum charge	10	No changes proposed as part of this application		
13	Interrup. Peaking and Backstopping	Commodity Chge/GJ	Rate under 2101 & 2102 less $0.85/GJ	13	Interruptible Peaking & Backstopping	Commodity Charge/GJ	Summer $1.85 Winter $4.69
22	Large Industrial Firm & Interruptible Transportation	Basic Charge Mo. Demand Chge/10^3M^3 of firm MDTV Commodity Rate/GJ Firm Volume Interruptible Level 1 Volume Level 2 Volume MINIMUM CHARGE OPTIONAL FIRM CURTAILMENT BUYOUT Buyout Surcharge/10^3M^3 of Firm Buyout Imbalance Charge	$800.00/mo n/a $1.687/GJ n/a $0.853/GJ Basic Chge plus amt based upon a minimum mo. vol. of 1,500 GJ $305.70/mo. $0.95/GJ	22	Large Industrial Interruptible Transportation	Basic Charge/mo. Delivery Charge/GJ Level 1 Level 2 Admin. Charge/mo. MINIMUM CHARGE Level 1 - Summer - Winter Level 2 - Summer - Winter	$1,350.00 Summer $0.70 Winter $0.95 Summer $0.50 Winter $0.75 $500.00 $15,850/mo. $20,850/mo. $11,850/mo. $16,850/mo.
				23	Transmission	Delivery Charge/GJ	Rates subject to negotiation
2103,2104	Residential Pension Service	As above for 2101, 2102	25% discount on above Residential & General Service	Schedules 2103 and 2104 are to be terminated.			
2191,2294	L.P. Gas Service	As above for 2101, 2102, 2207, 2208, 2209	Inactive	Schedules 2191 and 2294 are to be terminated.			

INLAND
SALES & TRANSPORTATION SERVICE
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES ✲

PRESENT RATE CLASSES				PROPOSED RATE CLASSES*			
Schedule	**Type of Service**	**Rate Block**	**Rate**	**Schedule**	**Type of Service**	**Rate Block**	**Rate**
1	Residential Service	Option A: Basic Charge First 10.5 GJ Excess over 10.5 GJ Option B: Basic Charge First 10.5 GJ Excess over 10.5 GJ	 $3.52/mo + 1.24 x amt of promo. incentive ÷ 100 $4.893/GJ $4.383/GJ $3.52/mo. $4.893/GJ $4.383/GJ	1	Residential	Option A: Basic Charge/mo. All gigajoules Option B: Basic Charge/mo. All gigajoules	 $7.00 + 1.24 x amt of promo. incentive ÷ 100 $4.20 $7.00 $4.20
2.1 2.2	General Service	Less than 6,000 GJ/yr Basic Charge First 6.0 GJ Next 99.5 GJ Excess over 105.5 GJ Excess of 6,000 GJ/yr Basic Charge First 6.0 GJ Next 99.5 GJ Excess over 105.5	 $12.91/mo $5.574/GJ $4.914/GJ $4.314/GJ $12.91/mo $5.225/GJ $4.565/GJ $3.965/GJ	2 3	Small Commercial (0 - 2,000 GJ per year) Large Commercial (over 2,000 GJ per year)	Basic Charge/mo. All gigajoules Basic Charge/mo. All gigajoules	$14.00 $ 4.121 $14.00 $ 3.79
4.1 4.2	Dual Fuel Service	Less than 96,000 GJ/yr Basic Charge/mo First 1,055 GJ Excess over 1,055 GJ Excess of 96,000 GJ/yr Basic Charge/mo First 1,055 GJ Excess over 1,055	 $325.00/mo. $2.593/GJ $2.546/GJ $325.00 $2.338/GJ $2.291/GJ	4	Seasonal Service	Basic Charge/mo. Each gigajoule MINIMUM CHARGE	$300.00 Summer $1.89 Winter $8.40 $300.00/mo. when gas is consumed.
5.1 5.2 5.3	Large Firm Service	Less than 96,000 GJ/yr Basic Charge/mo First 500 GJ Excess over 500 GJ Excess of 96,000 GJ/yr Basic Charge/mo First 500 GJ Excess over 500 GJ Excess of 360,000 GJ/yr Basic Charge/mo First 500 GJ Excess over 500 GJ	 $500.00/mo $4.231/GJ $3.091/GJ $500.00/mo $3.976/GJ $2.836/GJ $500.00/mo $3.749/GJ $2.609/GJ	5	General Firm Service (greater than 50% non-space heating)	Basic Charge/mo. Delivery Charge/GJ Gas Cost Recovery/GJ MINIMUM CHARGE	$300.00 Summer $0.75 Winter $1.50 $2.096 $300.00/mo.

* Franchise Fees to be collected in separate charge
✲ Excludes Revelstoke

INLAND
SALES & TRANSPORTATION SERVICE
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES *

PRESENT RATE CLASSES				PROPOSED RATE CLASSES*			
Schedule	Type of Service	Rate Block	Rate	Schedule	Type of Service	Rate Block	Rate
6	Special Industrial Firm Sales		Not Active	Schedule 6 is being terminated in its present form			
14	Firm Vehicle Service	Option A: First 10 GJ/mo. x N All additional GJ MINIMUM MO. BILL WITH NO SEASONAL OR TEMPORARY DISCONNECTS Option B: Per GJ MINIMUM MO. BILL WITH NO SEASONAL OR TEMPORARY DISCONNECTS	 $7.235/GJ $3.555/GJ $30.00/vehicle or $500.00/mo. whichever is greater $3.555/GJ $200.00/mo.	6	NGV	Basic Charge/mo. Delivery Charge/GJ Gas Cost Recovery/GJ MINIMUM CHARGE	$35.00 (0-4,000 GJ) $2.00 (>4,000 GJ) $1.00 $1.458 $35.00/mo.
7	General Interruptible Sales	From April 1 - October 31 Basic Charge Commodity Rate First 500 GJ Excess over 500 GJ From November 1-March 31 Basic Charge Commodity Rate First 500 GJ Excess over 500 GJ Unauthorized Overrun charge	 $750.00.mo. $3.234/GJ $2.094/GJ $750.00/mo. $3.847/GJ $2.533/GJ $13.863/GJ	7	General Interruptible Service	Basic Charge/mo. Delivery Charge/GJ Level 1 Level 2 Commodity Charge/GJ MINIMUM CHARGE	$700.00 Summer $0.75 Winter $1.20 Summer $0.70 Winter $0.95 Summer $1.10 Winter $1.90 $700.00/mo.
25	Small Industrial Transportation Service	CAPTIVE RATE Basic Charge Commodity Rate First 500 GJ Excess over 500 GJ Customer Charge NON-CAPTIVE RATE Basic Charge Commodity Rate SHORT TERM SALES Mo. Demand Charge Commodity Sales Rate From Apr 1 - Oct 31 From Nov 1 - Mar 31 Authorized Overrun sales	 $500.00/mo. $2.145/GJ $1.005/GJ $500.00/mo Negotiated Negotiated $253.62/$10^3M^3$ /MDSV $2.600/GJ $2.690/GJ $3.254/GJ	25	General Firm Transportation	Basic Charge/mo. Delivery Charge/GJ Admin. Charge/mo. MINIMUM CHARGE	$300.00 Summer $0.75 Winter $1.50 $175.00 $475.00/mo.

INLAND
SALES & TRANSPORTATION SERVICE
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES ✲

PRESENT RATE CLASSES				PROPOSED RATE CLASSES*			
Schedule	**Type of Service**	**Rate Block**	**Rate**	**Schedule**	**Type of Service**	**Rate Block**	**Rate**
				27	General Interruptible Transportation	Basic Charge/mo. Delivery Charge/GJ Level 1 Level 2 Admin. Charge/mo. MINIMUM CHARGE	$700.00 Summer $0.75 Winter $1.20 Summer $0.70 Winter $0.95 $175.00 $875.00/mo.
10	Large Volume Interruptible Sales	Mo. Reservation Charge/10^3M^3 of MDSV - Level 1 Commodity Charge/GJ Level 1 Level 2 MIN. CHARGE for LEVEL 1 MIN. CHARGE for LEVEL 2	$290.00 $1.15 -Winter $1.00 - Summer $1.60 -Winter $1.10 - Summer Reserv. Charge times MDSV No minimum charge	10	No changes proposed in this application		
13	Interruptible Peaking and Backstopping	Commodity Chge/GJ	$2.464/GJ	13	Interruptible Peaking & Backstopping	Commodity Charge/GJ	Summer $1.85 Winter $4.42

* Franchise Fees to be collected in separate charge
✲ Excludes Revelstoke

INLAND
SALES & TRANSPORTATION SERVICE
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES*

PRESENT RATE CLASSES				PROPOSED RATE CLASSES*			
Schedule	**Type of Service**	**Rate Block**	**Rate**	**Schedule**	**Type of Service**	**Rate Block**	**Rate**
22	Large Industrial Firm & Interruptible Transportation	Basic Charge Mo. Demand Chge/10³M³ of firm MDTV Commodity Rate/GJ Mo. Firm Volume Interruptible Mo. Level 1 Volume Level 2 Volume MINIMUM CHARGE OPTIONAL FIRM CURTAILMENT BUYOUT Buyout Surcharge/10³M³ of Firm Buyout Rate for Imbalance Quantities	n/a $254.94 $0.0882/GJ n/a $0.3800/GJ Shall be the greater of $7,214.80 or Mo. Demand Chge x firm MDTV. If no firm service contracted, min. chge for interrup. service of $11,400.00/mo. $256.06/mo. $0.95/GJ	22A	Large Industrial Firm & Interruptible Transportation	Basic Charge/mo. Mo. Demand Charge/10³M³ of DTQ Transportation Variable Charge/GJ Firm Volume Interrup. Volume Admin. Charge/mo. Unauthorized Gas/GJ MINIMUM CHARGE OPTIONAL FIRM CURTAILMENT BUYOUT Buyout Surcharge/10³M³ of Firm Buyout Rate for Imbalance Quantities	$2,700.00 $254.94 $0.044/GJ $0.380/GJ $500.00 Table of charges $ Depends on firm nomination $256.06/mo. $0.95/GJ
				22	Large Industrial Interruptible Transportation	New Schedule 22 will be identical to that proposed for the Lower Mainland	
23	Interruptible Transportation	Commodity Rate	Rates subject to negotiation	23	Transmission	Delivery Charge/GJ	Rates subject to negotiation
30	Interruptible Transportation		Not active	Schedule 30 is being terminated in its present form.			

* Franchise Fees to be collected in separate charge
* Excludes Revelstoke

COLUMI
SALES & ıRANSPORTATION SERVICE
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES

PRESENT RATE CLASSES				PROPOSED RATE CLASSES*			
Schedule	**Type of Service**	**Rate Block**	**Rate**	**Schedule**	**Type of Service**	**Rate Block**	**Rate**
1	Residential Service	Option A: Basic Charge All gigajoules Option B: Basic Charge All gigajoules	$3.90/mo. x amt of promo. incentive ÷ 100 $3.829/GJ $3.90/mo. $3.829/GJ	1	Residential	Basic Charge/mo. All gigajoules	$7.00 $3.78
2.1 2.2	General Service	Basic Charge First 50 GJ Next 50 GJ Excess over 100 GJ Basic Charge First 50 GJ Next 50 GJ Excess over 100	$8.75/mo $3.581/GJ $3.481/GJ $3.402/GJ $8.75/mo $3.581/GJ $3.481/GJ $3.402/GJ	2	Small Commercial	Basic Charge/mo. All gigajoules	$14.00 $3.56
4	Seasonal Service	Basic Charge/mo All gigajoules	$1,000.00/mo. $2.856/GJ	4	Seasonal Service	Basic Charge/mo. Each gigajoule MINIMUM CHARGE	$300.00 Summer $2.07 Winter $7.56 $300.00/mo. (when gas is consumed)
3	Small Industrial Service	Basic Charge/mo First 500 GJ Next 2000 GJ Excess over 2,500 GJ	$500.00/mo $3.105/GJ $2.855/GJ $2.642/GJ	5	General Firm Service (greater than 50% non-space heating)	Basic Charge/mo. Delivery Charge/GJ Gas Cost Recovery/GJ MINIMUM CHARGE	$300.00 Summer $0.75 Winter $1.50 $2.067 $300.00/mo.

* Franchise Fees to be collected in separate charge

COLUMI
SALES & TRANSPORTATION SERVICE
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES

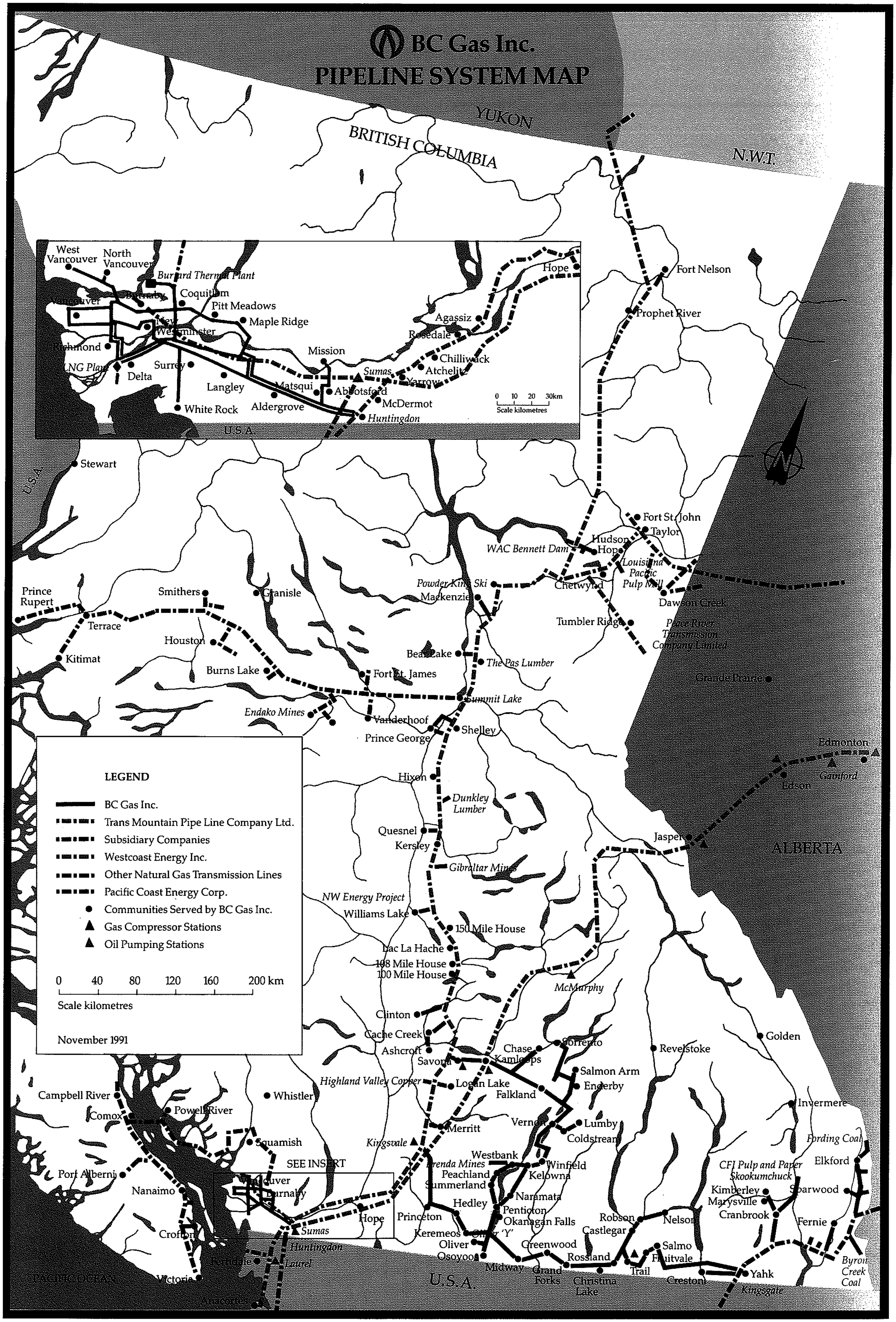
PRESENT RATE CLASSES				PROPOSED RATE CLASSES*			
Schedule	Type of Service	Rate Block	Rate	Schedule	Type of Service	Rate Block	Rate
5	Natural Gas Vehicle Fuel Service	Option A: Fleet Vehicle Service First 10 GJ/mo x N All Additional GJ MINIMUM MO.BILL WITH NO SEASONAL OR TEMPORARY DISCONNECTS Option B: General Vehicle Service All gigajoules MINIMUM MO. BILL WITH NO SEASONAL OR TEMPORARY DISCONNECTS	 $6.881/GJ $3.136/GJ $30.00/natural gas converted vehicle of $500.00, whichever is greater $3.136/GJ $200.00/mo	6	NGV	Basic Charge/mo. Delivery Charge/GJ Gas Cost Recovery/GJ MINIMUM CHARGE	$35.00 (0-4,000 GJ) $2.00 (>4,000 GJ) $1.00 $1.779 $35.00/mo.
				7	General Interruptible Service	Basic Charge/mo. Delivery Charge/GJ Level 1 Level 2 Commodity Charge/GJ MINIMUM CHARGE	$700.00 Summer $0.75 Winter $1.20 Summer $0.70 Winter $0.95 Summer $1.70 Winter $2.07 $700.00/mo.
7	Large Volume Firm Service	Cost of gas charges under Tariff Sheet No. 59, Section 6(b) Mo. Demand Charges - $/10^3M^3 Cominco Crestbrook Fording Westar Balmer Westar Greenhills Line Creek	Cost of gas Commodity Charge $229.57/10^3M^3/mo — $0.6795/GJ $211.01/10^3M^3/mo — $0.2562/GJ $176.58/10^3M^3/mo — $0.8118/GJ $ 64.59/10^3M^3/mo — $0.1704/GJ $178.26/10^3M^3/mo — $0.2391/GJ $255.49/10^3M^3/mo — $0.3116/GJ	22B	Large Industrial Firm & Interruptible Transportation	Large Industrial Service to existing firm customers to be continued on a closed schedule.	
				25	General Firm Transportation	Basic Charge/mo. Delivery Charge/GJ Admin. Charge/mo. MINIMUM CHARGE	$300.00 Summer $0.75 Winter $1.50 $175.00 $475.00/mo.

* Franchise Fees to be collected in separate charge

COLUMB
SALES & TRANSPORTATION SERVICE
PERMANENT RATES EFFECTIVE JAN 1, 1993 COMPARED WITH PROPOSED RATES

PRESENT RATE CLASSES				PROPOSED RATE CLASSES*			
Schedule	Type of Service	Rate Block	Rate	Schedule	Type of Service	Rate Block	Rate
				27	General Interruptible Transportation	Basic Charge/mo.	$700.00
						Delivery Charge/GJ Level 1	Summer $0.75 Winter $1.20
						Level 2	Summer $0.70 Winter $0.95
						Admin. Charge/mo.	$175.00
						MINIMUM CHARGE	$875.00/mo.

* Franchise Fees to be collected in separate charge


BC Gas Inc.
PIPELINE SYSTEM MAP
YUKON
BRITISH COLUMBIA
N.W.T.
ALBERTA
U.S.A.
PACIFIC OCEAN
LEGEND
BC Gas Inc.
Trans Mountain Pipe Line Company Ltd.
Subsidiary Companies
Westcoast Energy Inc.
Other Natural Gas Transmission Lines
Pacific Coast Energy Corp.
Communities Served by BC Gas Inc.
Gas Compressor Stations
Oil Pumping Stations
0 40 80 120 160 200 km
Scale kilometres
November 1991
SEE INSERT
West Vancouver
North Vancouver
Burrard Thermal Plant
Vancouver
Burnaby
Coquitlam
Pitt Meadows
Maple Ridge
New Westminster
Richmond
LNG Plant
Delta
Surrey
Langley
White Rock
Aldergrove
Matsqui
Abbotsford
Mission
Sumas
Yarrow
Huntingdon
McDermot
Chilliwack
Atchelitz
Rosedale
Agassiz
Hope
0 10 20 30km
Scale kilometres
Fort Nelson
Prophet River
Stewart
Fort St. John
Taylor
Hudson Hope
WAC Bennett Dam
Louisiana Pacific Pulp Mill
Chetwynd
Dawson Creek
Tumbler Ridge
Peace River Transmission Company Limited
Grande Prairie
Powder King Ski
Mackenzie
Prince Rupert
Smithers
Granisle
Terrace
Kitimat
Houston
Burns Lake
Fort St. James
Bear Lake
The Pas Lumber
Summit Lake
Endako Mines
Vanderhoof
Prince George
Shelley
Hixon
Dunkley Lumber
Quesnel
Kersley
Gibraltar Mines
NW Energy Project
Williams Lake
150 Mile House
Lac La Hache
108 Mile House
100 Mile House
Clinton
Cache Creek
Ashcroft
Savona
Kamloops
Chase
Sorrento
Salmon Arm
Enderby
Logan Lake
Falkland
Highland Valley Copper
Merritt
Kingsvale
McMurphy
Jasper
Edson
Edmonton
Gainford
Golden
Revelstoke
Invermere
Vernon
Lumby
Coldstream
Winfield
Kelowna
Westbank
Brenda Mines
Peachland
Summerland
Naramata
Penticton
Okanagan Falls
Hedley
Princeton
Keremeos
Oliver
Osoyoos
Oliver 'Y'
Greenwood
Midway
Grand Forks
Christina Lake
Rossland
Trail
Castlegar
Robson
Nelson
Salmo
Fruitvale
Creston
Yahk
Kingsgate
Kimberley
Marysville
Cranbrook
CFI Pulp and Paper Skookumchuck
Fording Coal
Elkford
Sparwood
Fernie
Byron Creek Coal
Campbell River
Comox
Powell River
Whistler
Squamish
Port Alberni
Nanaimo
Crofton
Victoria
Ferndale
Laurel
Anacortes

REGULATORY CONSOLIDATION

1.0 INTRODUCTION

BC Gas seeks approval for the consolidation of the Lower Mainland, Inland and Columbia Divisions for regulatory purposes. That is, that the utility's revenue requirement (exclusive of gas costs) be determined as one regulated entity and not on the basis of three separate divisions. It is the proposal of the Company that once the Commission has determined the overall consolidated revenue requirement that any shortfall in revenue requirement should be recovered through an equal percentage increase to the gross utility margin contained in the rates of all customers (except those to whom special circumstances apply). Consolidation does not seek to adjust the historical rate differentials. Rather, that discussion is left to a separate consideration under the proposed postage stamping of margins (exclusive of gas costs) discussed in the Application Outline. What is meant by consolidation is that the increases in the overall revenue requirement occurring as a result of changes since 1992 would be spread evenly to all customers as a percentage of gross margin. Consolidation also means the elimination of divisional differences and the adoption of common accounts, common depreciation rates, common accounting policies and common cost of capital. This method was directed by the Commission in the 1992 BC Gas Revenue Requirement Decision on the basis that consistency and neutrality would be maintained.

Consolidating the revenue requirement and recognizing the three divisions as one regulated entity will allow BC Gas to capture the additional efficiencies flowing from consolidation. Consolidation will recognize the economic reality that BC Gas is one corporate entity which manages its affairs in a consolidated manner. Consolidation reconciles the managerial conflicts which arise as a result of divisionalizing BC Gas. That is, on a divisional basis management would be required to make decisions on the basis of optimizing for a specific division irrespective of the concerns of the others. This can be illustrated through the difficulties in assessing the appropriateness of the company's integrated resource plan (IRP). The efficiency of the plan would be uncertain unless the IRP were reviewed in the context of each individual division. This is clearly neither feasible nor desirable.

Consolidation enhances the efficiencies and stability in the rates as between all the divisions. The area of stability was discussed at some length in the 1992 Revenue Requirement hearing and is graphically illustrated when Columbia is considered on a divisional and consolidated revenue requirement basis. On a consolidated basis, the 1993 rate increase is 11% expressed as a percent of margin, on a divisional basis 30%.

In the 1992 revenue requirement proceedings, these efficiencies and benefits were discussed at considerable length in the evidence of Mr. John Butler and BC Gas company witnesses. Mr. Butler provided a thorough history of this matter in major Canadian gas utility jurisdictions. He set out how technology in the industry leads to the need, first, for acquisitions and amalgamations and, subsequently, for consolidations in the continuous pursuit of efficiencies. BC Gas is much the same as those outlined in his report, which is attached as Appendix C under this Tab. In addition to the evidence of the Company and that of Mr. Butler, Dr. Waters acting on behalf of the staff of the Utilities Commission also acknowledged the benefits of consolidating the divisions of BC Gas. At page 80 of his evidence he states:

> "consolidation may be regarded as the final step in a process that brought four independent, distinct

> and disparate companies under a single corporate roof. At present, the four still operate as separate divisions, the full benefits of amalgamating the four companies cannot be realized until the remaining diseconomies that result from operating separate divisions can be eliminated".

He concurred with the study of Mr. Butler as to the major potential benefits of approving consolidation. They include:

"(1) reduced regulatory expense;

(2) simplification of management;

(3) simple regulatory oversight and savings to the BCUC and the Company;

(4) savings and accounting costs for keeping a single set of books instead of four sets;

(5) more flexible use of manpower;

(6) the elimination of complexity and administering projects which cross divisional boundaries;

(7) more flexibility in the utilization of gas supplies; and

(8) cost savings from the integration of service departments such as marketing and advertising, engineering and safety, planning, maintenance, legal and purchasing."

In the 1992 Revenue Requirement Decision the Commission found that the evidence submitted indicated that consolidation would achieve savings and efficiency and that consolidation would not impede the ability of BC Gas to finance future capital requirements, to continue the existing covenants, or to maintain service at the required levels. The Commission recognized 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 Phase B Rate Design hearing will provide an appropriate forum for the 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 also found that no one in the hearing favoured the "stand alone" approach or divisional approach. Moreover, the Commission did acknowledge and order that the independent capital structures of the subsidiary utilities, which had been accepted in the past on the basis that each separate legal entity had a distinct source of funds and a "stand alone" capital structure, had become extinct with the amalgamation that formed BC Gas. The Commission directed that the BC Gas utility divisions adopt a common capital structure for regulatory purposes. While the Commission emphasized that it did not mean that divisional accounts, rate base, revenue and operating costs should also be terminated, the Commission did approve a consolidated capital structure and ordered that the applicant must address the equitable treatment of the deferred income tax carried in the books of the divisions and other similar distinct and separate accounts unique to any particular division.

2.0 FULLY DISTRIBUTED COST STUDIES

This application, in accordance with the Commission's earlier decision, includes fully distributed cost studies for each of the Lower Mainland, Inland and Columbia Divisions. One of the findings is that the cost margins incurred by BC Gas in serving the residential class are quite similar. The residential per unit costs to serve (excluding gas supply cost) as indicated on pages 1.2, 2.2 and 3.2 of the Lower Mainland, Inland and Columbia cost of service studies in Volume 2, Tabs 2A, 2B, 2C, respectively, are as follows:

		($/GJ)	
	PR	NCD	AED
Lower Mainland	$2.489	$2.304	$2.283
Inland	2.579	2.481	2.462
Columbia	2.560	2.520	2.481

The same can also be said for the Small Commercial Schedule 2 class. The FDC results found on pages 1.2A, 2.2A and 3.2A of Sections 3, 4 and 5 in Volume 2, Tab 2D, are as follows:

		($/GJ)	
	PR	NCD	AED
Lower Mainland	$2.060	$1.859	$1.819
Inland	1.846	1.725	1.682
Columbia	1.657	1.615	1.568

Similarly, the FDC results found on pages 1.2A, 2.2A and 3.2A of Sections 3, 4 and 5 in Volume 2, Tab 21D for the Large Commercial Schedule 3 are as follows:

		($/GJ)	
	PR	NCD	AED
Lower Mainland	$1.358	$1.192	$1.198
Inland	1.223	1.123	1.160
Columbia	N/A	N/A	N/A

The FDC results found on pages 1.2A, 2.2A and 3.2A of Sections 3, 4 and in Volume 2, Tab 2D for General Service Schedule 5 are as follows:

	($/GJ)		
	PR	NCD	AED
Lower Mainland	$0.973	$0.861	$0.932
Inland	0.934	0.859	0.932
Columbia	0.874	0.846	0.918

The treatment of depreciation rates, deferred tax balances and other deferral account balances are discussed below.

3.0 DEPRECIATION

Except for a few categories, the depreciation and amortization rates approved for the four divisions are the same.

In order to move to common ground, BC Gas hereby applies for Commission approval of:

a) common depreciation rates applicable to similar plant categories for all divisions where rates presently differ or where no rate presently exists;

b) deletion of certain depreciation rates for categories where there is no plant in any of the four divisions; and

c) common amortization rates applicable to similar contributions in aid of construction categories for all divisions where rates presently differ;

all as set out in Appendix B of this Tab; and

d) an effective date of January 1, 1994 for these changes.

The proposed changes in Appendix B, based on forecast December

31, 1992 plant balances as contained in the 1993 Revenue Requirement Application Volume 1, reduce the depreciation expense by $1.8 million.

	Division ($ 000)				
	Lower Mainland	Inland	Columbia	Fort Nelson	Total
Existing Rates					
- Depreciation	$24,352	$9,352	$978	$118	$34,800
- Amortization	(526)	8,691	(57)	94	(1,268)
	23,826	8,691	921	94	33,532
Proposed Rates					
- Depreciation	22,530	9,356	978	118	32,982
- Amortization	(540)	(661)	(57)	(20)	(1,278)
	21,990	8,695	921	98	31,704
Increase (Decrease)	$(1,836)	$ 4	$ --	$ 4	$(1,828)

In Appendix B (Pages 7 to 9), there is a description of the proposed depreciation rate changes.

4.0 FRANCHISE FEES

There are no franchise fees payable in the Lower Mainland and Fort Nelson Divisions and, hence, no costs are embodied in the rates of those divisions.

In the Inland and Columbia Divisions, a 3% franchise fee is payable to cities and municipalities on the amount received by the Company for gas consumed within city or municipal boundaries. The respective average franchise fees are part of the rates applicable to all customers of the two divisions. If, for example, it has been determined that 90% of the Inland division residential revenues are generated within municipal boundaries, then an average franchise fee expense equal to 2.7% (3% x 90%) of all residential revenues is calculated and collected, whether customers reside within municipal boundaries or not. This has made "postage stamp" rates feasible which include franchise fees as part of the rates, rates which do not make a distinction with regard to the residence of a customer. A minor exception to the above is found in the large industrial rates of the Columbia division. Those rates do not include franchise fees. Customers are billed once a year for 3% of each customer's previous year's revenues earned within municipal boundaries.

While the Company believes that "postage stamp" rates (excluding gas costs) should apply to any and all customers of a rate class regardless of location within the overall BC Gas service area, it considers that franchise fees should be payable only by customers within the boundaries of those cities and municipalities which levy franchise fees.

Therefore, BC Gas hereby applies for Commission approval effective January 1, 1994 to

a) remove the average franchise fee contained in the rates applicable to customers within the Inland and Columbia divisions;

b) collect the amount of franchise fees by way of a separate Franchise Fee Charge to customers who reside or operate within the boundaries of cities or municipalities to which BC Gas pays franchise fees.

In addition, BC Gas seeks Commission approval for a negative Rider, equal to the Franchise Fee Charge, which will be applied as a draw-down of the accumulated deferred income tax balances of the Inland and Columbia Divisions. The net effect is that until the deferred tax balance has been depleted (estimated to be between 2.5 and 3 years for Inland, 1 year for Columbia), franchise fees will be paid out of the deferred income tax account balance.

Since the collection of franchise fees will be treated in a manner similar to the collection of a sales tax, franchise fee expense will no longer form part of utility margin.

The implementation of the proposed Franchise Fee Charge can be readily accommodated in the new CIS System scheduled to come on stream in 1994. However, special programming costs would have to be incurred if the existing Inland/Columbia CIS System were to be modified in the meantime. If the Franchise Fee Charge is to be shown as a separate item on customers' bills, a cost of approximately $125,000 for outside programming services would be incurred; if not shown separately on customers' bills, programming costs would be approximately $8,000. BC Gas favours approval of the latter.

5.0 DEFERRED INCOME TAX BALANCES - INLAND AND COLUMBIA DIVISIONS

By Order No. G-91-83 and Decision dated December 20, 1983, the Commission directed Inland Natural Gas Co. Ltd. and Columbia Natural Gas Limited (now the Inland and Columbia Divisions of BC Gas Inc.) to change the method of accounting for income taxes from the "normalized" to the "flow-through" method. The balances of deferred taxes as at January 31, 1984 were to remain on the books of both companies and were to be treated as a reduction from rate base.

Those balances, as reported in the 1993 Revenue Requirement Application Volume 4, are $11,031,000 and $1,559,000, respectively, for the Inland and Columbia Divisions.

In order to adjust the books of the divisions to a common level, BC Gas hereby applies for Commission approval to draw down the accumulated deferred income tax balances in the following manner:

a) <u>Inland</u>

The accumulated Inland deferred tax balance of $11,031,000 will be drawn down by a negative Rider in lieu of franchise fee charges, to be applied at 3.09% on the billings calculated under Inland rates. The draw-down is to commence January 1, 1994 and will cease when the balance is depleted, which is estimated to be between 2.5 and 3 years.

b) <u>Columbia</u>

The accumulated deferred tax balance of $1,559,000 will be drawn down as follows:

		$ 000
i)	An amount to be applied in 1993 to deferred charges in order to eliminate various accumulated balances under O.I.C. #953/89, NOVA/ANG toll increases etc., (see Appendix A, Page 4-03-14, Columbia)	$ 505
ii)	An amount to be applied in 1994 to Residential, Commercial and General Service rates to offset 50% of the proposed 1994 margin increase for those customer classes; (estimated amount)	$ 573
iii)	A negative Rider in lieu of 1994 franchise fee charges, similar to that proposed for the Inland service area in Item a), above (estimated balance)	$ 481
		$1,559

6.0 CONTRIBUTIONS IN AID OF CONSTRUCTION

Contributions in aid of construction result from customer contributions or government grants if construction costs are higher than allowed under the mains extension tests. Also, contributions are received for other reasons, such as highway relocations.

Since, in every case, contributions are an offset against plant costs, they do not constitute an issue on consolidation. Except for minor differences in the historic divisional mains extension tests, the existence of a substantial balance in the contributions account in one division as opposed to another must be associated with higher plant costs in the former as opposed to the latter. After netting costs and contributions, the divisions would be on a similar footing. Accordingly, BC Gas does not propose any special treatment for contributions in aid of construction on consolidation.

7.0 DIFFERENCES IN DIVISIONAL POLICIES WITH REGARD TO OPERATION AND MAINTENANCE EXPENSE CHARGED TO CONSTRUCTION

Consolidation of BC Gas Inc. will not increase the amount of overheads capitalized. The Capitalization Policy will not change. In service areas of the Company, overhead will continue to be capitalized, generally on the basis of labour costs directly charged to capital work. Capitalization ratios which are currently calculated at cost centre levels will be rolled up to higher organizational levels and composites will be determined and utilized. This will simplify the capitalization procedure. For those cost centres providing general and administrative services or corporate direction and management, a composite of the current capitalization ratios will be calculated and applied universally throughout the company.

8.0 DEFERRED CHARGES

8.1 Background

i) A forecast of December 31, 1992 deferred charge balances is found in 1993 Revenue Requirement Application Volume 1, Page 1-03-14, and by division on Page 4-03-14 under Tabs 2, 3, 4 and 5 in Revenue Requirement Volume 4.

The actual December 31, 1992 balances including an update of the relevant sections to be addressed on consolidation are shown in a similar fashion in Appendix A of this Tab.

The major difference between the forecast and actual 1992 year end balances is in the area of higher Valley Gas Sales Margins and VIA/Capacity Utilization Credits received, which reduced the total debit balance for all divisions from $5.1 to $3.6 Million.

ii) In the December 31, 1992 updated balances in Appendix A (and also in the 1993 Revenue Requirement Application) deferred charges are shown in two groups:

- Debits and credits to the line labelled "Subtotal" constitute balances accumulated to December 31, 1992 for items such as

  - net deferrals approved under Order in Council #953/89,

  - Rate Design Phase A rate changes deferred,

  - deferred 1992 Westcoast Energy and other toll increases by gas suppliers,

- valley gas sales margins deferred which in Rate Design Phase A were considered to be available as an offset to core customers' gas costs.

It is this first group of accounts which should be disposed of on consolidation.

- The second group of accounts of the respective Pages 1-03-14 in Appendix A are those below the subtotal. Balances represent items such as:

  - VIA/Capacity Utilization Credits for which Commission approval for a draw-down has already been received,

  - various costs for which Commission approval for amortization has already been received and where corresponding benefits are accruing in the divisions, such as increased sales from water-heater or NGV fuel grants,

  - items which require future resolution, such as the deferred Burrard Thermal Plant gas purchase cost deferral or the deferred B.C. Energy Council levies.

8.2 Disposition of Deferral Account Balances

The December 31, 1992 balances of the first group of accounts in Appendix A can be summarized as follows:

Division	$ 000
i) Lower Mainland	$ (771)
ii) Inland	(417)
iii) Columbia	505
iv) Fort Nelson	(128)
Total	$ (811)

i) Lower Mainland Division
Appendix A, Page 4-03-14

<u>Line No.</u>

1 T-Service Lost Margin

BC Gas proposes that the total of $3,271,000 be recovered from Lower Mainland customers (except Burrard Thermal, PCEC, and certain other accounts), through the application of a billing rider on all throughput for a 12-month period beginning January 1, 1994.

2 to 11 The December 31, 1992 balances for this group of deferral accounts total $(1,753,000).

In order to dispose of the various accounts, BC Gas proposes that the debit and credit balances be closed out to Line 3 - Phase A Rate Design Cost of Gas Deferrals re Rates 2501/2502 and the remaining balance of $(1.753) million in that account be flowed through to reduce firm sales gas costs, according to the Phase A methodology.

13/14 Rate Design Phase A - Burrard Interruptible

The disposition of this balance is subject to resolution of the dispute with B.C. Hydro.

15 VIA/Capacity Utilization Credits

A draw-down of the December 31, 1992 balance has been approved by BCUC Order No. G-110-92. BC Gas proposes that the balance remaining in that account on December 31, 1993 be credited to firm customers during 1994 according to the Phase A methodology.

16/17 1993 Rates 2501/02 Gas Cost Deferral and Rate 10 Margin Deferral

While approved under separate BCUC Orders, 1993 additions must be considered as part of the Gas Cost Reconciliation Account (GCRA) approved on an interim basis by BCUC Order No. G-5-93. Any balances as at December 31, 1993 will be dealt with in accordance with the GCRA methodology.

ii) Inland Division
Appendix A, Page 4-03-14

<u>Line No.</u>

1 to 12 The December 31, 1992 balances for this group of deferral accounts total $(417,000).

In order to dispose of the various accounts, BC Gas proposes that the debit and credit balances be closed out in 1993 to Lines 2/3 - Phase B Rate Design Cost of Gas/Margin

Deferrals re Rate 10 and the remaining balance in that account, $0.417 million, be flowed through to reduce Inland Division firm sales gas costs, according to the Phase A methodology.

13 VIA/Capacity Utilization Credits

A draw-down of the December 31, 1992 balance has been approved by BCUC Order No. G-110-92. BC Gas proposes that the balance remaining in that account on December 31, 1993 be credited to firm customers according to the Phase A methodology.

14/15 1993 Rate 10 Margin Deferral $(1.1) Million

While approved under separate BCUC Order in Phase A of the Rate Design Hearing, 1993 additions must be considered as part of the Gas Cost Reconciliation Account (GCRA) approved on an interim basis by BCUC Order No. G-5-93. Any balance as at December 31, 1993 will be dealt with in accordance with the GCRA methodology.

iii) Columbia Division
Appendix A, Page 4-03-14

<u>Line No.</u>

1 to 7 The December 31, 1992 balances for this group of deferral accounts total $505,000.

In order to dispose of the various accounts, BC Gas proposes that the debit and credit balances be closed out in 1993 to the accumulated deferred income tax balance of the Columbia Division. See also "Deferred Income Tax Balances" at page 9 of this Tab.

9 Westar Mining Receivables $524,000

Deferral of the Westar Mining accounts receivable plus related incidental expenses was approved by BCUC Order No. G-54-92. The outstanding balance will not be recoverable from Westar. BC Gas proposes that, commencing January 1, 1993, the account be amortized to Depreciation and Amortization Expense over 10 years.

iv) Fort Nelson Division
Appendix A, Page 4-03-14

<u>Line No.</u>

1 to 3 The December 31, 1992 balances for this group of accounts total $(128,000).

BC Gas will file in 1993 a separate application for the disposition of the credit balance.

9.0 DIFFERENT TARIFF PROVISIONS

In response to the Commission's comments on differences in tariff provisions, BC Gas has developed common general terms and conditions for all customers. They can be found under Tab 12 of Volume 1.

10.0 CONCLUSION

In conclusion, BC Gas believes that consolidation is an inevitable step, as, from an operation, financial and cost perspective, the divisions have merged. BC Gas has set out in this application proposals for the reconciliation of the remaining matters. BC Gas requests approval for consolidation in the manner as set out in this application.

BC GAS INC.
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1993
($000)

Line No.	Particulars	Account	Recorded Balance 12/31/92	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/93	Mid-Year Average 1993
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	T-Service Lost Margin	#179-065	$982	$2,289	$0	$2,289	$0	$0	$3,271	$2,127
2	Cost of Gas - Phase A	#179-067	1,825	0	0	0	(1,825)	0	0	913
3	Cost of Gas - Ph. A Rates 2501/2	#179-073	(2,828)	0	0	0	1,075	0	(1,753)	(2,291)
4	Cost of Gas/Margin - Phase A Rates 10 and 12	#279-060/ #179-073	(1,032)	0	0	0	615	0	(417)	(725)
5	Valley Gas Sales - Margin	#279-057	(6,191)	0	0	0	6,191	0	0	(3,096)
6	Valley Gas Sales Margin -V.I.J.V.	#279-061	(130)	0	0	0	130	0	0	(65)
7	WEI 1992 Tolls Increase	#179-068	4,637	0	0	0	(4,637)	0	0	2,319
8	WEI Liquid Recovery Service	#179-071	904	0	0	0	(904)	0	0	452
9	WEI Fuel Cost Increase	#179-072	410	0	0	0	(410)	0	0	205
10	O.I.C. #953/89 Deferrals (Net)	#279-027	(614)	0	0	0	933	(319)	0	(307)
11	COG/Other Deferrals Oct.-Dec./91	#279-030	(244)	0	0	0	289	(45)	0	(122)
12	Revelstoke Propane Cost	#279-024	70	0	0	0	(70)	0	0	35
13	$0.057 Rider Deferral	#279-026	1,387	0	0	0	(1,387)	0	0	694
14	NOVA/ANG 1992 Toll Increase	#179-081	39	0	0	0	0	(39)	0	20
15	NOVA 1992 Toll Decrease	#279-062	(37)	0	0	0	0	37	0	(19)
16	Intercompany Sales #G-113-91	#179-082	40	0	0	0	0	(40)	0	20
17	AOR Revenue (CNG)	#279-018	(29)	0	0	0	0	29	0	(15)
18	Subtotal		(811)	2,289	0	2,289	0	(377)	1,101	145
19	Cost of Gas - Phase A									
20	- Burrard Interruptible	#179-067	(730)	(1,000)	0	(1,000)	0	1,730	0	(365)
21	VIA/Capacity Utilization Credits	#179-070	(5,690)	0	0	0	0	3,666	(2,024)	(3,857)
22	Cost of Gas - Ph. A Rates 2501/2	#179-073	0	(1,867)	0	(1,867)	0	0	(1,867)	(934)
23	Margin - Phase A	#279-060/								
24	Rate 10	#179-073	0	(2,419)	0	(2,419)	0	0	(2,419)	(1,210)
25	Westar Mining Receivable	#179-069	474	50	0	50	(52)	0	472	473
26	Valley Gas Sales - Schedule 23	#279-058	(285)	0	0	0	0	285	0	(143)
27	Deferred Interest	#179-008	1,567							
28	Market Rebate Incentive									
29	- Water Heater Grants *	#179-052	720							
30	- Multi-Family Space Heating *	#179-013	0							
31	- Commercial Fuel Substitution *	#179-013	0							
32	NGV Conversion Grants *	#179-018	743							
33	Conversion Grants - Revelstoke	#179-042	(63)							
34	Local Gas Development *	#179-053	6,779							
35	Rate Design Costs - Phase B *	#179-058	121							
36	Revenue Req. Hearing - 1992 *	#179-059	134							
37	Revenue Req. Hearing - 1993 *	#179-059	73							
38	Demand Side Management *	#179-063	19							
39	Integrated Resource Plan *	#179-064	9							
40	Appliance Insurance Program *	#179-079	144							
41	FNG Deferred Revenue Margin		0							
42	B.C. Energy Council Levy	#179-083	367							
43	Total Deferred Charges for Rate Base		$3,571							

BC GAS INC.
LOWER MAINLAND DIVISION
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1993
($000)

Line No.	Particulars	Account	Recorded Balance 12/31/92	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/93	Mid-Year Average 1993
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	T-Service Lost Margin	#179-065	$982	$2,289	$0	$2,289	$0	$0	$3,271	$2,127
2	Cost of Gas - Phase A	#179-067	2,179	0	0	0	(2,179)	0	0	1,090
3	Cost of Gas - Ph. A Rates 2501/2	#179-073	(2,828)	0	0	0	1,075	0	(1,753)	(2,291)
4	Cost of Gas/Margin - Ph.A Rate 10	#279-060	(128)	0	0	0	128	0	0	(64)
5	Valley Gas Sales - Margin	#279-057	(4,891)	0	0	0	4,891	0	0	(2,446)
6	Valley Gas Sales Margin -V.I.J.V.	#279-061	(130)	0	0	0	130	0	0	(65)
7	WEI 1992 Tolls Increase	#179-068	3,738	0	0	0	(3,738)	0	0	1,869
8	WEI Liquid Recovery Service	#179-071	715	0	0	0	(715)	0	0	358
9	WEI Fuel Cost Increase	#179-072	324	0	0	0	(324)	0	0	162
10	O.I.C. #953/89 Deferrals (Net)	#279-027	(569)	0	0	0	569	0	0	(285)
11	COG/Other Deferrals Oct.-Dec./91	#279-030	(163)	0	0	0	163	0	0	(82)
12	Subtotal		(771)	2,289	0	2,289	0	0	1,518	373
13	Cost of Gas - Phase A									
14	- Burrard Interruptible	#179-067	(730)	(1,000)	0	(1,000)	0	1,730	0	(365)
15	VIA/Capacity Utilization Credits	#179-070	(4,500)	0	0	0	0	3,012	(1,488)	(2,994)
16	Cost of Gas - Ph. A Rates 2501/2	#179-073	0	(1,867)	0	(1,867)	0	0	(1,867)	(934)
17	Margin - Phase A Rate 10	#179-073	0	(1,317)	0	(1,317)	0	0	(1,317)	(659)
18	Valley Gas Sales - Schedule 23	#279-058	0	0	0	0	0	0	0	0
19	Deferred Interest	#179-008	1,204							
20	Market Rebate Incentive									
21	- Water Heater Grants *	#179-052	284							
22	- Multi-Family Space Heating *	#179-013	0							
23	- Commercial Fuel Substitution *	#179-013	0							
24	NGV Conversion Grants *	#179-018	636							
25	Local Gas Development *	#179-053	5,443							
26	Rate Design Costs - Phase B *	#179-058	96							
27	Revenue Req. Hearing - 1992 *	#179-059	106							
28	Revenue Req. Hearing - 1993 *	#179-059	58							
29	Demand Side Management *	#179-063	19							
30	Integrated Resource Plan *	#179-064	9							
31	Appliance Insurance Program *	#179-079	144							
32	B.C. Energy Council Levy	#179-083	235							
33	Total Deferred Charges for Rate Base		$2,233							

BC GAS INC.
INLAND DIVISION
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1993
($000)

Line No.	Particulars	Account	Recorded Balance 12/31/92	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/93	Mid-Year Average 1993
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Cost of Gas - Phase A	#179-067	($354)	$0	$0	$0	$354	$0	$0	($177)
2	Cost of Gas - Phase A									
3	Rates 10 and 12	#179-073	(904)	0	0	0	487	0	(417)	(661)
4	Valley Gas Sales - Margin	#279-057	(1,300)	0	0	0	1,300	0	0	(650)
5	WEI 1992 Toll Increase	#179-068	899	0	0	0	(899)	0	0	450
6	WEI Liquids Recovery Service	#179-071	189	0	0	0	(189)	0	0	95
7	WEI Fuel Cost Increase	#179-072	86	0	0	0	(86)	0	0	43
8	O.I.C. #953/89 Deferrals (Net)	#279-027	(364)	0	0	0	364	0	0	(182)
9	COG/Other Deferrals Oct.-Dec./91	#279-030	(126)	0	0	0	126	0	0	(63)
10	Revelstoke Propane Cost	#279-024	70	0	0	0	(70)	0	0	35
11	$0.057 Rider Deferral	#279-026	1,387	0	0	0	(1,387)	0	0	694
12	Subtotal		(417)	0	0	0	0	0	(417)	(416)
13	VIA/Capacity Utilization Credits	#179-070	(1,205)	0	0	0	0	654	(551)	(878)
14	Margin - Phase A									
15	Rate 10	#179-073	0	(1,102)	0	(1,102)	0	0	(1,102)	(551)
16	Valley Gas Sales - Schedule 23	#279-058	(285)	0	0	0	0	285	0	(143)
17	Deferred Interest	#179-008	325							
18	Market Rebate Incentive									
19	- Water Heater Grants *	#179-052	393							
20	NGV Conversion Grants *	#179-018	106							
21	Conversion Grants - Revelstoke	#179-042	(63)							
22	Local Gas Development *	#179-053	1,336							
23	Rate Design Costs - Phase B *	#179-058	22							
24	Revenue Req. Hearing - 1992 *	#179-059	24							
25	Revenue Req. Hearing - 1993 *	#179-059	13							
26	B.C. Energy Council Levy	#179-083	112							
27	Total Deferred Charges for Rate Base		$361							

BC GAS INC.
COLUMBIA DIVISION
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1993
($000)

Line No.	Particulars	Account	Recorded Balance 12/31/92	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/93	Mid-Year Average 1993
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	O.I.C. #953/89 Deferrals (Net)	#279-027	$449	$0	$0	$0	$0	($449)	$0	$225
2	COG/Other Deferrals Oct.-Dec./91	#279-030	43	0	0	0	0	(43)	0	22
3	NOVA/ANG 1992 Toll Increase	#179-081	39	0	0	0	0	(39)	0	20
4	NOVA 1992 Toll Reduction	#279-062	(37)	0	0	0	0	37	0	(19)
5	Gas Cost Increase (ING Purchases)	#179-082	40	0	0	0	0	(40)	0	20
6	AOR Revenue (CNG)	#279-018	(29)	0	0	0	0	29	0	(15)
7	Subtotal		505	0	0	0	0	(505)	0	253
8	VIA/Capacity Utilization Credits	#179-070	15	0	0	0	0	0	15	15
9	Westar Mining Receivable	#179-069	474	50	0	50	(52)	0	472	473
10	Deferred Interest	#179-008	34							
11	Market Rebate Incentive									
12	- Water Heater Grants *	#179-052	41							
13	NGV Grants - General *	#179-018	0							
14	Cost of Gas - NGV	#279-028	1							
15	Rate Design Cost - Phase B *	#179-058	3							
16	Revenue Req. Hearing - 1992 *	#179-059	4							
17	Revenue Req. Hearing - 1993 *	#179-059	2							
18	B.C. Energy Council Levy	#179-083	19							
19	Total Deferred Charges for Rate Base		$1,098							

BC GAS INC.
FORT NELSON DIVISION
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1993
($000)

Line No.	Particulars	Account	Recorded Balance 12/31/92	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/93	Mid-Year Average 1993
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	O.I.C. #953/89 Deferrals (Net)	#179-027	($130)	$0	$0	$0	$0	$130	$0	($65)
2	Misc. Deferrals Oct.-Dec./91	#279-030	2	0	0	0	0	(2)	0	1
3	Subtotal		(128)	0	0	0	0	128	0	(64)
4	Deferred Interest	#179-008	4							
5	Market Rebate Incentive									
6	- Water Heater Grants *	#179-052	2							
7	NGV Conversion Grants *	#179-018	1							
8	Cost of Gas - NGV	#279-028	(1)							
9	Rate Design Costs - Phase B *	#179-058	0							
10	Revenue Req. Hearing - 1992 *	#179-059	0							
11	Revenue Req. Hearing - 1993 *	#179-059	0							
12	FNG Deferred Revenue Margin		0							
13	B.C. Energy Council Levy	#179-083	1							
14	Total Deferred Charges for Rate Base		($121)							

DEPRECIATION STUDY:
IMPACT OF STANDARDIZATION OF RATES

U= Unstipulated

Line No.	Particulars	BCUC Account #	Depreciation Rate (%) LM	ING	CNG	FNG	Proposed Rates (%)	1993 Depreciation Expense at Existing Rates ($000) LM	ING	CNG	FNG	Total	1993 Depreciation Expense at Proposed Rates ($000) LM	ING	CNG	FNG	Total	Total Increase (Decrease)
1	Intangible Plant																	
2																		
3	Utility Plant Acquisition Adjustments	117	1.00%	1.00%	U	U	1.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Unamortized Conversion Expense	175	1.00%	1.00%	U	U	1.00%	0	1	0	0	1	0	1	0	0	1	0
5	Organization Expense	178	1.00%	1.00%	U	U	1.00%	0	7	0	0	7	0	7	0	0	7	0
6	Other Deferred Charges	179-01	1.00%	1.00%	U	U	1.00%	0	0	0	0	0	0	0	0	0	0	0
7	Franchises and Consents	401	1.00%	1.00%	1.00%	1.00%	1.00%	0	1	0	0	1	0	1	0	0	1	0
8	Other Intangible Plant	402	1.00%	1.00%	U	U	1.00%	0	1	0	0	1	0	1	0	0	1	0
9	Other Intangible Plant - Lease	402	U	Lease Term	U	U	Lease Term	0	1	0	0	1	0	1	0	0	1	0
10																		
11	Total Intangible Plant							0	10	0	0	10	0	10	0	0	10	0
12																		
13	Gas Plant Held for Future Use	102																
14																		
15	Structures and Improvements																	
16	- Frame Buildings		0.00%	3.00%	U	U	3.00%	0	2	0	0	2	0	2	0	0	2	0
17	- Masonry Buildings		0.00%	1.50%	U	U	1.50%	0	0	0	0	0	0	0	0	0	0	0
18	Manufacturing Equipment		0.00%	3.00%	U	U	3.00%	0	8	0	0	8	0	8	0	0	8	0
19	Gas Holders		0.00%	2.00%	U	U	2.00%	0	2	0	0	2	0	2	0	0	2	0
20																		
21	Total Gas Plant Held for Future Use							0	12	0	0	12	0	12	0	0	12	0
22																		
23	Manufactured Gas/Local Storage Plant																	
24																		
25	Structures and Improvements	432																
26	- Frame Buildings		U	3.00%	U	U	3.00%	0	0	0	0	0	0	0	0	0	0	0
27	- Masonry Buildings		U	1.50%	U	U	1.50%	0	5	0	0	5	0	5	0	0	5	0
28	Manufacturing Equipment	433	U	3.00%	U	U	3.00%	0	9	0	0	9	0	9	0	0	9	0
29	Gas Holders - Manufacturing	434	U	2.00%	U	U	2.00%	0	7	0	0	7	0	7	0	0	7	0
30																		
31	Total Local Storage Plant							0	21	0	0	21	0	21	0	0	21	0
32																		
33	Storage Plant																	
34																		
35	Land and Land Rights	440/441	None	U	U	U		0	0	0	0	0	0	0	0	0	0	0
36	Structures & Improvements	442	4.00%	U	U	U	4.00%	60	0	0	0	60	60	0	0	0	60	0
37	Gas Holders Storage	443	4.00%	U	U	U	4.00%	369	0	0	0	369	369	0	0	0	369	0
38	Local Storage Equipment	449	4.00%	U	U	U	4.00%	389	0	0	0	389	389	0	0	0	389	0
39																		
40	Total Storage Plant							818	0	0	0	818	818	0	0	0	818	0
41																		
42	Transmission Plant																	
43																		
44	Land and Land Rights	460/461	None	None	None	None		0	0	0	0	0	0	0	0	0	0	0
45	Compressor Structures	462	U	3.00%	U	U	3.00%	0	23	0	0	23	0	23	0	0	23	0
46	Measuring Structures	463	1.50%	3.00%	3.00%	3.00%	3.00%	17	5	1	0	23	34	5	1	0	40	17
47	Other Structures & Improvements	464		3.00%	3.00%		3.00%	0	3	0	0	3	0	3	0	0	3	0
48	- Frame Buildings		U	U	U	3.00%	3.00%	0	0	0	0	0	0	0	0	0	0	0
49	- Masonry Buildings		U	U	U	1.50%	1.50%	0	0	0	0	0	0	0	0	0	0	0
50	- Measuring & Regulating		1.50%	U	U	U	3.00%	0	0	0	0	0	0	0	0	0	0	0
51	Mains	465	2.00%	2.00%	2.00%	2.00%	2.00%	2,170	1,437	227	21	3,855	2,170	1,437	227	21	3,855	0

DEPRECIATION STUDY:
IMPACT OF STANDARDIZATION OF RATES

U= Unstipulated

Line No.	Particulars	BCUC Account #	Depreciation Rate (%) LM	ING	CNG	FNG	Proposed Rates (%)	1993 Depreciation Expense at Existing Rates ($000) LM	ING	CNG	FNG	Total	1993 Depreciation Expense at Proposed Rates ($000) LM	ING	CNG	FNG	Total	Total Increase (Decrease)
1	Compressor Equipment	466	U	3.00%	U	U	3.00%	0	180	0	0	180	0	180	0	0	180	0
2	Measuring & Regulating Equipment	467-00	3.00%	3.00%	3.00%	3.00%	3.00%	156	33	10	0	199	156	33	10	0	199	0
3	Telemetering	467-10	10.00%	10.00%	U	10.00%	10.00%	125	135	0	0	260	125	135	0	0	260	0
4	Communications Structures & Equip.	468	10.00%	5.00%	10.00%	10.00%	10.00%	3	5	0	0	8	3	9	0	0	12	4
5	Other Transmission Equipment	469	U	5.00%	5.00%	5.00%	5.00%	0	1	0	0	1	0	1	0	0	1	0
6																		
7	Total Transmission Plant							2,471	1,822	238	21	4,552	2,488	1,826	238	21	4,573	21
8																		
9	Distribution Plant																	
10																		
11	Land and Land Rights	470/471	None	None	None	None		0	0	0	0	0	0	0	0	0	0	0
12	Structures and Improvements	472					3.00%											
13	- Leasehold Alterations		U	Lease Term	Lease Term	U		0	37	2	0	39	0	37	2	0	39	0
14	- Frame Buildings		3.00%	3.00%	3.00%	3.00%	3.00%	4	29	8	2	43	4	29	8	2	43	0
15	- Masonry Buildings		1.50%	1.50%	1.50%	1.50%	1.50%	2	124	6	0	132	2	124	6	0	132	0
16	Services	473	2.90%	2.00%	2.00%	2.00%	2.00%	5,889	1,457	137	21	7,504	4,061	1,457	137	21	5,676	(1,828)
17	House Regulators & Meter Installations	474	3.00%	3.00%	3.00%	3.00%	3.00%	429	547	41	3	1,020	429	547	41	3	1,020	0
18	Mains	475	2.00%	2.00%	2.00%	2.00%	2.00%	7,105	1,623	143	15	8,886	7,105	1,623	143	15	8,886	0
19	NGV Compressor Equipment	476	U	6.67%	6.67%	6.67%	6.67%	0	203	29	12	244	0	203	29	12	244	0
20	Compressed Natural Gas	476																
21	- Commercial Cardlock Station		20.00%	U	U	U	20.00%	16	0	0	0	16	16	0	0	0	16	0
22	- All Other		5.00%	U	U	U	5.00%	143	0	0	0	143	143	0	0	0	143	0
23	Measuring and Regulating Equipment	477-00	3.00%	3.00%	3.00%	3.00%	3.00%	394	286	38	3	721	394	286	38	3	721	0
24	Telemetering	477-10	10.00%	10.00%	U	U	10.00%	3	101	0	0	104	3	101	0	0	104	0
25	Meters	478	3.00%	3.00%	3.00%	3.00%	3.00%	1,921	519	59	4	2,503	1,921	519	59	4	2,503	0
26	Other Distribution Equipment	479	U	U	5.00%	3.00%	4.00%	0	0	0	1	1	0	0	0	1	1	0
27																		
28	Total Distribution Plant							15,906	4,926	463	61	21,356	14,078	4,926	463	61	19,528	(1,828)
29																		
30	General Plant																	
31																		
32	Land and Land Rights	480/481	None	None	None	None		0	0	0	0	0	0	0	0	0	0	0
33	Structures & Improvements	482																
34	- Leasehold Alterations		Lease Term	Lease Term	Lease Term	Lease Term		254	129	6	1	390	254	129	6	1	390	0
35	- Frame Buildings		3.00%	3.00%	3.00%	3.00%	3.00%	0	0	0	4	4	0	0	0	4	4	0
36	- Masonry Buildings		1.50%	U	1.50%	1.50%	1.50%	0	0	0	0	0	0	0	0	0	0	0
37	- Lochburn Admin. Warehouse		1.50%	U	U	U	1.50%	77	0	0	0	77	77	0	0	0	77	0
38	- All Other		3.00%	U	U	U	3.00%	183	0	0	0	183	183	0	0	0	183	0
39	Office Furniture and Equipment	483																
40	- Fraser Valley/Lochburn/LNG		5.00%	U	U	U	5.00%	120	0	0	0	120	120	0	0	0	120	0
41	- Computers - Software/LNG/Misc./Hardware		20.00%	20.00%	20.00%	20.00%	20.00%	1,480	268	32	5	1,785	1,480	268	32	5	1,785	0
42	- Micro-Computer Systems		12.52%	U	U	U	12.50%	332	0	0	0	332	332	0	0	0	332	0
43	- Computer Assisted Mapping System		22.66%	U	U	U	12.50%	34	0	0	0	34	19	0	0	0	19	(15)
44	- EDP Software & Equipment/ Corp. Div. Software		12.50%	12.50%	12.50%	12.50%	12.50%	1,708	953	69	7	2,737	1,708	953	69	7	2,737	0
45	- All Other		U	5.00%	5.00%	5.00%	5.00%	0	174	4	1	179	0	174	4	1	179	0
46	Transportation Equipment	484	15.00%		15.00%	15.00%	15.00%			91	12	103	0	0	91	12	103	0
47	- Special Work Equipment		5.50%	15.00%	U	U	15.00%	0	695	0	0	695	0	695	0	0	695	0
48	- Trailers & Corporate Trans. Equipment		10.00%	10.00%	U	U	15.00%	12	1	0	0	13	17	1	0	0	18	5

DEPRECIATION STUDY:
IMPACT OF STANDARDIZATION OF RATES

U= Unstipulated

APPENDIX B
PAGE 3

Line No.	Particulars	BCUC Account #	Depreciation Rate (%) LM	Depreciation Rate (%) ING	Depreciation Rate (%) CNG	Depreciation Rate (%) FNG	Proposed Rates (%)	1993 Depreciation Expense at Existing Rates ($000) LM	ING	CNG	FNG	Total	1993 Depreciation Expense at Proposed Rates ($000) LM	ING	CNG	FNG	Total	Total Increase (Decrease)
1	General Plant Contd...																	
2	--------------------																	
3	Heavy Work Equipment	485	5.00%	5.00%	5.00%	5.00%	5.00%	5	83	7	1	96	5	83	7	1	96	0
4	Tools and Work Equipment	486	5.00%	5.00%	5.00%	5.00%	5.00%	254	147	14	4	419	254	147	14	4	419	0
5	- Engineering Services		15.00%	U	U	U	Delete	0	0	0	0	0	0	0	0	0	0	0
6	- General		5.00%	U	U	U	Delete	0	0	0	0	0	0	0	0	0	0	0
7	Roads, Trails and Small Bridges		2.50%	U	U	U	Delete	0	0	0	0	0	0	0	0	0	0	0
8	Communication Equipment	488			5.00%	5.00%	5.00%			8	1	9	0	0	8	1	9	0
9	- Telemetry Equipment & Corporate Allocation		U	10.00%	10.00%	U	10.00%	0	1	0	0	1	0	1	0	0	1	0
10	- Other Structures & Equipment		5.00%	5.00%	U	U	5.00%	66	61	0	0	127	66	61	0	0	127	0
11	- Gas Supervisory System		10.00%	U	U	U	10.00%	0	0	0	0	0	0	0	0	0	0	0
12	- Microwave		5.00%	U	U	U	5.00%	0	0	0	0	0	0	0	0	0	0	0
13	- Radio		10.00%	U	U	U	10.00%	423	0	0	0	423	423	0	0	0	423	0
14	- Telephone		5.00%	U	U	U	5.00%	0	0	0	0	0	0	0	0	0	0	0
15	Equipment on Customers' Premises	487	5.00%	5.00%	5.00%	5.00%	5.00%	111	12	0	0	123	111	12	0	0	123	0
16	- VRA Compressor	487-XX	10.00%	10.00%	10.00%	10.00%	10.00%	37	13	2	0	52	37	13	2	0	52	0
17	- VRA Compressor Installation Cost	487-XX	33.33%	33.33%	33.33%	33.33%	33.33%	48	22	3	0	73	48	22	3	0	73	0
18	Stores Material, Capital	489	0.00%	U	U	U	Delete	0	0	0	0	0	0	0	0	0	0	0
19	Other General Equipment	489	5.00%	U	5.00%	5.00%	5.00%	0	0	0	0	0	0	0	0	0	0	0
20	Misc. Equipment and NGV Compressors	489	5.00%	U	U	U	Delete	0	0	0	0	0	0	0	0	0	0	0
21	Patterns, Dies, Moulds	489	10.00%	U	U	U	Delete	0	0	0	0	0	0	0	0	0	0	0
22																		
23	Total General Plant							5,144	2,559	236	36	7,975	5,134	2,559	236	36	7,965	(10)
24																		
25	Other																	
26	Byron Creek Trans. & Distrib. Plant	461/465/471	U	U	5.00%	U	5.00%	0	0	41	0	41	0	0	41	0	41	0
27		472/477																
28																		
29	Total Other							0	0	41	0	41	0	0	41	0	41	0
30																		
31	Allowance for funds used during const.	497	0.00%	U	U	U	0.00%	0	0	0	0	0	0	0	0	0	0	0
32	Unclassified Plant	498	2.37%	2.20%	2.20%	U	2.20%	13	1	0	0	14	12	1	0	0	13	(1)
33	Plant Suspense	499	0.00%	U	U	U	0.00%	0	0	0	0	0	0	0	0	0	0	0
34																		
35	GRAND TOTAL							$24,352	$9,351	$978	$118	$34,799	$22,530	$9,355	$978	$118	$32,981	($1,818)
36																		
37																		
38	Contributions in aid of construction	211																
39	------------------------------------																	
40	Computer Software Tax Credit		12.50%	12.50%	12.50%	12.50%	12.50%	385	103	13	2	503	385	103	13	2	503	0
41	NGV Vehicle Grants		U	15.00%	15.00%	15.00%	15.00%	0	8	0	0	8	0	8	0	0	8	0
42	NGV Compressor Grants		U	6.67%	6.67%	6.67%	6.67%	0	33	3	4	40	0	33	3	4	40	0
43	Leasehold Alterations		U	Lease Term	U	U		0	25	0	0	25	0	25	0	0	25	0
44	Alaska Highway Project		U	U	U	2.00%	Delete	0	0	0	0	0	0	0	0	0	0	0
45	Routine Contributions		2.00%	2.20%	2.20%	3.00%	2.20%	141	249	22	13	425	155	249	22	9	435	10
46	Furniture Acquisitions		U	5.00%	U	U	5.00%	0	6	0	0	6	0	6	0	0	6	0
47	Government Programs		U	2.20%	2.20%	2.20%	2.20%	0	237	19	5	261	0	237	19	5	261	0
48																		
49	Total CIAOC							$526	$661	$57	$24	$1,268	$540	$661	$57	$20	$1,278	$10
50																		

FORECAST PLANT BALANCES FOR BC GAS INC.
AS AT JANUARY 1, 1993
($000)

Line No.	Particulars	BCUC Account #	Forecast Plant Balance 01/01/93 LM	ING	CNG	FNG	Total
1	Intangible Plant						
2							
3	Utility Plant Acquisition Adjustments	117	$0	$0	$0	$0	$0
4	Unamortized Conversion Expense	175	0	109	0	0	109
5	Organization Expense	178	0	728	0	0	728
6	Other Deferred Charges	179-01	0	0	0	0	0
7	Franchises and Consents	401	0	94	5	0	99
8	Other Intangible Plant	402	0	63	0	0	63
9	Other Intangible Plant - Lease	402	0	85	0	0	85
10							
11	Total Intangible Plant		0	1,079	5	0	1,084
12							
13	Gas Plant Held for Future Use	102					
14							
15	Structures and Improvements						
16	- Frame Buildings		0	47	0	0	47
17	- Masonry Buildings		0	17	0	0	17
18	Manufacturing Equipment		0	274	0	0	274
19	Gas Holders		0	111	0	0	111
20							
21	Total Gas Plant Held for Future Use		0	449	0	0	449
22							
23	Manufactured Gas/Local Storage Plant						
24							
25	Structures and Improvements	432					
26	- Frame Buildings		0	0	0	0	0
27	- Masonry Buildings		0	336	0	0	336
28	Manufacturing Equipment	433	0	316	0	0	316
29	Gas Holders - Manufacturing	434	0	341	0	0	341
30							
31	Total Local Storage Plant		0	993	0	0	993
32							
33	Storage Plant						
34							
35	Land and Land Rights	440/441	897	0	0	0	897
36	Structures & Improvements	442	1,510	0	0	0	1,510
37	Gas Holders Storage	443	9,218	0	0	0	9,218
38	Local Storage Equipment	449	9,733	0	0	0	9,733
39							
40	Total Storage Plant		21,358	993	0	0	22,351
41							
42	Transmission Plant						
43							
44	Land and Land Rights	460/461	20,463	2,887	294	6	23,650
45	Compressor Structures	462	0	765	0	0	765
46	Measuring Structures	463	1,132	150	41	0	1,323
47	Other Structures & Improvements	464		96	7		103
48	- Frame Buildings		0	0	0	7	7
49	- Masonry Buildings		0	0	0	0	0
50	- Measuring & Regulating		0	0	0	0	0
51	Mains	465	108,508	71,852	11,327	1,047	192,734

FORECAST PLANT BALANCES FOR BC GAS INC.
AS AT JANUARY 1, 1993
($000)

Line No.	Particulars	BCUC Account #	Forecast Plant Balance 01/01/93 LM	ING	CNG	FNG	Total
1	Compressor Equipment	466	0	5,992	0	0	5,992
2	Measuring & Regulating Equipment	467-00	5,204	1,106	337	10	6,657
3	Telemetering	467-10	1,254	1,349	0	0	2,603
4	Communications Structures & Equip.	468	29	94	0	0	123
5	Other Transmission Equipment	469	0	19	0	0	19
6							
7	Total Transmission Plant		136,590	84,310	12,006	1,070	233,976
8							
9	Distribution Plant						
10							
11	Land and Land Rights	470/471	$17	$1,141	$131	$20	$1,309
12	Structures and Improvements	472					
13	- Leasehold Alterations		0	213	37	0	250
14	- Frame Buildings		140	951	270	57	1,418
15	- Masonry Buildings		115	8,267	418	0	8,800
16	Services	473	203,071	72,861	6,855	1,054	283,841
17	House Regulators & Meter Installations	474	14,313	18,226	1,372	102	34,013
18	Mains	475	355,220	81,136	7,150	732	444,238
19	NGV Compressor Equipment	476	0	3,041	432	186	3,659
20	Compressed Natural Gas	476					0
21	- Commercial Cardlock Station		81	0	0	0	81
22	- All Other		2,865	0	0	0	2,865
23	Measuring and Regulating Equipment	477-00	13,132	9,523	1,271	97	24,023
24	Telemetering	477-10	33	1,012	0	0	1,045
25	Meters	478	64,044	17,287	1,963	145	83,439
26	Other Distribution Equipment	479	0	0	5	26	31
27							
28	Total Distribution Plant		653,031	213,658	19,904	2,419	889,012
29							
30	General Plant						
31							
32	Land and Land Rights	480/481	3,798	0	0	1	3,799
33	Structures & Improvements	482					
34	- Leasehold Alterations		731	1,908	0	0	2,639
35	- Frame Buildings		0	0	0	148	148
36	- Masonry Buildings		0	0	1	0	1
37	- Lochburn Admin. Warehouse		5,164	0	0	0	5,164
38	- All Other		6,105	0	0	0	6,105
39	Office Furniture and Equipment	483					
40	- Fraser Valley/Lochburn/LNG		2,408	0	0	0	2,408
41	- Computers - Software/LNG/Misc./Hardware		7,404	1,338	158	23	8,923
42	- Micro-Computer Systems		2,648	0	0	0	2,648
43	- Computer Assisted Mapping System		149	0	0	0	149
44	- EDP Software & Equipment/Corp. Div. Software		13,665	7,626	555	58	21,904
45	- All Other		0	3,477	86	25	3,588
46	Transportation Equipment	484			609	78	687
47	- Special Work Equipment		0	4,633	0	0	4,633
48	- Trailers & Corp. Transportation Equipment		116	5	0	0	121

Appendix B, Page 5

FORECAST PLANT BALANCES FOR BC GAS INC.
AS AT JANUARY 1, 1993
($000)

Line No.	Particulars	BCUC Account #	Forecast Plant Balance 01/01/93 LM	ING	CNG	FNG	Total
1	General Plant Contd...						
2							
3	Heavy Work Equipment	485	$103	$1,661	$144	$13	$1,921
4	Tools and Work Equipment	486	5,057	2,946	268	71	8,342
5	- Engineering Services		0	0	0	0	0
6	- General		0	0	0	0	0
7	Roads, Trails and Small Bridges		0	0	0	0	0
8	Communication Equipment	488			157	21	178
9	- Telemetry Equipment		0	7	1	0	8
10	- Other Structures & Equipment		1,311	1,224	0	0	2,535
11	- Gas Supervisory System		0	0	0	0	0
12	- Microwave		0	0	0	0	0
13	- Radio		4,227	0	0	0	4,227
14	- Telephone		0	0	0	0	0
15	Equipment on Customers' Premises	487	2,215	244	1	3	2,463
16	- VRA Compressor	487-XX	372	132	18	0	522
17	- VRA Compressor Installation Cost	487-XX	142	66	9	0	217
18	Stores Material, Capital	489	0	0	0	0	0
19	Other General Equipment	489	1	0	0	0	1
20	Misc. Equipment and NGV Compressors	489	0	0	0	0	0
21	Patterns, Dies, Moulds	489	0	0	0	0	0
22							
23	Total General Plant		55,616	25,267	2,007	441	83,331
24							
25	Other						
26	Byron Creek Trans. & Distrib. Plant	461/465/471	0	0	812	0	812
27		472/477					
28							
29	Total Other		0	0	812	0	812
30							
31	Allowance for funds used during const.	497	0	0	0	0	0
32	Unclassified Plant	498	568	34	4	0	606
33	Plant Suspense	499	0	0	0	0	0
34							
35	Contributions in aid of construction	211					
36							
37	Computer Software Tax Credit		3,077	821	105	12	4,015
38	NGV Vehicle Grants		0	56	3	0	59
39	NGV Compressor Grants		0	493	50	61	604
40	Leasehold Alterations		0	593	0	0	593
41	Alaska Highway Project		0	0	0	0	0
42	Routine Contributions		7,055	11,338	984	426	19,803
43	Furniture Acquisitions		0	111	0	0	111
44	Government Programs		0	10,782	841	248	11,871
45							
46	Total CIAOC		10,132	24,194	1,983	747	37,056
47							
48	TOTAL CAPITAL AND DEPRECIATION EXPENSE		$867,163	$325,790	$34,738	$3,930	$1,231,621
49	(excludes acct. 211 above)						

DEPRECIATION RATE CHANGES

App. B Page	App. B Line		Division LM	Division ING	Division CNG	Division FNG	Proposed Common Rate
1	46	Account 463 - Transmission Measuring Structures	1.5%	3.0%	3.0%	3.0%	3.0%
			It is proposed that the LM rate for structures be increased to the same 3% level of measuring and regulating equipment housed by the structures and also to bring the rate in line with the practice in the other Divisions.				
2	4	Account 468 - Transmission Communications Structures and Equipment	10.0%	5.0%	10.0%	10.0%	10.0%
			The increase in the ING rate to 10% brings that Division in line with the other three.				
2	16	Account 473 - Distribution Services	2.9%	2.0%	2.0%	2.0%	2.0%
			The proposed decrease in the LM rate to 2.0% brings the practice of that Division in line with the other three, causing a cost reduction of $1.8 million.				
2	42	Account 483 - Micro Computer Systems	12.52%	U	U	U	12.50%

DEPRECIATION RATE CHANGES(Cont'd)

App. B Page	Line		Division LM	ING	CNG	FNG	Proposed Common Rate
2	43	Account 483 - Computer Assisted Mapping Systems	22.66%	U	U	U	12.50
			The adjustment in the above rates is intended to bring them in line with the Company's rate for Corporate Division Software (Line 44), which comprises the majority of the assets in that category.				
2	48	Account 484 - Special Work Equipment	5.5%	15.0%	U	U	15.0%
2	48	Account 484 - Trailers and Corp. Transportation Equipment	10.0%	10.0%	U	U	15.0%
			The intent of the adjustments is to bring the rate for all types of transportation equipment to one common level.				

DEPRECIATION RATE CHANGES (Cont'd)

App. B Page	Line		Division LM	ING	CNG	FNG	Proposed Common Rate
3	32	Unclassified Plant Account 498	2.37%	2.20%	2.20%	U	2.2%
			The make-up of the balance in the plant accounts to which this depreciation rate would be applied will vary from year to year depending on the type of asset which is temporarily suspended in Account 498, most likely over or under allocation of operating and maintenance costs charged to construction. An average common depreciation rate will simplify the determination of the depreciation expense related to this temporary situation.				
		Contributions in Aid of Construction Account 211					
3	45	-Routine Contributions	2.0%	2.2%	2.2%	3.0%	2.2%
			The intent of raising the common rate to 2.2% is to recognize the fact that a portion of contributions received is not solely for main extensions (2%), but also for alterations due to highway relocations etc. which would include plant depreciated at 3%. The rate of 2.2% is the approximate weighted average of depreciation rates applicable to Accounts 465, 473 to 475, 477 and 478.				

BC GAS INC.

WRITTEN EVIDENCE OF

<u>JOHN C. BUTLER</u>

Q. Mr. Butler, please identify yourself.

A. I am John C. Butler. I am Vice President, Consulting with A.E. Sharp and Associates Ltd. My curriculum vitae is appended to this evidence.

Q. Are you the author of the report which follows this evidence?

A. Yes.

Q. What did BC Gas Inc. ask you to address for the purposes of the Company's revenue requirements application?

A. BC Gas requested that I review matters relating to regulation of the gas utility operations of the Company on a consolidated basis. I have done so in my report. The report examines the regulatory practice in other provinces, the basis for the current divisions of BC Gas, the benefits and disadvantages of consolidation, and recommends that the regulation of BC Gas should be on a consolidated basis.

Q. Do you adopt your report as your evidence in this proceeding?

A. Yes, I do.

Q. Does that complete your evidence?

A. Yes.

J85

REGULATION OF BC GAS INC.

ON A

CONSOLIDATED BASIS

Prepared By
J.C. Butler
Vice President, Consulting
A.E. SHARP AND ASSOCIATES LTD
Toronto
Ontario, Canada.

INDEX

EXECUTIVE SUMMARY

BC Gas Inc. was formed through an amalgamation of four British Columbia gas distributors. In its first application to the British Columbia Utilities Commission for amended rates, it has used consolidated data in determining the revenue requirement. BC Gas believes that it should be regulated on a consolidated basis and this Report examines the practice in other Provinces, the basis for the current divisions, the benefits and disadvantages of consolidation, and offers conclusions and recommendations.

Regulation on a consolidated basis would require the BCUC to approve all of the components for determination of the revenue requirement on the basis of consolidated data for the Company's utility operations.

In examining practices in other provinces the utilities, legislation and regulatory process was reviewed to find regulatory proceedings that could be compared to this application. It was found that Manitoba and Ontario were reasonably similar, and that sufficient information for the required comparison was available.

The history of BC Gas, and the legislation dealing with the regulatory control from formation to the end of September 1991 is reviewed. This confirms that the Lieutenant Governor in Council had the rights and responsibility for regulation and that those rights and responsibilities were exercised. It also notes that there is legislation preventing a review or reconsideration of the actions of the LGC during that period.

The Report provides details of a number of relevant regulatory proceedings in Manitoba and Ontario, to demonstrate that the Boards in those provinces:

- imposed no schedule for integration, amalgamation or consolidation,
- accepted regulation on a consolidated basis when requested by the utility, and
- took comfort from the ongoing jurisdiction over rates since this allows scrutiny of future actions of the utility during rate applications.

The examination of the benefits and disadvantages of consolidation demonstrates that the current boundaries of the BC Gas Divisions, which are those of the four companies that were amalgamated, have little relevance under current circumstances, that BC Gas is no longer recognizing the four Divisions for operational purposes, and that further changes in the boundaries could occur.

A list of eight areas are identified, where potential benefits could result from acceptance of regulation on a consolidated basis. These will all result in savings, mainly in accounting and regulatory expense, that will flow through to the customers of BC Gas. Two possible disadvantages are identified but since these are within the control of the BCUC it is concluded that they should not influence the decision as to the regulatory treatment of BC Gas.

The Report concludes that there is no valid reason for separate accounts for each Division of BC Gas and recommends that the BCUC should indicate that such separation is no longer necessary and direct BC Gas to amend its accounting practices accordingly.

The Report also concludes that the overall benefit strongly supports regulation on a consolidated basis and recommends that, commencing with this proceeding, BC Gas should be regulated on a consolidated basis for the determination of the revenue requirement.

1. INTRODUCTION

BC Gas Inc ("BC Gas" or "the Company") was formed on July 1, 1989 through the amalgamation of four companies and, until the end of September 1991, it was regulated by the Lieutenant Governor in Council (the "LGC"). Commencing October 1, 1991, the British Columbia Utilities Commission (the "BCUC") assumed full regulatory responsibilities with respect to BC Gas.

As a result, the current application to the BCUC for the approval of amended rates, is the first opportunity for the BCUC to determine the revenue requirement for BC Gas. In its application, BC Gas has calculated its revenue requirement on the basis of consolidated data, not on a Divisional basis. This is consistent with the position of BC Gas, which is that the Company should now be regulated on a consolidated basis, rather than each Division being regulated separately.

Regulation on a consolidated basis will require the BCUC to approve a consolidated budget and forecast as the basis of the cost of service for the Company as a whole. A single rate base would also be approved by the BCUC, together with a common capital structure, a rate of return of return on equity, and one rate of return on rate base. From these the revenue requirement for the Company would be determined.

The purpose of this Report is to provide information on the experience in other provinces with respect to regulatory treatment following amalgamation, to consider the benefits and disadvantages of consolidation, and to offer conclusions and recommendations, based on the experience of the author, for consideration by the BCUC in deciding on the appropriate regulatory treatment of BC Gas.

It is recognized that there can be some confusion with respect to the use of the words "integration", "amalgamation" and "consolidation". For purposes of this Report;

Integration will refer to a centralising or merging of certain operations of the utility, such as purchasing, engineering or planning, so that one department can provide services to other regions or divisions,

Amalgamation refers to the legal combination of two or more companies into one corporate entity, and

Consolidation refers to the consolidation of the budgets, forecasts or projections and other data obtained from a number of regions or divisions.

2. THE HISTORY OF BC GAS INC.

BC Gas Inc. was formed on July 1, 1989, through the amalgamation of, Inland Natural Gas Co. Ltd. ("Inland"), Columbia Natural Gas Ltd ("Columbia"), and Fort Nelson Gas Ltd. ("Fort Nelson") with B.C. Gas Inc. ("B.C.G."). Prior to that date, although each of the four natural gas distribution companies had a separate corporate identity, some integration of the operations of these companies had taken place. As a result of the amalgamation the four systems became divisions which are referred to as:

B.C.G.	-	the Lower Mainland Division,
Inland	-	the Inland Division,
Columbia	-	the Columbia Division, and
Fort Nelson	-	the Fort Nelson Division.

The events leading to and subsequent to the amalgamation that are of significance to this Report are as follows:

July 15, 1988	Bill 45-1988, The *Hydro and Power Authority Privatization Act*, came into force through Regulation No. 273/88. This Act authorized the privatization of the Lower Mainland Division of BC Hydro and Power Authority, permitting the sale to Inland.
September 29, 1988	Agreement entered into between the Province 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.
September 30, 1988	Order In Council ("OIC") 1823/88 - Authorized the transfer of all shares of B.C.G. (previously the

	Lower Mainland Gas Division of B.C. Hydro) to Inland.
September 30, 1988	OIC 1824/88 - Confirmed the September 29th Agreement and exempted Inland, Columbia and Fort Nelson from certain provisions of the *Utilities Commission Act* in respect of transactions related to the acquisition of B.C.G.
September 30, 1988	OIC 1830/88 - Established the rate base of B.C.G. as of July 16, 1988, for rate-setting and other purposes, depreciation rates, capital cost allowance, notice requirements for changes in costs, deferral accounts, and other matters related to the B.C.G. rate freeze.
May 5, 1989	OIC 681/89 - Approval was given to the amalgamation of Inland, Columbia and Fort Nelson with B.C.G.
June 29, 1989	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 from July

1, 1989 until the end of September 1991.

Section 18 of The *Hydro and Power Authority Privatization Act* resulted in the regulatory responsibilities with respect to B.C.G., as contained in the *Utilities Commission Act* and the *Gas Utility Act*, being transferred from the BCUC to the LGC.

OIC 1824/88 confirmed the rate freeze for Inland, Columbia and Fort Nelson and, as a result, there were no rate applications to the BCUC from these companies between September 30, 1988 and the amalgamation on July 1, 1989. OIC 953/89 ensured that from July 1, 1989 to the end of September 1991, BC Gas and its four divisions were regulated by the LCG. During this period, all the rights, powers, obligations, duties and functions of the BCUC under the *Utilities Commission Act* and the *Gas Utility Act* had been transferred to the LGC.

The effect of the above legislation and the OICs has been, therefore, that B.C.G. (the Lower Mainland), Inland, Columbia, and Fort Nelson, either as separate companies or as Divisions of BC Gas, have effectively been regulated by the LGC from the date of the acquisition of B.C.G. by Inland until the end of September 1991.

Section 22 of the *Hydro and Power Authority Privatization Act* states that sections 12 to 15 and 18 to 20 are repealed on October 1, 1991, effectively transferring all of the regulatory powers and responsibilities from the LGC to the BCUC. It 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."

Based on the above it has been assumed that the approval of the amalgamation of the four companies, and other actions of the LGC during the above mentioned period, will be accepted by the BCUC.

3. AMALGAMATIONS & CONSOLIDATIONS IN OTHER PROVINCES

3.1 BACKGROUND

All business enterprises face continual change as the companies that are active in an industry make adjustments to meet changes in the markets that they serve. The gas industry is no exception, as evidenced by the many changes that have taken place throughout its history. Probably the most important change in the industry, however, resulted from the technological developments that allowed high pressure pipelines to be constructed that would safely transport natural gas over long distances. This resulted in the construction in the 1950's of the Westcoast system in British Columbia to bring gas to markets in the interior and the lower mainland area and in TransCanada PipeLine Ltd ("TCPL") constructing a pipeline system to carry natural gas from Alberta to serve the markets in Manitoba, Ontario and Quebec, (sometimes referred to as the "consuming provinces").

Prior to the arrival of natural gas in these market areas, the gas industry consisted of a few companies distributing either, locally produced natural gas, with some propane or manufactured gas in the more densely populated areas. For a short time prior to western Canadian natural gas becoming available in the consuming provinces through the TCPL system, a relatively small amount of natural gas was imported from the USA into southwestern Ontario. The arrival of significant quantities of low cost natural gas created an opportunity for the companies already distributing gas to expand their franchised areas and for new companies to be formed to serve new areas which now became economic. However, the need for capital and other problems ultimately resulted in most of the smaller companies being absorbed or purchased by the larger, better financed companies. The result is that today the vast majority of natural gas distributed to consumers in British Columbia, Manitoba, Ontario and Quebec is through 6 major companies. British Columbia has 3 major distributors, Manitoba has one natural gas distributor, Ontario has three major distributors, (one of which is a sister company to a BC distributor and the Manitoba distributor) two municipal utilities and a few small local systems. Quebec has one major and one small distributor.

Changes in ownership or control of a corporation may or may not benefit the consumer but, where the consumer has a choice of supplier, market forces will determine the success or failure of each company operating in a particular industry. Canadian natural gas distributors, however, are generally investor-owned monopolies, and as such, the provinces in which ownership or control of these distributors could be an issue have required that prior approval be obtained for proposed changes in ownership or control. Responsibility for the approval process is usually delegated by legislation to the provincial regulatory authority.

As noted above the provinces of Manitoba, Ontario and Quebec are generally known as the consuming provinces, whereas British Columbia, Alberta, and Saskatchewan, since they produce gas in excess of internal demand, are generally referred to as the "producing provinces".

In developing this Report the gas distributors in the consuming and producing provinces were examined to identify those that could be considered as comparable to BC Gas. An examination was also carried out of the legislation and regulatory process in the provinces in which comparable utilities were located, to determine if the regulatory jurisdiction is similar to that of the BCUC, specifically with respect to ownership or control of natural gas and the rates charged by such utilities.

The examination of the gas distributors indicated that those in Quebec and Saskatchewan involve public ownership or public funds and as such they were not comparable with BC Gas. These provinces were eliminated.

The examination of legislation indicated that the BCUC, the Manitoba Public Utilities Board (the "MPUB") and the Ontario Energy Board (the "OEB") each has jurisdiction with respect to changes in control and/or ownership of a gas distributor and over the rates that the gas distributor can charge for the sale of gas. It was considered, therefore, that the experience in Manitoba and Ontario could be of value to the BCUC in this proceeding.

It was recognized that amalgamations and consolidations had taken place in Alberta but, since it appeared that the Alberta experience would add little to that of Manitoba and Ontario, Alberta was not included in the examination. An additional reason for restricting the examination to Manitoba and Ontario was that some of the regulatory proceedings dealing with the results of consolidations are very recent and as such, were considered to be more relevant.

The examination also included a review of the process or sequence of events for the Manitoba and Ontario utilities in the acquisition, integration of operations, amalgamation and subsequent consolidation, to determine if there were any significant differences to the BC Gas sequence of events. In the absence of significant differences, it was concluded that the experience in those proceedings could be helpful to the BCUC in considering the appropriate regulatory treatment for BC Gas.

As noted above, the BCUC, the MPUB and the OEB, each have jurisdiction over ownership or control of the gas distributors and also over rates. As such, a Decision, Report or Order approving a change of ownership or control need not deal explicitly with the total impact of the change since the changes resulting from the integration of operations, amalgamation or consolidation, will be subject to further regulatory scrutiny when the utility seeks approval of proposed rate changes.

It is recognized that the MPUB and the OEB could condition an Order approving an acquisition or an amalgamation, requiring the utility to follow a specific schedule and process for integration of operations and for consolidation. The review of the Manitoba and Ontario Decisions, Reports and Orders included, therefore, those proceedings that dealt with the approval of acquisitions and amalgamations, to determine if such conditions had been attached. The proceedings dealing with the determination of revenue requirement subsequent to an amalgamation or consolidation were also reviewed.

3.2 MANITOBA

3.2.1 Amalgamations and Consolidations

The history of the most significant changes in the ownership of gas distributors in Manitoba since the arrival of natural gas is as follows:

1956 Initially there were three gas distribution companies that were actively engaged in selling natural gas in Manitoba. These were; Plains Western Gas (Manitoba) Ltd. ("Plains Western"), Inter-City Gas Utilities Ltd. ("Inter-City Gas"), and Greater Winnipeg Gas Company ("GWG"). All three distributors were under separate corporate ownership.

1965 Northern Ontario Natural Gas Company (later Northern and Central Gas Corporation Limited) acquired GWG, with the approval of the MPUB.

1976 Inter-City Gas Corporation ("ICG"), the parent of Inter-City Gas, acquired Plains Western in the purchase of Canadian Hydrocarbons Ltd. The MPUB approved both the change in ownership of Plains Western and that Plains Western be operated by Inter-City Gas.

1984 Inter-City Gas, Inter-City Gas Transmission Ltd ("ICGT") and Plains Western, filed a joint application with the MPUB, requesting approval of the merging or consolidation of these three companies under the name of ICG Utilities (Manitoba) Ltd ("ICGUM"). ICGT was a Manitoba gas transmission company wholly-owned by ICG. The MPUB approved both the merging and the legal amalgamation of the three companies, effective as of the date of the Order, December 14, 1984. The transaction was completed, however, on January 1, 1985.

1985 ICG acquired Northern and Central Gas Corporation and took control of GWG. The MPUB issued an Order approving the transaction.

1989 The MPUB approved a joint application by ICGUM and GWG which resulted ICGUM being dissolved, with all assets being transferred to GWG and the merger of ICGUM and GWG. The transactions took place on January 1, 1990, but with an immediate name change to ICG Utilities (Manitoba) Ltd. ("ICG Manitoba").

1990 In April of 1990, Westcoast Energy Inc. ("Westcoast Energy") purchased the utility operations of ICG, including ICG Manitoba, with the approval of the MPUB. Subsequently the name was changed to Centra Gas (Manitoba) Inc., ("Centra Manitoba").

As indicated above, applications were filed with the MPUB with respect to each of the above transactions and, following public hearings, Orders were issued approving the transaction(s). The 1976 and 1985 Orders dealt with changes in control of a distributor, but neither included any restriction or conditions on the applicants that would require either; amalgamation, the integration of operations, or consolidation within any specific period of time.

Although ICG acquired control of Plains Western in 1976, it was not until 1984 that ICGUL, ICGT, and Plains Western applied to the MPUB for approval of the merger and amalgamation into ICGUM. Similarly, although control over GWG was achieved by ICG in 1985, it was 1989 before the MPUB was asked to approve the merger of ICGUM and GWG.

In Order 160/84, dealing with the 1984 merger, the MPUB referred to the evidence that; the operations of the three companies had been slowly integrated so that by 1978 they had been operating as one company. The evidence that significant benefits had already been realized was noted and that further significant benefits could be achieved from the merger, through reduced regulatory costs.

The MPUB noted in that order that there were three distinct rate divisions which would continue and that:

> "Any change to rates in the future will be a result of a combined cost of service study and rate review, and be subject to the examination and approval of the Board".

The MPUB also noted that the concerns of the intervenors dealt primarily with the possible future adverse affect on rates and rate structure and stated:

"Having examined all the evidence submitted by the applicants in support of the merger of the companies, together with expressions of concern of the intervenors the Board finds that the proposed merger will not have an effect on the customers at this time. However, the Board recognizes that certain benefits might accrue to the customers from a merged operation."

The Board went on to approve the merger and amalgamation of the three companies without any conditions as to consolidation.

In the Order 183/89, dealing with the merger of GWG and ICGUM, the Board referred to the evidence that the companies had already been operating as one company since 1985 so that most of the cost savings had already been realized. However, it noted that the merger would produce additional savings as a result of reduced regulatory costs.

The evidence was also noted that the existing four rate divisions, and the existing rates for all special contract customers, would remain unchanged until further order of the Board.

Opposition to the merger, through a resolution of a Rural Municipality, was based on a concern that the merging of GWG and ICGUM would create a monopoly that may be detrimental to gas users throughout the Province of Manitoba. In dismissing this concern the MPUB stated, "...there is an existing approved monopoly and that formal amalgamation or merger will not alter this structure or the rates charged to customers."

The Board approved the application for the merger as proposed by the applicants without any conditions as to consolidation.

3.2.2 Rate Hearings

The first rate application by ICGUM subsequent to the merger of the three companies was heard by the MPUB in 1985. In its Order with respect to that application, Order 132/85, the MPUB accepted that the rate bases of the two utilities should be combined and the rate base approved by the MPUB was the combination or consolidation of the rate bases of the two utilities. In addition, the MPUB approved a single capital structure for the consolidated company and determined a single revenue requirement for the consolidated company.

There is no indication in Order 132/85 that either Board staff or any of the intervenors objected to, or even commented on, a single revenue requirement being determined on the basis of the consolidated result for ICGUM.

In 1989, some four years after ICG had acquired GWG, ICGUM and GWG filed separate applications for the determination of Rate Base, Rate of Return and Rates, the hearings to be held concurrently. In 1990, however, following Board approval of the merger and amalgamation of ICGUM and GWG, ICG Manitoba filed an application for the determination of Rate Base, Rate of Return and Rates, based on the consolidation of both companies.

In its Order 133/90, the MPUB noted the sequence of events that led to ICG Manitoba filing its application with supporting evidence based on consolidated results, but there is no indication that any party was opposed to; the approval of a combined rate base, a single capital structure and rate of return or the determination of the revenue requirement on a consolidated basis. The MPUB, in Order 133/90, decided all of the components involved and the revenue requirement, on the basis of the consolidated data that had been filed.

3.3 ONTARIO

3.3.1 Amalgamations and Consolidations

3.3.1.1 Union Gas Ltd. and Consumers' Gas Company Ltd.

Both Union Gas Limited ("Union") and Consumers' Gas Company Limited ("Consumers Gas") were very active in acquiring smaller gas distributors throughout the 1950's and 1960's. With a few exceptions, they were successful in dividing the southern and south-western area of Ontario between the two companies. By the early 1970's, the operations of all the companies that had been acquired were fully integrated with the parent organization, although different rate zones were in effect in some of the franchised regions.

During the above period the Ontario utilities were able to achieve significant economies of scale as service areas were expanded. As a result, the utilities were able to maintain rates for a number of years and in some cases rates were reduced. As a result, there were very few rate applications and they were generally for small rate reductions or adjustments to relatively very low rates.

In exercising its powers, the Ontario Fuel Board, and later the OEB, chose not to impose any conditions on the utilities at the time another company was acquired, as to the rate of integration of operations, or the timing of amalgamation or consolidation. It was apparently considered that utility management should have the responsibility to choose both the rate at which operations should be integrated and the timing of any amalgamation and consolidation.

During this period it appears that the utilities were able, through the decreased costs brought about by economies of scale and by maintaining different rate zones for some classes of customers, to avoid major problems associated with the merging of operations or the consolidation process. Since the 1970's the areas served by both Union and Consumers Gas have remained relatively stable and although there have been changes in ownership - the takeover of Union by Unicorp Canada Corporation and the purchase of Consumers' Gas by British Gas plc - these did not result in any amalgamations or consolidation.

3.3.1.2 Centra Gas Ontario Inc.

Natural gas service to the northern and eastern Ontario communities was originally provided by several different distributors but over the years changes in ownership took place so that ICG Utilities (Ontario) Ltd ("ICG Ontario") became a major distributor serving many communities from the Manitoba border to the Quebec border. Throughout this period the rate of integration of operations, amalgamation and consolidation of the companies acquired was at the discretion of utility management. In 1991 all of the utility operations of ICG, including ICG Ontario, were acquired by Westcoast Energy Inc. and ICG Ontario was renamed Centra Gas Ontario Inc. ("Centra Ontario").

Three recent hearings have dealt with issues relating to consolidation that have some similarity with the BC Gas situation.

The three proceedings were:

a) the ICG reorganization, in which the system serving the Fort Frances region was sold by the ICG Manitoba operations to the ICG Ontario, (E.B.R.L.G. 31 - October 1987);

b) the acquisition of ICG Utilities (Canada) Ltd. and ICG (Ontario) by Westcoast Energy Inc. (E.B.R.L.G. 34 - January 1990); and

c) the ICG Ontario rate hearing in which ICG proposed that the Fort Frances system be included with the balance of the system for determination of revenue requirement and rate-making. (E.B.R.O. 467 - May 1991)

It should be noted that a number of the proceedings with respect to ownership or control are through a reference from the Lieutenant Governor in Council, ("LGIC") usually because the transaction involves the parent of the gas distributor. In these proceedings to OEB issues a report to the LGIC, not a decision.

The Fort Frances gas distribution system, consisting of the Town of Fort Frances, one large volume industrial customer (Boise Cascade Company of International Falls, Minnesota), and several small communities around the Town of Fort Frances, was originally owned by ICG and operated by ICG Manitoba. The gas supply to the Fort Frances area is delivered through a transmission pipeline, owned and operated by another ICG subsidiary and, since it is partially located in the USA, it is under the jurisdiction of the National Energy Board (the "NEB").

In its Report with respect to a) above, the OEB recommended approval of the reorganisation but it also included statements indicating that a commitment had been given during the hearing by ICG Ontario that the Fort Frances area would continue as a separate rate zone with separate rate base determination. The OEB endorsed this approach in its Decision. The paragraphs from the EBRLG 31 Report dealing with this matter are as follows;

"3.2 In considering the public interest associated with this Application, the Board must be mindful of any changes to rates that may result. The Board must satisfy itself that approval of this Application will not be to the detriment of current and future Ontario customers of Inter-City and ICG Ontario."

"3.5 ICG Ontario proposed that if the transaction is approved, ICG Ontario will maintain the Fort Frances system as a separate and fourth rate zone. Such a policy is consistent with the decision of the Board in E.B.R.O. 364-II which recognized that where the cost of gas associated with an identifiable group of customers can be determined, these costs should be assigned to these customers."

"3.6 Special Counsel stated that it was important that a fourth ICG Ontario rate zone be established and maintained. He pointed out that by instituting a fourth rate zone the existing rate structure would be preserved as well as the unique relationship between the large industrial customer and the residential customers of the area."

The Board's Conclusion

"3.9 The Board recognizes that significantly different rates apply in the Fort Frances distribution area than those in the three other operating zones of ICG Ontario. The Board believes that it would be beneficial that a fourth rate zone be created for the Fort Frances system and be maintained on a basis separate from ICG Ontario's other operating zones."

"4.2 With respect to this Application, the public interest essentially consists of ensuring that the present and future Ontario customers of Inter-City and ICG Ontario are not made any worse off if this Application, as proposed, is approved."

"4.9 In the Board's opinion, the customers of the Fort Frances and the ICG Ontario system will not be disadvantaged by the approval of the proposed transaction in that there will be no immediate rate impact on Inter-City's customers in the Fort Frances area or ICG Ontario's customers. Any future rate changes will continue to be subject to the approval of this Board."

The OEB also concluded that the transaction would be in the public interest and recommended that the transaction be approved, provided that certain conditions were imposed. The transaction was completed, and although some conditions were imposed, none dealt with the regulatory treatment of the Fort Frances system.

In the Report arising from b) above the OEB did not recommend any special rate treatment for the Fort Frances system and it is evident that no such conditions was imposed on Centra Ontario or on Westcoast Energy.

A Report from the OEB in response to a reference from the LGIC, is not binding unless the LGIC takes action with respect to the recommendations. As such, since the above statements from the OEB report with respect to Fort Frances were not specifically adopted by the LGIC, they are not binding and, as noted in sub-section 3.3.2.2 below, Centra Ontario chose to ignore them in its next rate application.

3.3.2 <u>Rate Hearings</u>

3.3.2.1 Union and Consumers Gas

In the early 1970's both Union and Consumers Gas filed applications with the OEB for approval or fixing of rates. These applications resulted from an inability to obtain any further economies of scale to offset proposed increases in the wellhead price of gas. Hence, significant rate increases were anticipated in the rates charged by each utility.

The Union application included a request that the OEB base its Decision with respect to revenue requirement on Union's consolidated utility results and that rate zones be eliminated in favour of uniform rates across the entire franchised territory.

The Consumers Gas application also requested that the revenue requirement be based on consolidated utility results and that the differential in rates in the Provincial, Ottawa and Central regions, be eliminated in favour of uniform rates.

The Decisions issued by the OEB in these proceedings made no reference to any objections, by any of the parties to the hearings, to the use of consolidated utility results for purposes of the revenue requirements for both utilities. The calculation of revenue requirement by the OEB, in both Decisions, was based on the consolidated results, a common capital structure and single rate of return.

3.3.2.2 Centra Ontario

As in the case of Union and Consumers Gas, Centra Ontario's predecessor also requested the OEB to approve uniform rates for the services it provided. Although there were more difficulties with this proposal, largely because of the significant component of industrial customers compared to the other classes, uniform rates were approved for all distribution services. Since the Centra Ontario system extended over three of TCPL's rate zones, the rates approved by the OEB reflected the difference in gas costs between zones.

It is also worthy of note that a proposal that individual rates be set for certain of the major industrial customers, based on cost separation studies, was rejected by the OEB. The cost separation studies would have established a cost of service, including separate rate base, for each customer. This proposal was rejected by the OEB, mainly because the cost separation methodology was too subjective and the results of the studies were inconsistent.

From sub-Section 3.3.1.2 herein it would appear that, at the time of the sale of the Fort Frances system to ICG Ontario, both ICG and ICG Ontario intended that the Fort

Frances area would remain as a separate rate zone. However, the Application filed by ICG Ontario (now Centra Ontario) in 1990 (E.B.R.O. 467) requested approval of rates which would result in all customers on the Centra Ontario system, including Fort Frances customers, paying the same rates for the distribution services provided by Centra Ontario.

With respect to the gas supply charge, Centra proposed that a separate rate zone be created for the Fort Frances region, in recognition that the transportation of gas to the Fort Frances area is different from the majority of those served by Centra. Centra suggested that this would permit the gas supply charge to reflect the actual cost of transporting the gas to Fort Frances, which would differ from those receiving gas supply directly through the rate zones of the TCPL system.

Centra Ontario recognized that the proposed rates for its distribution services would be significantly higher than those then in effect and proposed that the increase be phased in over its next five rate cases.

The Town of Fort Frances opposed the proposed rates and requested that the Board determine rates for the Fort Frances area on a "stand-alone" basis. The Board interpreted this request as meaning that the rate base, operating costs and revenues attributable only to the Fort Frances area be separated and used to design rates for that area.

In spite of the strong arguments put forward by the Town of Fort Frances, and the statements made in the Board Report E.B.R.L.G. 34, the OEB found, in the EBRO 467

Decision, that the rate base and operating costs for Centra Ontario should be consolidated for purposes of revenue determination and for rate-making purposes. The OEB effectively reversed the earlier statements in its Report to the LGIC.

The Board was obviously persuaded by Centra's argument that the Fort Frances System is not administered separately and that it is not unique just because it is served from a separate transmission line.

3.3.2.3 Appeal to the Lieutenant Governor in Council by the Town of Fort Frances

Subsequent to the OEB issuing it's Order E.B.R.O. 467 the Town filed an appeal with the Lieutenant Governor in Council dated July 31, 1991, petitioning for relief from that Order. As of the date of this Report, no decision has been issued with respect to that petition.

3.4 <u>CONCLUSIONS FROM THE REVIEW</u>

There are several significant conclusions that can be drawn from the experience in Manitoba and Ontario that have relevance to the current application before the BCUC. In reaching these conclusions, and in making the comparisons with BC Gas, it has been recognized that BC Gas was regulated by the LGC from the date of amalgamation to the end of September 1991.

Comparing the procedures, or sequence of events, followed by the Manitoba and Ontario utilities with that followed by BC Gas, in acquiring companies, subsequent integration of operations, amalgamation and consolidation, it can be concluded that there are no significant differences.

It can also be concluded that regulation in Manitoba, Ontario and British Columbia has been comparable, even though the utilities in Manitoba and Ontario have been continually regulated by the MPUB and the OEB respectively, whereas BC Gas has been regulated by the LGC until the end of September 1991. From section 2.0 herein, it is apparent that appropriate legislation was in place and that the LGC exercised the rights and responsibilities with respect to BC Gas prior to October 1, 1991. As such there appears to be no reason to consider the BC Gas regulatory situation as being different from that of the utilities in Manitoba and Ontario.

It is evident from the review that changes in ownership in Manitoba and Ontario have always been approved without conditions as to the timing of integration of operations, amalgamation or consolidation. It can be concluded, therefore, that the MPUB and the OEB considered that utility management should determine when and how the integration of operations and consolidation should take place. As noted, the utilities involved in an acquisition have generally continued to operate as separate companies for some time following an acquisition.

Since the OEB has specifically rejected cost separation studies for industrial customers, and accepted consolidation over the objections of Fort Frances, it appears that at least that Board would disagree with the separation of costs by division.

It can be concluded, therefore, that the acceptance of regulation on a consolidated basis has been virtually automatic in Manitoba and Ontario, with the MPUB and the OEB accepting that benefits from the consolidation should flow to the customers as soon as practical. Neither the MPUB nor the OEB rejected the concept of regulation on a consolidated basis in any of the hearings reviewed, and there is no indication that such an event ever happened in the past.

In accepting regulation on a consolidated basis it is evident that both the MPUB and the OEB took comfort from the fact that an Order or Report with respect to an acquisition, amalgamation, or consolidation was not a final commitment since the subsequent actions by the utilities would be subject to further regulatory scrutiny when applications were made for rate changes.

Since the BCUC has similar jurisdiction over rates, it can also take comfort in the fact that subsequent rate changes that might result from the consolidation by BC Gas are within the control of the BCUC.

4. <u>Benefits and Disadvantages of Consolidation</u>

As noted in Section 3.0 herein, the utilities in Manitoba and Ontario have all integrated the operations of the various divisions to the maximum extent possible and all are now regulated on a consolidated basis. As a result, the customers of each utility are realizing the benefits that were anticipated when the initial acquisition, takeover or merger was contemplated.

In several proceedings before the MPUB and the OEB, in which approval of a proposed amalgamation or consolidation was requested, the potential benefits were used to support the proposed change. These benefits were referred to by the MPUB and OEB in Orders, Reports and Decisions, suggesting that these benefits were partially responsible for the change being approved.

In the rate proceedings reviewed for this Report, in which regulation on a consolidated basis was proposed, many of the benefits of integration were already flowing to the customers, and only those that result from consolidation remained to be achieved. In each such case, regulation on a consolidated basis was accepted by the MPUB and the OEB, without any reservation. Even in the most recent proceeding, that involving Centra Ontario and the consolidation of Fort Frances and area, the OEB accepted the proposed consolidation. The result is that the maximum benefits from the amalgamation and consolidation are being realized by the customers of Centra Ontario, even though Fort Frances believes that its inhabitants are paying more than they should.

The current circumstance of BC Gas are similar to several proceedings in Manitoba and Ontario where one or more companies had been amalgamated and a number of the operating functions integrated, so that benefits were already flowing to the customers. BC Gas has amalgamated the four operating companies, integrated many of the operations and the benefits are already flowing to its customers. Although further integration can be expected in the future, the full benefits that became available through the amalgamation can only be realized if BC Gas is regulated on a consolidated basis. The benefits that can be achieved from regulation on a consolidated basis are:

1) Reduced regulatory expense as a result of fewer hearings and/or shorter hearings,

2) Management of the Company will be simplified,

3) The responsibility of the BCUC to maintain general supervision will also be simplified, again reducing the regulatory expense to be recovered from the customers of BC Gas,

4) Accounting expenses incurred in maintaining separate accounts for each of the four divisions will be reduced if separate accounts are no longer necessary,

5) Employees can be used more freely throughout the organization if the need to account for costs on a divisional basis is removed,

6) Administration on Projects that cross divisional boundaries will be simplified, and costs reduced, if there is no longer a need to maintain a divisional separation,

7) Although security of supply for customers throughout the BC Gas service area is the responsibility of senior management, the elimination of the need to maintain accounts on a divisional basis will allow more flexibility in displacing gas from one area to another to meet operating requirements,

8) The elimination of divisional accounting will enable the maximum savings to be achieved from the integration of many of operating departments, including the following:

- marketing and advertising,
- engineering and safety standards,
- planning,
- maintenance,
- legal, and
- purchasing.

The current divisional boundaries are those that were established by the previous corporate entities. In many cases those boundaries were determined by circumstances peculiar to each company and its management, rather than through any economic or operational considerations. Such matters as the ability of the company to finance projects and to secure the rights to distribute gas were instrumental in determining the boundaries of the existing Divisions. Had those circumstances been different it is probable that the boundaries of the Divisions would have been different. The fact that BC Gas is currently managing the Inland, Columbia and Fort Nelson Divisions as the interior operating division, and the Lower Mainland as the Coastal operating division, supports that proposition. It is also possible that as circumstances change in the future BC Gas may find opportunities to improve efficiency, improve service, or other operating reasons to change the boundaries of either or both of those divisions.

It should be explained that the benefits referred to in 4) and 8) above, can be achieved through two areas. First, if four sets of records are no longer necessary then direct savings can result from the reduced accounting requirements, including; lower audit costs, less time to input data and a lower cost to produce the annual report for the BCUC instead of the four annual reports that might be required. Second, by eliminating the time required to ensure that all costs and expenses can be assigned or allocated to the appropriate divisions. With separate divisional accounts all expenses, all time records and all purchase orders should be coded to ensure that costs are properly assigned. The above manpower requirements, together with the time required to allocate the many common items among the divisions, can be classed as "Non Value Added Time". It should be noted that the items to be allocated will include Income Tax, which is usually fairly complex, time consuming and contentious, because of the judgment required in the process. Regulation on a consolidated basis would eliminate the need for this Non Value Added Time and result in lower overall rates to the customers.

In addition to the savings that will be achieved within BC Gas, the elimination of the allocation of common costs among Divisions (i.e. rate base items and other expenses), will remove a potentially contentious issue from the hearings before the BCUC, shorten hearing time as noted in 1) above, and reduce hearing expense. Further savings in hearing time and expense will result from the BCUC being required to approve only one rate base, capital structure, rate of return on equity and revenue requirement. It is recognized that the BCUC could accept some or all of the foregoing as common to all four Divisions, thereby realizing some of the savings, but the maximum benefits to the customers can only be achieved by regulating BC Gas on a consolidated basis.

With respect to regulatory expense, the BCUC has already expressed concern with respect to the level of such costs in a Fort Nelson proceeding. The Decision of the BCUC dated March 12, 1985 with respect to an application by Fort Nelson indicated that the total cost of the hearing was over $94,000, which was approximately 5% of the total Fort Nelson revenues for the test year. The Commission recognized that this was excessive and stated in the Decision:

> "The Commission is concerned with the magnitude of the cost incurred in this proceeding and believes steps must be taken to reduce these costs significantly (Appendix A)."

The high cost was apparently due to a long period without rate change, internal changes in the parent organization, and lack of regulatory experience on the part of utility personnel. It should be noted that this hearing was prior to the Inland acquisition of Fort Nelson. The Commission reference to the inexperienced utility personnel adds support to the value of a Head Office with highly qualified and experienced personnel. Even though there were extraordinary circumstances in that case, there is no assurance that hearing costs would be reduced to an acceptable level if the Fort Nelson Division were regulated separately. Regulation on a consolidated basis avoids both the regulatory cost and the problems experienced in that proceeding.

A strong head office, such as BC Gas offers to the operating divisions, includes financial, accounting, engineering, gas purchasing and other specialized services. Since this is the head office of a major company in the Province it can attract a broader spectrum of higher calibre staff than would the individual corporations or separate divisions. As a result, the operating divisions obtain a level of expertise from head office that would not be available to a separate entity. As noted, some of the benefits of integrating these functions are already flowing to the customers of BC Gas, but the complications involved in assigning or allocating these costs among the divisions will prevent the maximum benefits from reaching the customers.

It must be noted that elimination of the divisional separation could result in some disadvantages to the customers of BC Gas in the future. For example, BC Gas could propose that uniform rates be implemented across the entire service area for its distribution services. The result might be an increase for some customers and, depending on the timing of the change, a decrease for others. Since such a proposal by BC Gas will require approval, the BCUC will at that time have an opportunity to either approve, modify or reject the proposed rates.

A further disadvantage of consolidation could arise if BC Gas, because of its size, should become less efficient. Again, the BCUC is in a position to monitor this situation on a regular basis and, if it becomes evident that efficiency has fallen, the BCUC can take appropriate action.

In summary, therefore, it is clear from the above that although many of the benefits are already flowing to the customers of BC Gas there are still a number of benefits that can be achieved if the divisional separation is eliminated for regulatory purposes. These benefits will not be at the expense of any of the customers, neither will regulation on a consolidated basis result in any lack of control on the part of the BCUC. In addition, there is a benefit to those customers who wish to intervene, in that the determination of a revenue requirement for the Company as a whole will allow these customers to work together and file a joint intervention. The opportunity for joint interventions is greatly reduced if the four Divisions were regulated separately.

5. CONCLUSIONS AND RECOMMENDATIONS

It is recognized that OIC 953/89 required the Company to maintain separate accounts for the four Divisions until the end of September 1991, also that the BCUC has the jurisdiction to require that the separation of accounts by division be continued.

It is apparent from Section 3. herein that the experience in Manitoba and Ontario has been that the MPUB and the OEB have eliminated the divisional separation, and accepted regulation on a consolidated basis, as soon as the utility requested the change. The timing of the change was always at the discretion of the utility since the MPUB and the OEB did not require integration of operations or the consolidation of the divisions, regions or rate zones within any specific time period. The effect has been that the maximum benefits that can be achieved at any time, are passed through to the customers as soon as practical.

It was also noted in section 3. that, in those proceedings reviewed, none of the participants had objected to regulation on a consolidated basis and the MPUB or the OEB accepted that method in all such proceedings. Based on the lack of objections and the fact that the MPUB and the OEB approved that method of regulation in each case, it can be concluded that all concerned accepted that regulation on a consolidated basis was inherently the appropriate course of action.

In Section 4. the development of the divisional boundaries was reviewed and, since those boundaries were not established on any economic or operational basis, there appears to be no practical reason to maintain those boundaries. It was also clear that for operating efficiency those boundaries have changed and may change again in the future.

Based on the above it must be concluded that there is no valid reason to continue to maintain separate accounts based on the boundaries of the current Divisions.

It is recommended, therefore, that the BCUC should indicate that a separation of accounts by Division is no longer necessary and it should direct BC Gas to amend its accounting practices accordingly.

To summarize, the major conclusions from sections 3. and 4. were, that the experience in Manitoba and Ontario has been to consolidate as soon as practical; that regulation on a consolidated basis should result in maximum savings to the customers of BC Gas; that the administration of the Company will be simplified without affecting the control by the BCUC; that there will be no negative impact on any customer or interested party and that intervenors will have a better opportunity to group together and minimize costs.

Certain possible disadvantages were identified in section 4. However, since these are insignificant in comparison to the potential benefits and, since they are within the control of the BCUC, they should not influence the decision with respect to the regulatory treatment of BC Gas.

Based on the above comments it is evident that the benefits to the BCUC, to BC Gas, to the intervenors and other customers of BC Gas, strongly support regulation on a consolidated basis, at least for the determination of the revenue requirement.

It is recommended, therefore, that the BCUC should, commencing with this proceeding, regulate BC Gas on a consolidated basis for purposes of the determination of the revenue requirement.

As noted earlier herein, the BCUC can take comfort in accepting consolidation, as have the MPUB and the OEB in many of their Decisions, Reports and Orders, in the knowledge that future rate applications will provide the opportunity to deal with any concerns it might have that the proposed rates may cause undue discrimination among BC Gas customers.

JOHN C. BUTLER

A.E. SHARP & ASSOCIATES LTD.

2 SHEPPARD AVENUE EAST, TORONTO, ONTARIO. [illegible]

SUMMARY

A mechanical engineer with background in the regulatory process, energy utilization, cogeneration systems, natural gas acquisition, ratemaking principles, the uniform system of accounts for utility operation, energy economics, combustion systems, fuel-switching for appliances and industrial equipment.

PROFESSIONAL EXPERIENCE

1989-Present	**A.E. Sharp and Associates Ltd.** Vice President, Consulting Senior Consultant
1981-1985	**J.C. Butler Management Ltd.** President
1974-1989	**The Ontario Energy Board** Vice Chairman Board Member Part-time Board Member Director of Operations.
1958-1974	**The Gas Machinery Co. (Canada) Ltd.** President and General Manager. Vice President Manager of Operations Project Engineer

EDUCATION:

Educated in England. Mechanical Engineering at Liverpool College of Technology. Additional external courses.

PROFESSIONAL AFFILIATIONS:

Association of Professional Engineers, Ontario.

Institution of Mechanical Engineers.

Honorary Member, Canadian Association of Members of Public Utility Tribunals

REPRESENTATIVE CONSULTING ASSIGNMENTS

- Assisting clients with interventions in rate proceedings before the Ontario Energy Board, the Régie de Gaz Naturel du Québec and the Manitoba Public Utilities Board.

- Testifying before the Régie de Gaz Naturel du Québec on the merits of expanding the deregulation of natural gas in Québec,

- Project manager for client in preparing an application, supporting evidence, answers to interrogatories, argument and reply argument in an application to the Ontario Energy Board for approval of a by-pass competitive rate,

- Advising both private and public sector clients, industrial gas consumers and groups of industrial, and commercial gas users, in all phases of the acquisition of gas including direct purchase and purchase from distributors, long and short term contracts, buy/sell and transportation contracts, and all other options.

- Advising clients on all operational facets of Direct Purchase of Gas, Nomination, Dispatching, Monitoring and Reporting (private and public sector clients).

- Technical advice relative to improving the efficiency of energy utilization. (private sector clients)

- Advising client in a meter dispute with utility including the evaluation of measurement systems and extent of error; recommendation for action resulting in resolution of dispute.

- Advising a Regulatory Board in an application for approval of rates for supply of electricity,

- Advising a Regulatory Board with respect to an application for a permit to construct two oil pipelines.

FIELDS OF SPECIAL COMPETENCE:

Regulation

- Thorough knowledge of Ontario Legislation with respect to regulation and regulatory procedures.
- Experience in conducting public hearings of a quasi-judicial nature.
- Uniform system of accounts for regulated industries.
- Cost allocation procedures and practices for the apportioning of costs among classes of customers or users.
- Evaluation of rate structures.
- Organizing and Managing multi-discipline technical teams.

Energy Utilization

- Energy utilization including coal, oil, and various gases.
- Conversion of appliances and industrial process equipment from other fuels to natural gas or dual-fuel operation.
- Combustion systems, for special purposes, including multi-fuel systems.
- Economic optimization of available energy sources.
- Design of specialty ovens and high temperature furnaces for industrial processes.

HIGHLIGHTS OF PRIOR EXPERIENCE

- Experience with coal and oil gasification processes and associated gas cleaning systems.
- Design of combustion system for jet aircraft engines and for marine applications.
- Pilot in the Royal Air Force.

PROPOSAL TO REVISE RESIDENTIAL GAS RATES

1.0 REVIEW OF RESIDENTIAL RATE DESIGN

The level and structure of residential rates in the Inland and Columbia Divisions were last reviewed by the Commission during 1987. Rate increases for the residential class of customers authorized in the Columbia and Inland Divisions were phased in over two and three years, respectively. BC Hydro was preparing a natural gas rate case during 1986, however, the case preparation was discontinued because of the Provincial privatization initiative. As a result, the structure and design of residential rates in the Lower Mainland Division were not reviewed at that time and have never undergone a thorough examination by the Commission or its predecessors.

1.1 Introduction

A review of BC Gas' residential class rate design, especially with regard to revenue margin and cost margins (exclusive of gas costs) is one focus of this application. The residential class rate design proposals of the Company include:

1. The consolidation of the residential classes in the Lower Mainland, Inland and Columbia Divisions.

2. The implementation of postage stamp uniform delivery rates to recover BC Gas' costs exclusive of gas supply costs.

3. Monthly basic charges that improve the recovery of fixed margin costs incurred by BC Gas in providing service to the residential class.

4. Rate levels that improve the ratio of revenue margin to cost margin imbalances between residential classes in the three service areas and between rate classes.

5. Common general terms and conditions for the residential class of customers.

6. A phase-in process to ameliorate the effect of the rate levels and rate design changes.

8. Franchise fees in the Inland and Columbia service areas will be billed as a separate charge in addition to base rates.

In reviewing its residential rates BC Gas has considered studies relating to the costs to serve residential customer and information relating to the prices of alternate energy sources.

1.2 Long Run Incremental Cost

A long run incremental cost (LRIC) study has been undertaken by the Company. The focus of the LRIC is mainly on the costs associated with serving new customers rather than the cost associated with additional consumption by existing customers. This approach more properly identifies the costs of system expansion, as opposed to more intensive use of gas in areas already saturated.

The long run incremental cost study indicates that residential margin costs are those shown below. The average revenue margins for residential service under present rates are compared to the LRIC information.

LRIC Compared to Average Margin Revenue

	LRIC/GJ	Avg Margin/GJ	Excess (Deficiency)
Lower Mainland	$2.68	$1.91	($0.77)
Inland	2.73	2.37	(0.36)
Columbia	3.24	1.90	(1.34)

Customer growth in BC Gas' service territory is primarily due to the increased number of residential customers. If the LRIC deficiency persists in the long run the Company must price industrial and commercial customers in excess of the costs they cause BC Gas to incur.

Enclosed in the Technical Appendix, page 36, is a chart that shows per unit LRIC costs at various levels of consumption. Graphics that compare the LRIC to present and proposed rates in the three divisions are also contained in the residential class Technical Appendix, pages 37 through 39.

BC Gas expects significant natural gas infrastructure investments over the next five years. The benefits of such investments must be compared to the costs. One means of doing so is to put the burden for the decision on the consumers, requiring them to pay a price that equals the cost of the additional facilities. This cost is known as the marginal or incremental cost.

Integrated resource planning requires that investment costs be estimated and, in a sense, the use of these estimates for pricing purposes is a by-product of system planning. It should also be emphasized that marginal or incremental cost pricing should not be an absolute rule. Rather, it should be one benchmark by which divergences between price and costs can be evaluated. Indeed, there may be very sound reasons why even on economic grounds prices should diverge from marginal costs, e.g., the consumer may not be the best judge: there may be so-called "external" effects, such as the effect of sustained regional growth or employment, which may not be recognized or thought to be important by the consumer. Governments may also wish to subsidize certain classes of consumer, e.g., low industrial rates to stimulate development of depressed areas.

1.3 Fully Distributed Cost

The basic purpose of a fully distributed cost (FDC) study is to compare the revenue generated by rates to the cost that a utility incurs in serving its customer classes. A FDC study takes the total cost incurred by a utility in the service of its customers and fully distributes that cost to the various classes of service. No cost apportionment formula, whether it is fully distributed or marginal, is perfect from a theoretical standpoint and, at the same time, practical from an administrative point of view. There are arguments that can be made for variants of fully distributed capacity cost allocation methodologies: peak responsibility (PR), non-coincident demand peak (NCD); or average and excess demand (AED). These demand cost allocation methodologies are more fully described in the description of the FDC studies in Volume 2, Tab 2. Charts that compare FDC between divisions and to present and proposed rates are enclosed in the Technical Appendix pages 41 through 44.

The results of the FDC study for Lower Mainland, Inland, Columbia and Consolidated are found respectively in Volume 2, Section 1 of Tabs 2A, 2B and 2C and Section 2 of Tab 2D.
The findings of the Fully Distributed Cost (FDC) studies indicate that the ratio of the revenue margin to the cost margin for the residential class are:

	PR	NCD	AED
Lower Mainland	76.88%	83.08%	83.82%
Inland	92.04%	95.67%	96.42%
Columbia	74.13%	75.30%	76.50%
Consolidated	80.36%	85.90%	86.66%

The conclusions to be drawn from this information is that BC Gas recovers only about 77 to 84 percent of its cost margin when serving residential customers in the Lower Mainland service area, about 92 to 96 percent of its margin cost in the Inland service area, and 74 to 77 percent of its margin cost in the Columbia service area. In total, BC Gas recovers about 80 to 86 percent of the margin cost that it incurs to serve its residential customers. Regardless of the demand cost allocation methodology, Inland residential customers have a higher ratio of revenue margin to cost margin than residential customers in the Lower Mainland and Columbia service areas.

Rates based on costs are considered by many to be fair. On that basis, fairness suggests adjusting the revenue margins for Columbia and Lower Mainland residential customers to place their rates on parity with Inland residential rates. If this is accomplished under proposed rates, revenue from all BC Gas residential customers will continue to be about ten percent less than the cost that BC Gas incurs to provide this service.

1.4 Price of Competitive Energy

Table 2 of the BC Gas Competitive Energy study (see Volume 2, Tab 4, page 4) is a tabulation of the price for natural gas and competing fuels throughout the BC Gas service areas. The current rates for natural gas relative to competing fuels in the residential market indicate the ability to increase residential class gas rates and not lose market share and also provide to the customers a signal to use natural gas more efficiently. Charts that compare present and proposed rates to the price of competitive energy are in the residential class Technical Appendix, see pages 46 through 48.

1.5 Environmental Responsiveness

The most effective tools for environmental protection are adequate public education and fostering an ethic of efficient energy use that includes efficient appliances and encouraging home insulation programs. These are matters primarily involved in the Company's Integrated Resource Plan.

Environmental responsiveness involves adopting a reasonable price level and structure for residential service to help assure the wise use of the natural gas resources and the natural gas infrastructure. The Company believes that its recommended revenue requirement allocation to the residential class is necessary to more efficiently allocate its infrastructure resources and those of the Provincial natural gas resources.

Environmental responsiveness includes the reduction of harmful effects of the products of combustion on the environment. If there are drastic increases in residential rate levels or the price for 20 to 40 gigajoules of gas per month, residential customers may substitute wood or electric power as their fuel choice. Care in designing rates and setting rate levels must be exercised to avoid this possibility. The economic expansion of natural gas service to non-gas customers must be continued so that natural gas will be substituted for other fuels that cause large emissions of harmful waste products.

Environmental responsiveness also involves adopting reasonable rate design for residential service. Open access to natural gas transmission and distribution facilities and rapidly increasing competition in the natural gas marketplace has tended to lower price levels for natural gas. A primary rate design concern in this application is to have rates implemented that adequately recover the largely fixed cost of the natural gas infrastructure owned by BC Gas. In this application the Company has proposed that the monthly basic charge for residential customers be increased to reflect fixed costs and that the commodity rate paid by the residential customers be calculated by adding together one portion to recover the cost of natural gas supply and another portion to recover the cost of owning and operating the infrastructure.

1.6 Rate Design Principles

Rate design should send appropriate signals to customers to cause them to wisely use the natural gas supply, but at the same time, the Company must dependably recover the costs that it incurs in serving the customers. The purpose of the following rate design discussion is to highlight the needed balance between sending appropriate signals and dependable recovery of costs.

The present residential service rates consist of a customer service charge, called the Basic Charge, and a volumetric charge which varies with the amount of gas consumed. Gas meter readings taken at the beginning of the billing period are subtracted from the readings taken at the end of the period. The result is a measurement of the volume of gas taken during the entire billing period. Gas meters employed for residential service do not have the capability of measuring the maximum rate of consumption during the billing period, which means that residential rates are not demand metered. BC Gas does not plan to change the residential class metering arrangement because the cost for more complicated metering exceed the benefits that can be derived from the small volume of gas taken by each residential customer.

Several types of non-demand metered rates are employed to price gas served to residential customers, all of which consist of two components. The first component is a monthly customer service charge, which is called the Basic Charge, to recover customer-related costs to the maximum extent possible. The alternative is a monthly minimum charge, which combines monthly basic charges and a certain amount of gas, say two gigajoules. Basic charges are contained in the present residential rates in the Lower Mainland, Inland, and Columbia Divisions. The Fort Nelson Division residential rate employs a monthly minimum charge that includes the first two gigajoules of gas each month.

The second component of residential rates is a volumetric charge which varies with the volume of gas taken. This charge may be under a declining block rate, a uniform energy rate, or inverted block rate. The Lower Mainland Division rate, which is applicable to several types of service including residential, has its first declining block price change at 500 gigajoules. Residential customers generally use no more than 30 to 40 gigajoules per month, hence the volumetric rate can be accurately described as a uniform commodity charge. The Columbia Division residential rate contains a uniform commodity charge.

The Inland Division residential rate is a declining block rate form that has a constant price per gigajoule until 10.5 gigajoules per month are consumed and a slightly lesser rate for all consumption over 10.5 gigajoules per month. Prior to 1987, the Inland Division residential rate contained three blocks that had declining prices, zero to one, 1.1 to 10.5, and over 10.6. The first block of zero to one gigajoule per month was eliminated in 1987.

The charts on pages 38 and 43 in the residential class Technical Appendix reveal that the present rate for consumption over 10.5 gigajoules per month in the present Inland Division exceeds both the LRIC and FDC. The Inland declining block rate for residential service consumption over 10.5 gigajoules per month is cost justified and, hence, cannot be termed promotional. In fact, the rate over charges for consumption during the cold part of the year when consumption is highest. After reviewing these rates, LRIC, and FDC the inadequacy of the Inland Division residential rate becomes obvious: it under-recovers costs during low consumption periods that persists for seven or eight months per year.

Declining block rates are perceived by many people to be inconsistent with energy conservation measures. Others complain that minimum charges, which includes an amount of gas, encourage waste. Energy conservation by residential customers usually requires an expenditure of capital to replace existing appliances with more efficient units, upgrade insulation levels, weather seal doors and windows, etc. Since there is a need to consider efficient use of natural gas in this review, and even though cost-justified declining block rates exist in the Inland Division service territory, they are not being proposed in this application.

Inverted block rates exacerbate cost recovery of fixed costs during low consumption period, which persists for seven or eight months per year.

The Company's present residential rate design over collects costs during cold periods. Inverted block rates cause excessive over collection during the winter and could result in a deluge of high bill complaints by residential customers. An inverted block rate form is inappropriate for a gas utility.

2.0 PROPOSED RESIDENTIAL RATES

It is necessary for the Company to respond to the increasingly competitive situation in the gas markets to develop rates that recover its cost margin by adopting rates that recover its fixed capacity-related costs and its fixed customer-related costs. The most appropriate rate form for these conditions is one that recovers fixed customer-related costs as a monthly Basic Charge, and a uniform price for all energy. This rate design balances the need for environmentally responsive rates and dependable cost recovery.

The Company has taken many factors into consideration in the design of rates for residential service. The explicit rate design factors are present rate levels and design, value of service or the price of competitive energy, long run incremental costs, and fully distributed costs. The Company also considered certain other factors in the design of its residential rates, such as perceived equity and fairness, simplicity, and customer reaction to rate levels and rate design. The Company does not rank any one rate making factor higher than others, all have a place in the determination of residential rate design.

Based on the 1993 Revenue Requirement filing, BC Gas proposes a standard Residential Rate Schedule 1, with a $7.00 monthly basic charge and a uniform delivery charge of $1.540 per gigajoule. The appropriate cost of gas for residential customers in each service area would be added to these charges to arrive at the total rate. Please refer to the revenue calculation workpapers that are in the Technical Appendix, pages 21 through 24.

The present divisions of BC Gas are basically the four original gas utilities that merged to form BC Gas. Residential customers in each of the service areas have different rate structures that developed throughout the history of those utilities. A move to consistent rates for BC Gas residential customers in the Lower Mainland, Inland and Columbia service areas will have varying impacts on the annual gas bills of customers depending upon their current rate structure. BC Gas has conducted a number of customer impact reviews to determine changes in annual bills that could be expected as a result of revising rates.

BC Gas has evaluated the impact on the annual bills at proposed rates for residential customers in the Lower Mainland, Inland and Columbia services areas, at high, medium, and low consumption levels, with different uniform Basic Monthly Charges and commodity charges. To determine the annual gas consumption levels that would represent high, medium and low consumption customers, BC Gas analyzed the distribution of Lower Mainland residential customers by annual consumption. The analysis indicates that 80% of the residential customers in the Lower Mainland division consume between 60 GJ and 180 GJ per year. These two levels of consumption represent the low and high consumption customers respectively, and 120 GJ per year will represent the medium consumption customers. These three levels of consumption are also considered reasonable for considering the impact on residential customers in the Inland and Columbia service areas.

An important issue must be addressed. The FDC has identified that the Inland commercial customers are contributing revenues considerably in excess of the cost to serve them and the Inland commercial customers are contributing a greater margin than their Lower Mainland and Columbia counterparts. The rates paid by interruptible customers in the Lower Mainland are considered to be too high and the Company is proposing a decrease in their rates. In addressing these matters, BC Gas is proposing to remove approximately $11 million of revenue requirement from the Lower Mainland industrial customers and $2.9 million from the Inland commercial customers. The uniform delivery charge for residential rates has been established after the reduced rates to those commercial and interruptible customers and other rate revisions were taken into account. Table 1 provides a summary of the impact the proposed uniform monthly basic charge and delivery charge for all BC Gas residential customers will have on annual bills: the comparison is based on 1993 projected sales volumes and permanent rates effective January 1, 1993.

Table 1

ANALYSIS OF THE IMPACT THAT A $7.00 BASIC MONTHLY CHARGE AND $1.540/GJ DELIVERY CHARGE HAS ON ANNUAL RESIDENTIAL GAS BILLS

*** Cost of Gas Included ***

Division	Annual Consumption (GJ)	Current Annual Bill	Proposed Annual Bill with $7 Basic Monthly Charge and $1.540/GJ Delivery Charge	
			Annual Bill Increase (Decrease)	% Increase (Decrease)
Lower Mainland	High *	$846	$43	5%
	Medium *	$583	$38	7%
	Low*	$319	$33	10%
Inland	High	$882	($20)	(2%)
	Medium	$613	($10)	(2%)
	Low	$336	$8	2%
Columbia	High	$736	$49	7%
	Medium	$506	$45	9%
	Low	$276	$41	15%

* High = 180 GJ/year * Medium = 120 GJ/year * Low = 60 GJ/year

Note: The proposed annual bills take into account revised rates in the industrial and commercial classes. The gas cost allocation methodology from the Phase A Rate Design Decision was used to establish the gas supply costs for Inland and Lower Mainland customers. Franchise fee charges for Inland and Columbia customers are included.

The Company believes that the proposed residential rates strike the best compromise of a number of rate design factors. The proposed rates are fair and equitable since they will recover more fairly the significant fixed margin cost component of residential service and there will be uniform charges for all service areas.

The proposed rates are simple since consumption and cost of gas are the only variables other than franchise fees. Billing adjustments, customer comprehension, and other administrative functions will be simplified.

The proposed rates will lessen cross subsidization. The uniform monthly basic charge and uniform delivery charge decreases subsidization of low consumption customers by medium and high residential consumers and non-residential customers.

The proposed rates will encourage efficiency and conservation since the commodity charge is sufficiently large to indicate that BC Gas encourages gas conservation and efficiency for medium and high consumption customers. The removal of declining blocks eliminates perceived pricing signals that are inconsistent with energy conservation.

The proposed rates will contribute to more stable revenue and earnings from year to year: a higher monthly basic charge will make customer bills more consistent throughout the year, reducing high bills in the winter months. BC Gas will have a more even monthly distribution of revenues.

The proposed rates should have good customer acceptance. Only low consumption customers face significant increases, but they will pay rates more closely matched to their cost of service. Motivation for greater use of gas, possibly in place of more environmentally harmful energy, may increase.

2.1 Use of Uniform Charge in Other Jurisdictions

The use of uniform monthly basic and commodity charges is consistent with British Columbia's other major utility, B.C. Hydro and Power Authority, and the following other major utilities in the vicinity of the BC Gas service territory:

Canadian Western Natural Gas
NorthWestern Utilities Ltd.
Cascade Natural Gas
Washington Water Power
SaskEnergy
Centra Gas (Manitoba) Ltd.

3.0 TERMINATION OF CERTAIN LOWER MAINLAND DIVISION RESIDENTIAL SCHEDULES

BC Gas proposes to terminate certain Lower Mainland Division residential rate schedules. Closed Schedule Nos. 2103 and 2104 are residential sales with and without space heating respectively for BC Hydro pensioned employees, and they receive a 25% discount. Only one customer remains on Schedule No. 2104, none on 2103. BC Gas will work with the BC Hydro Human Resources Department to ensure that the lone Schedule No. 2104 customer is appropriately treated.

Schedule Nos. 2191 and 2294 are for residential and non-residential L.P. gas service respectively. These schedules are no longer necessary since the service is no longer offered and should be discontinued.

4.0 GAS COST ALLOCATION

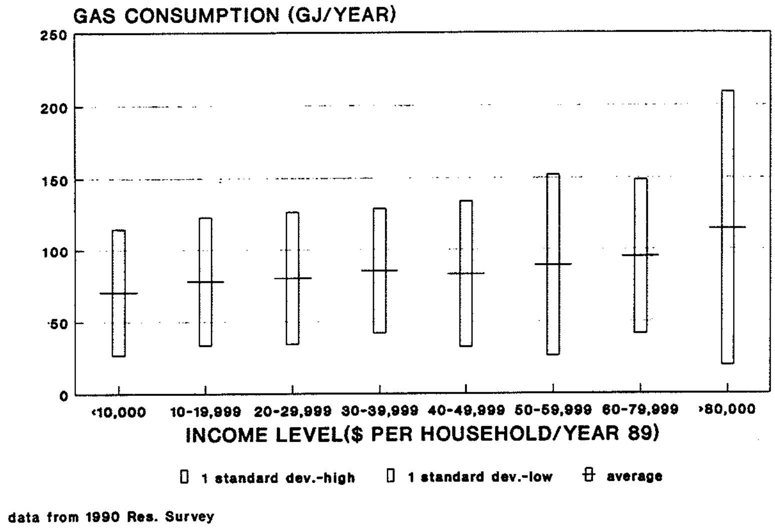
The methodology for allocating gas costs to the rate schedules in the Lower Mainland and Inland Divisions was determined in Phase A of the Rate Design Hearing. Under this methodology, demand and other fixed charges were allocated on the basis of coincident peak demand by rate schedule. The methodology of gas cost allocation to the standardized residential class Schedule 1 is the same as under the Phase A methodology. In Columbia the gas cost allocation methodology has been maintained so the unit gas cost for the standardized residential class is unchanged.

The only residential customers being affected by gas cost changes are in the Lower Mainland. In the Lower Mainland Division there is a gas cost increase of $0.043 per gigajoule which results from the disaggregation of gas costs which previously had been averaged for the residential, commercial and medium industrial classes. The new gas cost reflects only the load characteristics of the residential class. For more information on gas cost allocation see Tab 11 of this Volume.

4.1 Annual Income/Annual Gas Consumption

BC Gas has information on the correlation between annual income and annual consumption in the BC Gas service area in the 1990 Residential Energy Use Survey conducted by Campbell Goodell and Associates for the energy utilities in British Columbia. The chart below provides an analysis of annual gas usage by income for the BC Gas service area:

ANNUAL GAS USAGE BY INCOME
(BC Gas Service Area)



The graph indicates there is not a significant correlation between annual gas usage and annual income. In fact, higher income households display a wide variation in annual consumption and in some cases, annual gas consumption is even lower than in low income households. The fact is that one cannot read a gas meter and determine the income of that residential customer. There are more effective means to assist low income households than through gas pricing, such as government assistance programs.

5.0 IMPLEMENTATION OF THE PROPOSED BC GAS RESIDENTIAL RATES

BC Gas proposes that all new residential rate schedules and related charges become effective January 1, 1994 as well as the proposed new General Terms and Conditions. Specifically, all of the proposed monthly basic charges, commodity charges, and application for service fees will take effect on that date.

The customer impact review has indicated that many residential customers will experience increases in their annual gas bills when the full effect of increased monthly basic charges and postage stamp commodity charges are implemented. BC Gas proposes to mitigate the increases in the Columbia rates and phase them in over a two year time period. Funds currently held in income tax deferral accounts, increased revenue from application for service charges, and the revenue from interruptible and off-system gas sales will also affect the impact experienced by the residential customers.

The following table provides a summary of the existing and proposed revenue to be obtained from residential customers in the Lower Mainland, Inland and Columbia divisions. The table is based on 1993 projected sales volumes and the permanent rates effective January 1, 1993.

	Lower Mainland	Inland	Columbia
Projected Sales Volumes (GJ)	50,636,500	15,448,600	1,763,946
Proposed Total Revenue	$261,108,742	$78,941,840	$ 8,114,797
Existing Total Revenue	$245,350,461	$79,485,281	$ 7,443,448
Total Revenue Increase (Decrease)	$ 15,758,281	($ 543,442)	$ 671,350
Revenue Difference	6.42%	-0.68%	9.01%

BC Gas proposes to reduce the total revenue required from residential customers by:

1. Increasing Application for Service fees from $10 to $25 in those cases where gas service already exists but simply requires a change from one customer to another. In the case where a new gas service must be provided, the fee will increase from $10 to $75. Details of these proposed increases are available in Tab 12 of this Volume. The $4 million in increased fees will be applied to reduce the Company's revenue requirement.

2. In the case of Columbia residential customers $336,000 of funds in the deferred income tax account will be applied directly to the Columbia residential revenue requirement in the first year of the proposed rate changes.

3. Interruptible gas sales revenue and off-system gas sales revenue in excess of gas supply costs will be applied to reduce the cost of gas for Lower Mainland and Inland service area customers.

4. For a 12-month period, all Lower Mainland service area "captive" customers will be billed a separate charge to recover the revenue loss of $0.41 per gigajoule currently in the deferral account established to capture the difference in margin for the Lower Mainland customers that switched from interruptible sales to interruptible service (B.C.U.C. Order Number G-92-91). The balance forecast to be in that deferral for transportation volumes to November 1, 1993, when the $0.41 per gigajoule discrepancy should end, is $3,271,000.

5. Establishing common depreciation rates will reduce the depreciation expense by $1.8 million, as set out in the discussion on Regulatory Consolidation at Tab 5 of this Volume.

The following table summarizes the impact in 1994 of the actions listed.

	Lower Mainland	Inland	Columbia	Total
Reduction Attributable to Increase in Application Fees	$3,000,000	$ 708,000	$ 92,000	$3,800,000
Withdrawal from Divisional Deferred Income Tax Balances	N/A	0	$336,000	$336,000
Allocation of estimated 1994 Off-system Sales Revenues & Gas Margin Revenues	$5,630,900	$1,649,400	N/A	$7,280,300
Repayment of 41¢ Deferred Account	($1,600,000)	N/A	N/A	($1,600,000)
Allocation of $1.8 Million Depreciation Reduction	$ 673,000	$ 204,000	$ 23,000	$ 900,000
Total Reduction in Residential Revenue Requirement through other sources	$7,703,900	$2,561,400	$451,000	$10,716,300
New Revenue Difference %	3.28%	-3.91%	2.96%	

The Inland and Columbia residential customers will also receive the benefit of the draw-down of the deferred income tax balance to pay franchise fees. That draw-down is not reflected in the table above.

TECHNICAL APPENDIX

RESIDENTIAL CLASS

REVENUE CALCULATION WORKPAPERS

The following four pages contain calculations of residential class revenue under present and proposed rates.

Revenue under existing rates and proposed rates are shown on Pages 21 and 22, respectively. Page 22 also shows the calculation of margin revenue under existing and proposed rates.

Pages 23 and 24 contain residential class existing and proposed rates and billing determinates.

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED RESIDENTIAL TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

Ln. No.	TABLE 1 - Base Case ANNUAL 1993 Residential Rates	EXISTING TARIFF STRUCTURE LM Revenue	INL Revenue	COL Revenue	FT NEL Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)
1	Basic Charge	$23,076,743	$6,132,512	$697,800	$0	$29,907,055
2	Minimum Charge	0	0	0	133,602	133,602
3	1st Block	$76,117,710	$23,739,573	$2,616,079	($55,970)	$102,417,393
4	2nd Block	6,204	6,646,218	0	231,047	6,883,469
5	3rd Block	0	0	0	15,531	15,531
6	4th Block	0	0	0	0	0
7	5th Block	0	0	0	0	0
8						
9	Total Exs. Net Margin Rev. (1)	$99,200,657	$36,518,304	$3,313,879	$324,211	$139,357,051
10						
11	ADJ 1 = Commodity Costs	$50,165,581	$14,435,172	$3,304,400	$392,320	$68,297,472
12	ADJ 2 = Fixed Costs	96,103,013	26,650,380	644,546	1,587	123,399,526
13	ADJ 3 = Franchise Fees	0	1,992,867	189,124	0	2,181,991
14						
15	Total Adjustments	$146,268,594	$43,078,419	$4,138,070	$393,907	$193,878,989
16						
17	Total Existing Rate Revenue	$245,469,251	$79,596,723	$7,451,949	$718,118	$333,236,041
18						
19	Spread Adjustment Factor (2)	-0.05%	-0.14%	-0.11%	0.14%	-0.07%
20						
21	Total Adj. Exs. Rate Rev. (3)	$245,350,461	$79,485,281	$7,443,448	$719,100	$332,998,290
22						
23						
24						
25						
26	Notes:					
27						
28	(1) Total Existing Net Margin does not include Franchise Fee, Revelstoke or Inland Option A revenues					
29	(2) Spread Adjustment Factor imported from Reconciliation Model which reconciles Billed Rev. with Calculated Rev.					
30	(3) Total Adjusted Exs. Rate Revenue = Total Existing Rate Revenue * (1 + Spread Adjustment Factor)					

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED RESIDENTIAL TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

Ln. No.	TABLE 2 - Base Case ANNUAL Proposed Rates	PROPOSED TARIFF STRUCTURE LM Revenue	INL Revenue	COL Revenue	FT NEL Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)
1	Basic Charge	$34,814,052	$12,195,337	$1,252,461	$0	$48,261,850
2	Minimum Charge	0	0	0	133,602	133,602
3	1st Block	$77,980,210	$23,790,844	$2,716,477	($55,970)	$104,431,561
4	2nd Block	0	0	0	231,047	231,047
5	3rd Block	0	0	0	15,531	15,531
6	4th Block	0	0	0	0	0
7	5th Block	0	0	0	0	0
8						
9	Total Prop. Net Margin Revenue	$112,794,262	$35,986,181	$3,968,938	$324,211	$153,073,592
10						
11	ADJ 1 = Commodity Costs	$50,165,581	$14,435,172	$3,304,400	$392,320	$68,297,472
12	ADJ 2 = Fixed Costs	98,275,319	26,651,925	644,546	1,587	125,573,377
13	ADJ 3 = Franchise Fees	0	1,979,242	206,182	0	2,185,423
14						
15	Total Adjustments	$148,440,900	$43,066,338	$4,155,128	$393,907	$196,056,273
16						
17	Total Proposed Rate Revenue	$261,235,162	$79,052,519	$8,124,065	$718,118	$349,129,864
18						
19	Spread Adjustment Factor	-0.05%	-0.14%	-0.11%	0.14%	-0.07%
20						
21	Total Adj. Prop. Rate Revenue	$261,108,742	$78,941,840	$8,114,797	$719,100	$348,884,479
22						
23						
24	Total Adj. Exs. Rate Revenue	$245,350,461	$79,485,281	$7,443,448	$719,100	$332,998,290
25						
26	Diff Betw. Prop. & Exs. Revenue	$15,758,281	($543,442)	$671,350	$0	$15,886,189
27						
28						
29	Revenue Difference (%)	6.42%	-0.68%	9.01%	0.00%	4.77%
30						
31						
32						
33	GROSS MARGINS:					
34	--------------					
35	Existing Margin Revenue	$99,152,651	$36,467,176	$3,310,099	$324,654	$139,259,710
36	Proposed Margin Revenue	112,739,677	35,935,798	3,964,410	324,654	152,966,669
37						
38	Margin Difference	$13,587,026	($531,378)	$654,311	$0	$13,706,959
39						
40	Margin Difference (%)	13.70%	-1.46%	19.77%	0.00%	9.84%
41						
42						
43	UNIT VALUES:					
44	------------					
45	Existing Avg Margin	$1.958	$2.361	$1.877	$1.534	
46	Proposed Avg Margin	$2.226	$2.326	$2.247	$1.534	

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED RESIDENTIAL TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

Ln. No.	TABLE 3 - Base Case EXISTING INPUT TABLE RESIDENTIAL ANNUAL	EXISTING TARIFF STRUCTURE LM RWH&RWOH	INL Rate 1	COL Rate 1	FT NEL Rate 1	BC Gas Total Rate 1
	(a)	(b)	(c)	(d)	(e)	(f)
1	EXISTING RATES ($/GJ): (1),(2)					
2						
3	Basic Charge	$4.640	$3.520	$3.900	$0.000	$0.000
4	Minimum Charge	0.000	0.000	0.000	8.390	0.000
5						
6	Price 1st Block	$1.503	$2.105	$1.483	($1.861)	$0.000
7	Price 2nd Block	1.013	1.595	0.000	1.361	0.000
8	Price 3rd Block	0.763	0.000	0.000	1.321	0.000
9	Price 4th Block	0.543	0.000	0.000	0.000	0.000
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000
11						
12	Price of ADJ 1=Commodity Costs	$0.991	$0.934	$1.873	$1.854	$0.000
13	Price of ADJ 2=Fixed Costs	1.898	1.725	0.365	0.008	0.000
14	Price of ADJ 3=Franchise Fees	0.000	0.129	0.107	0.000	0.000
15						
16						
17	EXISTING BLOCK ENDINGS (GJ):					
18						
19	End of 1st Block	500	10.5	999,999.9	2	0
20	End of 2nd Block	8,000	999,999.9	0	30	0
21	End of 3rd Block	25,000	0	0	999,999.9	0
22	End of 4th Block	999,999.9	0	0	0	0
23	End of 5th Block	0	0	0	0	0
24						
25	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	0
26	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	0
27	ADJ 3 = Franchise Fees	0	999,999.9	999,999.9	0	0
28						
29						
30	NUMBER OF GJ's:					
31						
32	1st Block	50,630,378	11,280,386	1,763,946	30,070	63,704,780
33	2nd Block	6,122	4,168,214	0	169,800	4,344,136
34	3rd Block	0	0	0	11,760	11,760
35	4th Block	0	0	0	0	0
36	5th Block	0	0	0	0	0
37						
38	ADJ 1 = Commodity Costs	50,636,500	15,448,600	1,763,946	211,630	68,060,676
39	ADJ 2 = Fixed Costs	50,636,500	15,448,600	1,763,946	211,630	68,060,676
40	ADJ 3 = Franchise Fees	0	15,448,600	1,763,946	0	17,212,546
41						
42	NUMBER OF BILLS	4,973,436	1,742,191	178,923	15,924	6,910,474
43						
44	Note:					
45	(1) Rates shown are those at Jan. 1/1993 and include the interim increase					
46	(2) Ft Nelson margins are adjusted to reflect gas costs associated with 2 free GJ due to Minimum Charge					

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED RESIDENTIAL TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

Ln. No.	TABLE 4 - Base Case PROPOSED INPUT TABLE RESIDENTIAL ANNUAL	PROPOSED TARIFF STRUCTURE LM RWH&RWOH	INL Rate 1	COL Rate 1	FT NEL Rate 1	BC Gas Total Rate 1
	(a)	(b)	(c)	(d)	(e)	(f)
1	PROPOSED RATES ($/GJ):					
2						
3	Basic Charge	$7.000	$7.000	$7.000	$0.000	$0.000
4	Minimum Charge	0.000	0.000	0.000	8.390	0.000
5						
6	Price 1st Block	$1.540	$1.540	$1.540	($1.861)	$0.000
7	Price 2nd Block	0.000	0.000	0.000	1.361	0.000
8	Price 3rd Block	0.000	0.000	0.000	1.321	0.000
9	Price 4th Block	0.000	0.000	0.000	0.000	0.000
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000
11						
12	Price of ADJ 1=Commodity Costs	$0.991	$0.934	$1.873	$1.854	$0.000
13	Price of ADJ 2=Fixed Costs	1.941	1.725	0.365	0.008	0.000
14	Price of ADJ 3=Franchise Fees	0.000	0.128	0.117	0.000	0.000
15						
16						
17	PROPOSED BLOCK ENDINGS (GJ):					
18						
19	End of 1st Block	999,999.9	999,999.9	999,999.9	2	0
20	End of 2nd Block	0	0	0	30.0	0
21	End of 3rd Block	0	0	0	999,999.9	0
22	End of 4th Block	0	0	0	0	0
23	End of 5th Block	0	0	0	0	0
24						
25	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	0
26	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	0
27	ADJ 3 = Franchise Fees	0	999,999.9	999,999.9	0	0
28						
29						
30	NUMBER OF GJ's:					
31						
32	1st Block	50,636,500	15,448,600	1,763,946	30,070	67,879,116
33	2nd Block	0	0	0	169,800	169,800
34	3rd Block	0	0	0	11,760	11,760
35	4th Block	0	0	0	0	0
36	5th Block	0	0	0	0	0
37						
38	ADJ 1 = Commodity Costs	50,636,500	15,448,600	1,763,946	211,630	68,060,676
39	ADJ 2 = Fixed Costs	50,636,500	15,448,600	1,763,946	211,630	68,060,676
40	ADJ 3 = Franchise Fees	0	15,448,600	1,763,946	0	17,212,546
41						
42						
43	NUMBER OF BILLS	4,973,436	1,742,191	178,923	15,924	6,910,474

BILL FREQUENCY ANALYSES

The frequency distribution of bills and sales of natural gas rendered to the residential customers in the Lower Mainland, Inland, and Columbia Divisions are shown on the upper portion of the three following pages. This type of display is commonly referred to as an ogive. The ogives depict the annual distribution of sales (GJ's) by the solid line and bills by the dotted line. The chart scales are probability on the y-axis and logarithmic on the x-axis.

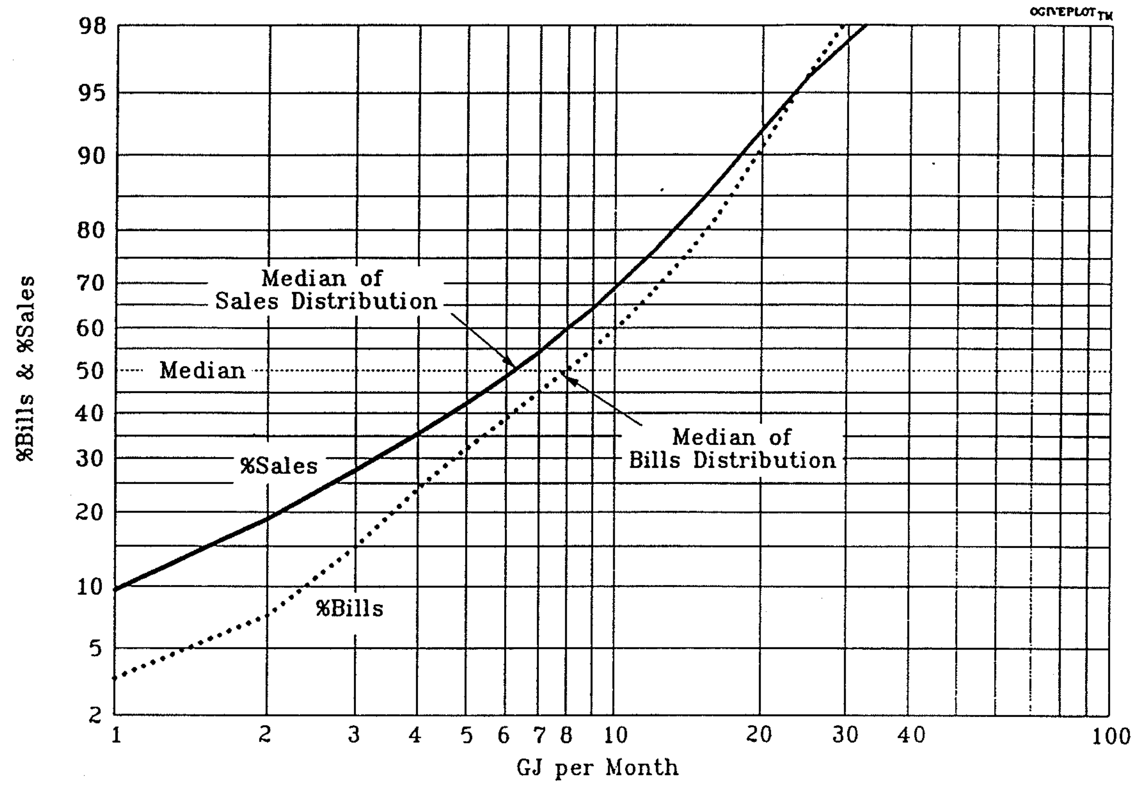
The lower portion of the graphs, with linear x- and y-axes, reveals the pronounced kurtosis of the sales (GJ's) distribution, or left-skewed sales distribution that characterizes the consolidated factor of sales of natural gas. The consolidated factor is made up of two parts: 1) sales in bills up to a specified interval plus 2) the sales up to that interval of excess bills (bills rendered that are in excess of the specified interval).

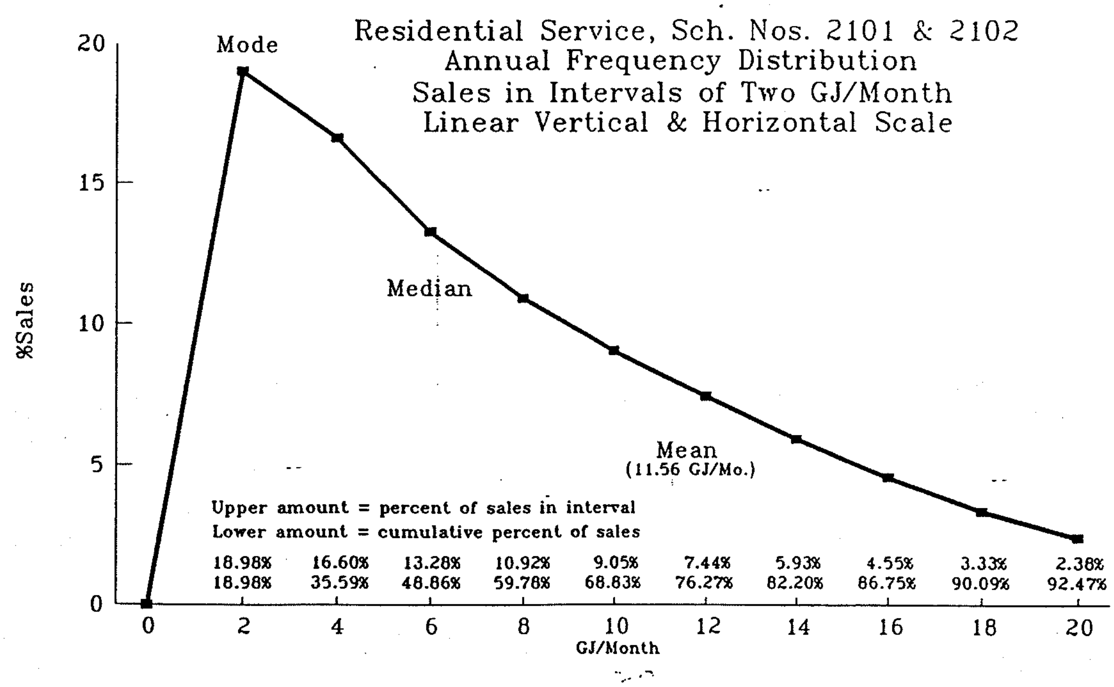
An important conclusion to be drawn from these sales profiles is that attention must be carefully paid to designing rates that recover most or all of the cost incurred by BC Gas in serving residential customers at very low levels of consumption, e.g., zero to six gigajoules per month, since such large percentages of sales are involved at very low levels of consumption. Under present Lower Mainland Division residential test year 1992 rates, over 90 percent of the revenue was derived from the sale of energy and only about nine percent was generated from the monthly Basic Charge.

After comparing the three following pages, another conclusion to be drawn is the remarkable similarity of the profile of sales to residential customers in the Lower Mainland, Inland, and Columbia Divisions.

BC Gas

LOWER MAINLAND DIVISION
Residential Service, Sch. Nos. 2101 & 2102
Annual Bill Frequency Analysis
Cumulative Percent on Probability/Logarithmic Scale

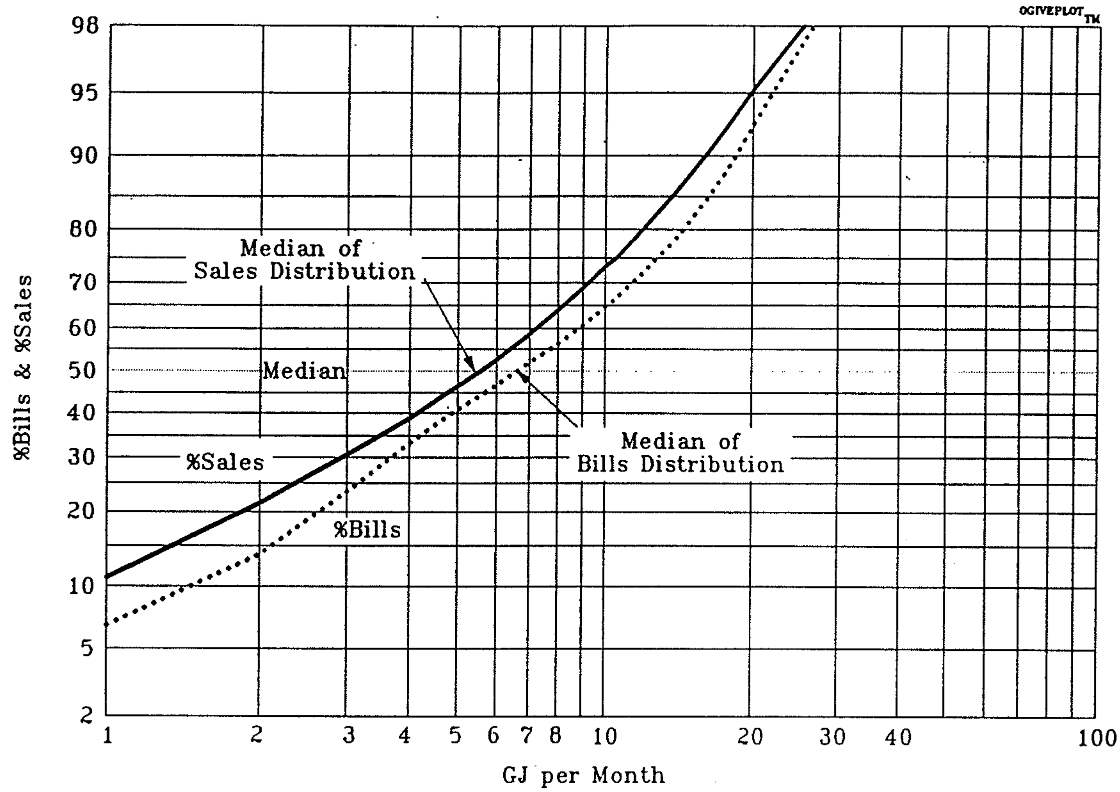




BC Gas

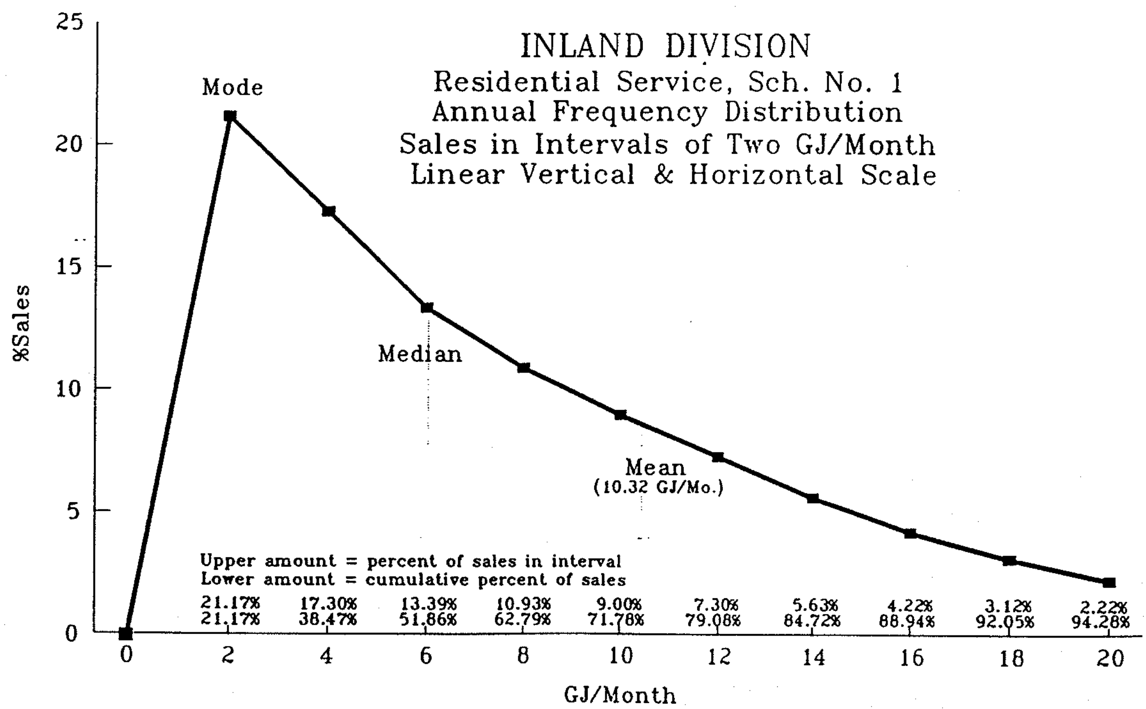
INLAND DIVISION

Residential Service, Sch. No. 1
Annual Bill Frequency Analysis
Cumulative Percent on Probability/Logarithmic Scale



INLAND DIVISION

Residential Service, Sch. No. 1
Annual Frequency Distribution
Sales in Intervals of Two GJ/Month
Linear Vertical & Horizontal Scale

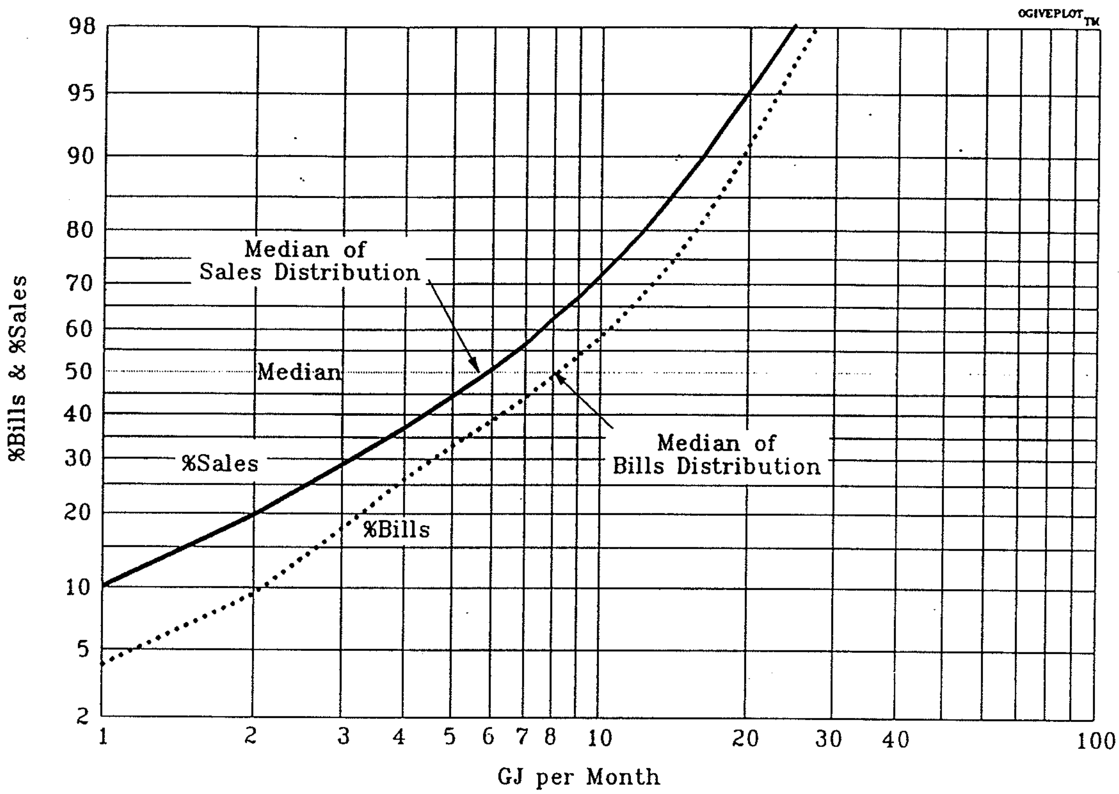


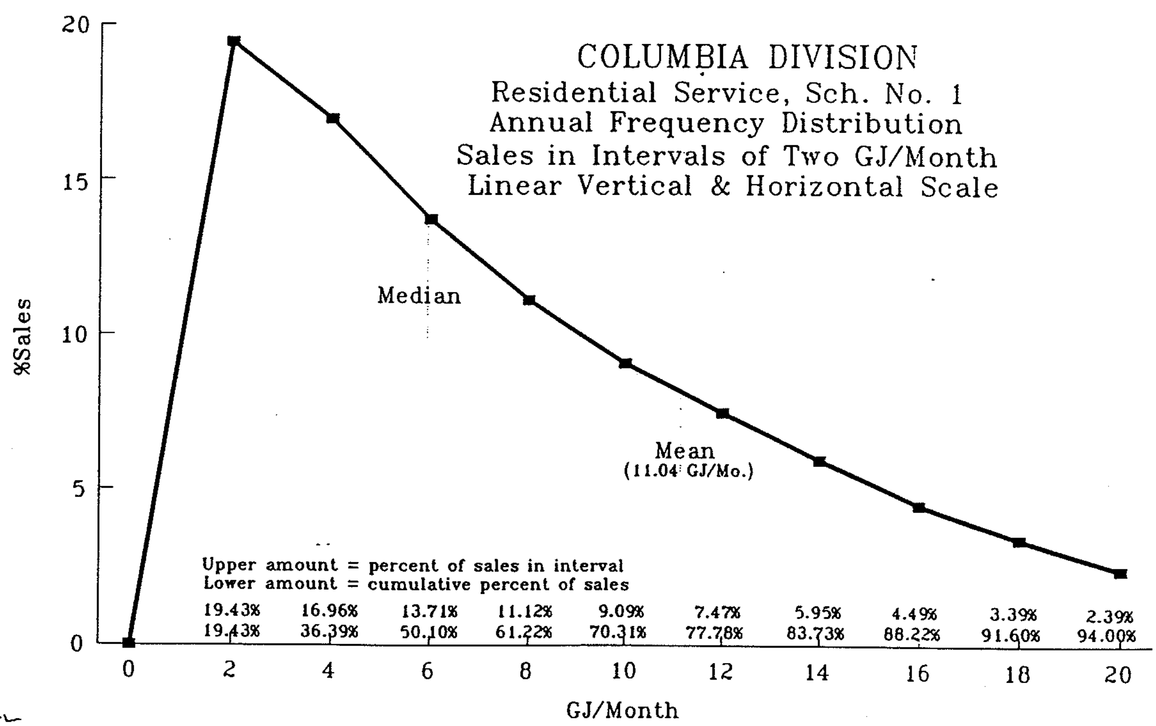
d:\bfe92\inl\rate_1\2_cycleo.drw

BCGas

COLUMBIA DIVISION

Residential Service, Sch. No. 1
Annual Bill Frequency Analysis
Cumulative Percent on Probability/Logarithmic Scale





d:\bfs92\int\rate_1\2_cycleo.drw

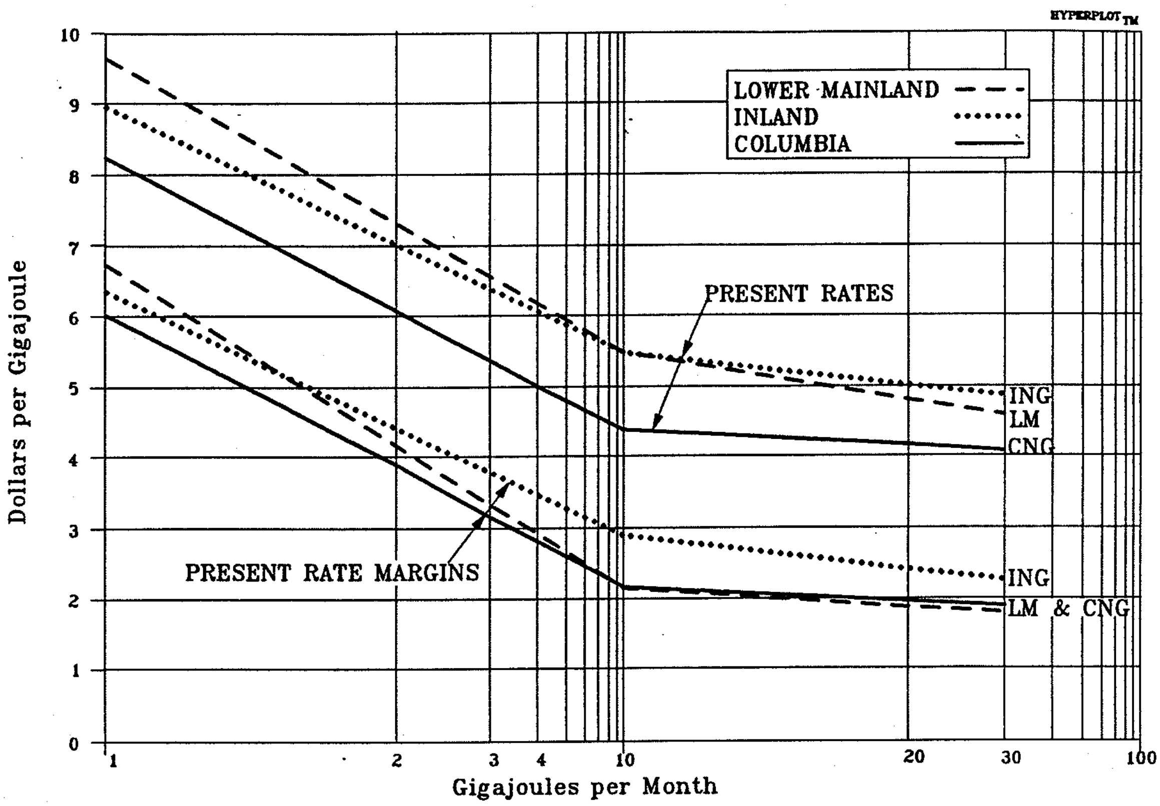
PRESENT RATES AND PRESENT RATE MARGINS

The page that follows has a hyperbolic rate chart that compares present rates for the Lower Mainland, Inland, and Columbia Division residential customers.

The chart also compares present rate margins for the Lower Mainland, Inland, and Columbia Division residential customers. The spread between present rate margins is less than the spread between divisional present rates that include cost of gas. Subtracting divisional cost of gas from present rates eliminates some of the apparent divergence between present rates.

The chart shows that the residential rate margin is higher for Inland Division residential customers than in the other two divisions. The chart helps explain why the residential class ratio of revenue margin to cost margin is higher for the Inland Division than that ratio for residential service in the other two divisions.

ALL DIVISIONS
Schedule No. 1, 2101 & 2102
Present Rates



INABILITY TO RECOVER RESIDENTIAL CLASS MARGIN COST

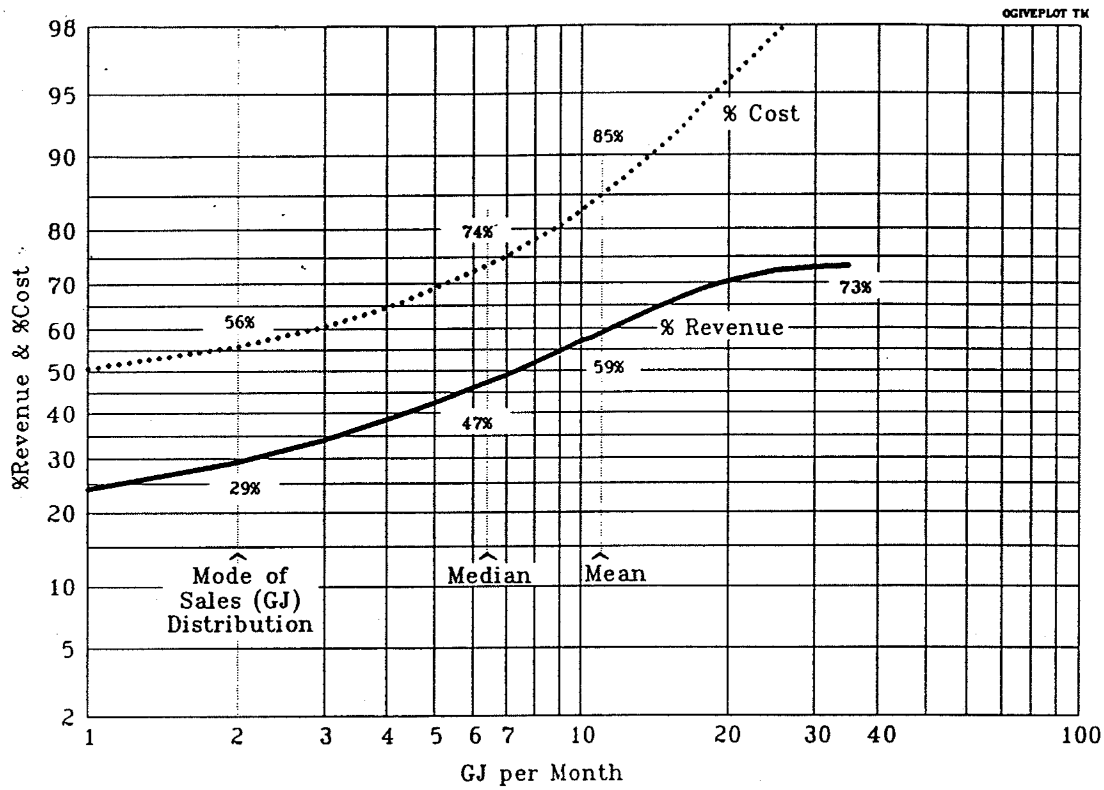
The three pages that follow contain charts that compare revenue margin production with the incurrence of cost margin at various levels of consumption under present residential rates. The inability of the Company to recover cost margins under present residential rate levels for all divisions becomes evident after reviewing the charts.

The cost margins on the charts are derived from the FDC peak responsibility method findings. Each chart contains annotations that describe the findings for that division.

BC Gas

LOWER MAINLAND DIVISION

Residential Margin Revenue & Margin Cost (PR), T.Y 1992

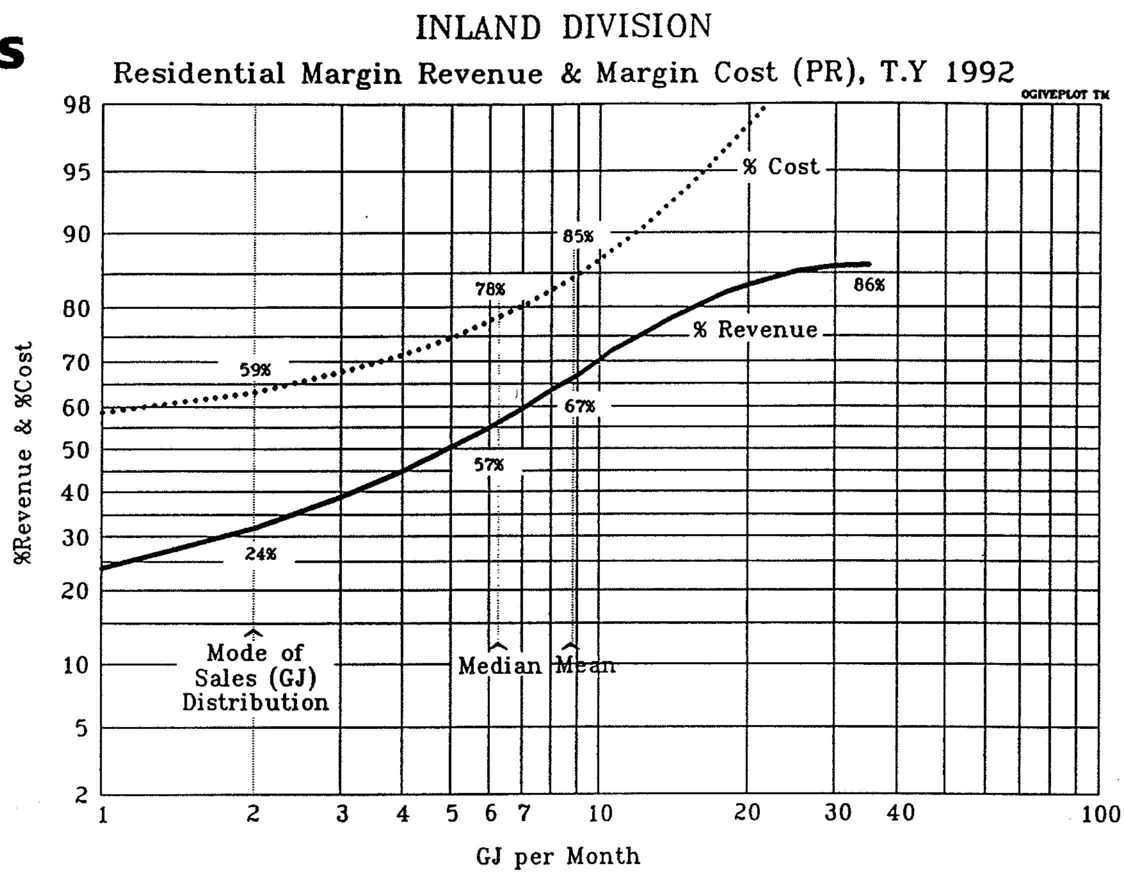


This chart compares Lower Mainland Division residential class margin revenue (gross revenue minus gas cost) to the margin cost (total cost to serve less cost of gas). The dotted line on the graph depicts cost incurrence under the peak responsibility method at various levels of use. The graph indicates that BC Gas incurs 56 percent of the margin cost at two gigajoules per month; 74 percent of margin cost is incurred at slightly over six gigajoules per month, the median of the sales distribution; and 85 percent of the margin cost at the mean of the sales distribution.

The margin revenue, shown by the solid line on the graph, depicts margin revenue generation (present rates less gas cost). Twenty-nine percent of margin revenue is generated at two gigajoules per month; 47 percent of margin revenue is generated at slightly over six gigajoules per month, the median of the sales distribution; and 59 percent of the margin revenue at the sales distribution mean.

The conclusion to draw from this graph is that present rates only generate about three-quarters of the margin cost incurred by BC Gas to serve Lower Mainland residential customers. In total, margin revenue is $88.7 million and margin cost is $119.5 million, or a ratio of only 74.3 percent. Finally, it should be observed that at six gigajoules per month, the median of sales distribution, only 47 percent of margin revenue has been generated while 74 percent of the margin cost has been incurred.

BC Gas

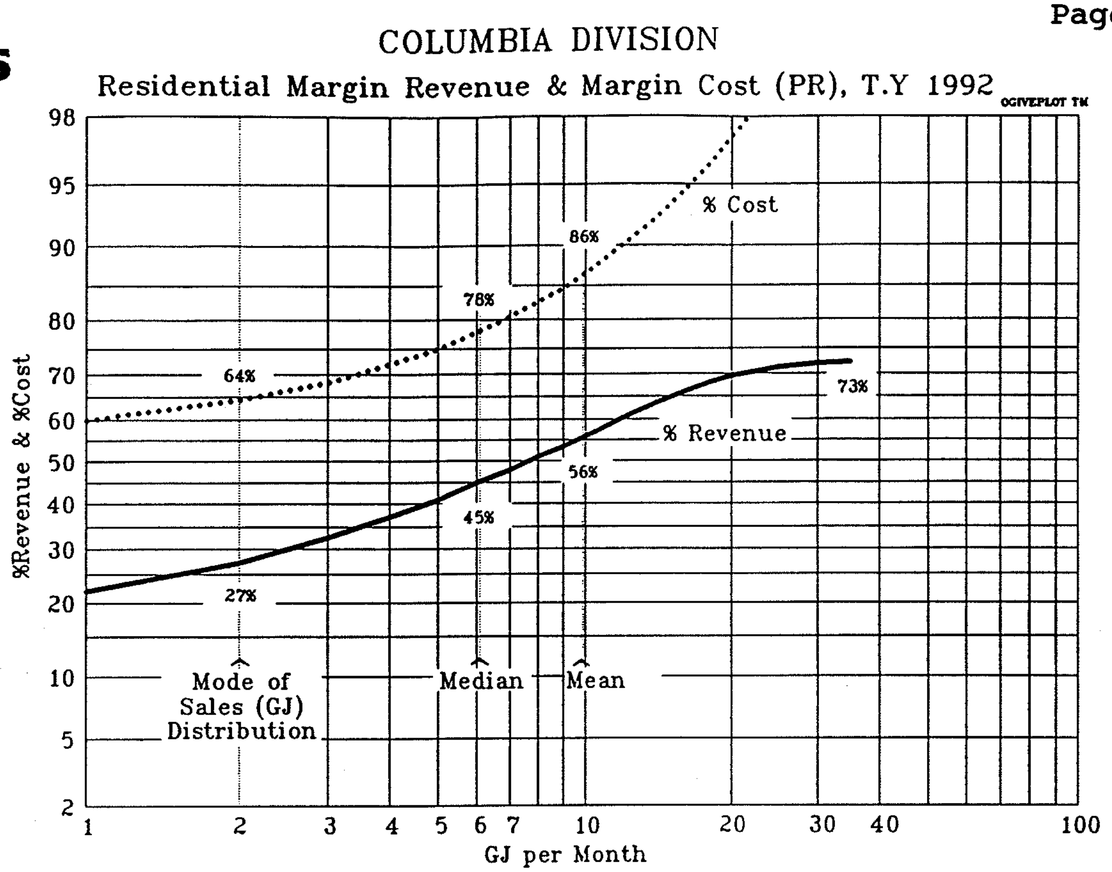


This chart compares Inland Division residential class margin revenue (gross revenue minus gas cost) to the margin cost (total cost to serve less cost of gas). The dotted line on the graph depicts cost incurrence under the peak responsibility method at various levels of use. The graph indicates that BC Gas incurs 59 percent of the margin cost at two gigajoules per month; 78 percent of margin cost is incurred at slightly over six gigajoules per month, the median of the sales distribution; and 85 percent of the margin cost at the mean of the sales distribution.

The margin revenue, shown by the solid line on the graph, depicts margin revenue generation (present rates less gas cost). Twenty-four percent of margin revenue is generated at two gigajoules per month; 57 percent of margin revenue is generated at slightly over six gigajoules per month, the median of the sales distribution; and 67 percent of the margin revenue at the sales distribution mean.

The conclusion to draw from this graph is that present rates only generate about 86 percent of the PR margin cost incurred by BC Gas to serve Lower Mainland residential customers. In total, margin revenue is $31.9 million and margin cost is $36.8 million, or a ratio of only 86.6 percent. It should be observed that at the point where 50 percent of the sales have been rendered only 57 percent of margin revenue has been generated while 78 percent of the margin cost has been incurred.

BCGas



This chart compares Columbia Division residential class margin revenue (gross revenue minus gas cost) to the margin cost (total cost to serve less cost of gas). The dotted line on the graph depicts cost incurrence under the peak responsibility method at various levels of use. The graph indicates that BC Gas incurs 64 percent of the margin cost at two gigajoules per month; 78 percent of margin cost is incurred at slightly over six gigajoules per month, the median of the sales distribution; and 86 percent of the margin cost at the mean of the sales distribution.

The margin revenue, shown by the solid line on the graph, depicts margin revenue generation (present rates less gas cost). Twenty-seven percent of margin revenue is generated at two gigajoules per month; 45 percent of margin revenue is generated at slightly over six gigajoules per month, the median of the sales distribution; and 56 percent of the margin revenue at the sales distribution mean.

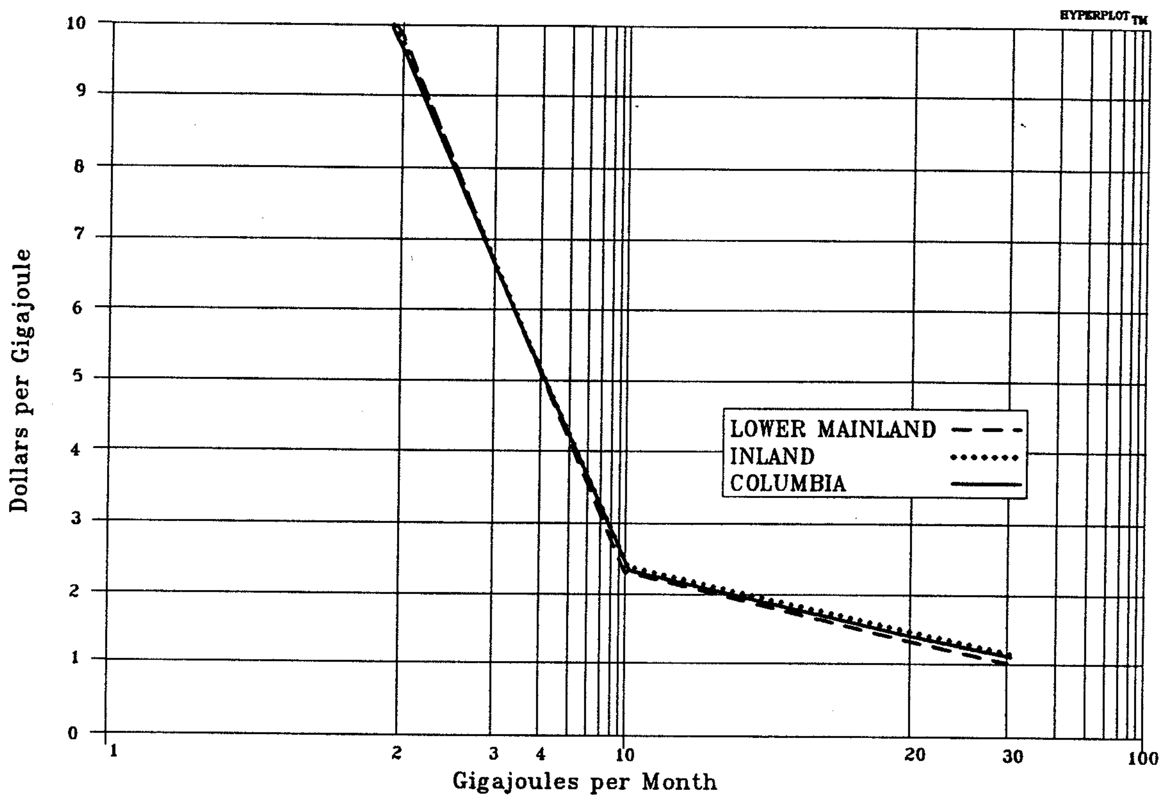
The conclusion to draw from this graph is that present rates only generate about three-quarters percent of the PR margin cost incurred by BC Gas to serve Lower Mainland residential customers. In total, margin revenue is $3 million and margin cost is $4.1 million, or a ratio of only 72.7 percent. At the point where 50 percent of the sales have been rendered only 45 percent of margin revenue has been generated while 78 percent of the margin cost has been incurred.

LONG RUN INCREMENTAL COSTS

The following four charts display LRIC relationships. The first chart compares divisional LRIC at various levels of gas consumption in the Lower Mainland, Inland, and Columbia Divisions. On the next three graphs, LRIC is compared to present and proposed residential rates.

BC Gas

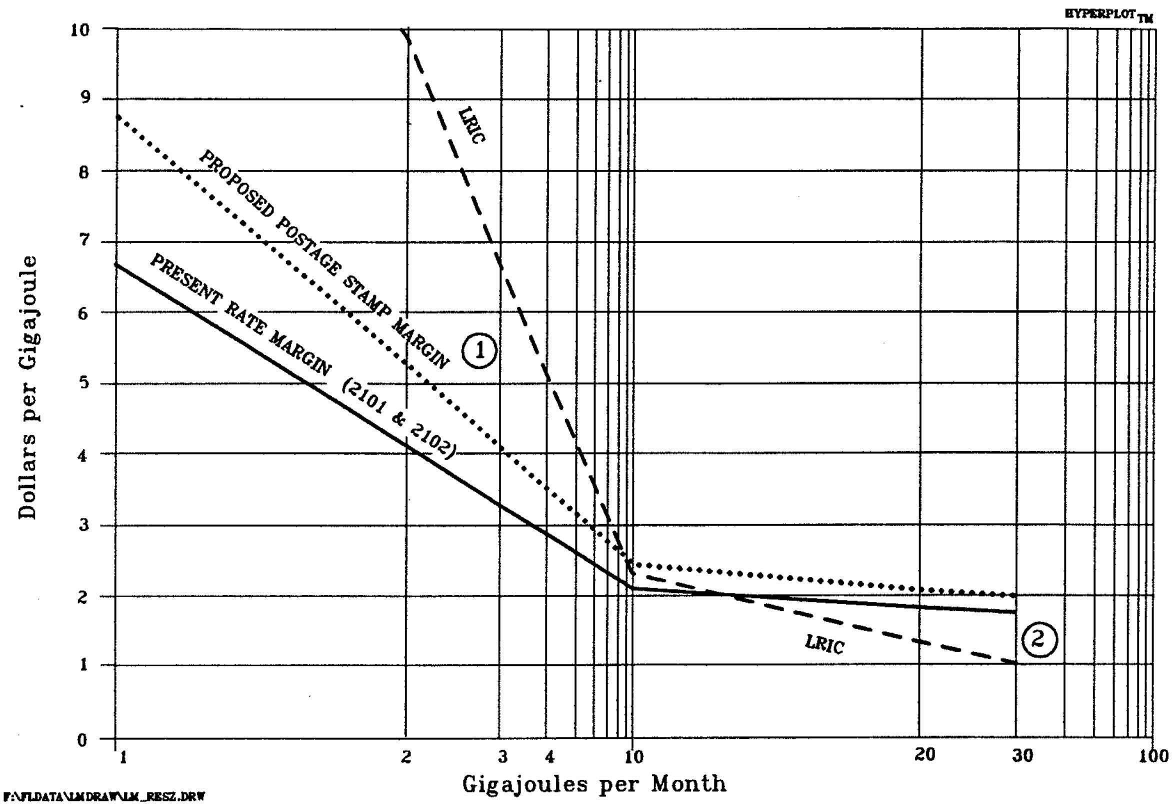
ALL DIVISIONS
Schedule No. 1 LRIC



BC Gas

LOWER MAINLAND DIVISION

Proposed Schedule No. 1.
Residential Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC



(1) LRIC indicates that the present rate margin below about 12 GJs per month could be increased.

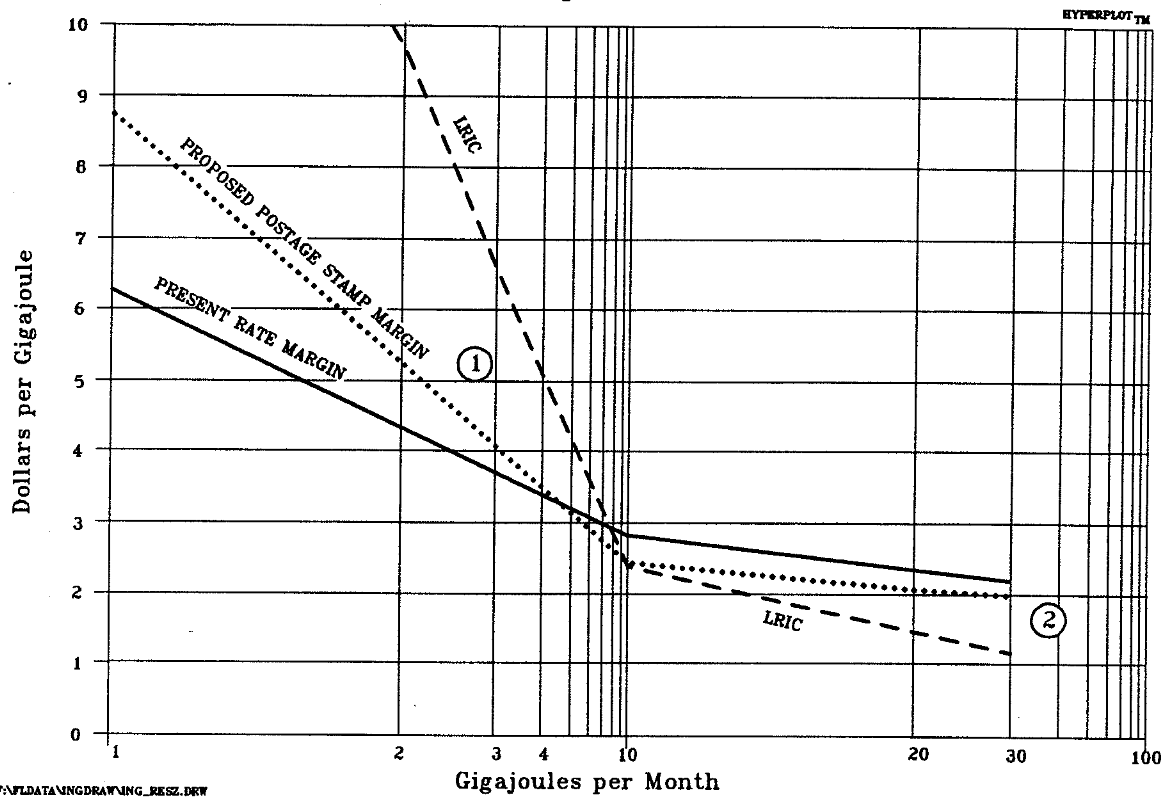
(2) LRIC indicates that the present rate margin above about 15 GJs per month could be decreased.

(3) LRIC is calculated using 100 GJs annual usage (or 8 GJs per month).

BC Gas

INLAND DIVISION

Proposed Schedule No. 1
Residential Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC



1. LRIC indicates that the present rate margin below 7 GJs per month could be increased.

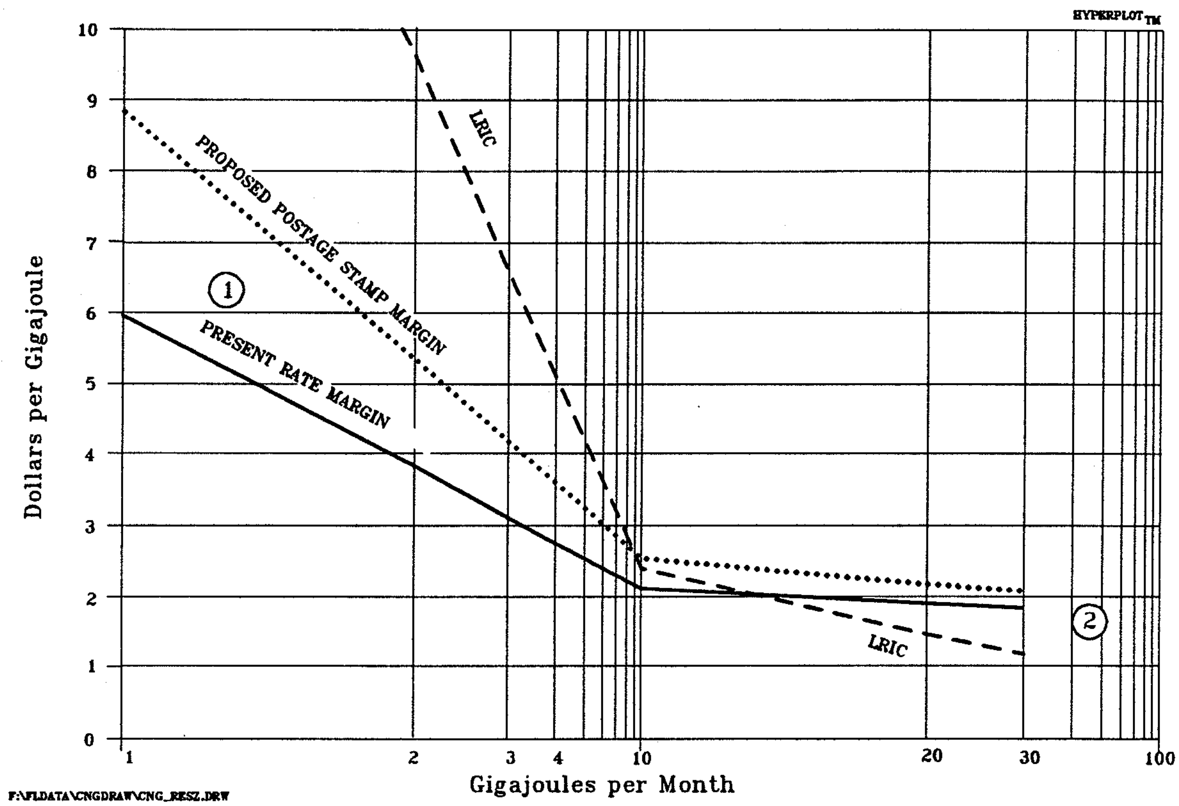
2. LRIC indicates that the present rate margin above 8 GJs per month could be decreased.

3. LRIC is calculated using 100 GJs annual usage (8 GJs per month).

BC Gas

COLUMBIA DIVISION

Proposed Schedule No. 1
Residential Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC



(1) LRIC indicates that the present rate margin at about 15 GJs per month could be increased.

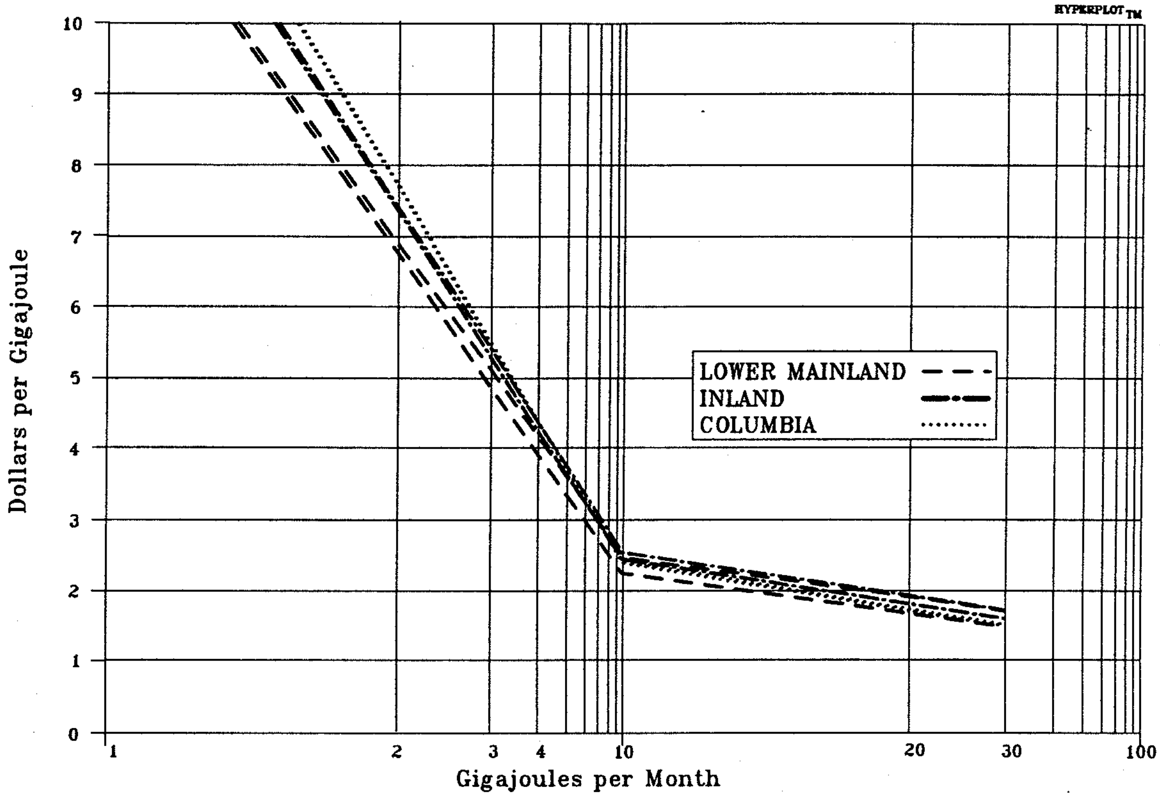
(2) LRIC indicates that the present rate margin above 15 GJs per month could be decreased.

FULLY DISTRIBUTED COSTS

The following chart compares the residential class FDC in each division. The three charts that follow compare the divisional FDC to present and proposed residential rates in the Lower Mainland, Inland, and Columbia Divisions.

BC Gas

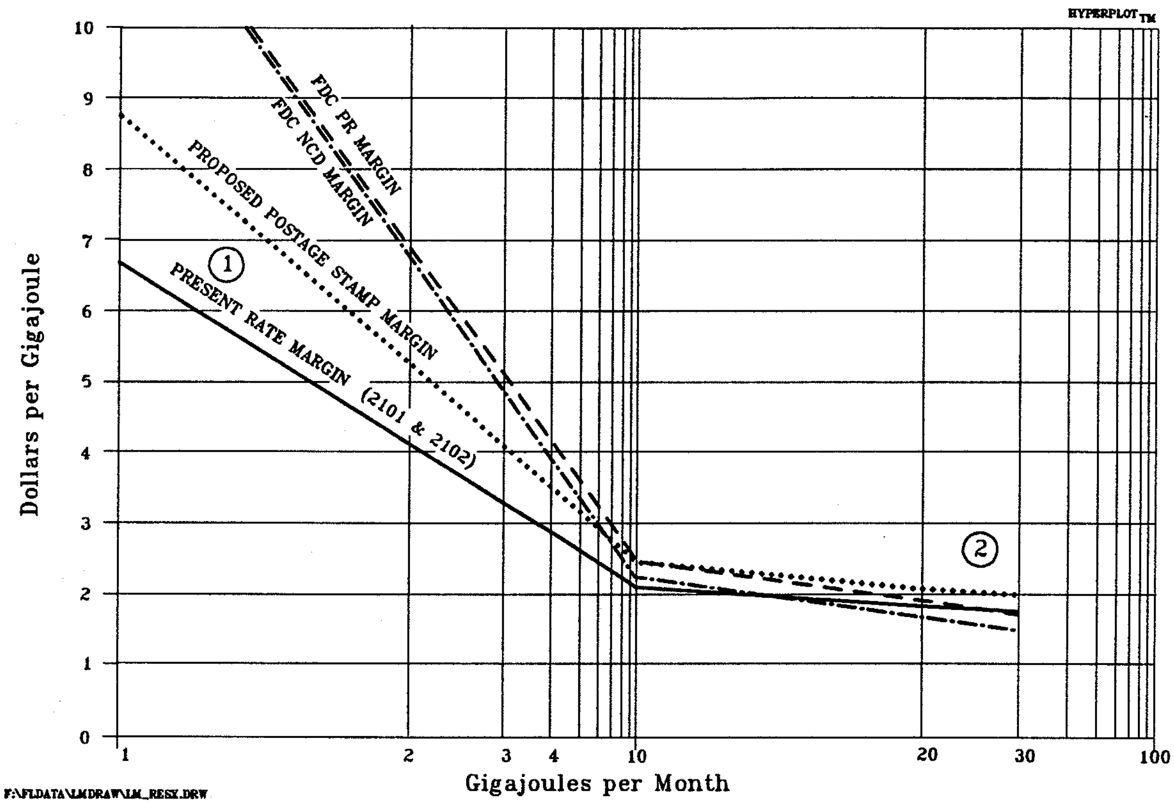
ALL DIVISIONS
Schedule No. 1
FDC Cost Margins



BC Gas

LOWER MAINLAND DIVISION

Proposed Schedule No. 1.
Residential Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to FDC Margin

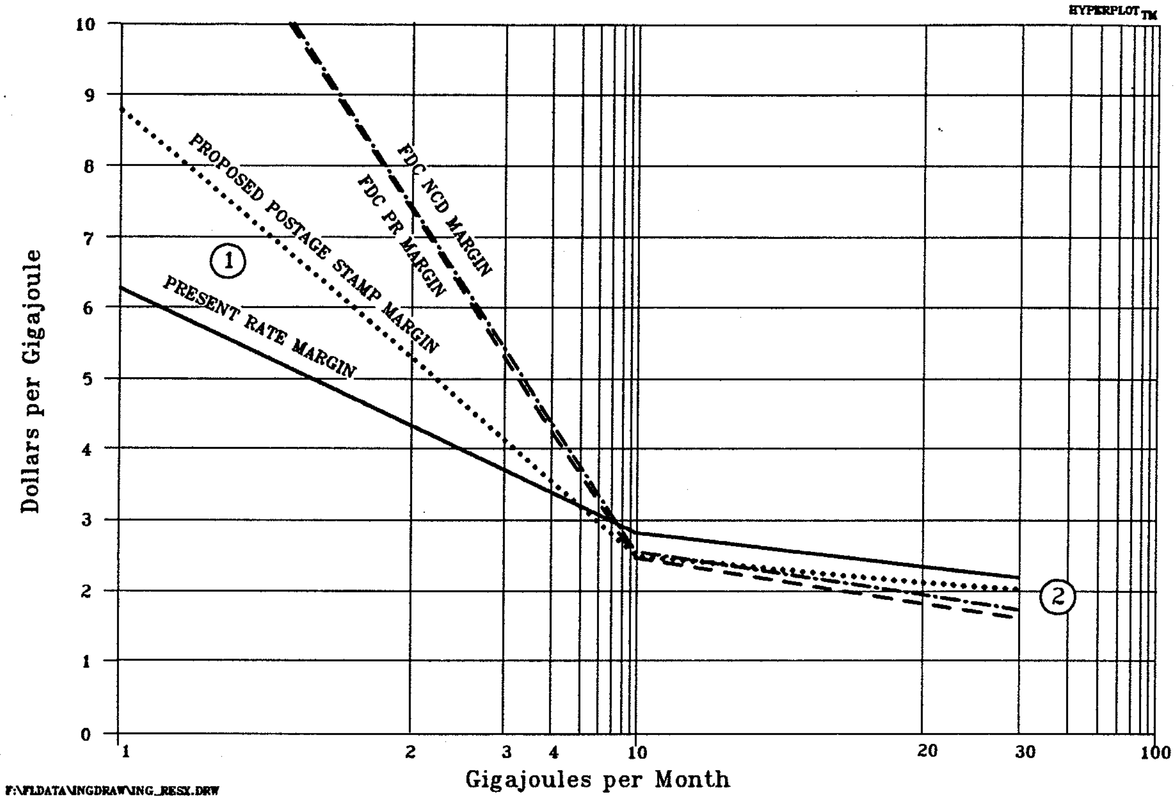


(1) FDC indicates that present rate margin below about 10 GJs per month could be increased.

(2) FDC indicates that present rate margin above 10 GJs per month is not unreasonable.

BC Gas

INLAND DIVISION
Proposed Schedule No. 1
Residential Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margins
Compared to FDC Margin



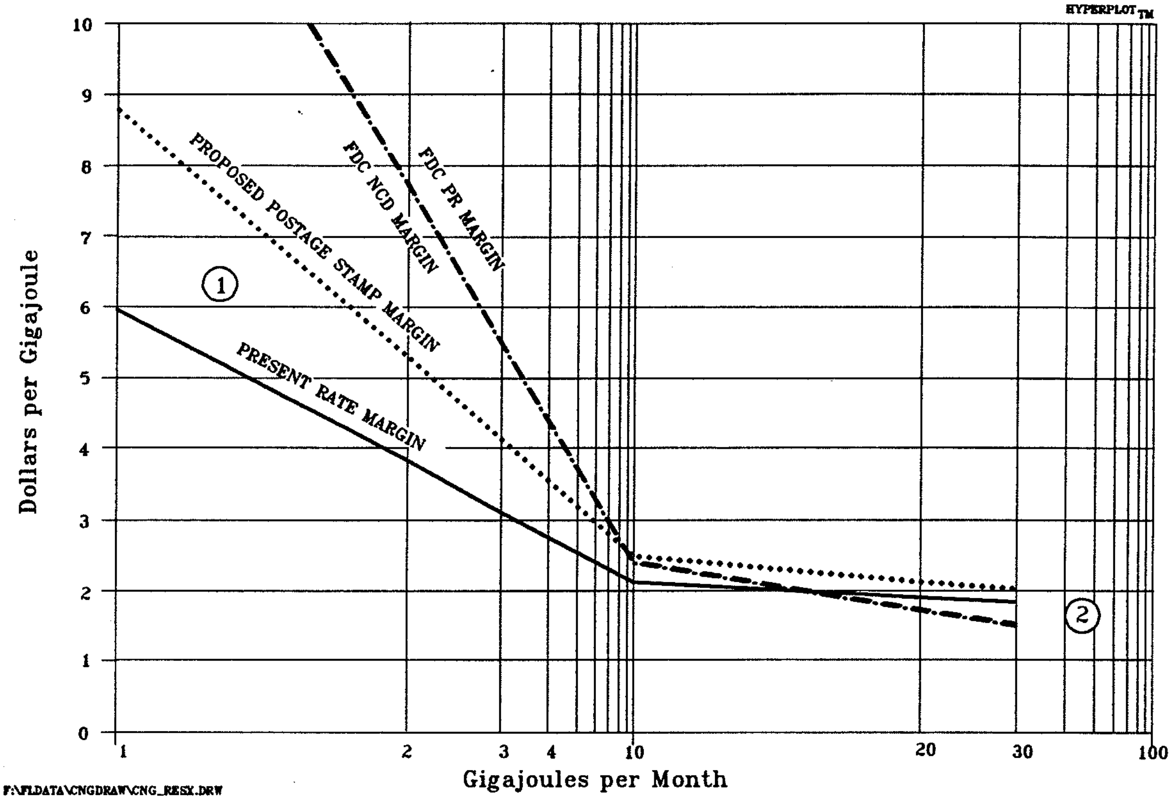
(1) FDC indicates that the present rate margin below 7 GJs per month could be increased.

(2) FDC indicates that the present rate margin above 10 GJs per month could be decreased.

BC Gas

COLUMBIA DIVISION

Proposed Schedule No. 1
Residential Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to FDC Margin



F:\FLDATA\CNGDRAW\CNG_RESX.DRW

(1) FDC indicates that the present rate margin at about 15 GJs per month could be increased.

(2) FDC indicates that the present rate margin at about 20 GJs per month could be decreased.

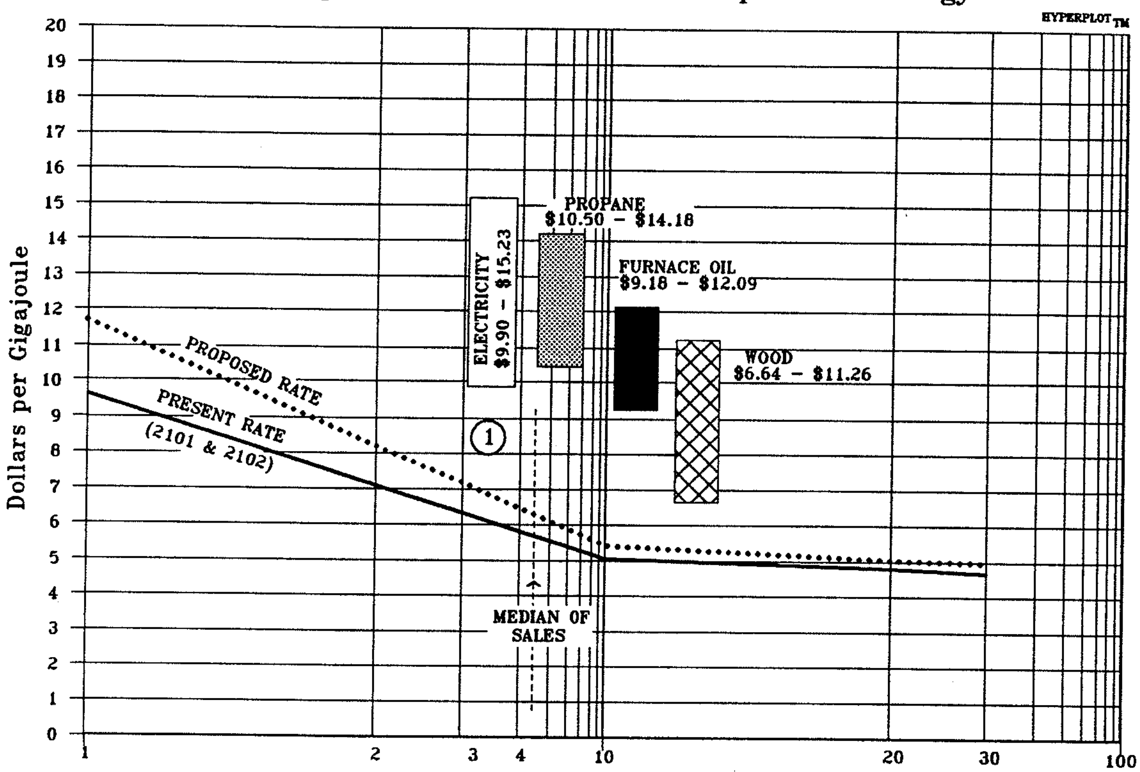
PRICE OF COMPETITIVE ENERGY

The following three charts compare the prices of competitive energy to present and proposed residential rates in the Lower Mainland, Inland, and Columbia Divisions.

BC Gas

LOWER MAINLAND DIVISION

Proposed Schedule No. 1
Residential Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy

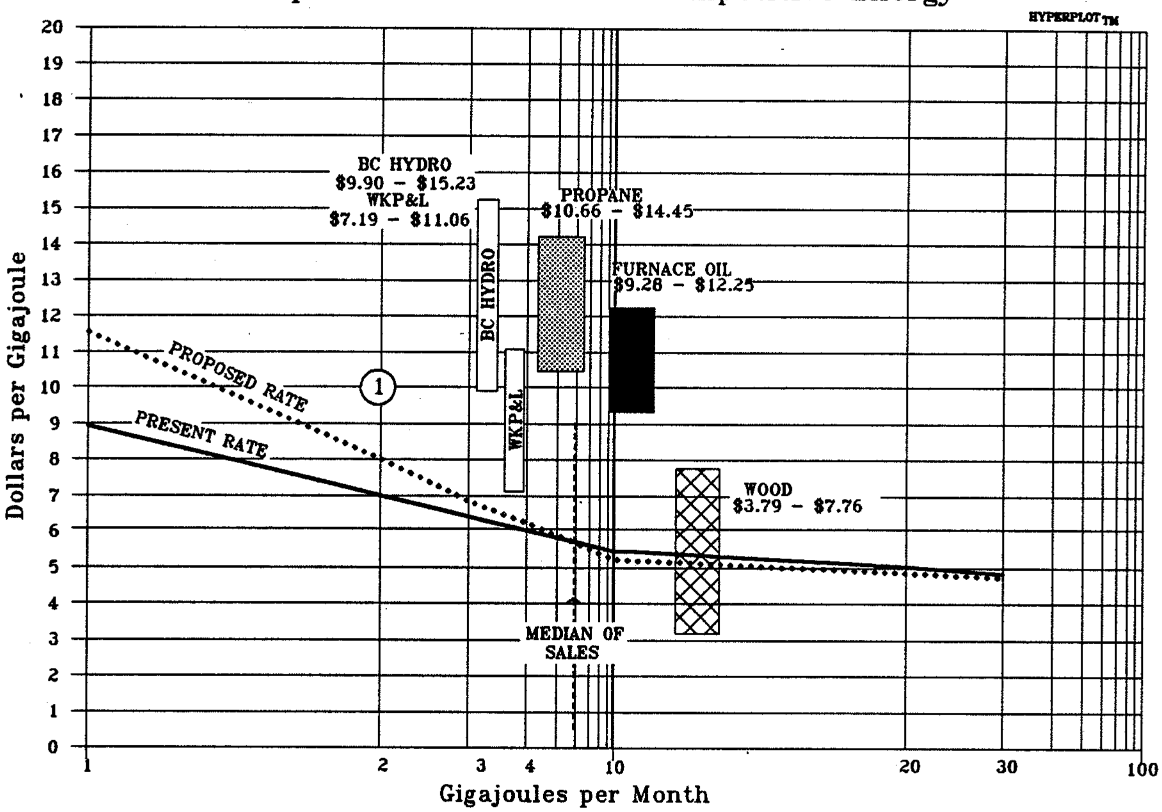


F:\FLDATA\LMDRAW\LM_RESY.DRW

(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

BC Gas

INLAND DIVISION
Proposed Schedule No. 1
Residential Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy

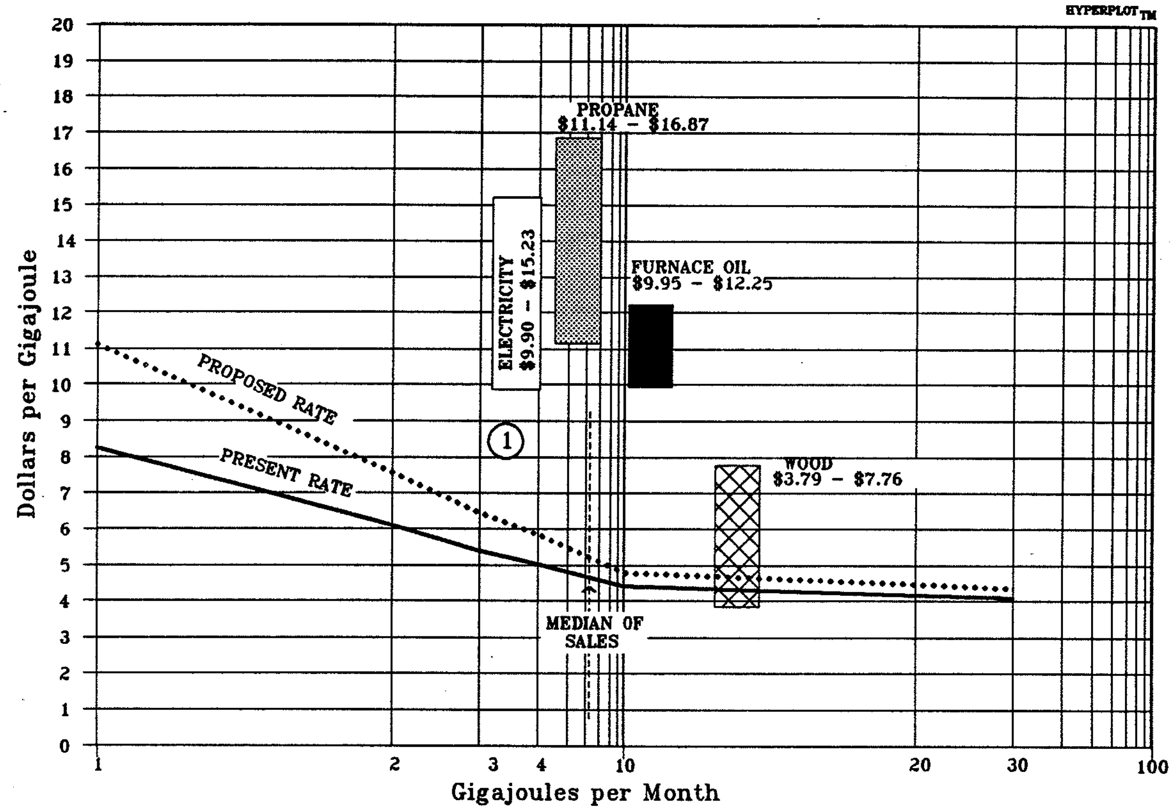


F:\FLDATA\INGDRAW\ING_RESY.DRW

(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

BC Gas

COLUMBIA DIVISION
Proposed Schedule No. 1
Residential Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy



F:\FLDATA\CNGDRAW\LM_RESY.DRW

(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

PROPOSAL TO REVISE COMMERCIAL GAS RATES

1.0 REVIEW OF COMMERCIAL RATE DESIGN

1.1 Introduction

In this application, BC Gas is proposing to introduce three rate groups for firm sales service to non-residential customers.

1. Small commercial service;
2. Large commercial service; and
3. General Firm service.

The distinction between small and large commercial customers is drawn at consumption under and over 2,000 gigajoules per year. The distinction is based on a number of factors with the most important being:

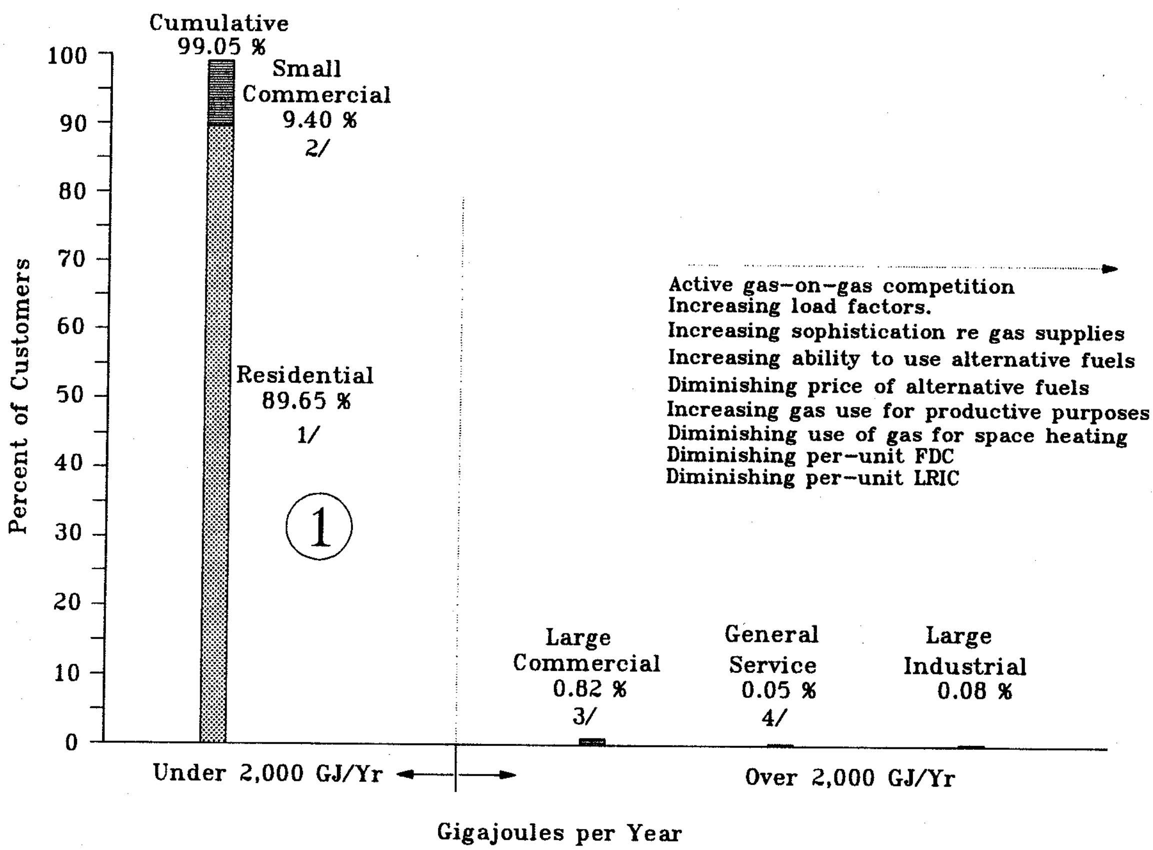
(a) the similarity in annual gas consumption profiles between the small commercial and residential customers;

(b) the similar load factors exhibited by the small commercial and residential customers; and

(c) the similarity in metering and pressure regulating equipment used by small commercial and residential customers.

The graph on the following page depicts how 99.05 percent of all BC Gas customers have annual gas consumption under 2,000 gigajoules per year. Approximately 89.65 percent of these customers are residential and 9.40 percent are small commercial. Large commercial, general service, and large industrial customer accounts for the remaining 0.82 percent, 0.05 percent and 0.08 percent of the total gas customers, respectively, and use over 2,000 gigajoules per year.

GAS CUSTOMERS PLACED ON A CONTINUUM
Lower Mainland, Inland, and Columbia Service Areas
Percent of Customers by Category



1/ Proposed sales service Rate Schedule 1
2/ Proposed sales service Rate Schedule 2
3/ Proposed sales service Rate Schedule 3
4/ Proposed sales service Rate Schedule 5
4/ The percentage (0.05%) includes T–service customers under Rate Schedule 25

1 These customers have similar annual profiles of sales (see BFA's).
These customers have similar annual load factors.
These customers utilize the same type of metering and requlating equipment.

Analysis of the Lower Mainland service area in-service gas meters and pressure regulating equipment indicates that 99.77 percent of residential customers and 72.63 percent of small and large commercial customers utilize metering equipment rated for 700 standard cubic feet per hour (SCFH) or less. Approximately 100 percent of the residential customers have consumption less than 2,000 gigajoules per year and approximately 90 percent of the small and large commercial customers use less than 2,000 gigajoules per year.

The conclusion that can be drawn from these three sets of data is that relatively few commercial customers display gas consumption patterns different from residential customers, especially the small commercial customers.

The material under this Tab addresses the proposed small and large commercial customers. The following Tab addresses the proposed General Firm Service customer group.

In the Lower Mainland and Inland service areas, the Company proposes to serve commercial customers under two rate schedules:

1. Rate Schedule 2 for commercial customers that use less than 2,000 gigajoules of firm gas per year.

2. Rate Schedule 3 for commercial customers that use more than 2,000 gigajoules of firm gas per year.

The allocation of gas supply costs to these two commercial rate schedules is described in under Tab 11 of this Volume. The methodology used to allocate gas costs to these schedules is consistent with that approved in Phase A.

Under the current gas cost allocation methodology for Columbia, only one gas cost is applied to residential and commercial customers under present rate schedules 1, 2.1, and 2.2. Until a gas cost allocation methodology is approved for Columbia service area customers that is on the same basis as Lower Mainland and Inland, the Company proposes to serve commercial customers in the Columbia service area under only one rate schedule, that is the proposed Rate Schedule 2. When a gas cost allocation methodology is approved for Columbia customers on the same basis as in the Lower Mainland and Inland customers, the Company will offer service to applicable commercial customers in the Columbia service area under Rate Schedule 3.

The proposed rate categories, in addition to the gas supply cost allocations discussed above, will include:

1. The implementation of postage stamp uniform delivery charges to recover BC Gas' costs, exclusive of gas supply costs.

2. A common monthly basic charge that will, overall, improve the recovery of fixed margin costs incurred by BC Gas in providing service to the commercial class.

3. Rate levels that improve the ratio of revenue margin to cost margin imbalances between commercial classes in the three service areas and between rate classes.

4. Common general terms and conditions for the commercial class of customers.

5. A phase-in process in Columbia to ameliorate the effect of the rate level and rate design changes.

6. Franchise fees in the Inland and Columbia service areas billed as a separate charge in addition to base rates.

In reviewing its commercial rates BC Gas has considered studies relating to the costs to serve commercial customer and information relating to the prices of alternate energy sources.

1.2 Long Run Incremental Cost

A long run incremental cost (LRIC) study has been undertaken by the Company. The focus of the LRIC is mainly on the costs associated with serving new customers rather than the cost associated with additional consumption by existing customers. This approach more properly identifies the costs of system expansion, as opposed to more intensive use of gas in areas already saturated.

The long run incremental cost study indicates that present commercial margin costs are those shown below. The average revenue margins for commercial service under present rates are compared to the LRIC information.

LRIC Compared to Average Margin Revenue

	LRIC/GJ	Avg Margin/GJ	Excess (Deficiency)
Lower Mainland	$0.82	$1.535	$0.715
Inland	0.93	2.160	1.230
Columbia	0.87	1.344	0.474

The conclusion to be drawn from the above tabulation is that present revenue margins from commercial customers in their current classification exceed their long run incremental costs. The Inland commercial customers exceed their long run incremental costs by a significantly greater amount than Lower Mainland and Columbia customers.

The following two tables compare average revenue margins to LRIC information under the proposed Rate Schedules 2 and 3.

LRIC Compared to Average Margin Revenue - Rate Schedule 2

	LRIC/GJ	Avg Margin/GJ	Excess (Deficiency)
Lower Mainland	$1.16	$1.47	$0.31
Inland	1.23	2.43	1.20
Columbia	1.25	1.38	0.13

LRIC Compared to Average Margin Revenue - Rate Schedule 3

	LRIC/GJ	Avg Margin/GJ	Excess (Deficiency)
Lower Mainland	$0.56	$1.55	$0.99
Inland	0.66	1.80	1.14

The two tables indicate that both the small and large commercial customers will continue under proposed rates to generate average margins in excess of long run incremental costs. Under proposed rates the Inland commercial customers will be closer to their counterparts in the Columbia and Lower Mainland service areas.

Enclosed in the Technical Appendix is a chart on page 30 that shows the per unit LRIC costs at various levels of consumption for proposed Rate Schedule 2. Graphics that compare the LRIC to present and proposed rates in the three divisions for proposed Rate Schedule 2 are also contained in the commercial class Technical Appendix pages 31 through 33. The same information for proposed Rate Schedule 3 is contained in the Technical Appendix, pages 44 through 46.

1.3 Fully Distributed Cost

The basic purpose of a fully distributed cost (FDC) study is to compare the revenue generated by rates to the cost that a utility incurs in serving its customer classes. A FDC study takes the total cost incurred by a utility in the service of its customers and fully distributes that cost to the various classes of service. The allocation methodologies employed in the FDC studies were peak responsibility (PR), non-coincident demand peak (NCD); and average and excess demand (AED). These demand cost allocation methodologies are more fully described in the description of the FDC studies in Volume 2, Tab 2.

The results of the FDC study for Lower Mainland, Inland and Columbia are found respectively in Volume 2, Section 1 of Tabs 2A, 2B and 2C.

The findings of the Fully Distributed Cost (FDC) studies indicate that the ratio of the revenue margin to the cost margin for the present commercial classes are:

Revenue Margin as a Percentage of Cost Margin
for Present Commercial Rates

	PR	NCD	AED
Lower Mainland	93.37%	104.85%	105.78%
Inland	135.27%	143.93%	145.41%
Columbia	91.95%	94.22%	94.68%

The conclusion to be drawn from this table is that Inland commercial customers have significantly higher revenue margin to cost margin rates and adjustments to bring Lower Mainland, Columbia and Inland revenue margins into parity are justified.

1.4 Price of Competitive Energy

Table 2 of the BC Gas Competitive Energy study (see Volume 2, Tab 4, page 4) is a tabulation of the price for natural gas and competing fuels throughout the BC Gas service areas. The current rates for natural gas relative to competing fuels in the commercial market indicate that commercial class gas rates are less than the price of alternate energy sources. Charts that compare present and proposed rates to the price of competitive energy for the proposed Rate Schedule 2 are in the commercial class Technical Appendix, see pages 40 through 42. The same information for proposed Rate Schedule 3 in the Lower Mainland and Inland service areas is contained in pages 52 and 53.

1.5 Environmental Responsiveness

Commercial customers exhibit similar gas use patterns to residential customers and should be encouraged to use energy efficiently through customer education programs that promote efficient equipment and insulation programs where space heating is involved. The Company will address energy efficiency in the commercial sector of its Integrated Resource Plan.

Care must be exercised in designing commercial rates to strike a balance where the annual bill for natural gas is large enough to encourage conservation yet not so high to motivate commercial customers to switch to other more environmentally harmful fuels. At the same time, commercial rates must be designed to adequately recover the largely fixed costs of the BC Gas infrastructure.

1.6 Rate Design Principles

As the gas use characteristics of most commercial customers are similar to those of residential customers, rate design for commercial customers should incorporate the same principles outlined in Section 1.6 of the preceding Tab 6. Specifically, rates should be designed to encourage the wise and efficient use of natural gas and ensure the dependable recovery of costs. Graphs in the commercial class Technical Appendix provide information regarding proposed commercial Rate Schedules 2 and 3 in relation to fully distributed costs and long run incremental costs.

2.0 PROPOSED COMMERCIAL RATES

The Company has taken many factors into consideration in the design of rates for commercial service. The explicit rate design factors are those outlined on page 10 of Tab 6 of this Volume together with the distinctions mentioned on page 1 of this Tab.

Based on the 1993 Revenue Requirement filing the proposed Rate Schedules 2 and 3 for small and large commercial service will have a $14.00 monthly Basic Charge and a uniform delivery charge of $1.322 per gigajoule. The appropriate gas supply cost for Lower Mainland and Inland small and large commercial customers, as described in Tab 11 of this Volume, will be added to these charges to arrive at the total rate. The gas supply cost for Columbia commercial customers will be added to the Basic Charge and the delivery charge to arrive at their total rate.

The monthly Basic Charge of $14.00 has been established on the basis of reviewing customer-related costs identification in the FDC study. The monthly customer costs, expressed as "Customer Costs, $/bill" in the FDC study found in Volume 2 on page 1.2 of Section 1, under Tabs 2A, 2B and 2C are compared to the current commercial basic charges in the following table.

	Commercial Customer Cost, $/bill	Current Monthly Basic Charges
Lower Mainland	$19.547	$ 4.64
Inland	$19.398	$12.91
Columbia	$20.462	$ 8.75

The above table indicates that current monthly Basic Charges in the Lower Mainland, Inland, and Columbia service areas are less than the monthly fixed costs to serve the customers. To achieve simplicity and parity, the Company proposes that the large commercial monthly basic charge for all service areas be increased to a uniform $14.00.

2.1 Demarcation Between Service Under Rate Schedules 2 and 3

The load factor of small volume commercial customers is somewhat lower than that of larger commercial customers, resulting in a higher gas supply cost for Schedule 2 customers. At this time, the Company is proposing to make the monthly Basic Charge and delivery charge of commercial service under the two Rate Schedules the same. The gas supply cost, which is roughly two-thirds of total gas bill, will be the only rate difference between these two services. Small commercial customers in the Inland and Lower Mainland service areas under Schedule 2 will have a gas cost rate about 38 cents per gigajoule higher than customers under Schedule 3 for large commercial service. As there is no gas supply cost differentiation for the commercial customers in Columbia at this time there will only be a Rate Schedule 2 in Columbia.

2.2 Impact of Proposed Rate Changes

A move to consistent rates for BC Gas small and large commercial customers in the Lower Mainland, Inland and Columbia service areas will have varying impacts on the annual gas bills of customers depending upon their current rate structure.

The Company estimates the following distribution of customers, by service area, resulting from proposed Rate Schedules 2 and 3.

	Small Commercial Rate Schedule 2	Large Commercial Rate Schedule 3
Lower Mainland	44,320	4,500
Inland	15,152	860
Columbia	1,773	Not applicable
Total	61,245	5,360

BC Gas has evaluated the impact on the annual bills at proposed rates for small and large commercial customers in the Lower Mainland, Inland and Columbia services areas, at high, medium, and low consumption levels, with different uniform monthly Basic Charges and commodity charges. To determine the annual gas consumption levels that would represent high, medium and low consumption customers, BC Gas analyzed the distribution of Lower Mainland commercial customers by annual consumption. The analysis indicates that the small commercial customers in the Lower Mainland generally consume between 50 gigajoules and 600 gigajoules per year and large commercial customers between 2,000 gigajoules and 10,000 gigajoules per year. The range of consumption for each class represents low and high consumption for that category of customers. The medium level consumption characteristics for commercial customers is in the range of 350 for the small commercial customers and 5,000 gigajoules per year for the large commercial customers. These three levels of consumption are also reasonable for considering the impact on commercial customers in the Inland service area. In Columbia higher volume customers will also be on Rate Schedule 2 and an analysis of the impact on a higher volume customer is also shown on Table 1. The 3,800 GJ per year represents the average consumption level of the higher volume Columbia customers.

An important issue that was discussed relative to proposed residential rates bears repeating. The FDC has identified that the Inland commercial customers are contributing revenues considerably in excess of the cost to serve them. The Inland commercial customers are also contributing a greater margin than their Lower Mainland and Columbia counterparts. In addressing this matter, BC Gas is proposing to remove approximately $2.9 million of revenue requirement from the Inland commercial customers. As discussed in the residential and industrial sections of this application, the Company is also proposing to reduce the rates of industrial customers, primarily in the Lower Mainland, which removes approximately $11 million of revenue requirement from those customers. The uniform delivery charge for commercial rates has been established after those reduced rates were taken into account.

Table 1 provides a summary of the impact that the proposed Rate Schedule 2 will have on annual bills compared to permanent rates in effect as of January 1, 1993.

Table 1

ANALYSIS OF THE IMPACT THAT A $14.00 BASIC MONTHLY CHARGE AND $1.322/GJ DELIVERY CHARGE HAS ON ANNUAL SMALL COMMERCIAL GAS BILLS

*** Cost of Gas Included ***

Division	Annual Consumption (GJ)	Current Annual Bill	Proposed Annual Bill with $14 Basic Monthly Charge and $1.322/GJ Delivery Charge	
			Annual Bill Increase (Decrease)	% Increase (Decrease)
Lower Mainland	High *	$2,690	$124	5%
	Medium *	$1,593	$119	7%
	Low*	$ 275	$113	41%
Inland	High	$3,151	($439)	(14%)
	Medium	$1,923	($271)	(14%)
	Low	$ 429	($ 49)	(11%)
Columbia	Very High	$13,178	$ 903	7%
	High	$2,235	$ 130	6%
	Medium	$1,356	$ 93	7%
	Low	$ 284	$ 67	24%

* High = 600 GJ/year * Medium = 350 GJ/year * Low = 50 GJ/year
Very High = 3800 GJ/year

Note: Gas supply costs for Inland and Lower Mainland were established by use of the allocation methodology from the Phase A Rate Design Decision. Franchise fee charges for Inland and Columbia customers are included.

Although the table indicates a 41% increase for low volume customers in the Lower Mainland service area those customers consume a small volume of gas and are not covering the fixed costs of supplying gas to them.

Table 2 provides a summary of the impact that the proposed Rate Schedule 3 will have on annual bills compared to permanent rates effective as of January 1, 1993.

Table 2

ANALYSIS OF THE IMPACT THAT A $14.00 BASIC MONTHLY CHARGE AND $1.322/GJ DELIVERY CHARGE HAS ON ANNUAL LARGE COMMERCIAL GAS BILLS

*** Cost of Gas Included ***

Division	Annual Consumption (GJ)	Current Annual Bill	Proposed Annual Bill with $14 Basic Monthly Charge and $1.322/GJ Delivery Charge Annual Bill Increase (Decrease)	 % Increase (Decrease)
Lower Mainland	High *	$41,832	($1,321)	(3%)
	Medium *	$21,703	($1,364)	(6%)
	Low*	$ 8,841	($ 604)	(7%)
Inland	High$_1$	$40,570	($1,563)	(4%)
	Medium$_1$	$20,766	($1,178)	(6%)
	Low$_2$	$ 9,488	($1,546)	(16%)

* High = 10,000/GJ year * Medium = 5,000 GJ/year * Low = 2,000 GJ/year

Note: Gas supply costs were established by use of the allocation methodology from the Phase A Rate Design Decision. Franchise fee charges for Inland customers are included.

$_1$ High and Medium calculations based on current Inland rate 2.2 customers moving to the proposed rate Schedule 3.

$_2$ Low calculations based on current Inland rate 2.1 customers moving to proposed rate Schedule 3.

The Company believes that the proposed small and large commercial rates under Rate Schedules 2 and 3 strike the best balance of a number of rate design factors. The proposed rates are fair and equitable since they will recover more fairly the significant fixed margin cost component of commercial service and there will be uniform charges for all service areas.

The proposed rates are simple since consumption and cost of gas are the only variables other than franchise fees. Billing adjustments, customer comprehension, and other administrative functions will be simplified.

The proposed rates will contribute to more stable revenue and earnings from year to year: An increased monthly basic charge for most of the commercial customers will make customer bills more consistent throughout the year, reducing high bills in the winter months. BC Gas will have a more even monthly distribution of revenues.

3.0 IMPLEMENTATION OF THE PROPOSED BC GAS COMMERCIAL RATES

BC Gas proposes that Rate Schedules 2 and 3 and related charges become effective January 1, 1994 as well as the proposed new General Terms and Conditions. Specifically, all of the proposed monthly Basic Charges, delivery charges, and application for service fees will take effect on that date.

BC Gas proposes to mitigate the increases in the Columbia Schedule 2 rates by phasing them in over a two year time period. Funds currently held in income tax deferral accounts, increased revenue from application for service charges, and the revenue from interruptible and off-system gas sales will also affect the impact experienced by the commercial customers.

The table below provides a summary of the existing and proposed revenue to be obtained from small commercial customers under Rate Schedule 2 in the Lower Mainland, Inland and Columbia divisions. The table is based on 1993 projected sales volumes and the permanent rates effective January 1, 1993.

PROPOSED RATE 2 SMALL COMMERCIAL REVENUES

	Lower Mainland	Inland	Columbia
Projected Sales Volumes (GJ)	15,038,642	5,261,577	909,753
Proposed Total Revenue	$73,779,736	$24,850,156	$3,629,350
Existing Total Revenue	$68,512,167	$28,228,647	$3,376,670
Total Revenue Increase (Decrease)	$ 5,267,569	$(3,378,491)	$ 252,680
Revenue Difference	7.69%	-11.97%	7.48%

The following table provides a summary of the existing and proposed revenue to be obtained from commercial customers under Rate Schedule 3 in the Lower Mainland and Inland service areas. The table is based on 1993 projected sales volumes and includes the permanent rates effective January 1, 1993.

PROPOSED RATE 3 LARGE COMMERCIAL REVENUES

	Lower Mainland	Inland
Projected Sales Volumes (GJ)	21,515,165	3,932,703
Proposed Total Revenue	$87,548,216	$15,429,310
Existing Total Revenue	$91,560,334	$17,193,023
Total Revenue Increase (Decrease)	$(4,012,118)	$(1,763,712)
Revenue Difference	-4.38%	-10.3%

The total revenue required from small and large commercial customers in 1994 will also be affected by:

1. Increasing Application for Service fees from $10 to $25 in those cases where gas service already exists but simply requires a change from one customer to another. In the case where a new gas service must be provided, the fee will increase from $10 to $75. Details of these proposed increases are available in Tab 12 of this Volume. The $4 million in additional revenues generated will be applied to reduce the Company's revenue requirement.

2. Applying $126,000 of funds in the deferred income tax account to the Columbia service area commercial customers.

3. Interruptible gas sales revenue and off-system gas sales revenue in excess of gas supply costs will be applied to reduce the cost of gas for Lower Mainland and Inland service areas customers.

4. For a 12 month period all Lower Mainland "captive" customers will be billed a separate charge to recover the revenue loss of $0.41 per gigajoule currently in the deferral account established to capture the difference in margin for the Lower Mainland Division customers that switched from interruptible sales to interruptible service (B.C.U.C. Order Number G-92-91) for a 12-month period. The balance forecast to be in that account for transportation volumes to November 1, 1993, when the $0.41 per gigajoule discrepancy should end, is $3,271,000.

5. Establishing common depreciation rates will reduce the depreciation expense by $1.8 million, as set out in the discussion on Regulatory Consolidation at Tab 5 of this Volume.

The following table summarizes the impact in 1994 of the actions listed on the small commercial customers under Schedule 2.

	Lower Mainland	Inland	Columbia	Total
Reduction Attributable to Increase in Application for fees	$ 110,000	$ 35,000	$ 8,000	$ 153,000
Withdrawal from Divisional Deferred Income Tax Balances	N/A	0	$126,000	$ 126,000
Allocation of estimated 1994 Off-system Sales Revenues & Gas Margin Revenues	$1,805,700	$606,500	N/A	$2,412,200
Repayment of 41¢ Deferred Account	($1,150,000)	N/A	N/A	($1,150,000)
Allocation of $1.8 million Depreciation Reduction	$ 218,000	$ 74,000	$ 14,000	$ 306,000
Total Reduction in Commercial Revenue Requirement through other sources	$ 983,700	$715,500	$148,000	$1,847,200
New Revenue Difference %	6.3 %	-14.5 %	3.1 %	

The following table summarizes the impact in 1994 of the actions listed on the large commercial customers under Schedule 3.

	Lower Mainland	Inland	Total
Reduction Attributable to Increase in Application for fees	$ 36,000	$ 11,000	$ 47,000
Withdrawal from Divisional Deferred Income Tax Balances	N/A	$ 0	$ 0
Allocation of estimated 1994 Off-system Sales Revenues & Gas Margin Revenues	$2,126,500	$373,200	$2,499,700
Repayment of 41¢ Deferred Account	$ (74,000)	N/A	$ (74,000)
Allocation of $1.8 million Depreciation Reduction	$ 260,000	$ 46,000	$ 306,000
Total Reduction in Commercial Revenue Requirement through other sources	$2,348,500	$430,200	$2,778,700
New Revenue Difference %	-6.9%	-12.8%	

The Inland and Columbia commercial customers will also receive the benefit of the draw-down of the deferred income tax balance to pay franchise fees. That draw-down is not reflected in the tables above.

TECHNICAL APPENDIX

COMMERCIAL CLASS

REVENUE CALCULATION WORKPAPERS

The following four pages contain calculations of commercial class revenue under present and proposed rates.

Revenue under existing rates is shown on page 21. Page 22 shows the calculation of proposed margin revenue under proposed rates. The difference in present and proposed gross margins is shown at the foot of page 22.

Under the proposed consolidated tariff rate schedules, it is necessary to reclassify customers in the various service areas. The rather succinct workpaper column headings may need to be clarified. Please refer to page 21, column (b). Customers under the Lower Mainland Rate Schedules 2207, 2208, and 2209 that have gas consumption in the range of zero to 2,000 gigajoules per year will be reclassified as proposed Rate Schedule 2. The heading on page 21, column (b), "LM 2207/8/9»2" means customers under present Lower Mainland Rate Schedules 2207, 2208, 2209 that will be moved to the Rate Schedule 2. The heading over column (f) that reads "INL 2.2»3" means customers under existing Inland Rate Schedule 2.2 will be subject to the consolidated tariff Rate Schedule 3.

Pages 23 and 24 contain commercial class existing and proposed rates and billing determinates.

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED COMMERCIAL TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 1 - Base Case

Ln. No.	ANNUAL Existing Rates	EXISTING TARIFF STRUCTURE LM 2207/8/9»2 Revenue	LM 2207/8/9»3 Revenue	INL 2.1»2 Revenue	INL 2.1»3 Revenue	INL 2.2»3 Revenue	COL 2.1&2.2»2 Revenue	FT NEL 2.1»2 Revenue	FT NEL 2.1»3 Revenue	FT NEL 2.2»3 Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Basic Charge	$2,467,747	$250,574	$2,347,361	$115,325	$18,151	$186,177	$0	$0	$0	$5,385,335
2	Minimum Charge	0	0	0	0	0	0	55,400	5,624	428	61,452
3	1st Block	$22,592,841	$22,784,621	$2,162,294	$144,986	$22,695	$586,829	($10,151)	($1,143)	($77)	$48,282,895
4	2nd Block	10,956	6,191,924	7,653,927	1,608,297	277,653	164,974	193,728	90,253	10,022	16,201,734
5	3rd Block	0	169,379	1,225,709	2,470,375	1,994,386	316,329	2,294	29,594	14,685	6,222,751
6	4th Block	0	15,131	0	0	0	0	0	0	0	15,131
7	5th Block	0	0	0	0	0	0	0	0	0	0
8											
9	Total Exs. Net Margin (1)	$25,071,544	$29,411,629	$13,389,290	$4,338,983	$2,312,885	$1,254,309	$241,270	$124,328	$25,058	$76,169,297
10											
11	ADJ 1 = Commod. Costs	$14,898,783	$21,315,074	$4,916,417	$2,285,097	$1,389,472	$1,704,240	$249,003	$148,315	$26,463	$46,932,864
12	ADJ 2 = Fixed Costs	28,541,839	40,833,631	9,216,178	4,283,578	2,152,544	332,424	1,007	600	124	85,361,926
13	ADJ 3 = Franchise Fees	0	0	706,762	280,109	150,354	85,697	0	0	0	1,222,921
14											
15	Total Adjustments	$43,440,622	$62,148,705	$14,839,357	$6,848,784	$3,692,370	$2,122,361	$250,010	$148,915	$26,586	$133,517,711
16											
17	Total Exs. Rate Rev.	$68,512,167	$91,560,334	$28,228,647	$11,187,767	$6,005,256	$3,376,670	$491,281	$273,242	$51,645	$209,687,008
18											
19	Spread Adj. Factor (2)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20											
21	Total Exs. Rate Rev. (3)	$68,512,167	$91,560,334	$28,228,647	$11,187,767	$6,005,256	$3,376,670	$491,281	$273,242	$51,645	$209,687,008

22
23
24
25 ____________
26 Notes:
27
28 (1) Total Existing Net Margin does not include Franchise Fees revenues.
29 (2) Spread Adjustment Factor not available for revised customer classes.
30 (3) Total Existing Rate Revenue does not include Revelstoke.

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED COMMERCIAL TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 2 - Base Case

Ln. No.	ANNUAL Proposed Rates	PROPOSED TARIFF STRUCTURE LM 2207/8/9»2 Revenue	LM 2207/8/9»3 Revenue	INL 2.1»2 Revenue	INL 2.1»3 Revenue	INL 2.2»3 Revenue	COL 2.1&2.2»2 Revenue	FT NEL 2.1»2 Revenue	FT NEL 2.1»3 Revenue	FT NEL 2.2»3 Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Basic Charge	$7,445,788	$756,042	$2,545,550	$125,062	$19,684	$297,883	$0	$0	$0	$11,190,009
2	Minimum Charge	0	0	0	0	0	0	55,400	5,624	428	61,452
3	1st Block	$19,881,085	$28,443,048	$6,955,805	$3,232,982	$1,966,052	$1,202,693	($10,151)	($1,143)	($77)	$61,670,293
4	2nd Block	0	0	0	0	0	0	193,728	90,253	10,022	294,003
5	3rd Block	0	0	0	0	0	0	2,294	29,594	14,685	46,573
6	4th Block	0	0	0	0	0	0	0	0	0	0
7	5th Block	0	0	0	0	0	0	0	0	0	0
8											
9	Total Margin Revenue	$27,326,874	$29,199,089	$9,501,355	$3,358,044	$1,985,736	$1,500,576	$241,270	$124,328	$25,058	$73,262,330
10											
11	ADJ 1 = Commod. Costs	$14,898,783	$21,315,074	$4,916,417	$2,285,097	$1,389,621	$1,704,240	$249,003	$148,315	$26,463	$46,933,012
12	ADJ 2 = Fixed Costs	31,554,079	37,034,053	9,810,210	3,746,297	2,278,211	332,424	1,007	600	124	84,757,005
13	ADJ 3 = Franchise Fees	0	0	622,175	241,121	145,184	92,110	0	0	0	1,100,589
14											
15	Total Gas Cost Rev.	$46,452,862	$58,349,127	$15,348,802	$6,272,515	$3,813,016	$2,128,774	$250,010	$148,915	$26,586	$132,790,606
16											
17	Total Prop. Rate Rev.	$73,779,736	$87,548,216	$24,850,156	$9,630,558	$5,798,752	$3,629,350	$491,281	$273,242	$51,645	$206,052,936
18											
19	Spread Adj. Factor (2)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20											
21	Total Prop. Rate Rev.	$73,779,736	$87,548,216	$24,850,156	$9,630,558	$5,798,752	$3,629,350	$491,281	$273,242	$51,645	$206,052,936
22											
23											
24	Total Exs. Rate Rev.	$68,512,167	$91,560,334	$28,228,647	$11,187,767	$6,005,256	$3,376,670	$491,281	$273,242	$51,645	$209,687,008
25											
26	Prop. - Exs. Rate Rev.	$5,267,569	($4,012,118)	($3,378,491)	($1,557,208)	($206,504)	$252,680	$0	$0	$0	($3,634,072)
27											
28											
29	Difference (%)	7.69%	-4.38%	-11.97%	-13.92%	-3.44%	7.48%	0.00%	0.00%	0.00%	-1.76%
30											
31											
32	GROSS MARGINS:										
33											
34	Exs. Margin Revenue	$25,071,544	$29,411,629	$13,389,290	$4,338,983	$2,312,885	$1,254,309	$241,270	$124,328	$25,058	$76,169,297
35	Prop. Margin Revenue	27,326,874	29,199,089	9,501,355	3,358,044	1,985,736	1,500,576	241,270	124,328	25,058	73,262,330
36											
37	Margin Difference	$2,255,329	($212,540)	($3,887,936)	($980,939)	($327,149)	$246,267	$0	$0	$0	($2,906,967)
38											
39	Margin Difference (%)	9.00%	-0.72%	-29.04%	-22.61%	-14.14%	19.63%	0.00%	0.00%	0.00%	-3.82%
40											
41	UNIT VALUES:										
42											
43	Existing Avg Margin	$1.67	$1.37	$2.54	$1.77	$1.56	$1.38	$1.80	$1.55	$1.52	
44	Proposed Avg Margin	$1.82	$1.36	$1.81	$1.37	$1.34	$1.65	$1.80	$1.55	$1.52	

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED COMMERCIAL TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 3 - Base Case

Ln. No.	EXISTING INPUT TABLE COMMERCIAL ANNUAL	EXISTING TARIFF STRUCTURE								
		LM 2207/8/9»2	LM 2207/8/9»3	INL 2.1»2	INL 2.1»3	INL 2.2»3	COL 2.1&2.2»2	FT NEL 2.1»2	FT NEL 2.1»3	FT NEL 2.2»3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	EXISTING RATES ($/GJ): (1									
2										
3	Basic Charge	$4.640	$4.640	$12.910	$12.910	$12.910	$8.750	$0.000	$0.000	$0.000
4	Minimum Charge	0.000	0.000	0.000	0.000	0.000	0	18.320	18.320	17.840
5										
6	Price 1st Block	$1.503	$1.503	$2.754	$2.773	$2.742	$1.248	($1.861)	($1.861)	($1.611)
7	Price 2nd Block	1.013	1.013	2.094	2.113	2.082	1.148	1.522	1.522	1.531
8	Price 3rd Block	0.763	0.763	1.494	1.513	1.482	1.069	1.474	1.474	1.483
9	Price 4th Block	0.543	0.543	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11										
12	Price ADJ 1=Comm. Costs	$0.991	$0.991	$0.934	$0.934	$0.934	$1.873	$1.854	$1.854	$1.604
13	Price ADJ 2=Fixed Costs	1.898	1.898	1.752	1.752	1.447	0.365	0.008	0.008	0.008
14	Price ADJ 3=Fran. Fees	0.000	0.000	0.134	0.115	0.101	0.094	0.000	0.000	0.000
15										
16										
17	EXISTING BLOCK ENDINGS (GJ)									
18										
19	End of 1st Block	500	500	6	6	6	50	2	2	2
20	End of 2nd Block	8,000	8,000	105.5	105.5	105.5	100	300	300	300
21	End of 3rd Block	25,000	25,000	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9
22	End of 4th Block	999,999.9	999,999.9	0	0	0	0	0	0	0
23	End of 5th Block	0	0	0	0	0	0	0	0	0
24										
25	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9
26	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9
27	ADJ 3 = Franchise Fees	0	0	999,999.9	999,999.9	999,999.9	999,999.9	0	0	0
28										
29										
30	No. GJ's IN INTERVAL:									
31										
32	1st Block	15,027,831	15,155,395	785,239	52,276	8,276	470,177	5,454	614	48
33	2nd Block	10,811	6,110,050	3,655,738	760,978	133,346	143,693	127,310	59,310	6,548
34	3rd Block	0	221,874	820,600	1,632,269	1,345,558	295,883	1,556	20,081	9,904
35	4th Block	0	27,846	0	0	0	0	0	0	0
36	5th Block	0	0	0	0	0	0	0	0	0
37										
38	ADJ 1 = Commodity Costs	15,038,642	21,515,165	5,261,577	2,445,523	1,487,180	909,753	134,320	80,006	16,500
39	ADJ 2 = Fixed Costs	15,038,642	21,515,165	5,261,577	2,445,523	1,487,180	909,753	134,320	80,006	16,500
40	ADJ 3 = Franchise Fees	0	0	5,261,577	2,445,523	1,487,180	909,753	0	0	0
41										
42										
43	NUMBER OF BILLS:	531,842	54,003	181,825	8,933	1,406	21,277	3,024	307	24
44										
45										
46	(1) Ft Nelson Margins adjusted to reflect 2 GJ gas costs associated with Minimum Charge									

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED COMMERCIAL TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 4 - Base Case

Ln. No.	PROPOSED INPUT TABLE COMMERCIAL ANNUAL	PROPOSED TARIFF STRUCTURE								
		LM 2207/8/9»2	LM 2207/8/9»3	INL 2.1»2	INL 2.1»3	INL 2.2»3	COL 2.1&2.2»2	FT NEL 2.1»2	FT NEL 2.1»3	FT NEL 2.2»3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	PROPOSED RATES ($/GJ):									
2										
3	Basic Charge	$14.000	$14.000	$14.000	$14.000	$14.000	$14.000	$0.000	$0.000	$0.000
4	Minimum Charge	0.000	0.000	0.000	0.000	0.000	0.000	18.320	18.320	17.840
5										
6	Price 1st Block	$1.322	$1.322	$1.322	$1.322	$1.322	$1.322	($1.861)	($1.861)	($1.611)
7	Price 2nd Block	0.000	0.000	0.000	0.000	0.000	0.000	1.522	1.522	1.531
8	Price 3rd Block	0.000	0.000	0.000	0.000	0.000	0.000	1.474	1.474	1.483
9	Price 4th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11										
12	Price ADJ 1=Comm. Costs	$0.991	$0.991	$0.934	$0.934	$0.934	$1.873	$1.854	$1.854	$1.604
13	Price ADJ 2=Fixed Costs	2.098	1.721	1.865	1.532	1.532	0.365	0.008	0.008	0.008
14	Price ADJ 3=Fran. Fees	0.000	0.000	0.118	0.099	0.098	0.101	0.000	0.000	0.000
15										
16										
17	PROPOSED BLOCK ENDINGS (GJ)									
18										
19	End of 1st Block	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	2	2	2
20	End of 2nd Block	0	0	0	0	0	0	300.0	300.0	300.0
21	End of 3rd Block	0	0	0	0	0	0	999,999.9	999,999.9	999,999.9
22	End of 4th Block	0	0	0	0	0	0	0	0	0
23	End of 5th Block	0	0	0	0	0	0	0	0	0
24										
25	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9
26	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9
27	ADJ 3 = Franchise Fees	0.0	0.0	999,999.9	999,999.9	999,999.9	999,999.9	0.0	0.0	0.0
28										
29										
30	No. GJ's IN INTERVAL:									
31										
32	1st Block	15,038,642	21,515,165	5,261,577	2,445,523	1,487,180	909,753	5,454	614	48
33	2nd Block	0	0	0	0	0	0	127,310	59,310	6,548
34	3rd Block	0	0	0	0	0	0	1,556	20,081	9,904
35	4th Block	0	0	0	0	0	0	0	0	0
36	5th Block	0	0	0	0	0	0	0	0	0
37										
38	ADJ 1 = Commodity Costs	15,038,642	21,515,165	5,261,577	2,445,523	1,487,180	909,753	134,320	80,006	16,500
39	ADJ 2 = Fixed Costs	15,038,642	21,515,165	5,261,577	2,445,523	1,487,180	909,753	134,320	80,006	16,500
40	ADJ 3 = Franchise Fees	0	0	5,261,577	2,445,523	1,487,180	909,753	0	0	0
41										
42										
43	NUMBER OF BILLS:	531,842	54,003	181,825	8,933	1,406	21,277	3,024	307	24

2 Jun 1993

BILL FREQUENCY ANALYSES, PROPOSED RATE SCHEDULE 2

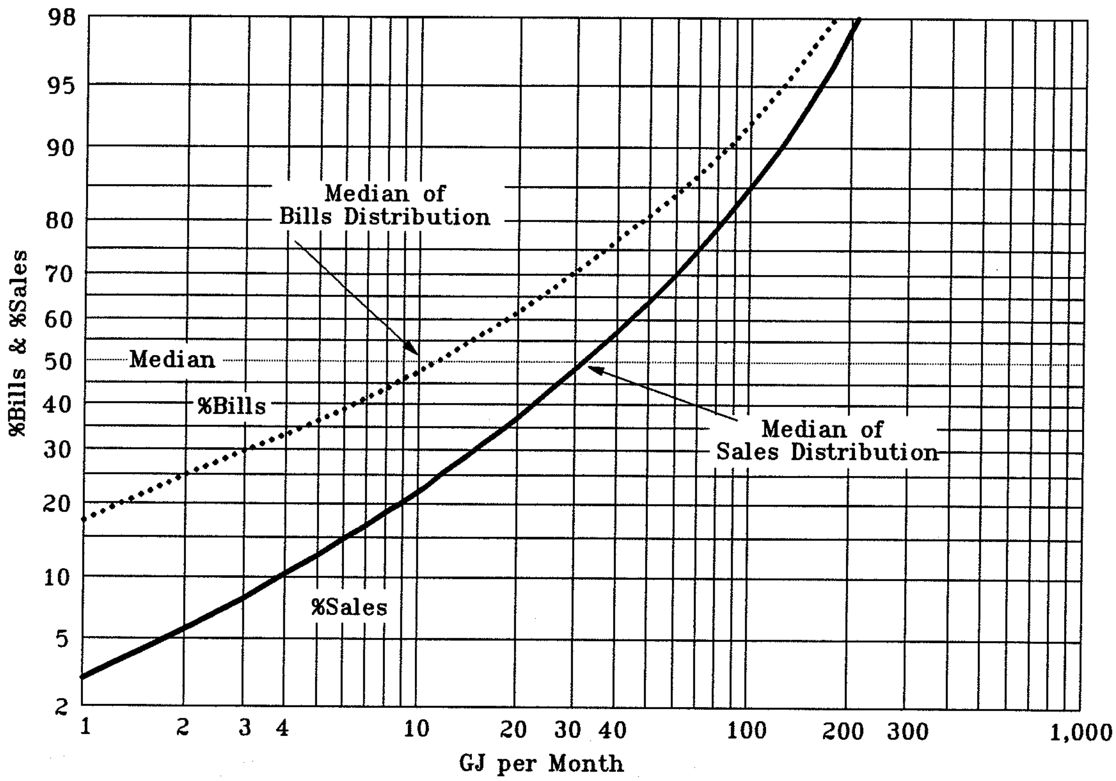
The frequency distribution of bills and sales of natural gas rendered to small commercial customers in the Lower Mainland, Inland, and Columbia Divisions are shown on the three following pages. Bill frequency analyses were prepared for customers in each of the Company's service areas that use under 2,000 gigajoules per year.

The solid black line that depicts the ogive of energy sales falls into almost the same position for small commercial customers in the Lower Mainland, Inland, and Columbia service areas. This can be seen by referring to each chart at 10 gigajoules per month. On page 26, the percent of total sales to the small volume commercial customers in the Lower Mainland is about 22 percent. On page 27, the graph at 10 gigajoules per month indicates that about 22 percent of the total Inland service small commercial customers sales are rendered at this point. On page 28, the sales ogive indicates about 22 percent of total energy sold to Columbia small commercial customers is at 10 gigajoules per month.

At 100 gigajoules per month, the percent of sales is 85, 82, and 85 percent respectively for the small commercial customers in the Lower Mainland, Inland, and Columbia service areas. The energy sales ogive is exceedingly important because it indicates the homogenous energy characteristics of these customers. Common energy sales ogives for small commercial customers in each service area is a positive factor for consolidation. A common price for service under Rate Schedule 2 treats all small commercial customers the same.

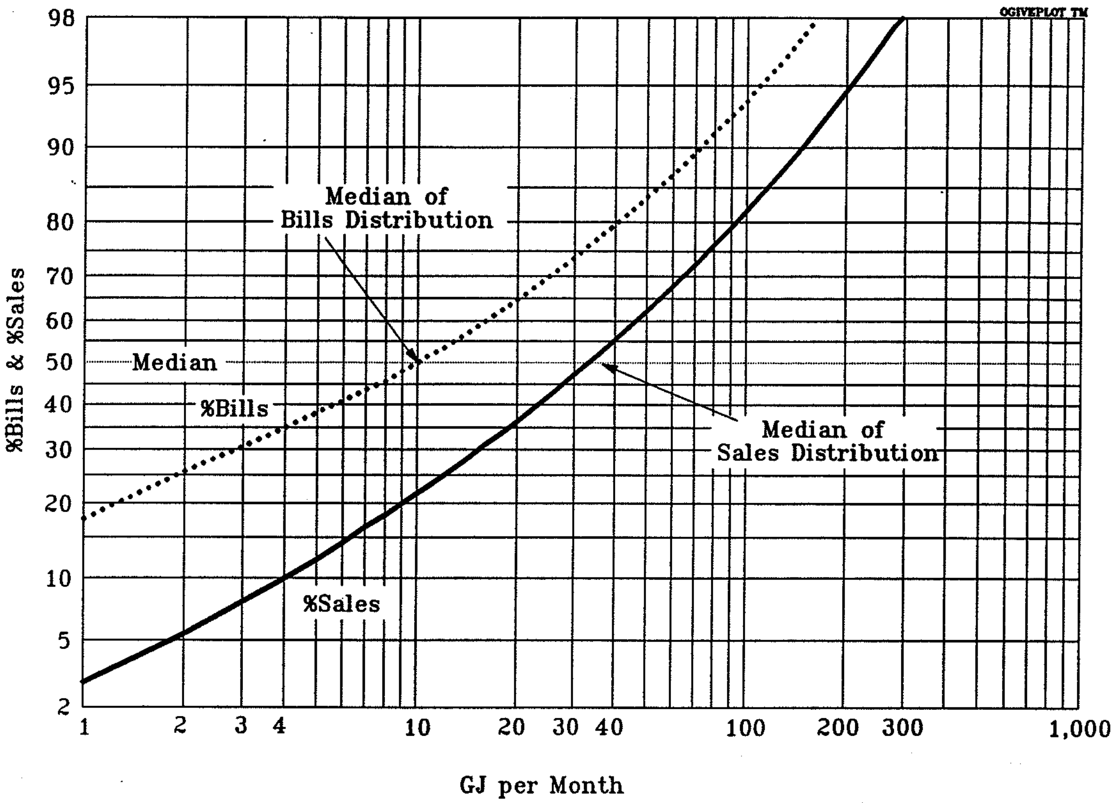
BC Gas

LOWER MAINLAND DIVISION
Small Commercial Service
Customers With Energy Use Under 2,000 GY/Year
Annual Bill Frequency Analysis
Cumulative Percent on Probability/Logrithmic Scale



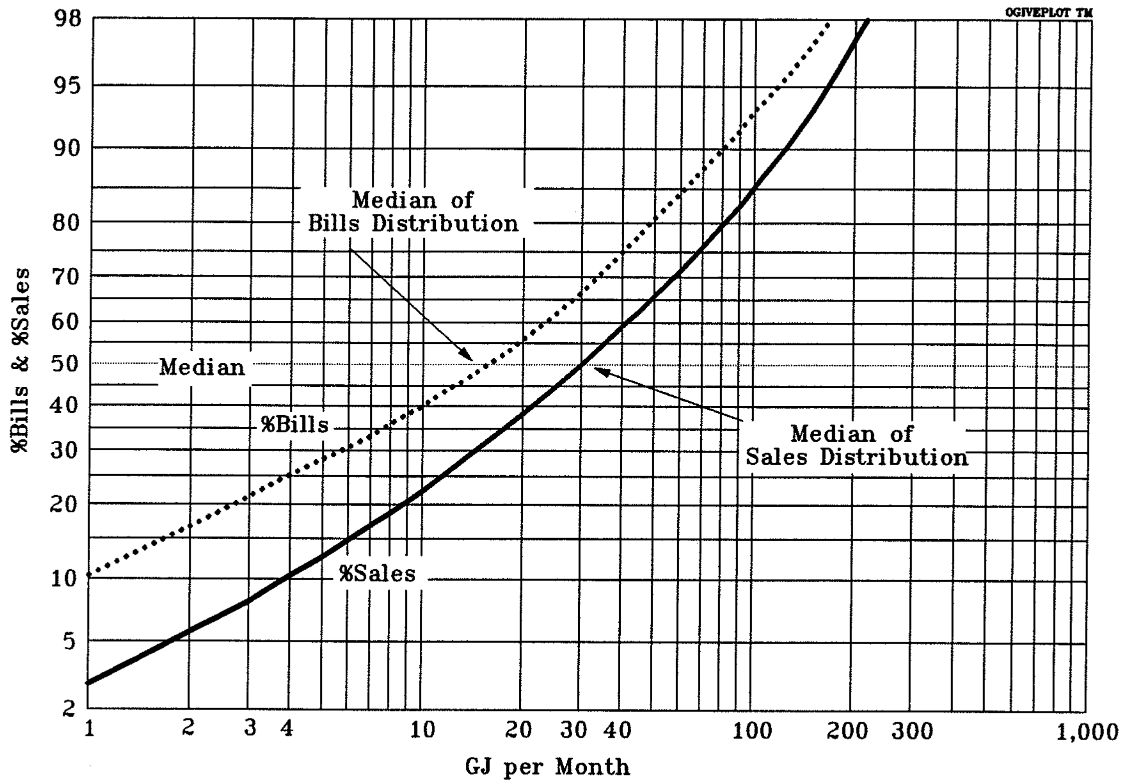
BC Gas

INLAND DIVISION
Small Commercial Service
Customers With Energy Use Under 2,000 GJ/Year
Annual Bill Frequency Analysis
Cumulative Percent on Probability/Logrithmic Scale



BC Gas

COLUMBIA DIVISION
Small Commercial Service
Customers With Energy Use Under 2,000 GY/Year
Annual Bill Frequency Analysis
Cumulative Percent on Probability/Logrithmic Scale

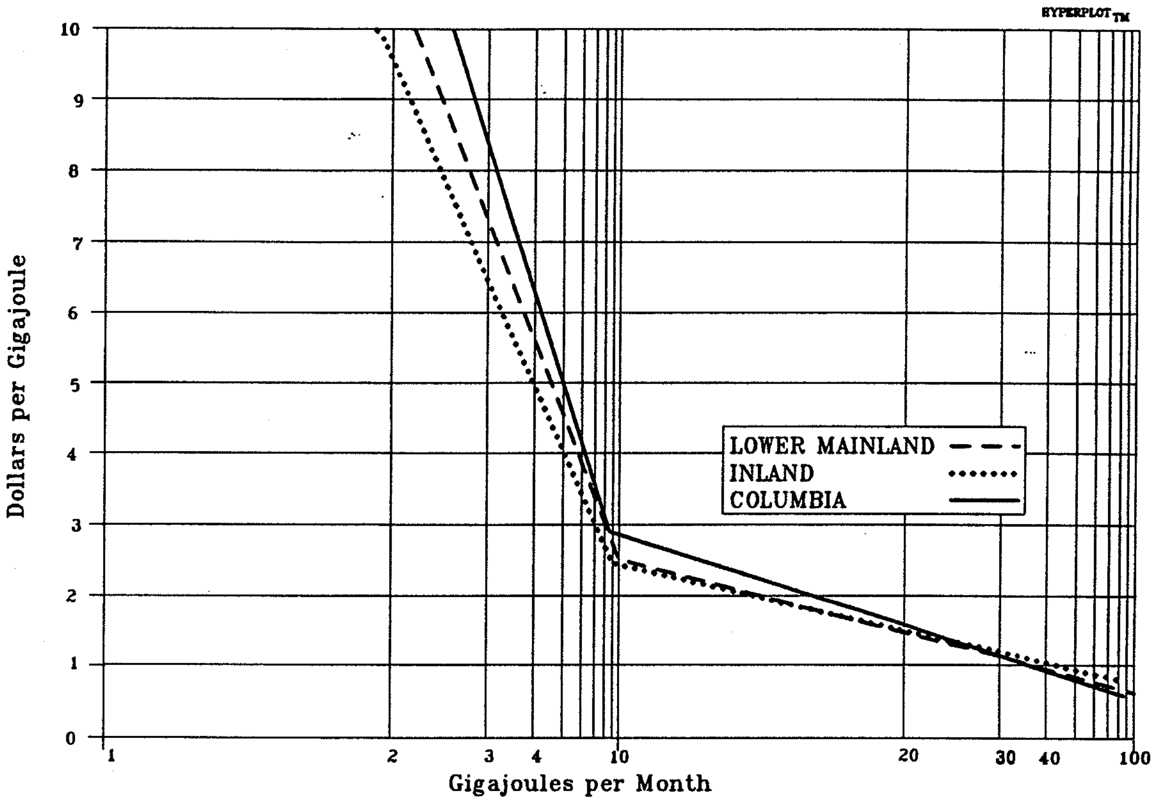


LONG RUN INCREMENTAL COSTS: SMALL COMMERCIAL SERVICE

The following four charts display LRIC relationships for proposed Rate Schedule 2. The first chart compares divisional LRIC at various levels of gas consumption in the Lower Mainland, Inland, and Columbia Divisions. On the next three graphs, LRIC is compared to present and proposed commercial rates for those service areas.

BC Gas

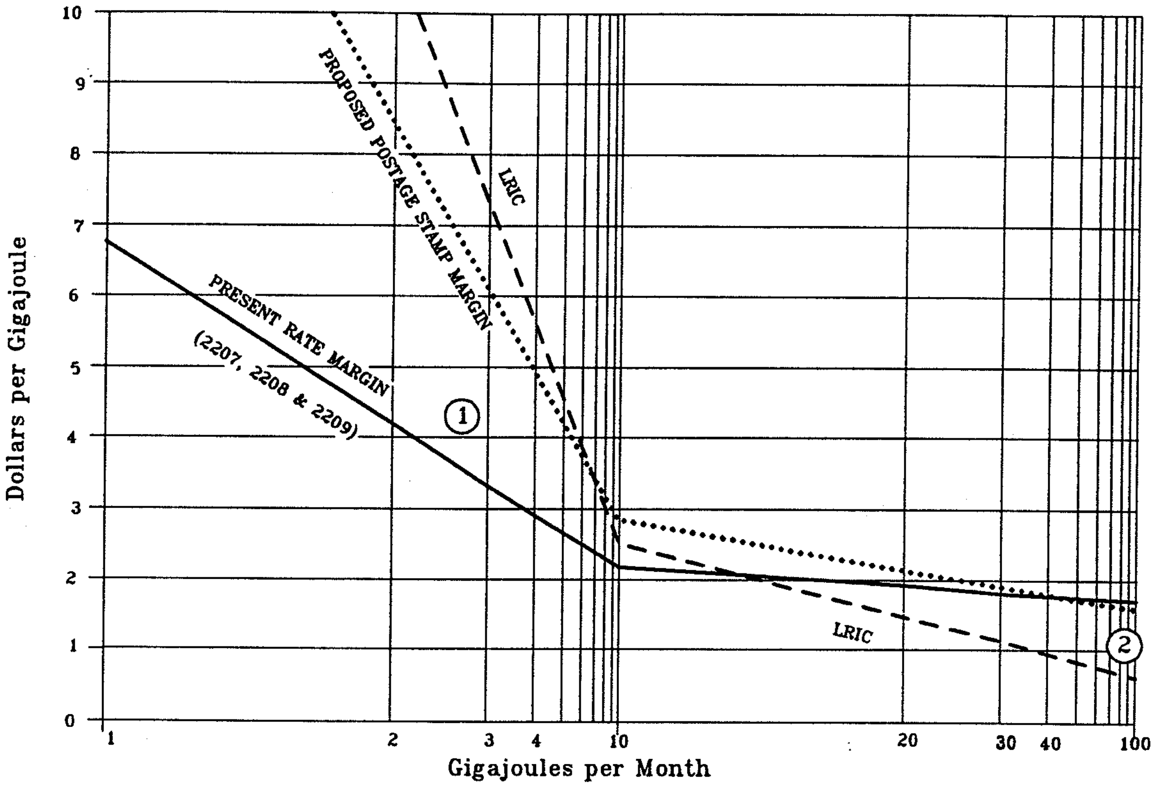
ALL DIVISIONS
Proposed Schedule No.2 LRIC



BC Gas

LOWER MAINLAND DIVISION

Proposed Schedule No.2
Small Commercial Service Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC

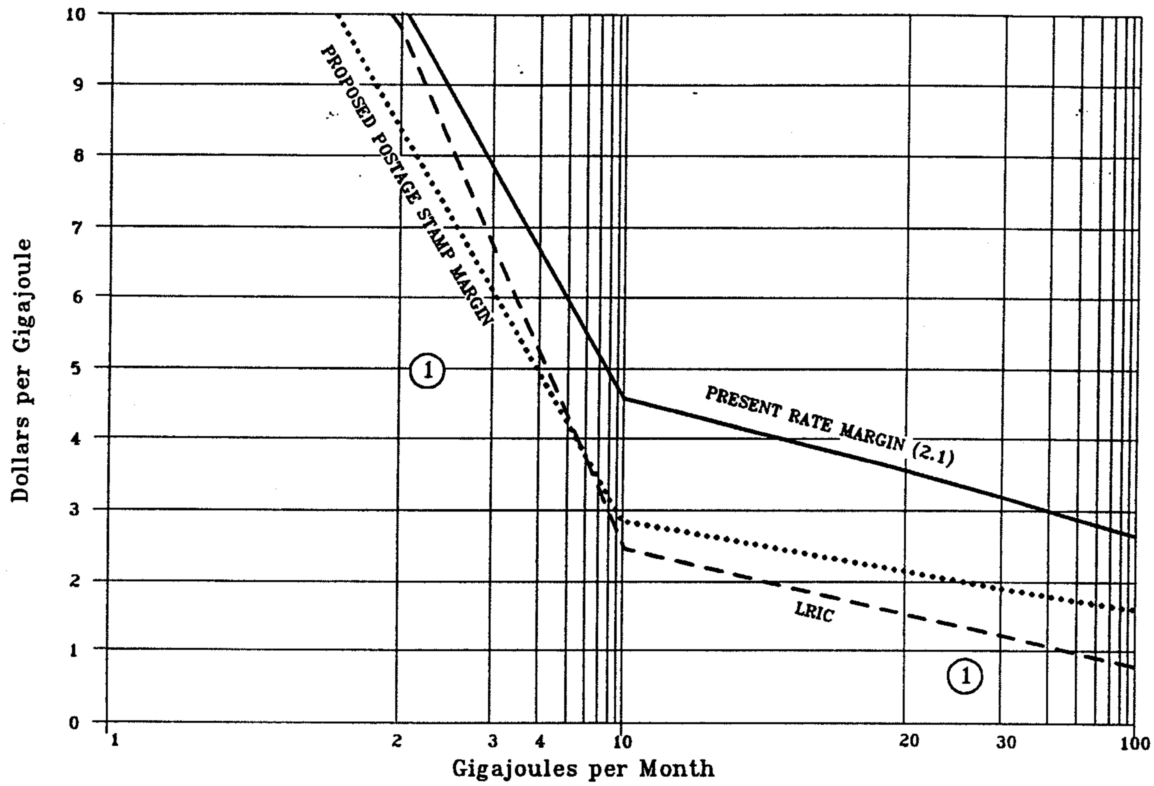


1. LRIC indicates that the present rate margin below about 12 GJs per month could be increased
2. LRIC indicates that the present rate margin above 20 GJs per month could be decreased.
3. LRIC is calculated using 350 GJs annual usage (or about 30 GJs per month).

BC Gas

INLAND DIVISION

Proposed Schedule No. 2
Small Commercial Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC



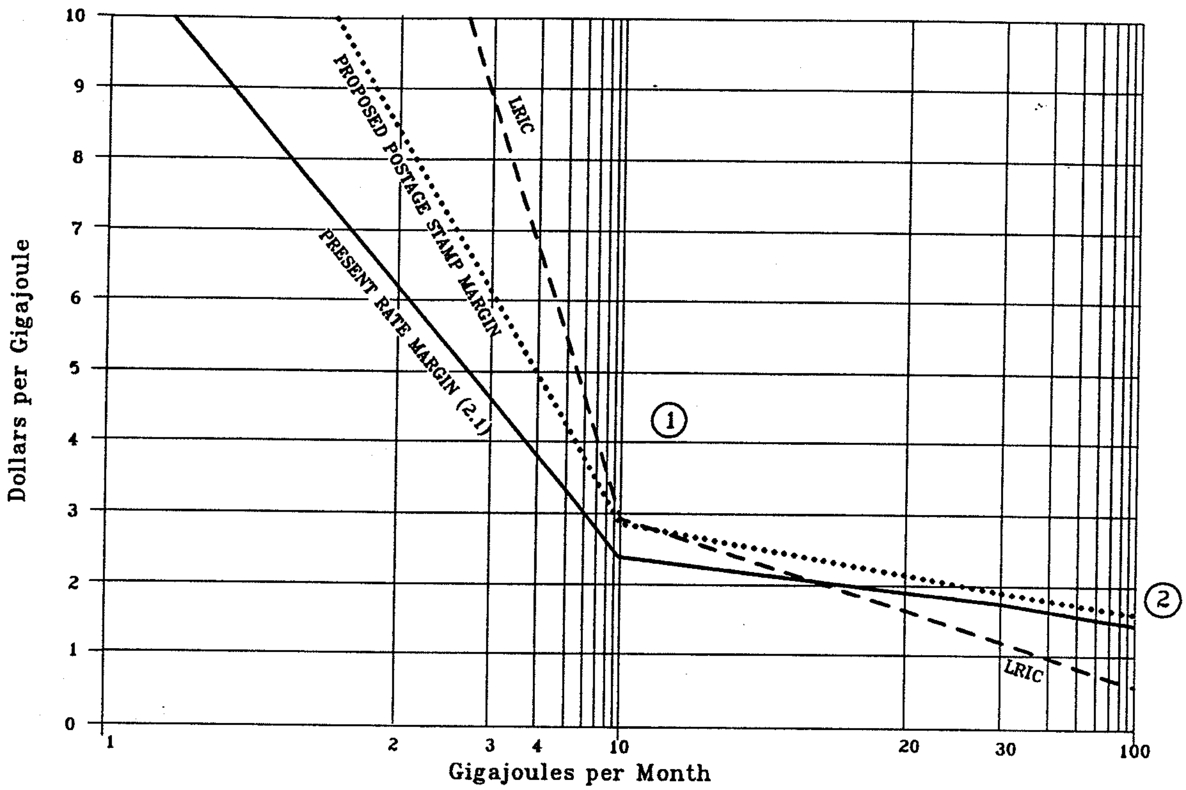
(1) LRIC indicates that the present rate margin could be decreased.

(3) LRIC is calculated using 350 GJs annual usage (or about 30 GJs per month).

BC Gas

COLUMBIA DIVISION

Proposed Schedule No. 2
Small Commercial Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC



(1) LRIC indicates that the present rate margin below 15 GJs per month could be increased

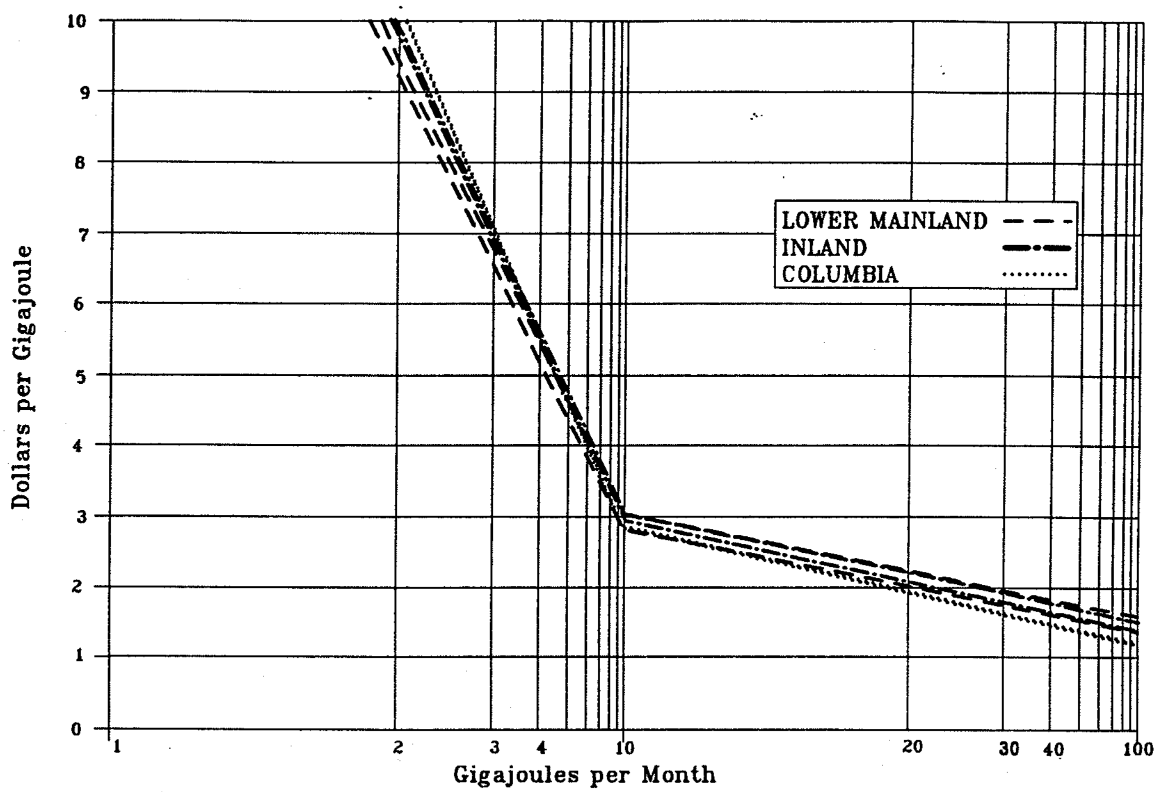
(2) LRIC indicates that the present rate margin above 15 GJs per month could be decreased

FULLY DISTRIBUTED COSTS: SMALL COMMERCIAL SERVICE

The following chart compares the small commercial class FDC in each division. The three charts that follow compare the divisional FDC to present and proposed commercial rates in the Lower Mainland, Inland, and Columbia service areas.

BC Gas

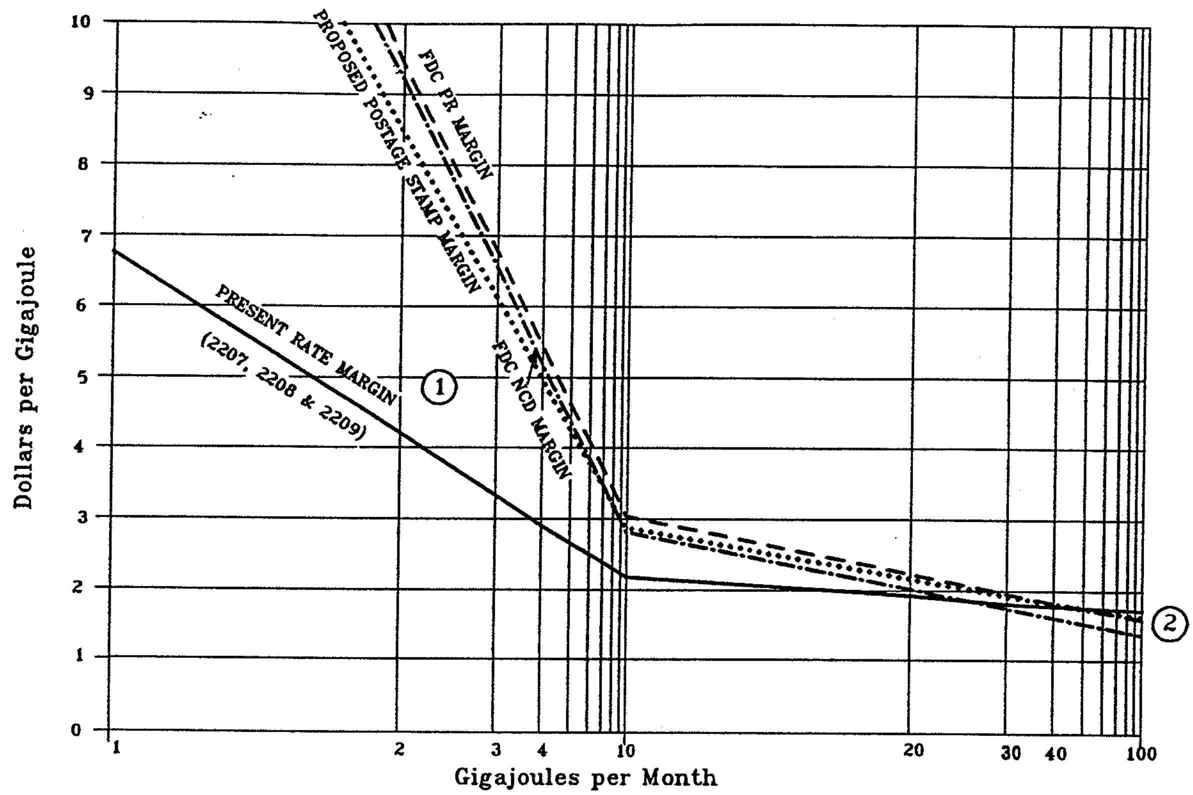
ALL DIVISIONS
Proposed Schedule No. 2
FDC Cost Margins



BC Gas

LOWER MAINLAND DIVISION

Proposed Schedule No.2
Small Commercial Service Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to FDC Margin

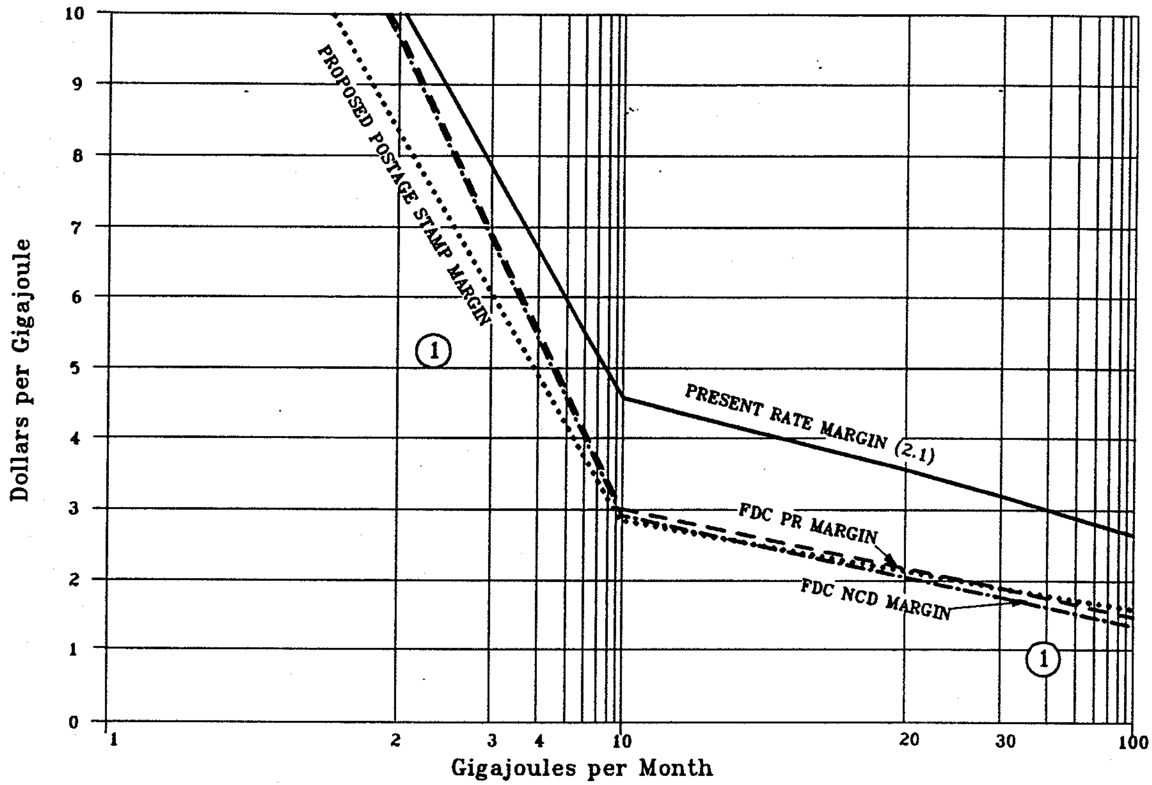


(1) FDC indicates that the present rate margin below 30 GJs per month could be increased.

(2) FDC indicates that the present rate margin above 30 GJs per month is not unreasonable.

BC Gas

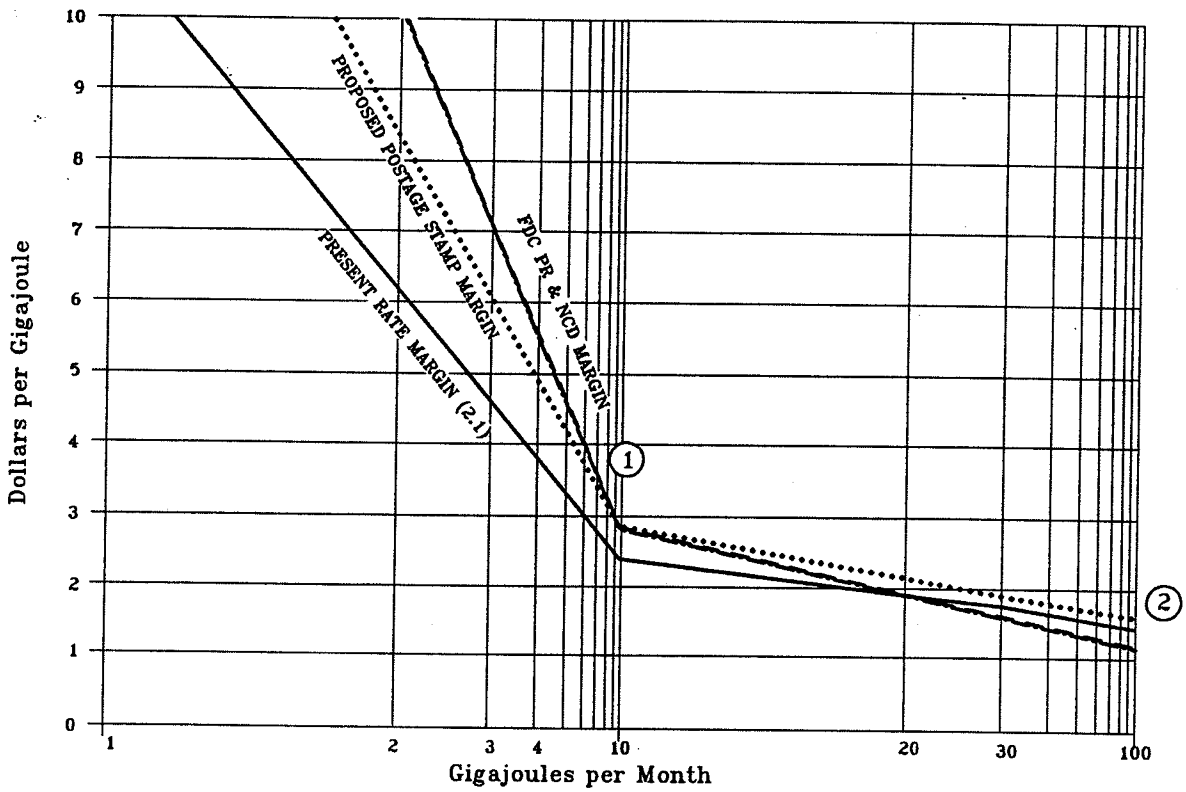
INLAND DIVISION
Proposed Schedule No. 2
Small Commercial Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to FDC Margin



(1) FDC indicates that the present rate margin could be decreased.

BC Gas

COLUMBIA DIVISION
Proposed Schedule No. 2
Small Commercial Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to FDC Margin



1. FDC indicates that the present rate margin at about 20 GJs per month could be increased.

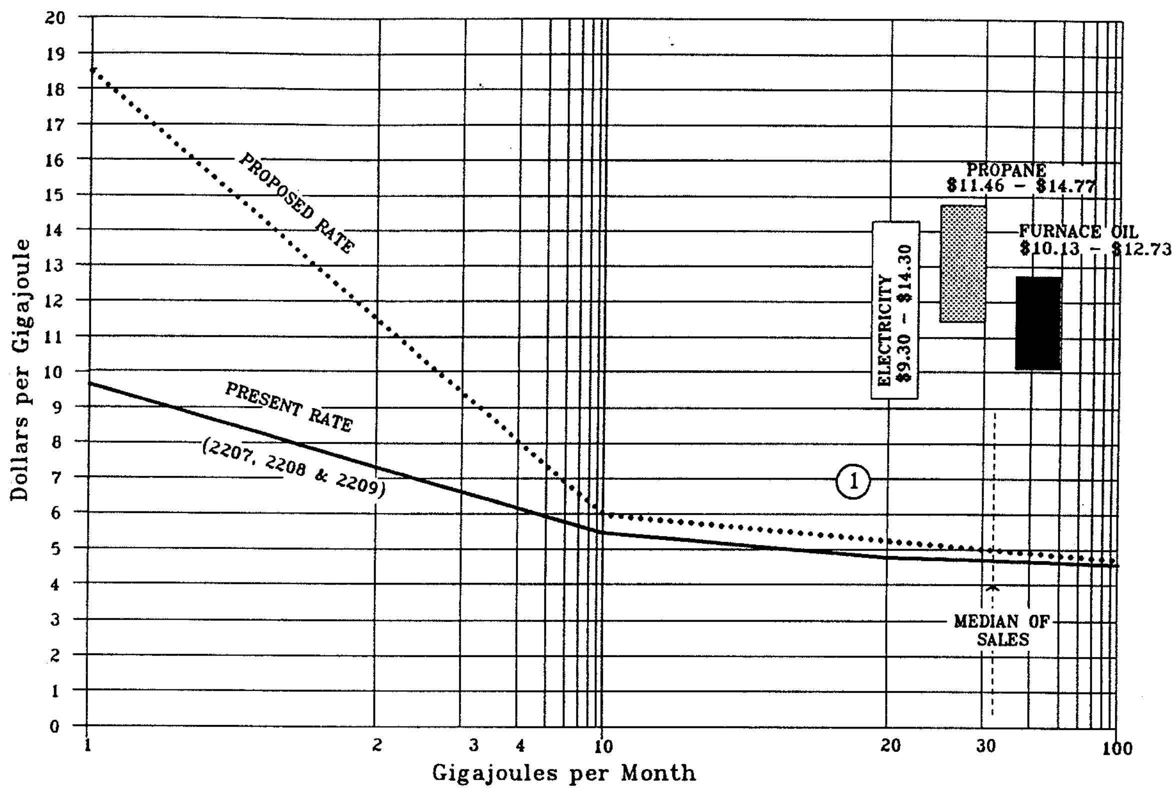
2. FDC indicates that the present rate margin above 20 GJs per month is not unreasonable.

PRICE OF COMPETITIVE ENERGY: SMALL COMMERCIAL SERVICE

The following three charts compare the prices of competitive energy to present and proposed commercial rates in the Lower Mainland, Inland, and Columbia service areas.

BC Gas

LOWER MAINLAND DIVISION
Proposed Schedule No. 2
Small Commercial Service Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy

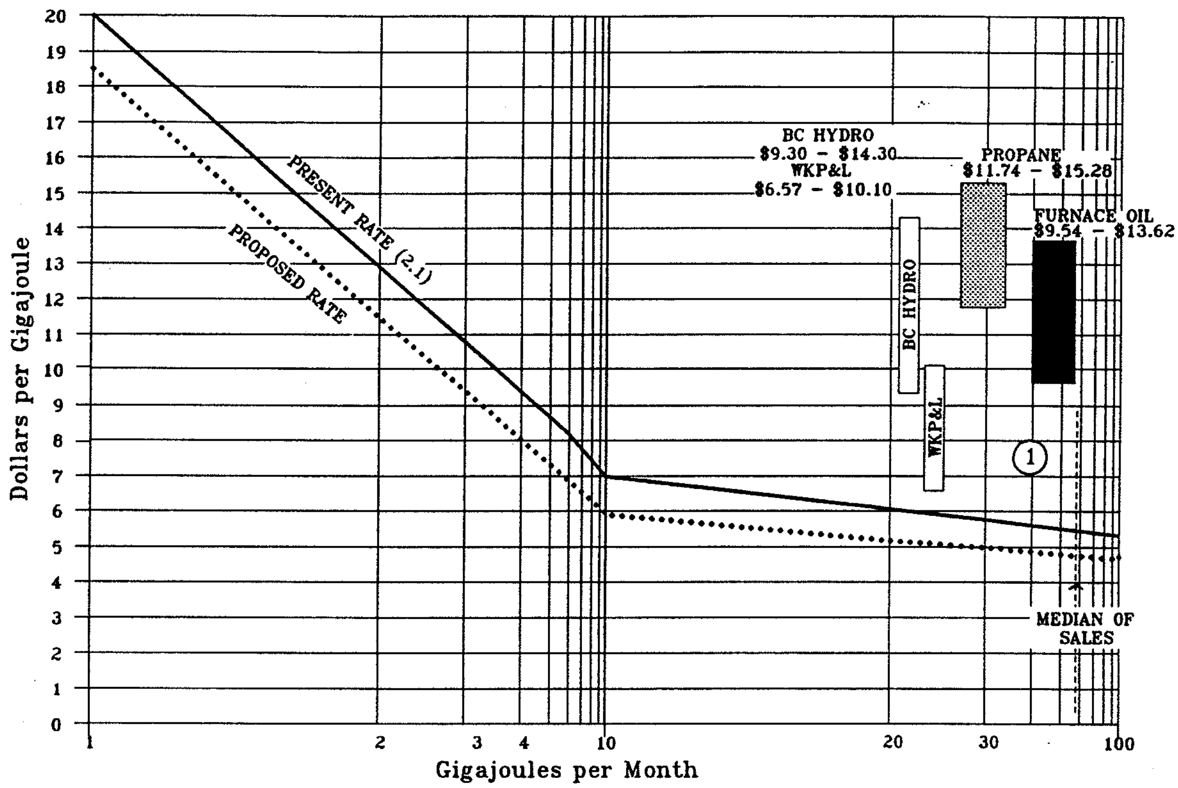


(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

BC Gas

INLAND DIVISION

Proposed Schedule No. 2
Small Commercial Service Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy



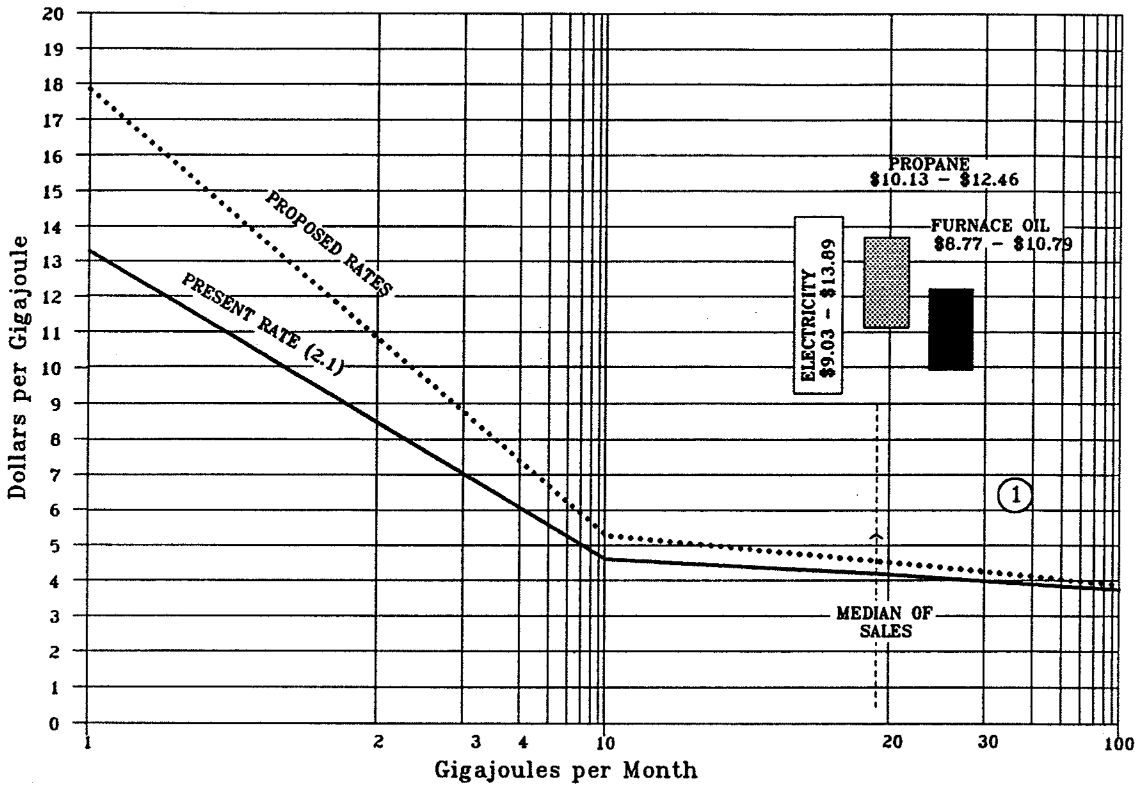
(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

BC Gas

COLUMBIA DIVISION

Proposed Schedule No. 2

Small Commercial Service Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy



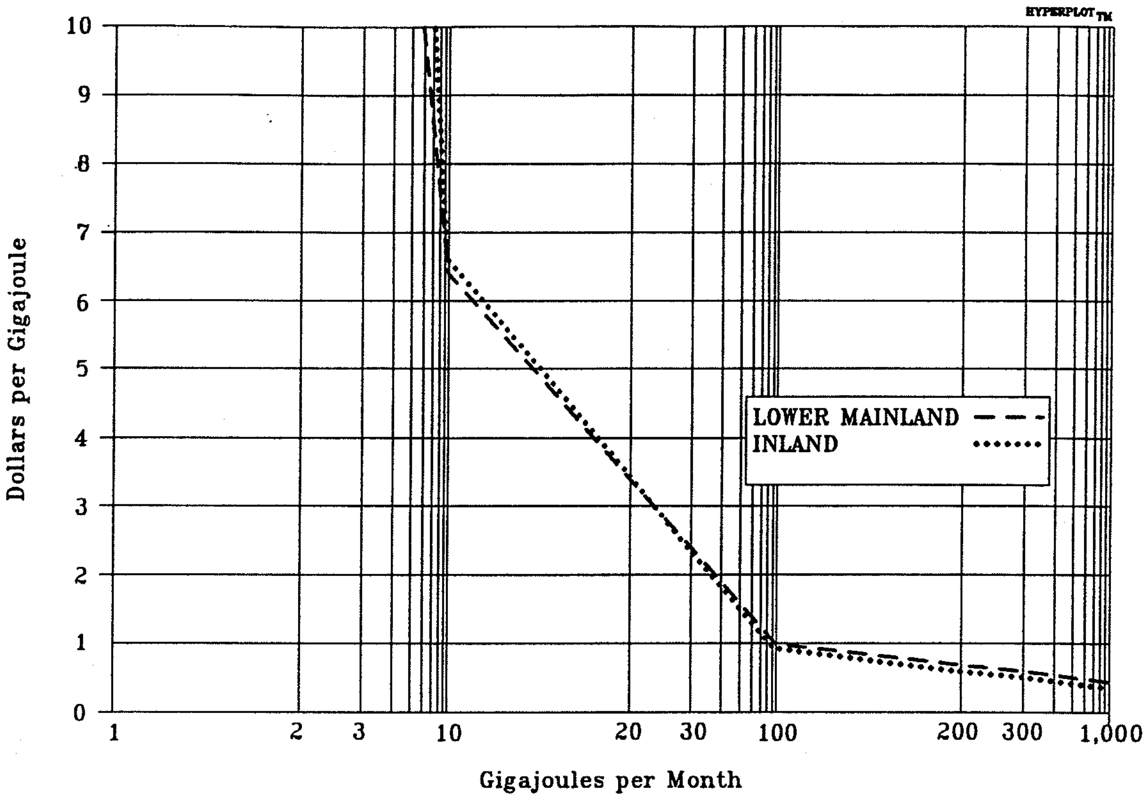
(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

LONG RUN INCREMENTAL COSTS: LARGE COMMERCIAL SERVICE

The following three charts display LRIC relationships for proposed Rate Schedule 3. The first chart compares divisional LRIC at various levels of gas consumption in the Lower Mainland, and Inland. On the next two graphs, LRIC is compared to present and proposed commercial rates in the Inland and Lower Mainland service areas.

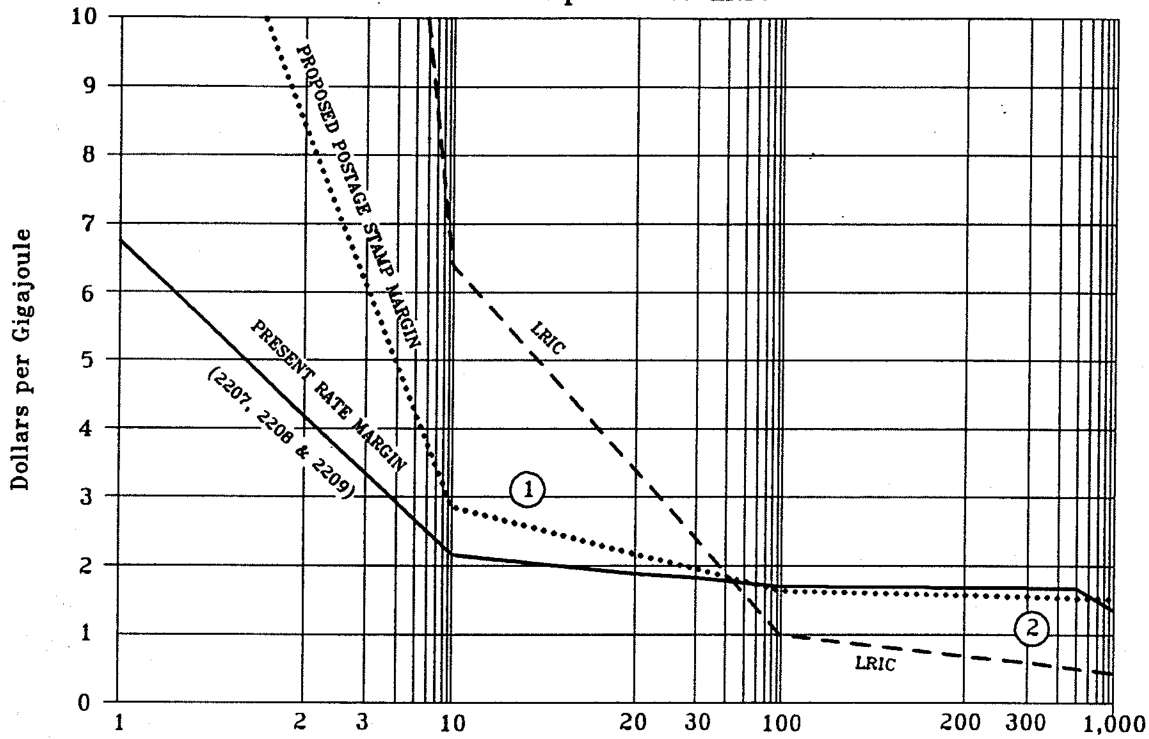
BC Gas

LOWER MAINLAND & INLAND DIVISIONS
Proposed Schedule No. 3 LRIC



BC Gas

LOWER MAINLAND DIVISION
Proposed Schedule No. 3
Large Commercial Service Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC



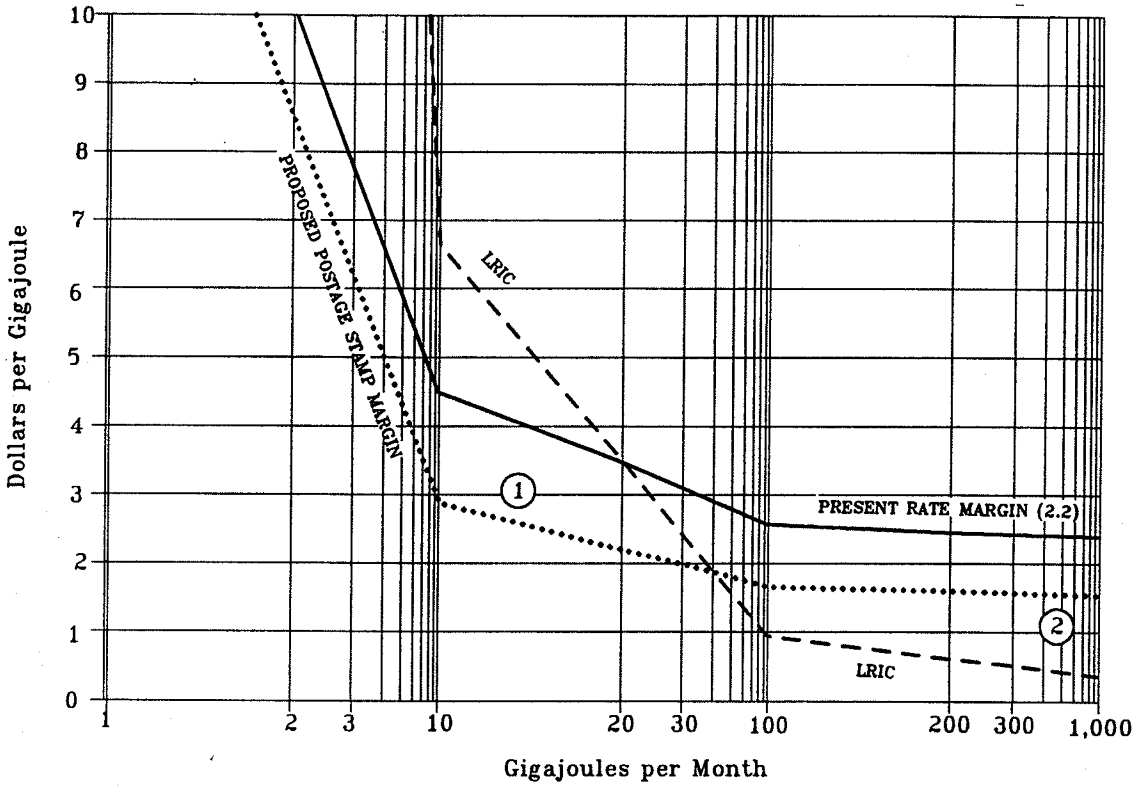
① LRIC indicates that the present rate margin below 45 GJs per month could be increased.

② LRIC indicates that the present rate margin above 45 GJs per month could be decreased.

③ LRIC is calculated using 4,000 GJs annual usage (or about 330 GJs per month).

BC Gas

INLAND DIVISION
Proposed Schedule No. 3
Large Commercial Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC



(1) LRIC indicates that the present rate margin below 20 GJs per month could be increased.

(2) LRIC indicates that the present rate margin above 20 GJs per month could be decreased.

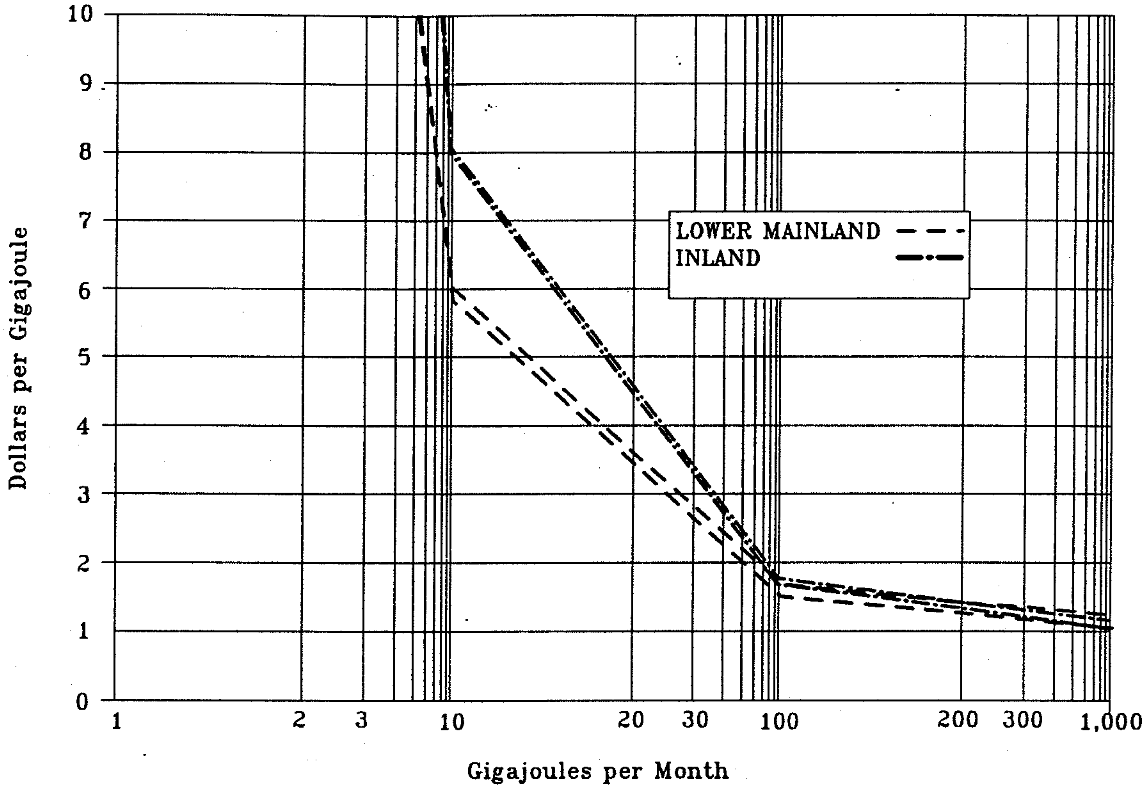
(3) LRIC is calculated using 4,000 GJs annual usage (or about 330 GJs per month).

FULLY DISTRIBUTED COSTS: LARGE COMMERCIAL SERVICE

The following chart compares the small commercial class FDC in Inland and Lower Mainland service areas. The two charts that follow compare the divisional FDC to present and proposed commercial rates in the Lower Mainland and Inland Divisions.

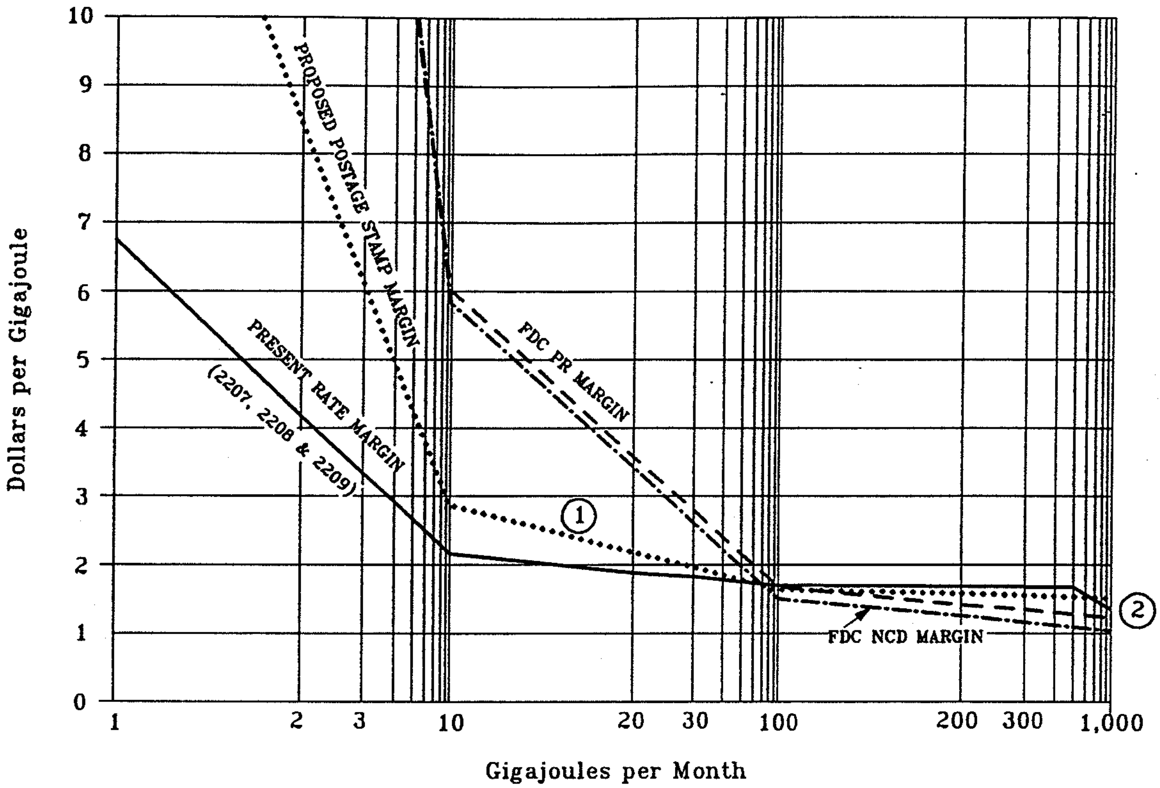
BC Gas

LOWER MAINLAND & INLAND DIVISIONS
Proposed Schedule No. 3
FDC Cost Margins



BC Gas

LOWER MAINLAND DIVISION
Proposed Schedule No. 3
Large Commercial Service Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to FDC Margin

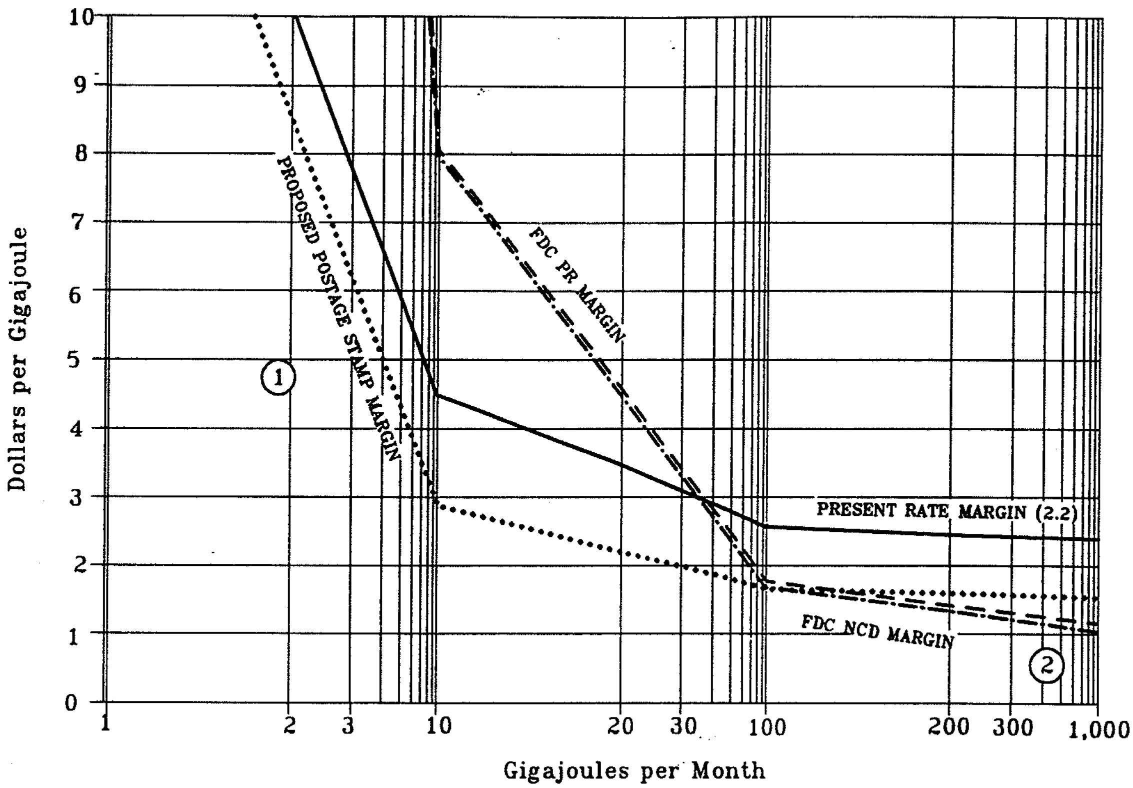


1. FDC indicates that the present rate margin below 80 GJs per month could be increased.

2. FDC indicates that the present rate margin at about 200 GJs per month could be decreased.

BC Gas

INLAND DIVISION
Proposed Schedule No. 3
Large Commercial Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to FDC Margin



(1) FDC indicates that the present rate margin below 35 GJs per month could be increased.

(2) FDC indicates that the present rate margin above 35 GJs per month could be decreased.

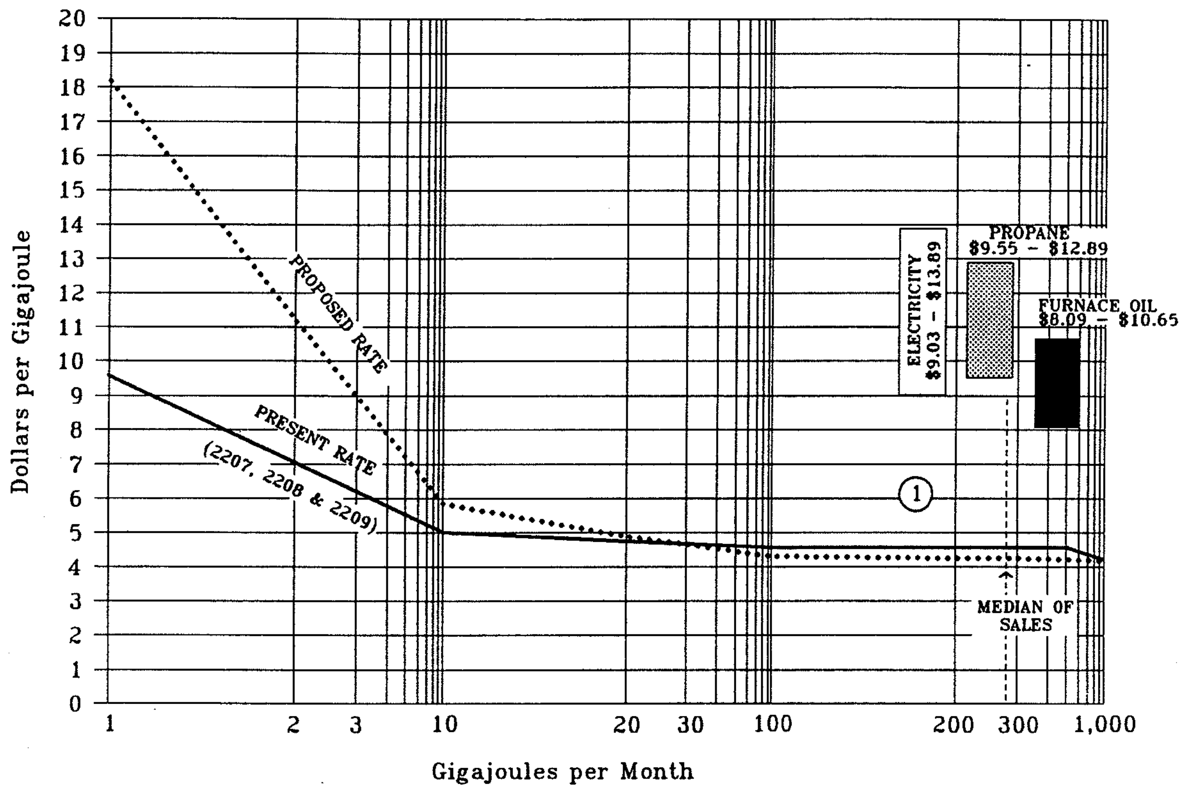
PRICE OF COMPETITIVE ENERGY: LARGE COMMERCIAL SERVICE

The following two charts compare the prices of competitive energy to present and proposed commercial rates in the Lower Mainland and Inland service areas.

BC Gas

LOWER MAINLAND DIVISION

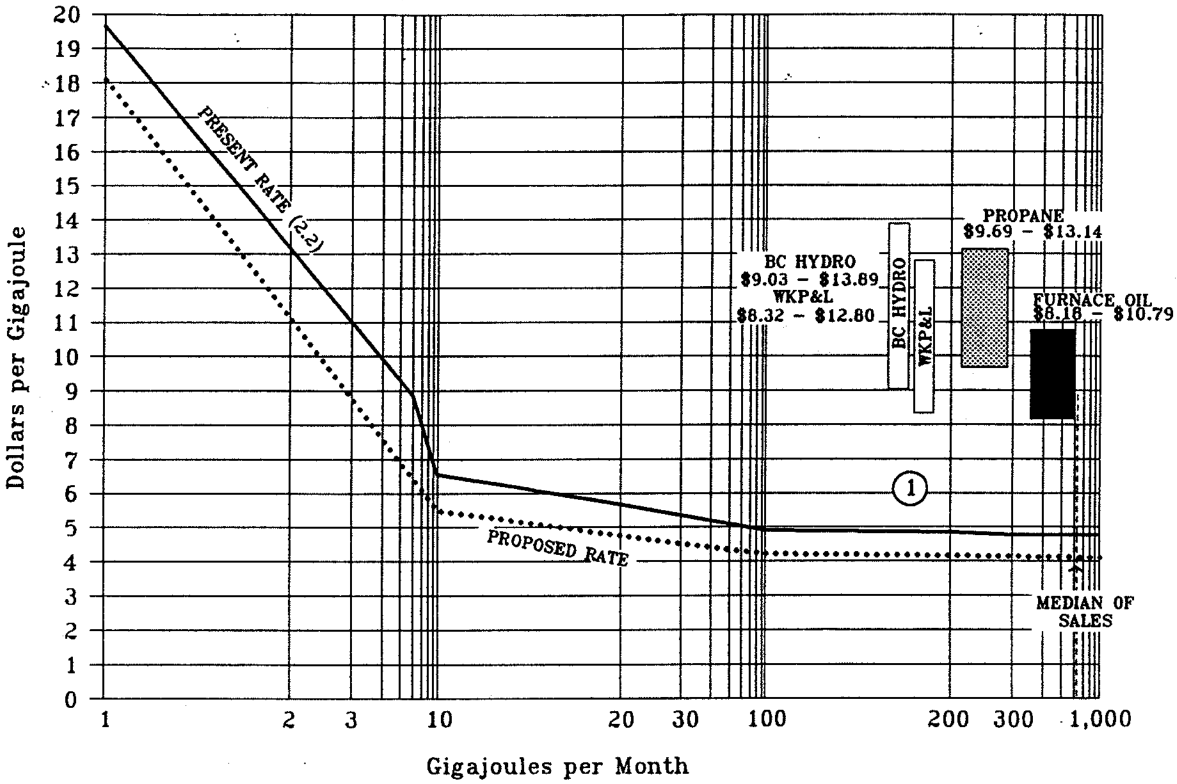
Proposed Schedule No. 3
Large Commercial Service Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy



(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

BC Gas

INLAND DIVISION
Proposed Schedule No. 3
Large Commercial Service Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy



(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

PROPOSED GENERAL FIRM SERVICE AND GENERAL FIRM TRANSPORTATION

1.0 INTRODUCTION

Customers that use gas in their processes generally exhibit a high load factor and are usually sophisticated in choosing their gas supply and delivery package. Under the existing rate schedules this type of large commercial or small industrial customer generally is offered firm service in the Lower Mainland under Rate Schedules 2209 and firm transportation under Rate Schedule 2007, while in the Inland service area, this type of customer is offered firm service under Rate Schedule 5 and firm transportation under Rate Schedule 25. In the Columbia service area the existing schedules only offer firm service under Rate Schedule 3. BC Gas now proposes to provide these services under the common Rate Schedule 5 - General Firm Service, and Rate Schedule 25 - General Firm Transportation.

Load factor analysis of commercial customers under existing Lower Mainland Rate Schedules 2207, 2208 and 2209 and Inland and Columbia Rate Schedules 2.1 and 2.2 indicates that there are customers who are now classified in "commercial" which have gas consumption profiles which are more akin to "industrial" customers than commercial space heating customers. Customers which use less than 50 percent of their gas for space heating and the balance for processing purposes have higher load factors throughout the year than commercial space heating customers. BC Gas has identified 151 customers under Lower Mainland Rate Schedules 2207, 2208 and 2209, 33 customers under Inland Rate Schedules 2.1 and 2.2, and 4 customers under Columbia Rate Schedules 2.1 and 2.2 that have processing loads that would benefit from proposed Rate Schedules 5 and 25.

The average load factor of the customers expected to be on Rate Schedules 5 and 25 is approximately 45%. This load factor is higher than that of the residential and commercial class of customers and represents a more efficient use of the gas transmission and distribution facilities. This more efficient use merits a separate classification. The separate classification is "General Service".

Merely classifying commercial and industrial customers by annual gas consumption has its limitations. It is the Company's intent under the general service class to recognize load factor as a primary criteria for setting rate levels. A firm service rate schedule should recognize that high annual consumption may not equate to high load factor. The proposed classification, however, is a first step toward more explicit means to determine customer load factor such as demand metering.

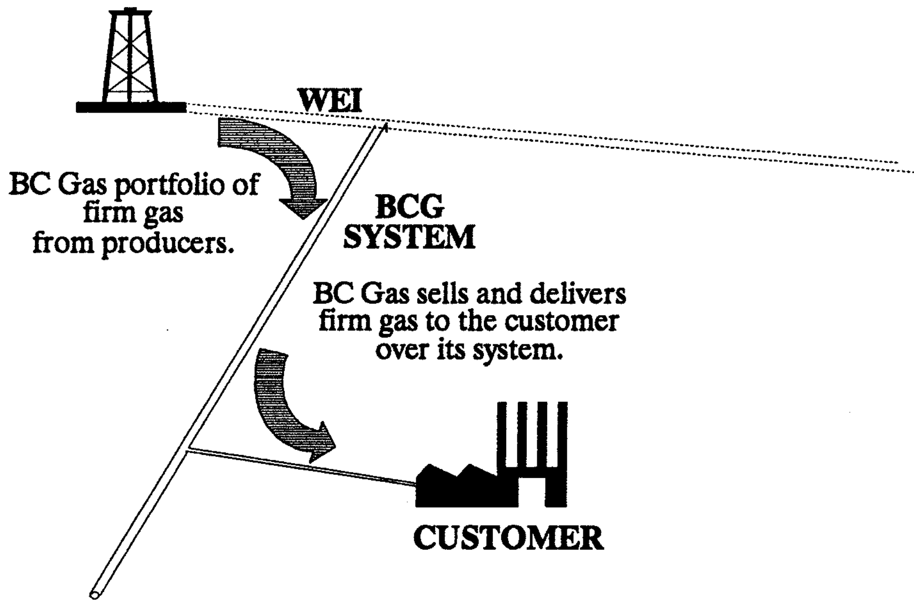
BC Gas will offer Rate Schedule 5 - General Firm Service, which includes the sale of gas and the provision of transportation. It is service which provides the gas at the outlet of the meter at the customer's premises. BC Gas will also offer Rate Schedule 25 - General Firm Transportation, which provides only firm transportation of gas purchased by the customer from a producer or marketer.

A discussion of the terms and conditions applicable to Rate Schedules 5 and 25 is found at Tab 9 of this volume, pages 29 and 30.

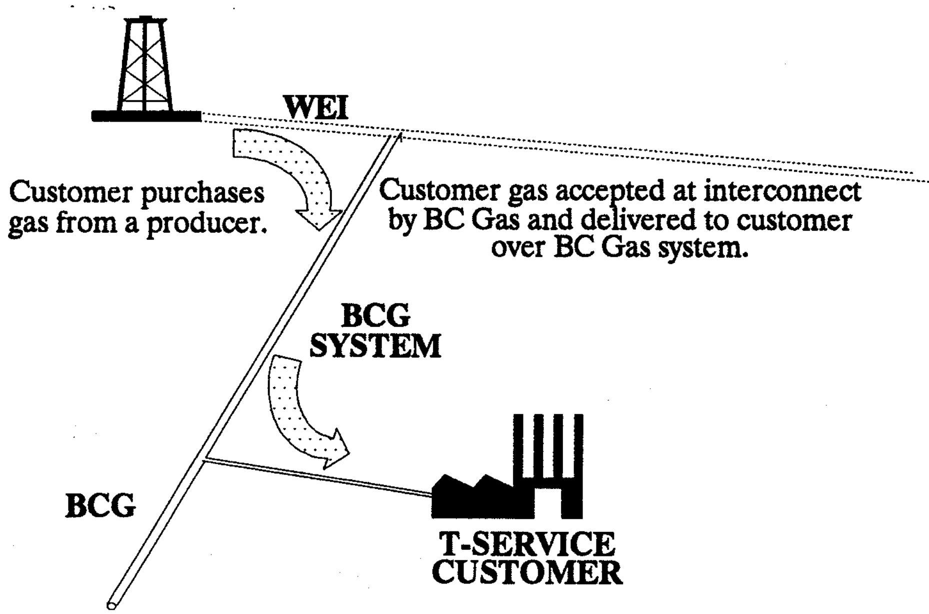
The graphic on the following page depicts the difference between the gas supply for Rate Schedules 5 and 25.

BC Gas

GENERAL FIRM SERVICE, RATE SCHEDULE 5



GENERAL FIRM TRANSPORTATION, RATE SCHEDULE 25



In determining the rates that should apply to the general service customers, BC Gas has considered studies relating to long run incremental and fully distributed costs to serve the proposed Rate Schedules 5 and 25 customers.

1.1 Long Run Incremental Cost

A long run incremental cost (LRIC) study has been undertaken by the Company. The focus of the LRIC is mainly on the costs associated with serving new customers rather than the cost associated with additional consumption by existing customers.

The long run incremental cost study indicates that the proposed Rate Schedules 5 and 25 margin costs are as shown below. The average revenue margins under present rates for the customers that will move to Rate Schedules 5 and 25 are compared to the LRIC information shown in the table.

LRIC Compared to Average Margin Revenue

	LRIC/GJ	Avg Margin/GJ	Excess (Deficiency)
Lower Mainland	$0.59	$1.79	$1.20
Inland	0.66	1.31	0.65
Columbia	0.58	0.78	0.20

The conclusion to draw from this table is that these customers which will move to the proposed Rate Schedules 5 and 25 have been paying average margins in excess of LRIC applicable to them.

Enclosed in the Technical Appendix, page 26 through 29, are charts that represent per-unit LRIC costs at various levels of consumption. The first chart shows that the LRIC in the Lower Mainland, Inland, and Columbia service areas are approximately the same. Graphics that compare the LRIC to present and proposed rates in the three service areas follow.

1.2 Fully Distributed Cost

The basic purpose of a fully distributed cost (FDC) study is to compare revenue generated by rates to the cost that BC Gas incurs in serving this class of customers. The Company studied three variants of fully distributed capacity cost allocation methodologies: the peak responsibility method (PR); non-coincident demand peak (NCD); and average and excess demand method (AED). These demand cost allocation methodologies are more fully described in the description of the FDC studies in Volume 2, Tab 2.

The results of the FDC study for Lower Mainland, Inland and Columbia are found respectively in Volume 2, Tab 2D, Sections 3, 4 and 5, pages 1.2A, 2.2A and 3.2A.

The findings of the FDC studies for the customers who are expected to be on Schedules 5 and 25, using the margins from the rate schedules on which the customers are at the present time, are:

Revenue Margin as a Percentage of Cost Margin
for Customers to be on Proposed Rate Schedules 5 and 25

	PR	NCD	AED
Lower Mainland	183.70%	207.50%	191.72%
Inland	139.90%	152.13%	140.29%
Columbia	89.25%	92.20%	84.94%

The conclusion to draw from the fully distributed cost studies is that the customers which will move to the proposed Rate Schedules 5 and 25 have been paying average margins in excess of the fully distributed costs applicable to them. It must be noted that the customers come from a variety of present customer classes.

2.0 PROPOSED GENERAL SERVICE RATES

BC Gas proposes Rate Schedules 5 and 25 with a $300 monthly Basic Charge and seasonal delivery charges of $1.50 per gigajoule for gas consumed between November 1st and March 31st and $0.75 per gigajoule for gas consumed between April 1st and October 31st.

The Company's gas distribution facilities are designed to meet the peak day requirements of firm service customers. There is a need to give customers a price signal to limit loads during peak load periods. This rate schedule recognizes this fact by introducing a higher delivery charge during the winter period. BC Gas is proposing a differential in both rate schedules between the delivery charge in the summer and winter, from $0.75 to $1.50 per gigajoule, as a step toward encouraging customers to better manage their annual gas consumption profile.

Another attribute of the summer/winter differential may be to shift some winter gas consumption to summer periods. Potential exists for these customers to manage gas consumption as part of their production process, far more than exists for commercial customers that use gas primarily for space heating. An example of this would be a sawmill scheduling lumber kiln drying, which requires large volumes of gas, in months that attract lower rates. Managing space heating requirements through more efficient equipment and insulation will be encouraged by the higher winter delivery charge that reflects the greater value of the gas resource and infrastructure in the winter months.

BC Gas believes that the customers in the general service class should eventually move to rates which include a demand charge. A demand charge will provide an incentive to customers to decrease their peak day demands on the system. At the present time only about 50% of the customers have demand meters installed and accordingly a demand charge is not possible for these customers at this time. Moreover, further information must be provided to these customers over time to make them better aware of the concept of demand charges.

2.1 Monthly Charges

The proposed $300.00 per month basic charge represents a significant decrease in the basic charges now paid by the Inland and Columbia small industrial customer (from $548.94), while it is a significant increase in the basic charge for customers in the Lower Mainland who receive gas from the utility. Those Lower Mainland customers have only paid a basic charge of approximately $5.00 per month. The transportation customers in the Lower Mainland (Schedule 2007) have been paying a transportation administration charge of $548.94. The proposed basic charge is roughly equal to the customer costs identified for customers in the FDC study (see Volume 2, Tab 2D, Page 1.2A, line 17) of $270.00. That amount relates to 1992 costs.

In addition to the monthly basic charge those customers which transport gas under Rate Schedule 25 will pay a Direct Purchase Administration Charge of $175.00 per month. This has been reduced from the transportation service administration Charge of $548.94 now in effect for these customers. for further discussion of the Direct Purchase Administration Charge, refer to page 11 at Tab 9 of this Volume.

2.2 Availability of General Firm Service

It is proposed that Rate Schedule 5 - General Firm Service, will be available only to a customer which uses more than 50% of its approved connected gas load for applications other than space heating. The gas supply costs allocated to this customer class will reflect the load factor of the class. In order to maintain a good load factor for the class, with a corresponding gas supply cost, the limitation is proposed.

2.3 Impact of Proposed Rates

The proposed rate schedules will have varying impacts on the annual bills of customers depending upon their current rate structure.

The customers in the Lower Mainland which now move their gas on transportation service (Schedule 2007) will all experience decreases in their annual bills. The total decrease to that group of customers exceeds $1.1 million. Overall the Inland transportation customers (Schedule 25) will also experience a decrease, although the effect on individual customers varies. For further details see page 16, columns (c) and (e) of this tab.

The Lower Mainland customers which purchase their gas from the utility generally will see decreases in their annual bills due to lower gas supply costs which more than offset margin increases to most customers. The overall decrease in revenue from these Lower Mainland customers is expected to be close to $1.0 million. See column (b) on page 16. The decrease in gas supply costs for these customers is $0.598 per gigajoule. For further details of the means by which gas supply costs were determined see Tab 11 of this volume. The margin increases in the Lower Mainland reflect the increased basic charge.

The customers in Inland which purchase their gas from the utility will generally experience lower annual bills. The revenue decrease can be seen in column (d) on page 16.

The customers in Columbia experience margin increases and only those moving from Rate Schedule 2.2 to the proposed Rate Schedule 5 will experience a reduced gas supply cost. The revenues and margins from Columbia customers will increase as their margins are presently below those in the Lower Mainland and Inland service areas.

BC Gas has evaluated the impact on the annual bills at proposed rates for the customers in the Lower Mainland, Inland and Columbia service areas which purchase gas from the utility. The evaluation was conducted at three levels of consumption: high (80,000 GJ per year), medium (30,000 GJ per year) and low (6,000 GJ per year). Table 1 provides a summary of the impact that the proposed monthly Basic Charge and seasonal delivery charges for Rate Schedules 5 and 25 customers will have on annual bills using permanent rates in effect as of January 1, 1993.

The impact on the total annual cost of gas for the customers which purchase their gas from producers or marketers cannot be evaluated by BC Gas since the cost of gas to these customers is not known by the utility. The overall impact on the transportation costs of those customers can be seen at Page 16 of this tab which sets out that the group of customers now on Lower Mainland Rate Schedule 2007 will experience a revenue decrease of 33% and the group of customers now on Inland Rate Schedule 25 will experience a revenue decrease of 0.3%.

3.0 IMPLEMENTATION OF PROPOSED BC GAS RATE SCHEDULES 5 AND 25

BC Gas proposes that Rate Schedule 5 become effective January 1, 1994 and Rate Schedule 25 become effective November 1, 1993 to coincide with natural gas contract years. Most customers in the Lower Mainland and Inland service areas will experience decreases in their monthly bills. BC Gas proposes to phase in increases in the Columbia rates in the same manner as the phase in of the Columbia residential and commercial rates.

The Company believes that the proposed Rate Schedules 5 and 25 strike the best compromise of a number of rate design factors.

The proposed rates are simple since consumption and cost of gas are the only variables other than franchise fees. Billing adjustments, customer comprehension, and other administrative functions will be simplified. The difference in winter and summer delivery charges will encourage energy conservation and gas system efficiency.

Table 1

ANALYSIS OF THE IMPACT THAT A $300.00 BASIC MONTHLY CHARGE AND A $1.50/GJ (WINTER) AND A $0.75 (SUMMER) DELIVERY CHARGE HAS ON ANNUAL RATE SCHEDULE 5 GAS BILLS

*** Cost of Gas Included ***

Division	Annual Consumption (GJ)	Current Annual Bill	Proposed Annual Bill with $300 Basic Monthly Charge and $1.50/GJ Winter and $0.75 Summer Delivery Charge: Annual Bill Increase (Decrease)	% Increase (Decrease)
Lower Mainland	High *	$315,156	($43,238)	(14%)
	Medium *	$120,056	($15,837)	(13%)
	Low*	$ 26,282	($ 2,558)	(10%)
Inland	High	$318,162	($43,716)	(14%)
	Medium	$119,912	$(14,745)	(12%)
	Low	$ 24,748	($ 834)	(3%)
Columbia	High	$225,250	$ 30,925	14%
	Medium	$ 92,796	$ 5,519	6%
	Low	$ 24,547	($ 2,003)	(8%)

* High = 80,000 GJ/year * Medium = 30,000 GJ/year * Low = 6,000 GJ/year

Note: Gas supply costs for Inland and Lower Mainland were established by use of the allocation methodology from the Phase A Rate Design Decision. Franchise fee charges for Inland and Columbia customers are included. The Lower Mainland example represents an existing Rate 2207/8 customer moving to the proposed Rate 5, the Inland example an existing Rate 2.2 customer to Rate 5, and the Columbia example an existing Rate 3 to Rate 5.

TECHNICAL APPENDIX

GENERAL SERVICE CLASS

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 1 - Base Case

Ln. No.	ANNUAL 1993 Industrial Rates	EXISTING TARIFF STRUCTURE LM 2207/8»5 Revenue	LM 2209»5 Revenue	INL Rate 5»5 Revenue	INL 2.2»5 Revenue	COL Rate 3»5 Revenue	COL 2.2»5 Revenue	FT NEL 3.1»5 Revenue	FT NEL 3.2»5 Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Basic Charge	$3,898	$5,457	$102,000	$4,622	$24,000	$735	$60,189	$27,364	$228,264
2	Minimum Charge	0	0	0	0	0	0	0	0	0
3	1st Block	$505,601	$714,784	$177,581	$5,456	$18,204	$34,139	$616	$308	$1,456,689
4	2nd Block	806,765	783,141	397,686	66,090	40,461	61,836	7,025	3,648	2,166,650
5	3rd Block	48,060	36,791	0	376,193	79,373	83,596	62,262	259,232	945,507
6	4th Block	2,552	607	0	0	0	0	0	0	3,158
7	5th Block	0	0	0	0	0	0	0	0	0
9	Total Exs. Net Margin Rev. (1)	$1,366,875	$1,540,779	$677,266	$452,361	$162,038	$180,305	$130,092	$290,553	$4,800,269
11	ADJ 1 = Commodity Costs	$1,188,892	$1,285,473	$480,138	$268,723	$380,236	$296,950	$113,082	$365,580	$4,379,074
12	ADJ 2 = Fixed Costs	2,277,580	2,462,602	591,014	416,301	91,713	57,922	212	810	5,898,154
13	ADJ 3 = Franchise Fees	0	0	39,549	29,208	13,827	13,936	0	0	96,521
15	Total Adjustments	$3,466,471	$3,748,076	$1,110,701	$714,233	$485,777	$368,808	$113,294	$366,390	$10,373,749
17	Total Existing Rate Revenue	$4,833,346	$5,288,855	$1,787,967	$1,166,594	$647,814	$549,113	$243,385	$656,943	$15,174,018
19	Spread Adjustment Factor (2)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Total Adj. Exs. Rate Revenue	$4,833,346	$5,288,855	$1,787,967	$1,166,594	$647,814	$549,113	$243,385	$656,943	$15,174,018

26 Notes:

28 (1) Total Existing Net Margin Revenue does not include Franchise Fee revenues.

29 (2) Spread Adjustment Factor not available for revised customer classes.

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 2 - Base Case

Ln. No.	ANNUAL 1993 Proposed Rates	PROPOSED TARIFF STRUCTURE								
		LM 2207/8»5 Revenue	LM 2209»5 Revenue	INL Rate 5»5 Revenue	INL 2.2»5 Revenue	COL Rate 3»5 Revenue	COL 2.2»5 Revenue	FT NEL 3.1»5 Revenue	FT NEL 3.2»5 Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Basic Charge	$252,000	$352,800	$61,200	$107,400	$14,400	$25,200	$60,189	$27,364	$900,553
2	Demand Charge	0	0	0	0	0	0	0	0	0
3	1st Block	$1,276,097	$1,497,785	$571,411	$351,631	$233,209	$176,926	$616	$308	$4,107,982
4	2nd Block	0	0	0	0	0	0	7,025	3,648	10,672
5	3rd Block	0	0	0	0	0	0	62,262	259,232	321,495
6	4th Block	0	0	0	0	0	0	0	0	0
7	5th Block	0	0	0	0	0	0	0	0	0
8										
9	Total Proposed Margin Revenue	$1,528,097	$1,850,585	$632,611	$459,031	$247,609	$202,126	$130,092	$290,553	$5,340,702
10										
11	ADJ 1 = Commodity Costs	$1,188,892	$1,285,473	$480,035	$268,723	$380,236	$263,931	$113,082	$365,580	$4,345,953
12	ADJ 2 = Fixed Costs	1,559,948	1,686,673	597,231	334,329	91,713	63,660	212	810	4,334,577
13	ADJ 3 = Franchise Fees	0	0	38,677	27,274	15,694	13,794	0	0	95,439
14										
15	Total Comm. & Fixed Cost Rev.	$2,748,840	$2,972,146	$1,115,943	$630,327	$487,643	$341,385	$113,294	$366,390	$8,775,968
16										
17	Total Proposed Rate Revenue	$4,276,937	$4,822,731	$1,748,554	$1,089,358	$735,252	$543,511	$243,385	$656,943	$14,116,671
18										
19	Spread Adjustment Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20										
21	Total Adj. Prop. Rate Revenue	$4,276,937	$4,822,731	$1,748,554	$1,089,358	$735,252	$543,511	$243,385	$656,943	$14,116,671
22										
23										
24	Total Adjusted Exs. Rate Rev.	$4,833,346	$5,288,855	$1,787,967	$1,166,594	$647,814	$549,113	$243,385	$656,943	$15,174,018
25										
26	Diff Betw. Prop. & Exs. Rev.	($556,409)	($466,124)	($39,413)	($77,236)	$87,437	($5,602)	$0	$0	($1,057,347)
27										
28										
29	Revenue Difference (%)	-11.51%	-8.81%	-2.20%	-6.62%	13.50%	-1.02%	0.00%	0.00%	-6.97%
30										
31										
32	GROSS MARGINS:									
33										
34	Existing Margin Revenue	$1,366,875	$1,540,779	$677,266	$452,361	$162,038	$180,305	$130,092	$290,553	$4,800,269
35	Proposed Margin Revenue	1,528,097	1,850,585	632,611	459,031	247,609	202,126	130,092	290,553	5,340,702
36										
37	Margin Difference	$161,222	$309,805	($44,656)	$6,670	$85,571	$21,821	$0	$0	$540,433
38										
39	Margin Difference (%)	11.79%	20.11%	-6.59%	1.47%	52.81%	12.10%	0.00%	0.00%	11.26%
40										
41	UNIT VALUES:									
42										
43	Existing Avg Margin	$1.139	$1.187	$1.318	$1.573	$0.710	$1.137	$1.845	$1.076	
44	Proposed Avg Margin	$1.273	$1.426	$1.231	$1.596	$1.084	$1.275	$1.845	$1.076	

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 3 - Base Case

Ln. No.	EXISTING INPUT TABLE INDUSTRIAL ANNUAL	EXISTING TARIFF STRUCTURE: LM 2207/8»5	LM 2209»5	INL Rate 5»5	INL 2.2»5	COL Rate 3»5	COL 2.2»5	FT NEL 3.1»5	FT NEL 3.2»5	BC Gas Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	EXISTING RATES ($/GJ): (1) Present Rates based on Nov. 1992 rates and do not include interim increases									
2										
3	Basic Charge	$4.640	$4.640	$500.000	$12.910	$500.000	$8.750	$2,507.870	$2,280.370	
4	Minimum Charge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
5										
6	Price 1st Block	$1.503	$1.503	$2.069	$2.742	$0.977	$1.255	$1.283	$1.284	
7	Price 2nd Block	1.013	1.013	0.929	2.082	0.727	1.155	1.191	1.192	
8	Price 3rd Block	0.763	0.763	0.000	1.482	0.514	1.076	0.971	0.972	
9	Price 4th Block	0.543	0.543	0.000	0.000	0.000	0.000	0.000	0.000	
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
11										
12	Price of ADJ 1=Commodity Costs	$0.991	$0.991	$0.935	$0.934	$1.665	$1.873	$1.604	$1.354	
13	Price of ADJ 2=Fixed Costs	1.898	1.898	1.150	1.447	0.402	0.365	0.003	0.003	
14	Price of ADJ 3=Franchise Fees	0.000	0.000	0.077	0.102	0.061	0.088	0.000	0.000	
15										
16										
17	EXISTING BLOCK ENDINGS (GJ):									
18										
19	End of 1st Block	500	500	500	6	500	500	20	20	
20	End of 2nd Block	8,000	8,000	999,999.9	105.5	2,500	2,500	275	275	
21	End of 3rd Block	25,000	25,000	0	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
22	End of 4th Block	999,999.9	999,999.9	0	0	0	0	0	0	
23	End of 5th Block	0	0	0	0	0	0	0	0	
24										
25	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
26	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
27	ADJ 3 = Franchise Fees	0	0	999,999.9	999,999.9	999,999.9	999,999.9	0	0	
28										
29										
30	NUMBER OF GJ's:									
31										
32	1st Block	336,305	475,445	85,824	1,990	18,617	27,216	480	240	946,117
33	2nd Block	796,097	772,786	427,967	31,752	55,592	53,566	5,898	3,060	2,146,718
34	3rd Block	62,955	48,193	0	253,878	154,161	77,736	64,122	266,700	927,744
35	4th Block	4,695	1,116	0	0	0	0	0	0	5,812
36	5th Block	0	0	0	0	0	0	0	0	0
37										
38	ADJ 1 = Commodity Costs	1,200,052	1,297,541	513,791	287,620	228,370	158,517	70,500	270,000	4,026,391
39	ADJ 2 = Fixed Costs	1,200,052	1,297,541	513,791	287,620	228,370	158,517	70,500	270,000	4,026,391
40	ADJ 3 = Franchise Fees	0	0	513,791	287,620	228,370	158,517	0	0	1,188,298
41										
42										
43	NUMBER OF BILLS	840	1,176	204	358	48	84	24	12	2,746

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 4 - Base Case

Ln. No.	PROPOSED INPUT TABLE INDUSTRIAL ANNUAL	PROPOSED TARIFF STRUCTURE LM 2207/8»5	LM 2209»5	INL Rate 5»5	INL 2.2»5	COL Rate 3»5	COL 2.2»5	FT NEL 3.1»5	FT NEL 3.2»5	BC Gas Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	PROPOSED RATES ($/GJ):									
2										
3	Basic Charge	$300.000	$300.000	$300.000	$300.000	$300.000	$300.000	$2,507.870	$2,280.370	
4	Demand Charge ($/GJ)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
5										
6	Price 1st Block	$1.063	$1.154	$1.112	$1.223	$1.021	$1.116	$1.283	$1.284	
7	Price 2nd Block	0.000	0.000	0.000	0.000	0.000	0.000	1.191	1.192	
8	Price 3rd Block	0.000	0.000	0.000	0.000	0.000	0.000	0.971	0.972	
9	Price 4th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
11										
12	Price of ADJ 1=Commodity Costs	$0.991	$0.991	$0.934	$0.934	$1.665	$1.665	$1.604	$1.354	
13	Price of ADJ 2=Fixed Costs	1.300	1.300	1.162	1.162	0.402	0.402	0.003	0.003	
14	Price of ADJ 3=Franchise Fees	0.000	0.000	0.075	0.095	0.069	0.087	0.000	0.000	
15										
16	PROPOSED BLOCK ENDINGS (GJ):									
17										
18	End of 1st Block	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	20.0	20.0	
19	End of 2nd Block	0	0	0	0	0	0	275	275	
20	End of 3rd Block	0	0	0	0	0	0	1,000,000	1,000,000	
21	End of 4th Block	0	0	0	0	0	0	0	0	
22	End of 5th Block	0	0	0	0	0	0	0	0	
23										
24	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
25	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
26	ADJ 3 = Franchise Fees	0.0	0.0	999,999.9	999,999.9	999,999.9	999,999.9	0.0	0.0	
27										
28										
29	NUMBER OF GJ's:									
30										
31	1st Block	1,200,052	1,297,541	513,791	287,620	228,370	158,517	480	240	3,686,611
32	2nd Block	0	0	0	0	0	0	5,898	3,060	8,958
33	3rd Block	0	0	0	0	0	0	64,122	266,700	330,822
34	4th Block	0	0	0	0	0	0	0	0	0
35	5th Block	0	0	0	0	0	0	0	0	0
36										
37	ADJ 1 = Commodity Costs	1,200,052	1,297,541	513,791	287,620	228,370	158,517	70,500	270,000	4,026,391
38	ADJ 2 = Fixed Costs	1,200,052	1,297,541	513,791	287,620	228,370	158,517	70,500	270,000	4,026,391
39	ADJ 3 = Franchise Fees	0	0	513,791	287,620	228,370	158,517	0	0	1,188,298
40										
41										
42	NUMBER OF BILLS	840	1,176	204	358	48	84	24	12	2,746
43										
44										

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

Ln. No.	TABLE 5 - Summary ANNUAL 1993 Proposed Rates	PROPOSED TARIFF STRUCTURE LM 2207/8/9»5 Revenue	LM 2007»25 Revenue	INL 2.2/5»5 Revenue	INL 25 » 25 Revenue	COL 2.2/3»5 Revenue	COL 3 » 25 Revenue	BC Gas Total»5 Revenue	BC Gas Total»25 Revenue	BC Gas Total 5&25 Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	VOLUMES:	2,497,593	1,867,017	801,411	2,120,360	386,887	278,500	3,685,891	4,265,877	7,951,768
4	REVENUES:									
6	Total Adjusted Exs. Rate Rev.	$10,122,201	$3,413,658	$2,954,561	$2,563,826	$1,196,928	$186,387	$14,273,690	$6,163,871	$20,437,561
7	Existing Avg. Revenue ($/GJ)	$4.05	$1.83	$3.69	$1.21	$3.09		$3.87	$1.44	$2.57
9	Total Adjusted Prop. Rate Rev.	$9,099,668	$2,304,027	$2,837,912	$2,555,411	$1,278,763	$323,744	$13,216,343	$5,183,182	$18,399,525
10	Proposed Avg. Revenue ($/GJ)	$3.64	$1.23	$3.54	$1.21	$3.31	$1.16	$3.59	$1.22	$2.31
12	Revenue Difference ($)	($1,022,533)	($1,109,631)	($116,649)	($8,415)	$81,835	$137,357	($1,057,347)	($980,689)	($2,038,036)
14	Revenue Difference (%)	-10.10%	-32.51%	-3.95%	-0.33%	6.84%	73.69%	-7.41%	-15.91%	-9.97%
18	MARGINS:									
20	Existing Margin Revenue	$2,907,654	$3,413,658	$1,129,628	$2,563,826	$342,343	$186,387	$4,379,625	$6,163,871	$10,543,496
21	Existing Avg. Margin ($/GJ)	$1.16	$1.83	$1.41	$1.21	$0.88	$0.67	$1.19	$1.44	$1.33
23	Proposed Margin Revenue	$3,378,682	$2,304,027	$1,091,642	$2,555,411	$449,735	$323,744	$4,920,058	$5,183,182	$10,103,240
24	Proposed Avg. Margin ($/GJ)	$1.35	$1.23	$1.36	$1.21	$1.16	$1.16	$1.33	$1.22	$1.27
26	Margin Difference ($)	$471,027	($1,109,631)	($37,986)	($8,415)	$107,392	$137,357	$540,433	($980,689)	($440,256)
28	Margin Difference (%)	16.20%	-32.51%	-3.36%	-0.33%	31.37%	73.69%	12.34%	-15.91%	-4.18%

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

Ln. No.	TABLE 1 - Base Case WINTER 1993 Industrial Rates	EXISTING TARIFF STRUCTURE LM 2207/8»5 Revenue	LM 2209»5 Revenue	INL Rate 5»5 Revenue	INL 2.2»5 Revenue	COL Rate 3»5 Revenue	COL 2.2»5 Revenue	FT NEL 3.1»5 Revenue	FT NEL 3.2»5 Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Basic Charge	$1,624	$2,274	$42,500	$1,988	$10,000	$306	$25,079	$11,402	$95,173
2	Minimum Charge	0	0	0	0	0	0	0	0	0
3	1st Block	$216,569	$311,189	$77,333	$2,420	$7,514	$15,094	$257	$128	$630,505
4	2nd Block	340,004	454,451	196,035	30,376	16,065	33,495	3,037	1,520	1,074,983
5	3rd Block	15,571	32,793	0	245,709	27,153	39,077	33,342	144,464	538,109
6	4th Block	789	607	0	0	0	0	0	0	1,395
7	5th Block	0	0	0	0	0	0	0	0	0
8										
9	Total Existing Margin Revenue	$574,557	$801,314	$315,868	$280,494	$60,732	$87,972	$61,715	$157,514	$2,340,165
10										
11	ADJ 1 = Commodity Costs	$496,747	$693,000	$231,840	$169,315	$137,487	$144,964	$59,489	$203,100	$2,135,943
12	ADJ 2 = Fixed Costs	951,626	1,327,592	285,378	262,300	33,162	28,276	111	450	2,888,896
13	ADJ 3 = Franchise Fees	0	0	18,844	18,287	5,046	6,802	0	0	48,980
14										
15	Total Adjustments	$1,448,373	$2,020,592	$536,062	$449,903	$175,696	$180,042	$59,600	$203,550	$5,073,819
16										
17	Total Existing Rate Revenue	$2,022,930	$2,821,907	$851,930	$730,397	$236,428	$268,014	$121,315	$361,064	$7,413,983
18										
19	Spread Adjustment Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20										
21	Total Adj. Exs. Rate Revenue	$2,022,930	$2,821,907	$851,930	$730,397	$236,428	$268,014	$121,315	$361,064	$7,413,983
22										
23										
24										
25										
26										
27										
28										
29										
30										

6 Jun 1993

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 2 - Base Case

Ln. No.	WINTER 1993 Proposed Rates	PROPOSED TARIFF STRUCTURE								
		LM 2207/8»5 Revenue	LM 2209»5 Revenue	INL Rate 5»5 Revenue	INL 2.2»5 Revenue	COL Rate 3»5 Revenue	COL 2.2»5 Revenue	FT NEL 3.1»5 Revenue	FT NEL 3.2»5 Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Basic Charge	$105,000	$147,000	$25,500	$46,200	$6,000	$10,500	$25,079	$11,402	$376,681
2	Demand Charge	0	0	0	0	0	0	0	0	0
3	1st Block	$752,115	$1,049,259	$372,135	$271,833	$123,863	$116,077	$257	$128	$2,685,665
4	2nd Block	0	0	0	0	0	0	3,037	1,520	4,557
5	3rd Block	0	0	0	0	0	0	33,342	144,464	177,806
6	4th Block	0	0	0	0	0	0	0	0	0
7	5th Block	0	0	0	0	0	0	0	0	0
8										
9	Total Proposed Margin Revenue	$857,115	$1,196,259	$397,635	$318,033	$129,863	$126,577	$61,715	$157,514	$3,244,708
10										
11	ADJ 1 = Commodity Costs	$496,747	$693,000	$231,790	$169,315	$137,487	$128,845	$59,489	$203,100	$2,119,774
12	ADJ 2 = Fixed Costs	651,783	909,288	288,380	210,652	33,162	31,078	111	450	2,124,903
13	ADJ 3 = Franchise Fees	0	0	20,761	17,925	6,554	7,460	0	0	52,700
14										
15	Total Comm. & Fixed Cost Rev.	$1,148,529	$1,602,288	$540,931	$397,892	$177,204	$167,383	$59,600	$203,550	$4,297,378
16										
17	Total Proposed Rate Revenue	$2,005,644	$2,798,547	$938,566	$715,925	$307,066	$293,959	$121,315	$361,064	$7,542,086
18										
19	Spread Adjustment Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20										
21	Total Adj. Prop. Rate Revenue	$2,005,644	$2,798,547	$938,566	$715,925	$307,066	$293,959	$121,315	$361,064	$7,542,086
22										
23										
24	Total Adjusted Exs. Rate Rev.	$2,022,930	$2,821,907	$851,930	$730,397	$236,428	$268,014	$121,315	$361,064	$7,413,983
25										
26	Diff Betw. Prop. & Exs. Rev.	($17,285)	($23,360)	$86,636	($14,472)	$70,638	$25,946	$0	$0	$128,102
27										
28										
29	Revenue Difference (%)	-0.85%	-0.83%	10.17%	-1.98%	29.88%	9.68%	0.00%	0.00%	1.73%
30										
31										
32	GROSS MARGINS:									
33										
34	Existing Margin Revenue	$574,557	$801,314	$315,868	$280,494	$60,732	$87,972	$61,715	$157,514	$2,340,165
35	Proposed Margin Revenue	857,115	1,196,259	397,635	318,033	129,863	126,577	61,715	157,514	3,244,708
36										
37	Margin Difference	$282,558	$394,945	$81,767	$37,539	$69,130	$38,605	$0	$0	$904,543
38										
39	Margin Difference (%)	49.18%	49.29%	25.89%	13.38%	113.83%	43.88%	0.00%	0.00%	38.65%
40										
41	UNIT VALUES:									
42										
43	Existing Avg Margin	$1.146	$1.146	$1.273	$1.548	$0.735	$1.137	$1.664	$1.050	$1.922
44	Proposed Avg Margin	$1.709	$1.710	$1.603	$1.755	$1.573	$1.636	$1.664	$1.050	$2.666

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 3

Ln. No.	EXISTING INPUT TABLE INDUSTRIAL WINTER	EXISTING TARIFF STRUCTURE LM 2207/8»5	LM 2209»5	INL Rate 5»5	INL 2.2»5	COL Rate 3»5	COL 2.2»5	FT NEL 3.1»5	FT NEL 3.2»5	BC Gas Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	EXISTING RATES ($/GJ):	Present Rates based on Jan. 1993 rates and include interim increases								
2										
3	Basic Charge	$4.640	$4.640	$500.000	$12.910	$500.000	$8.750	$2,507.870	$2,280.370	
4	Minimum Charge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
5										
6	Price 1st Block	$1.503	$1.503	$2.070	$2.742	$0.977	$1.254	$1.283	$1.284	
7	Price 2nd Block	1.013	1.013	0.930	2.082	0.727	1.154	1.191	1.192	
8	Price 3rd Block	0.763	0.763	0.000	1.482	0.514	1.075	0.971	0.972	
9	Price 4th Block	0.543	0.543	0.000	0.000	0.000	0.000	0.000	0.000	
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
11										
12	Price of ADJ 1=Commodity Costs	$0.991	$0.991	$0.935	$0.934	$1.665	$1.873	$1.604	$1.354	
13	Price of ADJ 2=Fixed Costs	1.898	1.898	1.150	1.447	0.402	0.365	0.003	0.003	
14	Price of ADJ 3=Franchise Fees	0.000	0.000	0.076	0.101	0.061	0.088	0.000	0.000	
15										
16										
17	EXISTING BLOCK ENDINGS (GJ):									
18										
19	End of 1st Block	500	500	500	6	500	500	20	20	
20	End of 2nd Block	8,000	8,000	999,999.9	105.5	2,500	2,500	275	275	
21	End of 3rd Block	25,000	25,000	0	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
22	End of 4th Block	999,999.9	999,999.9	0	0	0	0	0	0	
23	End of 5th Block	0	0	0	0	0	0	0	0	
24										
25	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
26	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
27	ADJ 3 = Franchise Fees	0	0	999,999.9	999,999.9	999,999.9	999,999.9	0	0	
28										
29										
30	NUMBER OF GJ's:									
31										
32	1st Block	144,053	206,990	37,355	883	7,689	12,033	200	100	409,302
33	2nd Block	335,508	448,442	210,735	14,587	22,088	29,015	2,550	1,275	1,064,202
34	3rd Block	20,397	42,957	0	165,752	52,798	36,337	34,338	148,625	501,203
35	4th Block	1,452	1,116	0	0	0	0	0	0	2,568
36	5th Block	0	0	0	0	0	0	0	0	0
37										
38	ADJ 1 = Commodity Costs	501,410	699,506	248,090	181,222	82,575	77,384	37,088	150,000	1,977,275
39	ADJ 2 = Fixed Costs	501,410	699,506	248,090	181,222	82,575	77,384	37,088	150,000	1,977,275
40	ADJ 3 = Franchise Fees	0	0	248,090	181,222	82,575	77,384	0	0	589,271
41										
42										
43	NUMBER OF ACCOUNTS	350	490	85	154	35	35	10	5	1,164

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 4

Ln. No.	PROPOSED INPUT TABLE INDUSTRIAL WINTER	PROPOSED TARIFF STRUCTURE LM 2207/8»5	LM 2209»5	INL Rate 5»5	INL 2.2»5	COL Rate 3»5	COL 2.2»5	FT NEL 3.1»5	FT NEL 3.2»5	BC Gas Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	PROPOSED RATES ($/GJ):									
2										
3	Basic Charge	$300.000	$300.000	$300.000	$300.000	$300.000	$300.000	$2,507.870	$2,280.370	
4	Demand Charge ($/GJ)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
5										
6	Price 1st Block	$1.500	$1.500	$1.500	$1.500	$1.500	$1.500	$1.283	$1.284	
7	Price 2nd Block	0.000	0.000	0.000	0.000	0.000	0.000	1.191	1.192	
8	Price 3rd Block	0.000	0.000	0.000	0.000	0.000	0.000	0.971	0.972	
9	Price 4th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
11										
12	Price of ADJ 1=Commodity Costs	$0.991	$0.991	$0.934	$0.934	$1.665	$1.665	$1.604	$1.354	
13	Price of ADJ 2=Fixed Costs	1.300	1.300	1.162	1.162	0.402	0.402	0.003	0.003	
14	Price of ADJ 3=Franchise Fees	0.000	0.000	0.084	0.099	0.079	0.096	0.000	0.000	
15										
16	PROPOSED BLOCK ENDINGS (GJ):									
17										
18	End of 1st Block	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	20	20	
19	End of 2nd Block	0	0	0	0	0	0	275	275	
20	End of 3rd Block	0	0	0	0	0	0	999,999.9	999,999.9	
21	End of 4th Block	0	0	0	0	0	0	0	0	
22	End of 5th Block	0	0	0	0	0	0	0	0	
23										
24	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
25	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
26	ADJ 3 = Franchise Fees	0	0	999,999.9	999,999.9	999,999.9	999,999.9	0	0	
27										
28										
29	NUMBER OF GJ's:									
30										
31	1st Block	501,410	699,506	248,090	181,222	82,575	77,384	200	100	1,790,487
32	2nd Block	0	0	0	0	0	0	2,550	1,275	3,825
33	3rd Block	0	0	0	0	0	0	34,338	148,625	182,963
34	4th Block	0	0	0	0	0	0	0	0	0
35	5th Block	0	0	0	0	0	0	0	0	0
36										
37	ADJ 1 = Commodity Costs	501,410	699,506	248,090	181,222	82,575	77,384	37,088	150,000	1,977,275
38	ADJ 2 = Fixed Costs	501,410	699,506	248,090	181,222	82,575	77,384	37,088	150,000	1,977,275
39	ADJ 3	0	0	248,090	181,222	82,575	77,384	0	0	589,271
40										
41										
42	NUMBER OF BILLS	350	490	85	154	20	35	10	5	1,149
43										
44										

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 1 - Base Case

Ln. No.	SUMMER 1993 Industrial Rates	EXISTING TARIFF STRUCTURE LM 2207/8»5 Revenue	LM 2209»5 Revenue	INL Rate 5»5 Revenue	INL 2.2»5 Revenue	COL Rate 3»5 Revenue	COL 2.2»5 Revenue	FT NEL 3.1»5 Revenue	FT NEL 3.2»5 Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Basic Charge	$2,274	$3,183	$59,500	$2,634	$14,000	$429	$35,110	$15,963	$133,092
2	Minimum Charge	0	0	0	0	0	0	0	0	0
3	1st Block	$289,032	$403,595	$100,248	$3,036	$10,690	$19,045	$359	$180	$826,184
4	2nd Block	466,760	328,690	201,651	35,714	24,397	28,341	3,987	2,128	1,091,667
5	3rd Block	32,489	3,998	0	130,484	52,219	44,519	28,920	114,769	407,398
6	4th Block	1,763	0	0	0	0	0	0	0	1,763
7	5th Block	0	0	0	0	0	0	0	0	0
8										
9	Total Existing Margin Revenue	$792,318	$739,465	$361,398	$171,868	$101,306	$92,334	$68,377	$133,039	$2,460,104
10										
11	ADJ 1 = Commodity Costs	$692,145	$592,473	$248,298	$99,408	$242,749	$151,986	$53,593	$162,480	$2,243,131
12	ADJ 2 = Fixed Costs	1,325,954	1,135,010	305,636	154,001	58,551	29,646	100	360	3,009,258
13	ADJ 3 = Franchise Fees	0	0	20,705	10,921	8,781	7,134	0	0	47,541
14										
15	Total Adjustments	$2,018,099	$1,727,483	$574,638	$264,330	$310,081	$188,766	$53,693	$162,840	$5,299,930
16										
17	Total Existing Rate Revenue	$2,810,417	$2,466,948	$936,037	$436,198	$411,386	$281,099	$122,070	$295,879	$7,760,034
18										
19	Spread Adjustment Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20										
21	Total Adj. Exs. Rate Revenue	$2,810,417	$2,466,948	$936,037	$436,198	$411,386	$281,099	$122,070	$295,879	$7,760,034
22										
23										
24										
25										
26										
27										
28										
29										
30										

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

Ln. No.	TABLE 2 - Base Case SUMMER 1993 Proposed Rates	PROPOSED TARIFF STRUCTURE LM 2207/8»5 Revenue	LM 2209»5 Revenue	INL Rate 5»5 Revenue	INL 2.2»5 Revenue	COL Rate 3»5 Revenue	COL 2.2»5 Revenue	FT NEL 3.1»5 Revenue	FT NEL 3.2»5 Revenue	BC Gas Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Basic Charge	$147,000	$205,800	$35,700	$61,200	$8,400	$14,700	$35,110	$15,963	$523,873
2	Demand Charge	0	0	0	0	0	0	0	0	0
3	1st Block	$523,982	$448,526	$199,276	$79,799	$109,346	$60,850	$359	$180	1,422,317
4	2nd Block	0	0	0	0	0	0	3,987	2,128	6,115
5	3rd Block	0	0	0	0	0	0	28,920	114,769	143,689
6	4th Block	0	0	0	0	0	0	0	0	0
7	5th Block	0	0	0	0	0	0	0	0	0
8										
9	Total Proposed Margin Revenue	$670,982	$654,326	$234,976	$140,999	$117,746	$75,550	$68,377	$133,039	$2,095,994
10										
11	ADJ 1 = Commodity Costs	$692,145	$592,473	$248,244	$99,408	$242,749	$135,086	$53,593	$162,480	$2,226,178
12	ADJ 2 = Fixed Costs	908,165	777,385	308,851	123,677	58,551	32,583	100	360	2,209,674
13	ADJ 3 = Franchise Fees	0	0	17,917	9,350	9,139	6,333	0	0	42,739
14										
15	Total Comm. & Fixed Cost Rev.	$1,600,311	$1,369,858	$575,012	$232,435	$310,439	$174,002	$53,693	$162,840	$4,478,591
16										
17	Total Proposed Rate Revenue	$2,271,293	$2,024,184	$809,988	$373,434	$428,186	$249,552	$122,070	$295,879	$6,574,585
18										
19	Spread Adjustment Factor	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20										
21	Total Adj. Prop. Rate Revenue	$2,271,293	$2,024,184	$809,988	$373,434	$428,186	$249,552	$122,070	$295,879	$6,574,585
22										
23										
24	Total Adjusted Exs. Rate Rev.	$2,810,417	$2,466,948	$936,037	$436,198	$411,386	$281,099	$122,070	$295,879	$7,760,034
25										
26	Diff Betw. Prop. & Exs. Rev.	($539,124)	($442,764)	($126,049)	($62,764)	$16,799	($31,548)	$0	$0	($1,185,449)
27										
28										
29	Revenue Difference (%)	-19.18%	-17.95%	-13.47%	-14.39%	4.08%	-11.22%	0.00%	0.00%	-15.28%
30										
31										
32	GROSS MARGINS:									
33										
34	Existing Margin Revenue	$792,318	$739,465	$361,398	$171,868	$101,306	$92,334	$68,377	$133,039	$2,460,104
35	Proposed Margin Revenue	670,982	654,326	234,976	140,999	117,746	75,550	68,377	133,039	2,095,994
36										
37	Margin Difference	($121,336)	($85,139)	($126,423)	($30,869)	$16,441	($16,784)	$0	$0	($364,110)
38										
39	Margin Difference (%)	-15.31%	-11.51%	-34.98%	-17.96%	16.23%	-18.18%	0.00%	0.00%	-14.80%
40										
41	UNIT VALUES:									
42										
43	Existing Avg Margin	$1.134	$1.236	$1.360	$1.615	$0.695	$1.138	$2.046	$1.109	$2.115
44	Proposed Avg Margin	$0.960	$1.094	$0.884	$1.325	$0.808	$0.931	$2.046	$1.109	$1.802

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

TABLE 3

Ln. No.	EXISTING INPUT TABLE INDUSTRIAL SUMMER	EXISTING TARIFF STRUCTURE LM 2207/8»5	LM 2209»5	INL Rate 5»5	INL 2.2»5	COL Rate 3»5	COL 2.2»5	FT NEL 3.1»5	FT NEL 3.2»5	BC Gas Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	EXISTING RATES ($/GJ):	Present Rates based on Jan. 1993 rates and include interim increases								
2										
3	Basic Charge	$4.640	$4.640	$500.000	$12.910	$500.000	$8.750	$2,507.870	$2,280.370	
4	Minimum Charge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
5										
6	Price 1st Block	$1.503	$1.503	$2.068	$2.741	$0.978	$1.254	$1.283	$1.284	
7	Price 2nd Block	1.013	1.013	0.928	2.081	0.728	1.154	1.191	1.192	
8	Price 3rd Block	0.763	0.763	0.000	1.481	0.515	1.075	0.971	0.972	
9	Price 4th Block	0.543	0.543	0.000	0.000	0.000	0.000	0.000	0.000	
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
11										
12	Price of ADJ 1=Commodity Cost	$0.991	$0.991	$0.935	$0.934	$1.665	$1.873	$1.604	$1.354	
13	Price of ADJ 2=Fixed Costs	1.898	1.898	1.150	1.447	0.402	0.365	0.003	0.003	
14	Price of ADJ 3=Franchise Fees	0.000	0.000	0.078	0.103	0.060	0.088	0.000	0.000	
15										
16										
17	EXISTING BLOCK ENDINGS (GJ):									
18										
19	End of 1st Block	500	500	500	6	500	500	20	20	
20	End of 2nd Block	8,000	8,000	999,999.9	105.5	2,500	2,500	275	275	
21	End of 3rd Block	25,000	25,000	0	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
22	End of 4th Block	999,999.9	999,999.9	0	0	0	0	0	0	
23	End of 5th Block	0	0	0	0	0	0	0	0	
24										
25	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
26	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
27	ADJ 3 = Franchise Fees	0	0	999,999.9	999,999.9	999,999.9	999,999.9	0	0	
28										
29										
30	NUMBER OF GJ's:									
31										
32	1st Block	192,252	268,455	48,469	1,108	10,928	15,183	280	140	536,815
33	2nd Block	460,589	324,343	217,232	17,165	33,504	24,551	3,348	1,785	1,082,516
34	3rd Block	42,558	5,237	0	88,126	101,363	41,399	29,784	118,075	426,541
35	4th Block	3,244	0	0	0	0	0	0	0	3,244
36	5th Block	0	0	0	0	0	0	0	0	0
37										
38	ADJ 1 = Commodity Costs	698,643	598,035	265,701	106,398	145,795	81,133	33,412	120,000	2,049,116
39	ADJ 2 = Fixed Costs	698,643	598,035	265,701	106,398	145,795	81,133	33,412	120,000	2,049,116
40	ADJ 3 = Franchise Fees	0	0	265,701	106,398	145,795	81,133	0	0	599,027
41										
42										
43	NUMBER OF ACCOUNTS	490	686	119	204	49	49	14	7	1,618

Revised June 7, 1993
Page 23
Tab 8

BC GAS INC.

DETAILED REVENUE CALCULATION
UNDER EXISTING AND PROPOSED GENERAL SERVICE TARIFF STRUCTURES
TEST YEAR ENDING DEC. 31, 1993

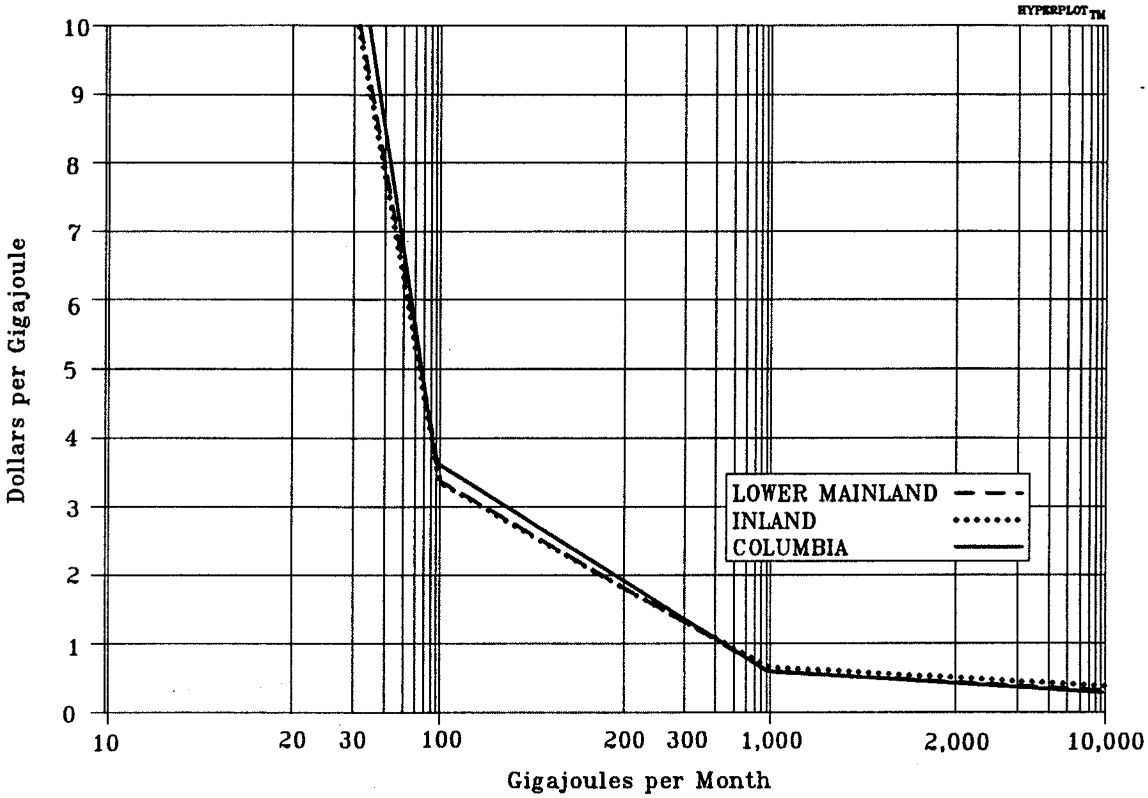
TABLE 4

Ln. No.	PROPOSED INPUT TABLE INDUSTRIAL SUMMER	PROPOSED TARIFF STRUCTURE LM 2207/8»5	LM 2209»5	INL Rate 5»5	INL 2.2»5	COL Rate 3»5	COL 2.2»5	FT NEL 3.1»5	FT NEL 3.2»5	BC Gas Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	PROPOSED RATES ($/GJ):									
3	Basic Charge	$300.000	$300.000	$300.000	$300.000	$300.000	$300.000	$2,507.870	$2,280.370	
4	Demand Charge ($/GJ)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
6	Price 1st Block	$0.750	$0.750	$0.750	$0.750	$0.750	$0.750	$1.283	$1.284	
7	Price 2nd Block	0.000	0.000	0.000	0.000	0.000	0.000	1.191	1.192	
8	Price 3rd Block	0.000	0.000	0.000	0.000	0.000	0.000	0.971	0.972	
9	Price 4th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
10	Price 5th Block	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
12	Price of ADJ 1=Commodity Cost	$0.991	$0.991	$0.934	$0.934	$1.665	$1.665	$1.604	$1.354	
13	Price of ADJ 2=Fixed Costs	1.300	1.300	1.162	1.162	0.402	0.402	0.003	0.003	
14	Price of ADJ 3=Franchise Fees	0.000	0.000	0.067	0.088	0.063	0.078	0.000	0.000	
16	PROPOSED BLOCK ENDINGS (GJ):									
18	End of 1st Block	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	20	20	
19	End of 2nd Block	0	0	0	0	0	0	275	275	
20	End of 3rd Block	0	0	0	0	0	0	999,999.9	999,999.9	
21	End of 4th Block	0	0	0	0	0	0	0	0	
22	End of 5th Block	0	0	0	0	0	0	0	0	
24	ADJ 1 = Commodity Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
25	ADJ 2 = Fixed Costs	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	999,999.9	
26	ADJ 3 = Franchise Fees	0	0	999,999.9	999,999.9	999,999.9	999,999.9	0	0	
29	NUMBER OF GJ's:									
31	1st Block	698,643	598,035	265,701	106,398	145,795	81,133	280	140	1,896,124
32	2nd Block	0	0	0	0	0	0	3,348	1,785	5,133
33	3rd Block	0	0	0	0	0	0	29,784	118,075	147,859
34	4th Block	0	0	0	0	0	0	0	0	0
35	5th Block	0	0	0	0	0	0	0	0	0
37	ADJ 1 = Commodity Costs	698,643	598,035	265,701	106,398	145,795	81,133	33,412	120,000	2,049,116
38	ADJ 2 = Fixed Costs	698,643	598,035	265,701	106,398	145,795	81,133	33,412	120,000	2,049,116
39	ADJ 3	0	0	265,701	106,398	145,795	81,133	0	0	599,027
42	NUMBER OF BILLS	490	686	119	204	28	49	14	7	1,597

LONG RUN INCREMENTAL COSTS: GENERAL FIRM SERVICE

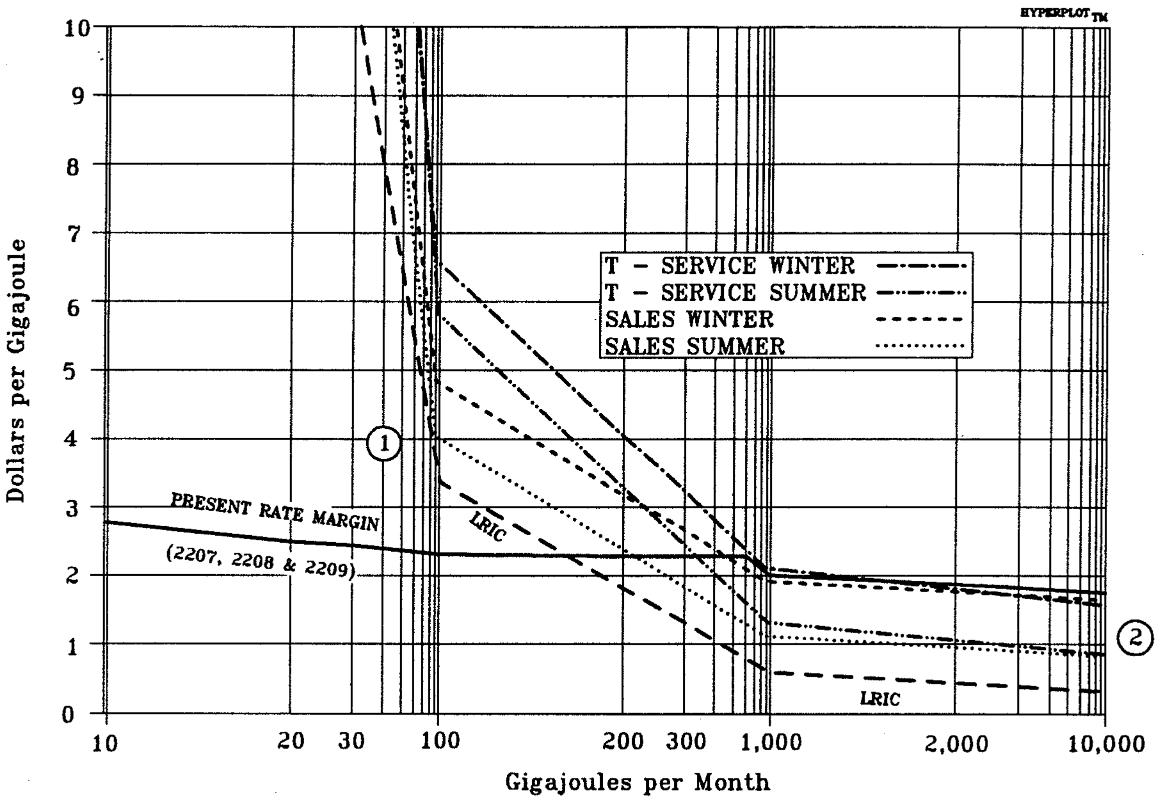
The following four charts display LRIC relationships for proposed Rate Schedule 2.5. The first chart compares divisional LRIC at various levels of gas consumption in the Lower Mainland, Inland, and Columbia Divisions. On the next three graphs, LRIC is compared to present and proposed general firm service rates for those service areas.

ALL DIVISIONS
Proposed Schedule No. 5 LRIC



LOWER MAINLAND DIVISION

Proposed Schedule No. 5
General Service Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC



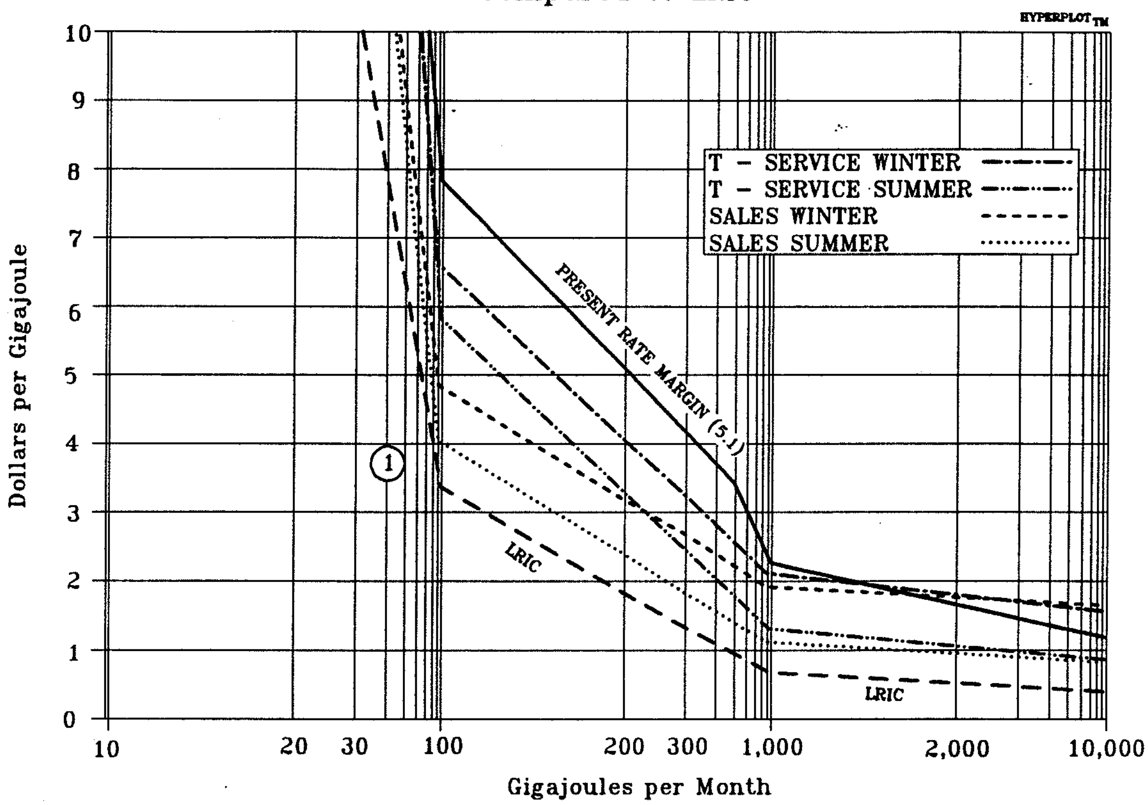
(1) LRIC indicates that the present rate margin below 140 GJs per month could be increased.

(2) LRIC indicates that the present rate margin above about 140 GJs per month could be reduced.

(3) LRIC is calculated using 12,000 GJs annual usage (or 1,000 GJs per month).

INLAND DIVISION

Proposed Schedule No. 5
General Service Rate & Cost Margins
Present Rate & Proposed Postage Stamp Margin
Compared to LRIC

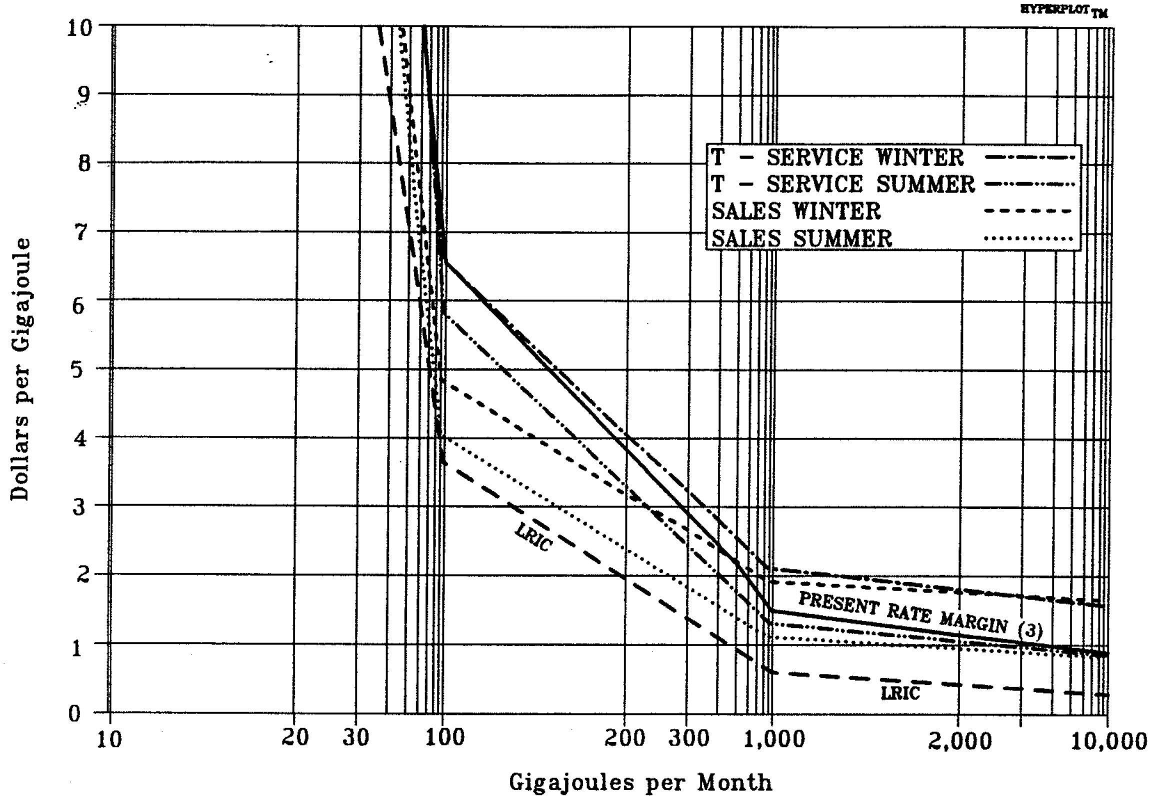


(1) LRIC indicates that the present rate margin could be decreased.

(2) LRIC is calculated using 12,000 GJs annual usage (1,000 GJs per month).

BC Gas

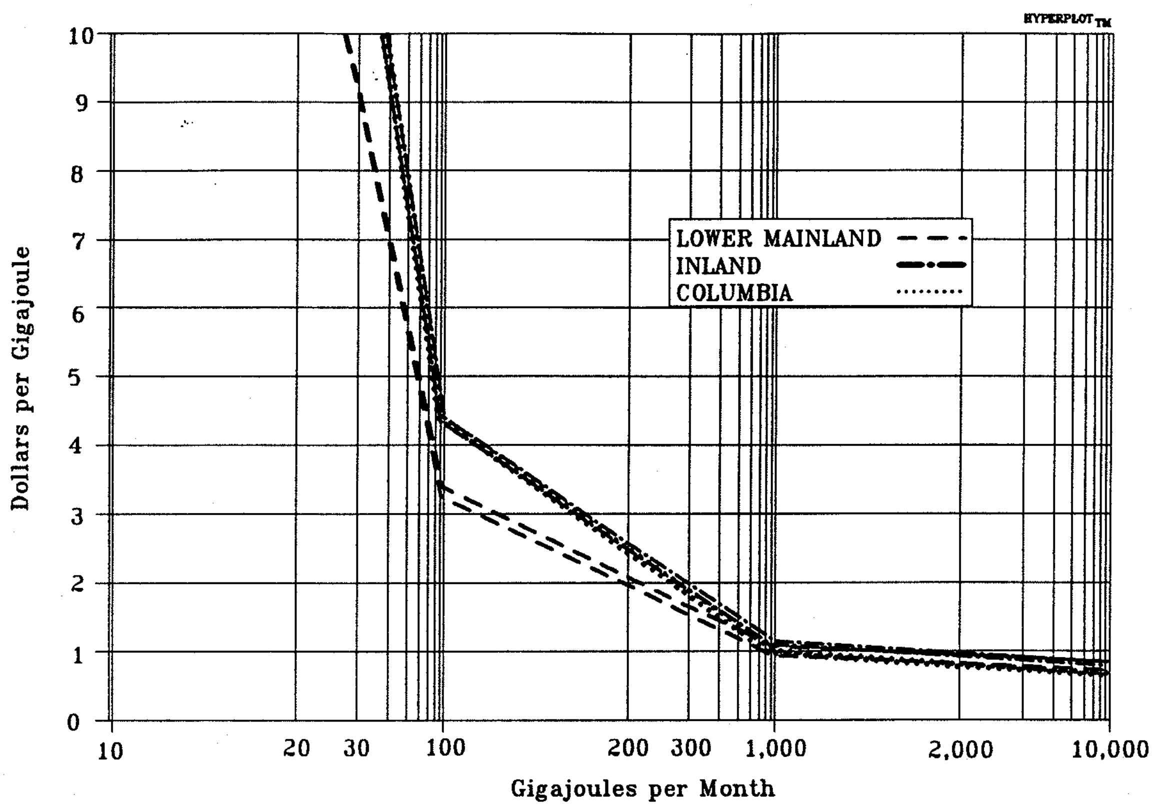
COLUMBIA DIVISION
Proposed Schedule No. 5
General Service Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margins
Compared to LRIC



FULLY DISTRIBUTED COSTS: GENERAL FIRM SERVICE

The following chart compares the general firm service class FDC in each division. The three charts that follow compare the divisional FDC to present and proposed general firm service rates in the Lower Mainland, Inland, and Columbia Divisions.

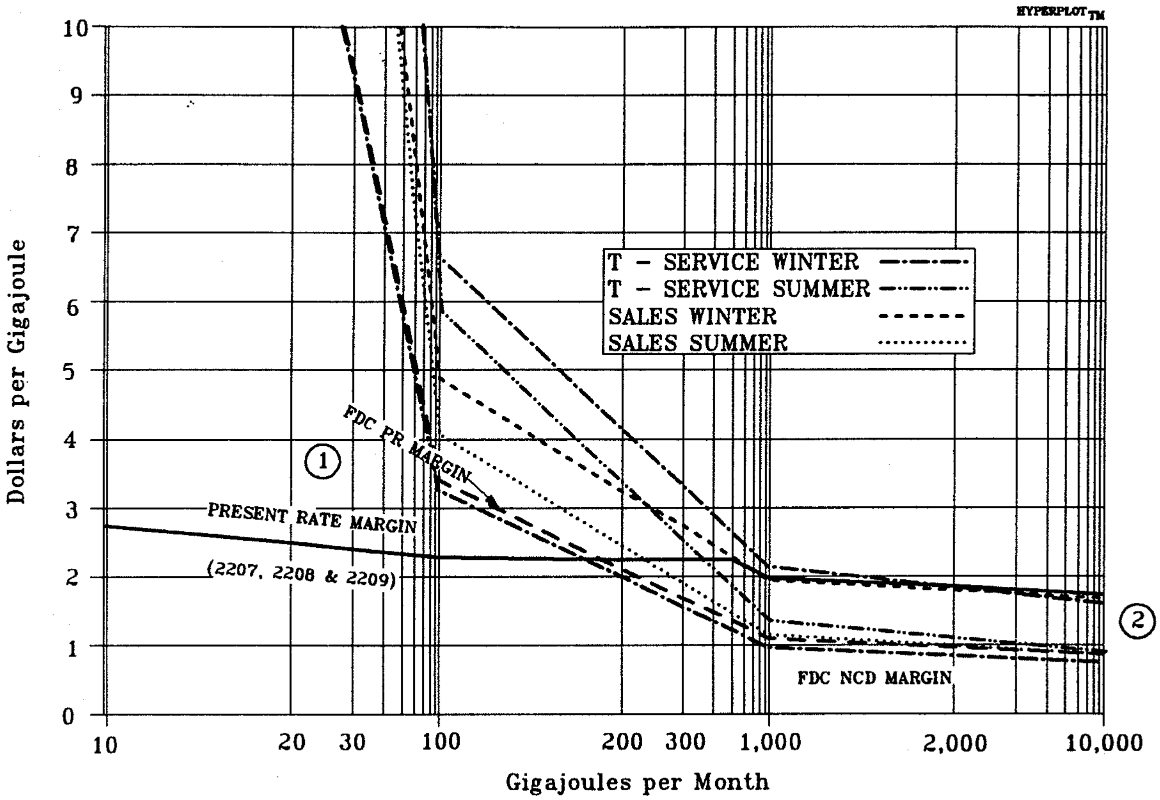
ALL DIVISIONS
Proposed Schedule No. 5
FDC Cost Margins



BC Gas

LOWER MAINLAND DIVISION

Proposed Schedule No. 5
General Service Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margins
Compared to FDC Margin

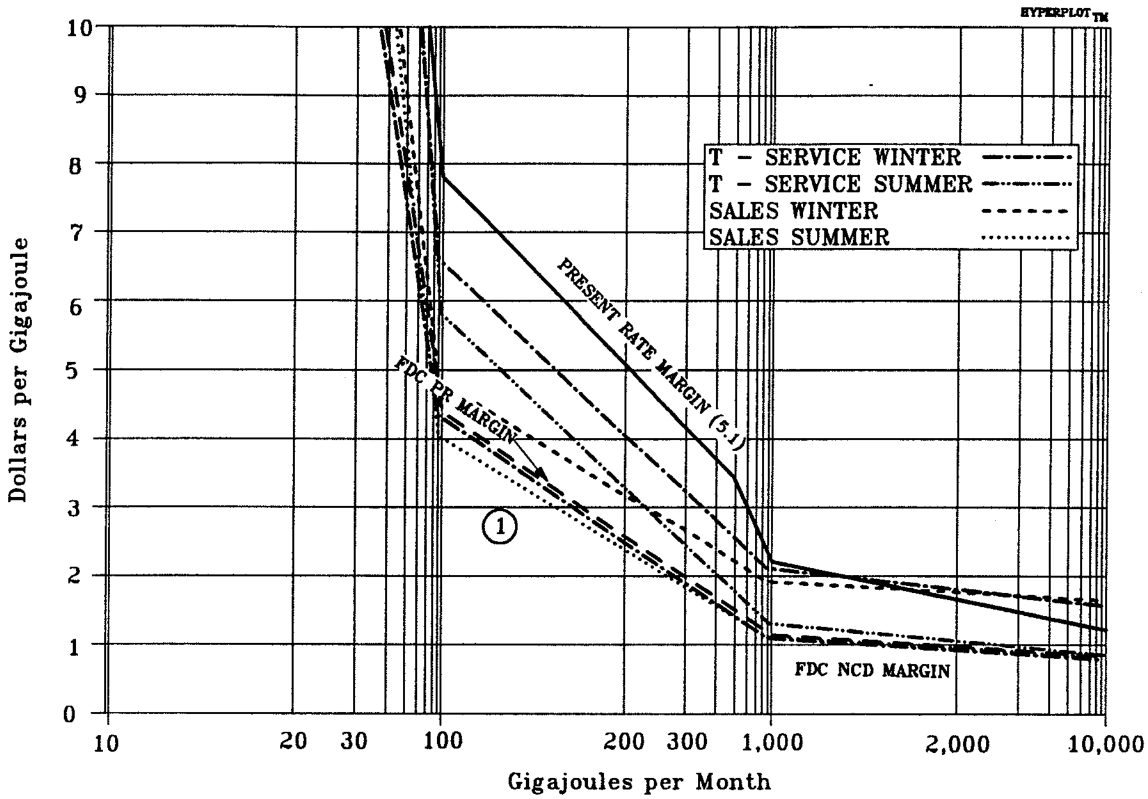


1 FDC indicates that the present rate margin below 160 GJs per month could be increased.

2 FDC indicates that the present rate margin at above 160 GJs per month could be decreased.

INLAND DIVISION

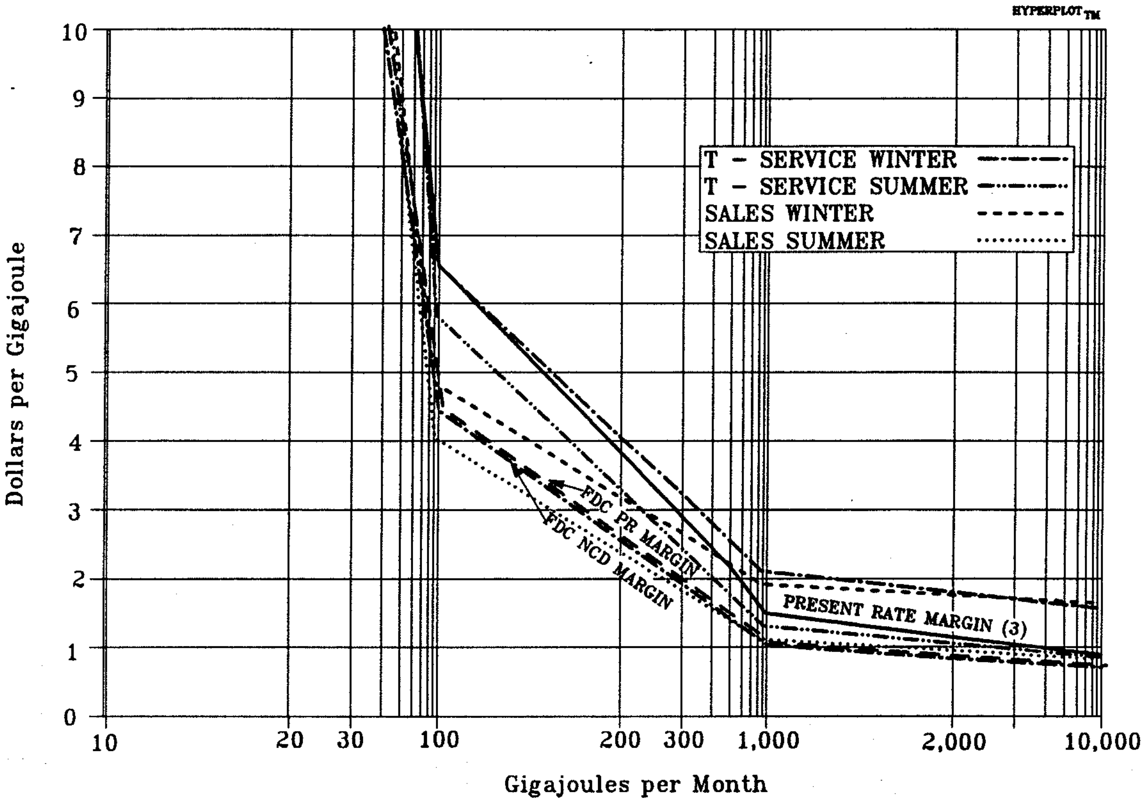
Proposed Schedule No. 5
General Service Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margins
Compared to FDC Margin



(1) FDC indicates that the present rate margin could be decreased.

COLUMBIA DIVISION

Proposed Schedule No. 5
General Service Rate and Cost Margins
Present Rate & Proposed Postage Stamp Margins
Compared to FDC Margin



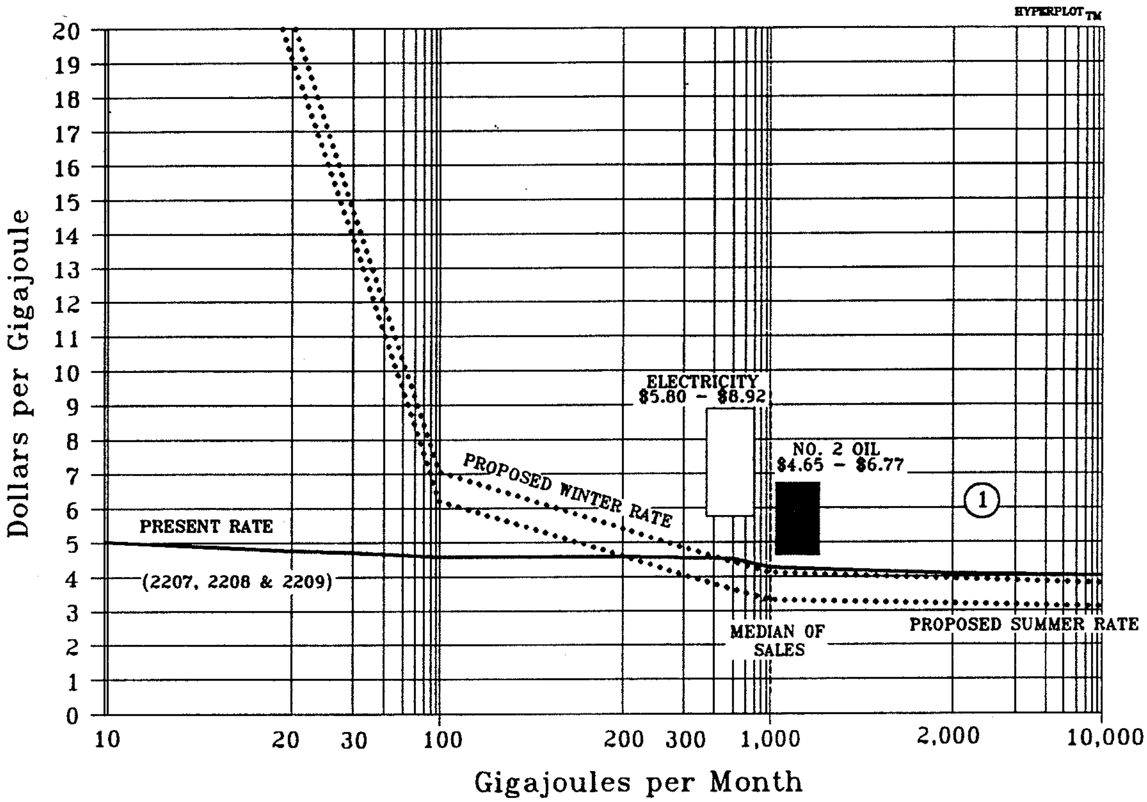
PRICE OF COMPETITIVE ENERGY: GENERAL FIRM SERVICE

The following three charts compare the prices of competitive energy to present and proposed general firm service rates in the Lower Mainland, Inland, and Columbia Divisions.

BC Gas

LOWER MAINLAND DIVISION

Proposed Schedule No. 5
General Service Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy

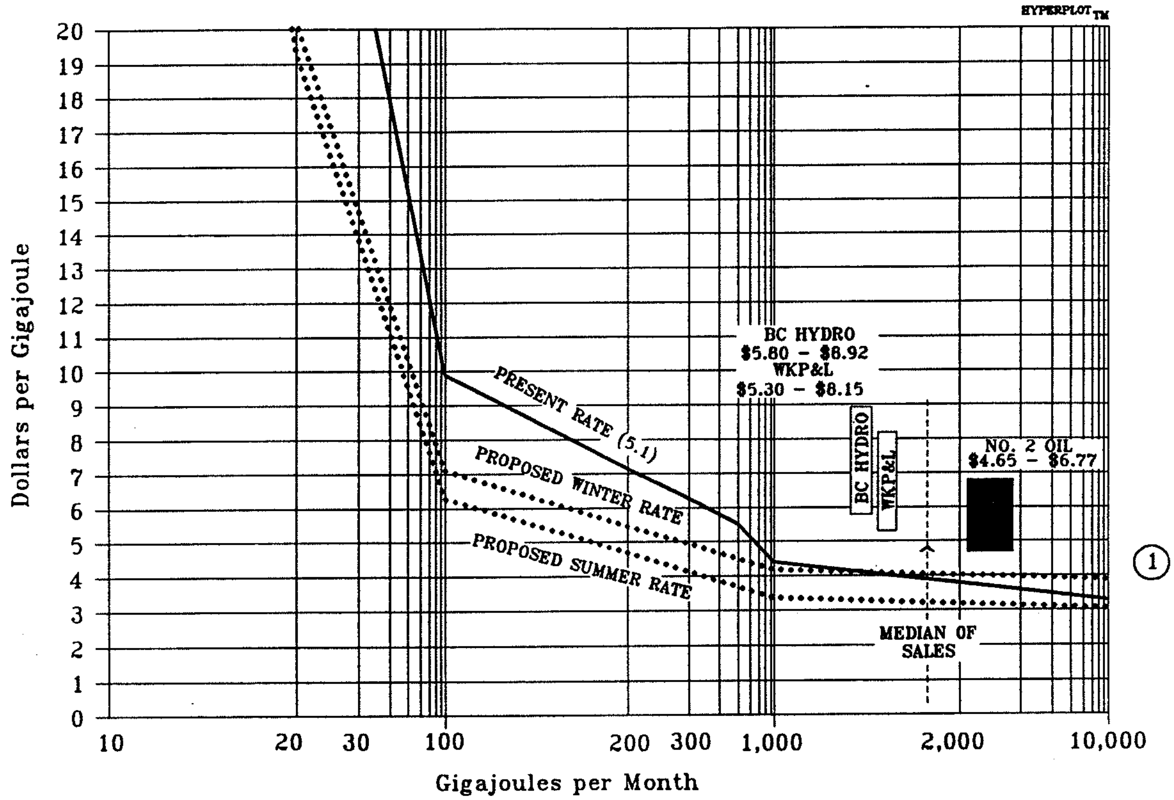


(1) Price of competitive energy indicates that the present rate might be increased slightly to give customers a signal to use natural gas more efficiently.

BC Gas

INLAND DIVISION

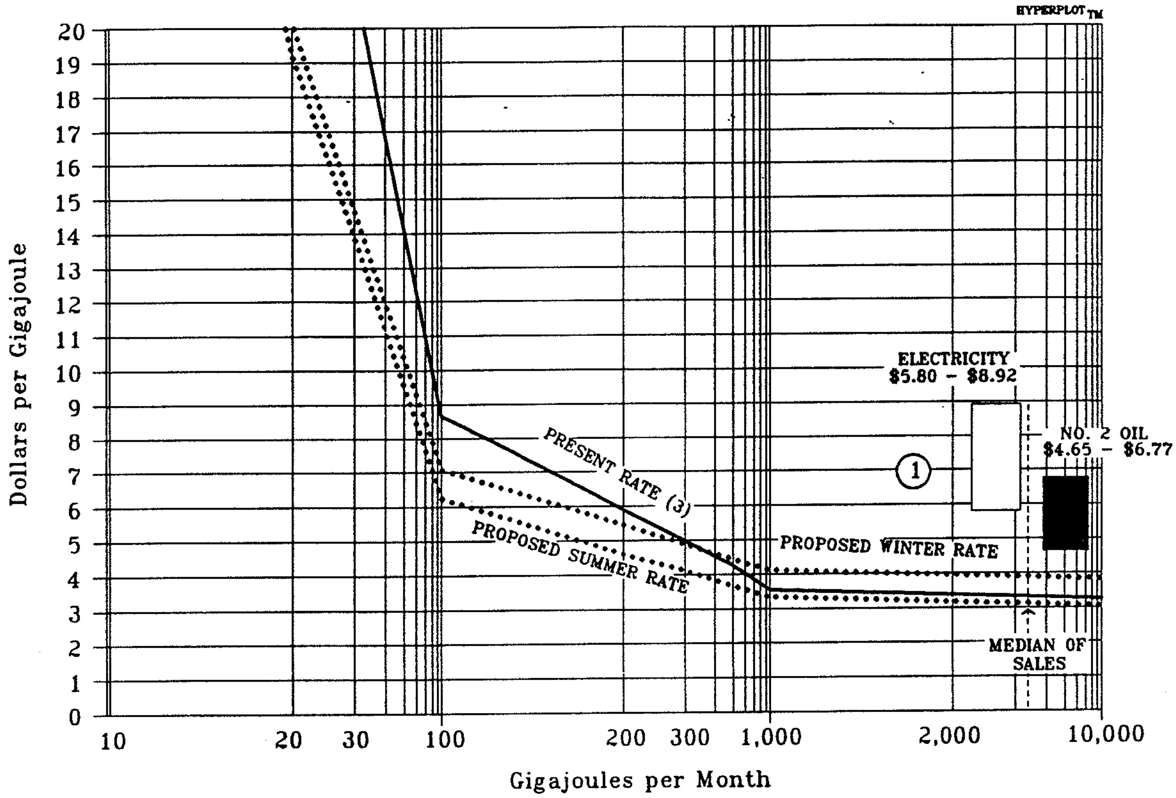
Proposed Schedule No. 5
General Service Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy



(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

COLUMBIA DIVISION

Proposed Schedule No. 5
General Service Burner Tip Rate
Present & Proposed Rates Including Cost of Gas
Compared to the Price of Competitive Energy



(1) Price of competitive energy indicates that the present rate can be increased without losing market share and to give customers a signal to use natural gas more efficiently.

PROPOSAL TO REVISE INDUSTRIAL GAS RATES

1.0 INTRODUCTION

A significant challenge BC Gas has faced in preparing its industrial rate design proposals was to meet its objective of reconciling the substantial differences in rates, terms, and conditions for industrial service throughout the different service areas of Inland, Columbia and the Lower Mainland.

Considerable focus was placed on trying to bring about a reasonable balance between the Company's fundamental rate design objectives and the diversity of rates, terms and conditions of service that currently prevail within each service territory. The task of ensuring that rates are fair and equitable, encourage conservation, provide reasonable security of recovering costs and keep changes to within reasonable limits is not an easy one. Nevertheless, BC Gas is confident it has achieved a measure of success in finding such a balance.

In addition to the issue of rates, the company also put considerable effort toward integrating the various terms and conditions of service. Much time was spent in developing more "user friendly" and market responsive tariffs by offering a range of services and operating terms that more closely match our customers requirements. For example:

1. The first stage was completed in Phase A when BC Gas applied for and received approval to separate its large industrial sales and transportation functions into two distinctly unique services: Schedules 10 and 22. The sales component (Schedule 10) is a market responsive option which offers industrial customers the flexibility to elect supply priority and pricing commensurate with

their individual needs. By moving the sales transaction to the interconnect point between the facilities of BC Gas and the pipeline which supplies the gas (the transmission pipeline of Westcoast), BC Gas has created a level playing field as between itself and other parties selling natural gas, all of whom are now subject to the same terms and conditions of transportation service (Schedule 22) on the utility's facilities.

2. A restructured more flexible Schedule 13 Peaking service approved in Phase A proved particularly beneficial this past winter in allowing BC Gas to source spot market gas supplies on behalf of its large industrial customers who would otherwise have been curtailed.

3. The proposed rate schedules have been revamped to provide further ease in accessing transportation service for customers. This occurs because of reduced "Direct Purchase Administration Charges" and the removal of restrictive pipeline contracting provisions which dictated "upstream" supply and pipeline capacity requirements.

4. BC Gas soon will table for review an optional best efforts load balancing service which it expects to offer as an add-on service to the utility's <u>daily</u> balanced transportation service. It will enable customers to improve supply and pipeline load factors and provide balancing gas on an interruptible basis when load requirements exceed their forecasts.

5. Rate schedules have been re-drafted with the objective of making them easier to administer and understand.

6. The company plans an extensive communication program, aimed at obtaining customer input and resolving outstanding issues.

The foregoing represents a brief outline of the Company's initiatives on industrial rate design. Others are provided in subsequent sections.

2.0 DEREGULATION - A REVIEW

Prior to 1985, gas could be purchased in only one way, from the local distribution company (LDC). Gas was sold by producers to the inter-provincial pipelines (e.g. Westcoast) which in turn sold the gas to LDCs for resale to consumers. In paying for gas service, customers paid a "bundled" rate which included all of the costs of bringing gas to the "burnertip": the gas, pipeline transmission charges and the LDC's cost of service. Alternative options for purchasing natural gas were not available.

With the advent of direct purchase arrangements came the requirement for utilities and pipelines to provide transportation service. Transportation service (t-service), enables customers to negotiate the purchase of gas directly with a producer or marketer, arrange for it to be gathered, processed and transported through the transmission pipeline system to the facilities of BC Gas, where the Company arranges to meter and deliver it to the customer. Under this arrangement, customers accept sole responsibility for the supply and delivery of gas to the distribution facilities of BC Gas.

3.0 EXISTING LOWER MAINLAND RATES & CUSTOMERS

3.1 Historic Development

The most notable feature of this application is the fact it is the first full public review of rates for the Lower Mainland. Unlike the customers located in the Inland service area which were differentiated by service class even before deregulation, the Lower Mainland, until this application, was limited in its service offerings to primarily two groups of customers: firm and interruptible.

The nature of the Lower Mainland's historical gas supply portfolio and its ratio of firm to interruptible customers has resulted in the development of a substantially different service profile for industrial customers on the Lower Mainland than for those in either the Columbia or Inland service areas. For example, on the Lower Mainland most of the larger commercial, institutional and industrial customers are "interruptible" rather than "firm" gas service customers. This is almost completely opposite to the requirements of Inland and Columbia industrial customers who are substantially "firm".

As the terms imply, firm refers to year round uninterrupted service (typically the need of residential and commercial customers) whereas larger volume commercial and industrial customers that are able to operate for intermittent periods without gas (either by use of an alternative fuel or by temporarily shutting down their operations) have tended to opt for interruptible service to achieve the related economic benefits. The interruptible service class on the Lower Mainland is comprised of some 120 customers of whom 20% (the top 24) represent about 70% (14 petajoules) of the total Lower Mainland interruptible/industrial gas consumption (aside from Burrard Thermal).

The successful development of the interruptible market on the Lower Mainland has been a function of the discount traditionally provided to interruptible service. The gas load on the Lower Mainland is predominantly heat sensitive. In order to maintain a reasonable gas purchase load factor, it was necessary to provide an incentive to encourage the development of off-peak load, and thus maintain reasonably high gas purchases during off-peak conditions (i.e. by "shaving" loads during peak demand conditions, but having the loads on at other times).

3.2 Review of Rates

Industrial customers in the Lower Mainland division are generally served or supplied under one of the following service classes: 2501, 2502A or 2502B and, since November 1, 1992, the new large industrial 10/22 rate class. A number of smaller industrials also receive service under either firm sales or transportation options; i.e. Schedules 2209 and 2007. The present rate structure for industrial service (both firm and interruptible) consists of declining block rates with a monthly basic charge. Only the Company's transportation service under Schedules 2006 and 2007 for firm transportation and under Schedule 22 for interruptible transportation have year round flat rates.

In this application BC Gas is proposes to reclassify many of its commercial and industrial customers into relatively similar customer groups. Within the industrial sector this includes a General Firm Service category and large and small volume interruptible service classifications. More detail on these customer classifications and their rates follow.

An anomaly in former cost allocation is also addressed in this application. In developing the margin associated with interruptible sales prior to deregulation, B.C. Hydro chose to incorporate a portion of the Westcoast gathering and processing costs ($0.41 per gigajoule) associated with the movement of gas to the Lower Mainland. When transportation service was first made available, the same assignment of Westcoast costs was carried forward. Taking issue with this methodology, transportation customers claimed it effectively meant a double charge to them for Westcoast service: once by the utility through its transportation rates, and once by way of their direct purchase arrangements. The Commission agreed with this argument and ordered the utility to delete the $0.41 per gigajoule component from its transportation service rates. Unfortunately, this left a $0.41 per gigajoule differential between the utility's sales and transportation rates and rendered the rates no longer revenue neutral. BC Gas now proposes to eliminate this inequity by pricing both sales and transportation (as it relates to the non-gas cost of service margin) at the same levels.

3.3 Interruptible Gas Pricing

In the Phase A Decision, in accordance with the application made by BC Gas, the Commission granted the Company approval to flow through gas supply costs, including both fixed and variable cost components, on a coincident peak demand allocation basis. For interruptible sales to Schedule 10 industrial customers, gas was to be priced at market value with the recovery of any revenues above cost to be credited to the utility's firm sales customers. In the Phase A Decision the Commission also approved freezing the gas price component in rate schedules 2501 and 2502 effective November 1, 1991. This yielded a net contribution of approximately a $0.12 per gigajoule (after payment of variable costs) by these interruptible sales customers towards the utility gas costs.

With this application BC Gas proposes to move its interruptible gas sales to full market pricing. Prices for interruptible gas sold by the utility will attract a reasonable sales margin commensurate with current market conditions.

4.0 EXISTING INLAND RATES AND CUSTOMERS

4.1 Review of Rates

Unlike customers in the Lower Mainland, Inland industrials experienced the impact of rate redesign and deregulation simultaneously. With deregulation came the ability for customers to purchase gas from sources other than a utility and the development of various new transportation service options. In 1987, Inland underwent a rate design hearing which dealt with a host of issues relating to industrial customers. The most significant of these were rate determination (both for captive and bypass customers) as well as the development of transportation terms and conditions relating to the large industrials.

On the basis of provincial policy with respect to deregulation, customers having a viable opportunity to construct and operate their own transmission pipeline (i.e. "bypass" line) were permitted to negotiate rates with the utility that represented a reasonable approximation of their bypass alternative. In the first year five customers sought and received special negotiated rates commensurate with their bypass alternative. To date, 18 industrial customers have applied for and had such rates approved by the Commission. The bypass rates are substantially below the rates paid by those customers before 1987. Customers without an economically viable bypass alternative are referred to as "captive" while those with such an alternative are referred to as "non-captive" or "bypass" customers.

At present, the Inland industrial services are:

(a) Seasonal Service - Schedule 4;
(b) Small Industrial Firm Sales Service - Schedule 5;
(c) Small Industrial Interruptible Sales - Schedule 7;
(d) Large Volume Interruptible Sales - Schedule 10;
(e) Large Industrial Firm & Interruptible Transportation - Schedule 22; and
(f) Small Industrial Firm Transportation - Schedule 25.

Seasonal service under Rate Schedule 4 currently has 15 customers, predominantly paving companies producing asphalt for road construction programs. At present, the rate structure consists of a basic charge with a declining block rate.

The Company's small volume industrial customers are separated into two rate classes: Schedule 5 for firm sales and Schedule 25 for firm transportation service. Of the captive customers receiving service under the two rate classes, 23 are on transportation (Schedule 25) and 21 are on utility sales (Schedule 5).

The rate structures for Schedule 5/25 are similar to those of Schedule 4, the seasonal service, in that they consist of basic charges and declining block rates. In addition, the transportation service incorporates a Customer Charge of $500 per month to cover costs associated with effecting transportation service.

Unlike the Lower Mainland, where most industrials have found interruptible service to be the more attractive option (because of the economics and reliability of supply), Inland's large industrials receive firm service, leaving only about 10 to 20% of the group's annual consumption as interruptible. The load characteristics of the customer mix within the Inland service area has meant that Inland industrials have not been able to take advantage of a "valley" in off-peak periods to the same extent as industrials in the Lower Mainland. Inland industrials also face some plant operating limitations which increase their requirement for firm gas supplies. To date these concerns have discouraged Inland customers from considering interruptible service as a viable long term alternative to firm service. However, Inland large industrials do have a significant level of fuel switching and backup capability and may be required to curtail their firm demand by 50% for up to 5 days in any year. These half-firm curtailment days provide peak shaving for BC Gas facilities planning and are also an important source of peaking gas for the core market during critical peak days.

Despite their substantial dependence on firm service, Inland captive large industrial customers do rely on interruptible gas. The usage occurs almost exclusively in winter, increasing its level of importance from that reflected in the annual ratio. Inland "bypass" customers require even greater amounts of interruptible gas.

Another feature that sets most Inland large industrials apart from their Lower Mainland counterparts is their direct connection to the utility's transmission system rather than its distribution system.

5.0 EXISTING COLUMBIA RATES & CUSTOMERS

At present the industrial customer base within the Columbia service area falls into similar small volume/large volume rate classes as in Inland. Schedule 3 serves the small industrial firm market, with Schedule 7 being the comparable Large Volume firm service. A seasonal Schedule 4 rate has also been maintained although at present no customers are active on it.

Rate structures for these classes also bear close resemblance to their Inland counterparts (Schedules 5 and 22) in that small volume industrials in both service areas are subject to a basic charge with a declining block rate structure, while the large industrials are subject to demand charges. However, whereas Inland's captive large industrials have a demand distance cost allocation on an averaged basis (in the current rate structure), the customers in the large industrial class in Columbia's 1987 rate design were each assigned customer specific costs that are recovered by way of individual monthly demand charges. Furthermore, the five original customers (now six) were grouped into a rate adjustment model which has, for four of the customers, linked their demand charges. For example, if member A chooses to alter its demand on the system (either up or down), the model acts to adjust rates for the others to ensure the total revenue collected from the large industrials remains unchanged. Columbia customers whose operating characteristics may remain reasonably consistent from year to year are affected by the cost model as a result of changing load demands by others within the group. As a consequence, had the financial failure of Westar in 1992 not been salvaged by the Fording and Teck Corporation buyouts, the current rate determination process would have reassigned Westar's costs to the remaining large industrials.

Until mid 1992, direct purchase arrangements within Columbia were handled by buy/sell arrangements. This process was dictated by the Company's arrangements with Alberta & Southern (A&S) and Alberta Natural Gas (ANG), which made transportation service impractical on the Columbia system. The Company moved to help customers effect direct purchase arrangements by utilizing a buy/sell procedure. In 1988 Crestbrook Forest Industries put into place the first buy/sell direct purchase, and others subsequently followed.

In 1992, the Westar failure caused the Company and its agent (A&S) and transporter (ANG) to revisit the buy/sell process and find an alternative solution: i.e. transportation. In the case of the Westar situation, BC Gas as the purchaser of record was required to pay for Westar's supply and related services, but Westar, having claimed CCAA protection, was not obligated to pay BC Gas or ANG. As previously indicated, substantially different operating and administrative practices on ANG made immediate utilization of Schedule 22 transportation impractical. As a result, the Company worked with its customers, their marketers, the transporter and A&S to effect special interim agreements that effectively provide transportation services to the Columbia large industrials.

At present no interruptible sales or transportation options exist in Columbia. This rate design application intends to remedy these shortcomings.

6.0 DIRECT PURCHASE ADMINISTRATION CHARGES

For transportation service, the utility has examined its cost assignments for direct purchase administration and has determined that a $325 per month decrease to $175 per month is appropriate for General Firm (small volume industrial) Transportation.

The calculation of appropriate direct purchase administration charges is detailed in Table 1 on page 13.

The Company's cost of direct purchase administration include the costs of two marketing representatives, t-service coordination within the Gas Supply and Gas Control departments, additional billing related costs and the costs of regulatory and management support. Costs have been estimated on a 1993 forecast basis assuming a normal level of direct, supervisory and management time and expenses.

To arrive at an appropriate customer charge, the Company has assumed its proposals in the application will lead to approximately a 50 percent increase in the smaller general service transportation category (both from new transportation customers and a shift of some customers currently classified as large industrial to general service). The number of large industrials is forecast to remain about the same as large volume customers replace those customers moving to general service. The second part of the calculation involved determining to what extent large volume customer administration (with its requirements for daily balancing and control) is more involved than general service administration (which allows for grouping and less daily monitoring). Considering the relative time devoted to the small and large volume groups and taking into account further streamlining proposed in this application, it was determined that the cost related to large volume customers was approximately 2.5 times the cost for proposed general service customers. Using this factor to weight the large industrials resulted in estimated costs (on forecast year end 1993 customers) of $192 for general service customers. This was subsequently rounded to $175.

TABLE 1

DIRECT PURCHASE ADMINISTRATION

COST ALLOCATION

FOR CALENDAR YEAR 1993

Particulars	**$/Annum**
Marketing Representatives	$159,000
T-Service Coordination	174,000
Additional Billing	24,000
Regulatory & Management Support	128,000
	$485,000

March/93 Customers		**Forecast Year End '93**		**Weighting Factor**
Inland Large	19			
Inland Small	34			
Lower Mainland Large	20	Small	110	1.0
Lower Mainland Small	39	Large	40	2.5
	112		150	

Estimated Costs For 1993:		
	Small	$193 per month
	Large	$481 per month

7.0 PROPOSED GENERAL FIRM SALES AND TRANSPORTATION - RATE SCHEDULES 5 AND 25

By way of this application BC Gas proposes to consolidate firm sales and transportation service for smaller volume customers into two distinct service rate schedules; Rate Schedule 5 for General Firm Service and Rate Schedule 25 for General Firm Transportation. It is proposed that these new service schedules replace the current Inland Schedules 5, 6 and 25, and the Lower Mainland Schedules 2209, 2006 and 2007.

Along with consolidating terms and conditions, BC Gas is also proposing to equalize rates amongst the utility's service areas. Based on the 1993 revenue requirement filing, BC Gas proposes a uniform (excluding Fort Nelson) Basic Charge of $300 per month along with seasonal delivery rates of $1.50 per gigajoule in winter and $0.75 per gigajoule in summer.

For further information relating to General Service refer to page 29 of this Tab and Tab 8 of this Volume.

8.0 PROPOSED GENERAL INTERRUPTIBLE SALES AND TRANSPORTATION - RATE SCHEDULES 7 AND 27

As detailed in Section 3, "Existing Lower Mainland Rates & Customers", industrials within the Company's Lower Mainland service area represent by far the largest percentage of the BC Gas' interruptible load. About 100 of the smaller 120 or so interruptible customers account for 30% of the total interruptible load. Only three customers are currently served under the comparable Inland Division service class. BC Gas proposes to implement Rate Schedule 7 - General Interruptible Service; i.e. Sales, throughout the service area of BC Gas with the exception of Fort Nelson. Although the Inland schedule number has been used, this service will be comparable to current Schedule 2502A and B in the Lower Mainland Division.

The separation of customers into small and large volume was proposed in Phase A and accepted in principle in the February 1992 Decision. The level of consumption proposed for Rate Schedule 7 will enable BC Gas to consolidate the present three Lower Mainland service schedules (2501, 2502A and 2502B) into one comprehensive General Interruptible Service rate schedule.

The new Rate Schedule 7 - General Interruptible Service and its proposed transportation counterpart, Rate Schedule 27, generally will apply to customers within the 1,500 - 20,000 gigajoules per month consumption category. Rates will consist of a basic charge plus tiered and seasonal delivery charges (see Table 2 at page 34). Transportation customers with firm gas supply and pipeline transportation may choose to pay the higher Level 1 rate which will provide for curtailment by BC Gas only if the distribution or transmission systems of BC Gas are at capacity. Other customers that can accept a lower level of service may choose Level 2 service. Level 2 service will be at lower rates than Level 1 but will permit BC Gas to curtail interruptible customers at times when the utility needs gas for its core market customers. In addition, seasonal delivery rates have been set that correspond with seasonal demand on the BC Gas system. Generally, all of the proposed interruptible delivery rates will result in annual reductions in these costs to interruptible customers, while giving customers market signals that will help shape their demands on the distribution system.

The replacement of the current Lower Mainland $4,176 per month minimum charge with a basic charge of $700 per month eliminates the obligation of low volume customers to pay for gas not taken. The $700 basic charge (not creditable for any reason) also ensures that the utility recovers its fixed customer costs and sets reasonable minimum limits for access to interruptible service. The proposed new charge should therefore further improve access to interruptible service.

Gas supply costs embedded in the rates for Schedule 2501/02 customers were frozen effective November 1, 1991 and then again for the current contract year commencing November 1, 1992. The current embedded gas supply cost for calendar 1993 is on average $1.1273 per gigajoule for Schedule 2501 customers including $0.1159 per gigajoule being credited to a Cost of Gas Deferral account for each unit of sale, and on average $1.2636 for Schedule 2502 customers with $0.1519 being credited to a Cost of Gas Deferral account.

BC Gas proposes that general interruptible sales gas will be priced on the basis of market conditions. Smaller volume general sales gas pricing will incorporate a service premium (compared to large volume) to reflect the "first call" priority that will be assigned to Rate Schedule 7 customers. Accordingly, BC Gas proposes to have Rate Schedule 7 pricing track Rate Schedule 10 Level 2 commodity rates, with a premium in winter months initially set at $0.30 per gigajoule. Based on present Schedule 10 rates, the gas commodity charge for sales under Schedule 7 would be $1.90 per gigajoule in winter and $1.10 per gigajoule in summer.

Rate Schedule 7 is designed to remain a "burnertip" sales option for smaller volume interruptible customers (as opposed to the combination Schedule 10/22 Sales and Transportation alternative available to large industrials). Nevertheless, the utility intends to place no restriction on access. Each customer's individual demand profile and gas service options and preferences will dictate that customer's choice of service level and volume category.

BC Gas proposes to cancel existing rate Schedules 2501, 2502A, 2502B and the current Inland Schedule 7 and to replace them with the Company's new General Interruptible Service - Rate Schedule 7.

9.0 PROPOSED LARGE VOLUME INTERRUPTIBLE TRANSPORTATION - RATE SCHEDULE 22

BC Gas favours the widespread use of interruptible service in order to achieve economically efficient use of the utility's facilities as well as the economically efficient use of facilities of the pipeline supplier. In the design of interruptible rates for industrial classes, BC Gas has used as its upper benchmark the General Firm Service rates referred to in Section 8 with recognition given to alternative fuel costs arising from curtailment, the value of peak shaving, capacity constraints of the distribution system and differences in operating and administrative burdens. Taking into account the foregoing, BC Gas proposes the following adjustments to the large industrial interruptible service provisions:

1. A basic charge to be set at $1,350 per month. The amount of the basic charge is to a degree based upon the Lower Mainland FDC assignment which has determined customer related costs for large interruptibles at approximately $1,300/month (based upon the proposed service classifications). The FDC results understate customer costs as they do not include an assignment of distribution costs, such as additional piping and regulator station costs. On the Inland system, for instance, most large volume customers require separate regulation from transmission pressure - on the Lower Mainland this is provided by the distribution system.

2. The establishment of interruptible delivery charges on a

seasonal basis, commensurate with the utility's peak and off-peak system demands. As with the proposed General Interruptible rates, Large Volume interruptible delivery charges will be further differentiated by way of two tiers that provide a discount to customers who are prepared to provide the Company with access to their direct purchased gas for peak shaving purposes. The per gigajoule large volume interruptible delivery charges proposed are:

	Winter	Summer
Level 1 - Capacity curtailment only	$0.95	$0.70
Level 2 - Peak shaving access	$0.75	$0.50

These delivery charges reflect a discount from those available for small volume interruptibles in recognition of the size of these customers and the operating and administrative conditions which are part of the large volume interruptible service:

- service is balanced daily
- no grouping of large volume accounts is permitted
- service priority will be slightly below small volume interruptible service.

3. The introduction of a Direct Purchase Administration Charge set at $500 per month. This charge relates to the costs incurred to facilitate and administer transportation service for large volume industrial customers. For greater detail on the cost and allocation methodology upon which this charge has been determined, refer to Table 1 at page 13.

4. A revision to the payment terms to standardize them with those made available to other utility customers, including the residential and commercial classes. While a proposed change in payment time provides customers with

a less restrictive period in which to process a payment, the new payment terms also incorporate a more significant penalty for overdue amounts.

5. A minimum volume requirement of 20,000 gigajoules per month; up from the current 1500 gigajoules per month but less than the 30,000 gigajoules per month proposed in the Company's original filing in Phase A. This change in minimum volume will enable approximately 20 of the largest Lower Mainland interruptible customers (representing about 70% of the total Lower Mainland interruptible load) to access large volume service.

Current Inland Division Schedule 30 interruptible transportation service will be redundant and should be cancelled. The agreement made between Inland Natural Gas Co. Ltd. and Westcoast Energy Inc. and dated January 17, 1977 is not in use and should be cancelled. Additional changes to terms and conditions are detailed under Tab 9, Section 16 "Proposed Terms and Conditions for Industrial Rate Schedules". A revised Rate Schedule 22 will also be filed at an early date.

10.0 PROPOSED LARGE VOLUME FIRM TRANSPORTATION - RATE SCHEDULE 22

BC Gas believes, as did the Commission in its 1987 Decision relating to Inland's rate design application, that negotiation of rates for non-captive and captive large volume firm industrial customers is the appropriate manner in which to value service for those customers. While the potential for new large firm industrial service in the BC Gas system continues to exist, the filing of fixed rates on the basis of hypothetical requirements in advance of need is not believed appropriate. It is desirable to develop customer specific rates, when and if needed, taking into account the exact nature of the service desired, and the costs that exist at that point in time. BC Gas therefore proposes to make large industrial firm transportation available to new large industrial loads on a negotiated basis only, subject to Commission review and approval of any such negotiated rates.

Proposed firm large industrial transportation would, at a minimum, be determined on the basis of rolled in historic costs plus any incremental expense that may reasonably be associated with providing firm capacity to a new customer. As stated in the 1987 Decision the rate must be sufficient to "yield a fair and reasonable compensation for the service rendered", and in so doing, should "fully recover the cost of new facilities required and make some contribution to facilities supported by the existing customers".

It should be recognized that customer specific rate setting is not a new concept for BC Gas customers. As indicated earlier, 18 of the Company's Inland industrials are on special "bypass" rates; 8 others are on rates negotiated to compete with alternative fuel options. In addition, Columbia large industrials have each been assessed demand/distance related cost of service rates that take into account each customer's distance from the Alberta Natural Gas transmission line and the customers' particular capacity requirements. Louisiana-Pacific (on the Inland system) and Byron Creek and Crowsnest Resources (on the Columbia system) are recent examples of customers that have individual rates designed to recover their respective costs of service as these customers were added.

The LRIC study in Tab 3 of Volume 2 illustrates the need for negotiated large industrial rates. In fact, without a specific policy addressing this issue the Company has already, with the Commission's approval, instituted negotiated rates where major new facilities were added.

BC Gas must ensure new large industrial firm rates are fair to both existing and new customers. As suggested by the Commission in its 1987 decision, "Amongst other matters negotiated rates will provide the utility the flexibility to encourage the location of new industrial customers at locations within its system at the lowest cost of providing the service while at the same time making a contribution to the success of the new customer." While the Commission accepted the fact that this might give a new customer a competitive advantage over an existing competitor, they acknowledged that this "in principle is no different than that which has already taken place with 'bypass'."

11.0 PROPOSED INLAND LARGE INDUSTRIAL FIRM TRANSPORTATION - RATE SCHEDULE 22A

Although it is the position of BC Gas that firm rates for new large volume industrial loads should be negotiated, the Company proposes to grandfather the present Inland firm transportation rates, except for the incorporation of a Basic Charge and Direct Purchase Administration Charge, for the existing Inland large industrials. The rates would be closed to new customers but would continue to be subject to normal revenue requirement changes. The schedule for the existing Inland large firm industrials will be renamed Schedule 22A.

The Company offers the following as a basis for doing so:

1. Customers currently served under firm Schedule 22 transportation are likely to have made business plans and decisions based on the current rate structure with the reasonable belief that such rates and rate structure would prevail over the longer term. Subjecting each customer to a negotiated process to establish individual rates would be a significant departure from that

expectation and may cause undue hardship.

2. On the basis of total throughput using the peak responsibility method of the FDC, the present customers currently contribute 108% of the costs to serve them.

3. The existing large industrials must continue to provide the utility with peak shaving access in the amount of one-half their firm contract demands for five days.

4. The existing Inland large industrials served under the present Schedule 22 rate structure are distinguished from those served in the General Firm Service class in terms of their point of supply on the BC Gas system. Over 80% of the service supplied is off the BC Gas high pressure transmission facilities as opposed to the distribution system. As a consequence, the cost of service to large industrial customers is considerably less than to the General Firm Service customers.

5. BC Gas wishes to provide uniform rates throughout its combined service area, hence widespread application of the existing Schedule 22 rates is not compatible with other proposed firm and interruptible rates.

BC Gas proposes a basic charge of $2700.00 per month be introduced for this closed large industrial service. The basic charge will recover most of the customer related costs of large industrial service, providing greater equity in the collection of related revenue requirements. This will be accomplished by reducing the current $.088 per gigajoule delivery charge for firm transportation by $0.044 per gigajoule to $0.044 per gigajoule (see Table 2 for exact rates). In addition, a monthly "Direct Purchase Administration Charge" of $500 will be incorporated to recover those costs. With the exception of rates, all customers qualifying for the closed service will continue to be subject to changes in the terms and conditions of service under Rate Schedule 22, as from time to time approved by the Commission.

BC Gas proposes to limit availability of Level 1 interruptible service to captive customers only. Non-captive customers seeking access to Level 1 transportation service will be required to negotiate peak shaving rights with the utility. Bypass customers are not required to pay for interruptible service, and would otherwise decontract their firm transportation on BC Gas, with a concurrent loss of peak shaving rights negotiated in existing long term agreements with BC Gas.

12.0 PROPOSED COLUMBIA INDUSTRIAL RATES

12.1 Small Industrial

BC Gas proposes to implement the new Rate Schedule 5 - General Firm Service as the replacement for the current Small Industrial rate class 3. The basic charge and rate structure will be the same as those applied to Inland and Lower Mainland customers, with the per gigajoule delivery charge phased in over two years. In addition, the Company proposes, subject to the review of a Tolls & Tariff Committee comprising of members from the companies affected, to introduce for the first time a transportation service schedule applicable to small volume firm customers: General Firm Transportation Rate Schedule 25.

In recognition of the Company's demand side management goals and initiatives, BC Gas proposes to make an interruptible service option available for the first time in the Columbia service area through Rate Schedule 7 General Interruptible Service. For Columbia, this service will be priced considering the costs of gas assigned to the General Firm

Service class. Gas commodity market prices of $1.70 in the summer and $2.067 in the winter (the equivalent firm cost) have been established to which must be added the appropriate seasonal delivery charge.

12.2 Proposed Columbia Large Industrial Firm Transportation - Rate Schedule 22B

The complex rate design methodology used as the basis for setting the present level of rates and the results of the Company's FDC study (which indicates the revenue to cost ratio for the class at 1.0) are sufficiently in accord to support the conclusion that rates for this class should not be revised and should be maintained under the same group allocation methodology first approved in 1987. Notwithstanding this conclusion, the Company will seek to work with the large industrials in the Columbia service area in order to secure individual long term service agreements that take into account each customer's distinct needs and costs. The Company will endeavour to reach consensus with the customers on a mechanism that separates the change in contracting requirements of one operation from those of another - a consequence of the present methodology.

Subject to the review of the Tolls & Tariff Committee (comprising of representatives of customers to be affected), the Company proposes to introduce Rate Schedule 22 for large industrial transportation to be made available in the Columbia service area as soon as practicable. This would include Schedule 22 for new large volume industrial service and Schedule 22B as a replacement for the current interim transportation agreements. In the meantime, it is proposed that BC Gas and the large Columbia industrials continue to use the special transportation agreements already developed as an interim measure. As a result of the current arrangements and proposed new Rate Schedules, BC Gas proposes to terminate the existing Schedule 7 - Large Volume Firm Service.

13.0 RATE SCHEDULE 10 - LARGE VOLUME INTERRUPTIBLE SALES

First filed in October 1991, this market based sales service was approved for implementation November 1, 1992 by way of the Commission's Decision in Phase A. It introduced the concept of interruptible gas sales by the utility to non-core customers at market competitive rates instead of cost. Justified on the basis of industrial customers having market alternatives available to them, and core customers being entitled to earn a contribution toward the fixed gas supply costs, Schedule 10 has proven to be a success.

The terms and conditions of Rate Schedule 10 will be updated to correspond with contractual and format changes proposed for Rate Schedule 22. Revised documentation will follow at an early date. Otherwise BC Gas does not propose to alter the market based pricing concept for gas sold under Rate Schedule 10.

With full implementation of market based pricing for all non-core interruptible sales (including Rate Schedule 7) effective November 1, 1993, and based on current market trends, the Company projects a potential annual contribution to core market gas supply costs of $5.7 million.

14.0 RATE SCHEDULE 13 - PEAKING AND BACKSTOPPING

When first initiated as a peaking service by Inland Natural Gas Limited, Schedule 13 was intended as a limited availability service to back up the Company's previous Schedule 12 interruptible sales if and when the utility was purchasing higher priced peaking gas from Alberta (by way of its Alberta & Southern peaking supply agreement). With the amalgamation of Inland Natural Gas and the Lower Mainland Gas Division of B.C. Hydro, BC Gas chose to expand the service (along with its Schedule 10 interruptible sales) to Lower Mainland customers and at the same time increase the flexibility of Rate Schedule 13 such that the customers and the utility would both benefit from a broader application of the service than was initially contemplated. This decision proved to be extremely fortuitous given the winter of 1992-93.

Prior to November 1, 1992, Schedule 13 was a peaking service which consisted of a posted rate with no provision enabling the Company to adjust the rate to reflect incremental costs. Consequently, the availability of supply was limited by the price set out in the Schedule. In the revised Rate Schedule 13, BC Gas incorporated a provision to allow for rate negotiation subject to consideration of such items as "Buyer's alternative fuel or direct purchase gas costs and Company's cost of gas". This revision proved timely. In January of this year BC Gas made available over 300,000 gigajoules of peaking gas to some 23 different industrial customers. While the communication and administrative tasks associated with these sales were extensive for both the Company and the customers, BC Gas is proud to have played a part in maintaining normal operations for these customers, albeit at somewhat greater cost to them. Despite the higher spot market prices, BC Gas believes the program was able to save customers tens of thousands of dollars in energy costs and operating downtime and disruption during the lengthy cold spells. This past winter has shown that a peaking service such as Schedule 13 offers the utility and its customers supply options heretofore considered too complex and labour intensive to be viable. To the Commission's credit, its timely approval of gas purchases also played an important role in making the process work smoothly.

Consequently, BC Gas proposes to make few changes to Rate Schedule 13 other than the following:

1. Standardization of the rates across all service areas.
2. Introduction of winter/summer seasonal commodity charges.
3. Increased discretion to BC Gas on the take-or-pay provisions contained in the Schedule.

15.0 PROPOSED SEASONAL SERVICE

BC Gas proposes to set the basic charge at $300 per month (chargeable in the months of usage only) with a per unit delivery charge set at $0.60 per gigajoule. Combined with a gas supply cost allocation of $1.286 per gigajoule this will reduce the average burnertip rate to customers within the Inland service area by approximately 25%. As a result of the higher Lower Mainland gas costs and traditionally lower margins, the Lower Mainland seasonal customer group will see only about a 3% reduction in costs.

For operating simplicity the Company proposes to make this service firm as it relates to supply, but in restricted areas of the distribution system service will be subject to interruption for capacity constraints. BC Gas proposes to price any winter requirements at twice the residential service rate as a deterrent to customers who may wish to utilize seasonal service as an alternative to interruptible. This is similar to current Lower Mainland winter pricing.

16.0 BURRARD THERMAL / PACIFIC COAST ENERGY CORPORATION (PCEC)

BC Gas concurrently has three ongoing arrangements to transport and supply gas to B.C. Hydro's Burrard Thermal facility. They are:

1. The Burrard Thermal Interruptible Gas Purchase Agreement;
2. The Burrard Thermal Firm Gas Purchase Agreement; and
3. The Letter Agreement for the Supply of Swing Gas at the Burrard Thermal Plant.

The pricing and priority of service relating to the Interruptible Gas Purchase Agreement are being discussed between B.C. Hydro and BC Gas. BC Gas does not propose changes to the Burrard Thermal agreements as part of this application.

BC Gas has contracted with Pacific Coast Energy Corporation (PCEC), on the basis of a bypass equivalent rate, to transport gas from the interconnect with Westcoast Energy at Huntingdon through the BC Gas system to Coquitlam, the take off point for PCEC's transmission of gas to Vancouver Island. Gas first flowed under this agreement in July of 1991.

BC Gas does not propose changes to the PCEC Agreement as part of this application.

17.0 PROPOSED TERMS AND CONDITIONS FOR INDUSTRIAL RATE SCHEDULES

The proposed industrial rate schedules are in Volume 2, Tab 5.

The following are brief summaries for each service schedule highlighting major changes or new conditions.

<u>Rate Schedules 5/25</u> - General Firm Service and Transportation

BC Gas proposes to make the following modifications to the rates, terms and conditions:

1. The basic charge for this service is to be set at $300 per month; down from over $500 per month within the Inland Service area, up from $5.00 per month in the Lower Mainland.

2. Seasonal delivery rates as set out in Table 2 - Page 34 are to be implemented.

3. The present "Direct Purchase Administration Charge" is to be reduced from $500 per month to $175.

4. Customers will be permitted to amalgamate into groups and assign a group "Customer Agent" to handle all gas management functions and certain gas and penalty charge payment functions.

5. Payment terms have been standardized with the Company's General Terms and Conditions.

6. Authorized overrun gas on firm transportation service will be priced at the residential rate in winter, the general interruptible service rate in summer.

7. Although the rate schedules will consist of generic terms and conditions applicable throughout the BC Gas service territory, grouping and supply management will be possible by a service area only.

8. Incorporation of a service applicability limitation on Rate Schedule 5 to "a customer who, ...uses more than

50% of its approved connected gas load for applications other than space heating."

9. Revision to the terms of the agreement such that service will run from November to November.

10. Inclusion of "Warnings" related to accessibility to firm sales.

11. Expanded table of charges which details each of the following:

    (a) Basic Charge
    (b) Delivery Charge
    (c) Gas Cost Recovery Charge (where applicable)
    (d) Authorized Overrun charges (where applicable)
    (e) Unauthorized Overrun charges (where applicable)
    (f) Direct Purchase Administration Charges (where applicable)
    (g) Franchise Fee Charge (where applicable)

12. Relocation of "Definitions" section to the end of the Rate Schedule.

Rate Schedules 7/27 - General Interruptible Service and Transportation

BC Gas proposes to make the following modifications to the rates, terms and conditions:

1. The basic charge for this service is to be set at $700 per month.

2. Tiered and seasonal rates as set our in Table 2 are to be implemented.

3. The transportation service for this class will allow group balancing and year round monthly balancing as is presently provided for in Schedule 25 and 2007 (small industrial firm transportation).

4. Payment terms have been standardized with the Company's General Terms and Conditions.

5. The sales service continues to allow for negotiation of rates based on competing alternative fuels.

6. Repeated failures to curtail usage when directed by the Company may be cause for conversion to firm service.

7. Customers will be permitted to amalgamate into groups and assign a "Customer Agent" to handle all gas management functions and certain gas and penalty charge payment functions.

8. Authorized overrun gas on interruptible transportation service will be priced in accordance with the current Lower Mainland methodology: the residential rate in winter, the general interruptible service rate in summer.

9. A "Direct Purchase Administration Charge" for transportation customers is to be set at $175 per month.

10. Document format and arrangement will be similar to Rate Schedules 5 and 25.

11. The notification period for curtailment will be increased from 2 hours to 8 hours.

<u>Rate Schedule 22</u> - Large Industrial Transportation

BC Gas proposes to make the following modifications to the rates, terms and conditions.

1. The Basic Charge for this service is to be set at $1,350 per month.

2. Tiered and seasonal rates as set out in Table 2 are to be implemented.

3. An increase from 2.5% to 10% in the tolerance affecting UOR Demand Surcharge is to be implemented.

4. Discontinuance of the Curtailment Buyout Option is to be effective November 1, 1994. Changing circumstances in the availability of winter peaking supplies compel BC Gas to withdraw the buyout option as soon as possible. In order to provide customers with adequate opportunity to make alternative arrangements, the Company is prepared to continue with the present option for a transitional period of one year.

5. In place of the buyout option, provisions for customers to contract for and supply BC Gas with peaking gas in lieu of half firm curtailments are under consideration. If implemented, such supplies would be required over a longer period than five days to account for the Company's much reduced operating flexibility with such supplies.

6. A monthly "Direct Purchase Administration Charge" of $500 per month is to be set.

7. In accordance with the Commission's order, prior to the commencement of hearings of this application, the Company will file a Balancing Report and table a Load Balancing Service. It is the Company's intent to work with the customers affected to develop a service which adequately meets the needs of all parties. The company will file a

Load Balancing Report by June 21, 1993.

18.0 SUMMARY

Despite the obstacles which confronted the Company in first tackling the issue of industrial rates and service integration, BC Gas is confident it has accomplished its mission while still adhering to its fundamental rate design objectives.

Starting from a conglomeration of different rates and service schedules, which in 1989 numbered over 30 throughout the various service territories, BC Gas has been able to trim this down to about 10. BC Gas believes it has brought about equalized rates and service terms without imposing undue hardship. The Company has drafted "user friendly" market responsive service schedules which aim to make access to, and the administration of, direct purchase arrangements as trouble-free as the operating parameters of the transmission companies and the utility permit. BC Gas commenced its industrial rate design with the primary objectives of equity, fairness and balance. This application, the Company believes, satisfies those aspirations.

BC GAS INC.
PROPOSED INDUSTRIAL RATES

GENERAL AND SEASONAL SERVICE	WINTER	SUMMER
A. GENERAL FIRM SALES & TRANSPORTATION - RATE SCHEDULE 5/25		
a) Basic Charge Per Month	$ 300.00	$ 300.00
b) Delivery Charge	$ 1.50	$ 0.75
c) Commodity Charges (Rate 5 only)		
-Lower Mainland	$ 2.29	$ 2.29
-Inland	$ 2.10	$ 2.10
-Columbia	$ 2.07	$ 2.07
d) Direct Purchase Administration Charge per month (Rate 25 only)	$ 175.00	$ 175.00
B. GENERAL INTERRUPTIBLE SALES & TRANSPORTATION - RATE SCHEDULE 7/27		
a) Basic Charge Per Month	$ 700.00	$ 700.00
b) Delivery Charges		
Level 1	$ 1.20	$ 0.75
Level 2	$ 0.95	$ 0.70
c) Commodity Charges (Rate 7 only)		
-Lower Mainland & Inland	$ 1.90	$ 1.10
-Columbia	$ 2.07	$ 1.70
d) Direct Purchase Administration Charge Per Month (Rate 27 only)	$ 175.00	$ 175.00
C. SEASONAL SERVICE		
a) Basic Charge Per Month	$ 300.00	$ 300.00
b) Commodity Charge		
-Lower Mainland	$ 8.94	$ 1.98
-Inland	$ 8.40	$ 1.89
-Columbia	$ 7.56	$ 2.07

Note:
- a) Level 1 = Capacity Curtailment Only
- b) Level 2 = Peak Shaving Access
- c) All Delivery & Commodity Charges in $/gigajoule

BC GAS INC.
PROPOSED INDUSTRIAL RATES

LARGE VOLUME SERVICE	WINTER	SUMMER
D. LARGE VOLUME FIRM & INTERRUPTIBLE TRANSPORTATION - RATE SCHEDULE 22 (PROPOSED)		
a) Basic Charge Per Month	$1,350.00	$1,350.00
b) Firm	Negotiable	
c) Interruptible - Delivery Charges		
Level 1	$ 0.95	$ 0.70
Level 2	$ 0.75	$ 0.50
d) Direct Purchase Admininistration Charge Per Month	$ 500.00	$ 500.00
E. LARGE VOLUME FIRM & INTERRUPTIBLE TRANSPORTATION - RATE SCHEDULE 22A (CLOSED)		
a) Basic Charge Per Month	$ 2,700.00	
b) Rates {Demand Charge ($/GJ/day)	$ 6.60	
{Commodity Toll	$ 0.044	
{Interruptible Delivery Charges		
Level 1	$ 0.55	
Level 2	$ 0.38	
c) Direct Purchase Admininistration Charge per month	$ 500.00	
{ Note: These rates are closed; available only to existing customers presently receiving firm service under this Rate Schedule. }		

Note:
a) Level 1 = Capacity Curtailment Only
b) Level 2 = Peak Shaving Access
c) All Delivery & Commodity Charges in $/gigajoule

PROPOSAL TO REVISE NGV GAS SERVICE RATES

1.0 RATES UNDER CONSIDERATION

This proposal to revise NGV rates pertains to firm gas service rates for Natural Gas Vehicles, specifically, the "uncompressed" gas rates sold under Schedules 2206 (Lower Mainland), 14 (Inland), and 5 (Columbia). A new Schedule 6 is proposed to replace those schedules.

BC Gas also serves NGV customers under negotiated Tariff Supplements for compression/dispensing service at rates designed to be fully compensatory. Those supplements comprise five year renewable, fixed rate contracts that do not require review at this time. BC Gas does not propose to alter services or rates under Schedule 2216 (Lower Mainland) that pertain to Vehicle Refuelling Appliance service, other than to rename it as Schedule 6.1. The Vehicle Refueling Service rate, per Order G-113-92, is approved for the Lower Mainland Division only. If the Commission subsequently approves the extension of this service to other divisions, BC Gas will, at that time, seek to determine appropriate "postage stamp" rates.

2.0 IMPORTANT CONSIDERATIONS IN NGV RATE DESIGN

NGV firm service has a number of distinctive characteristics compared to other gas services provided:

a) NGV service has a very high load factor, almost 100%.

b) Customers tend to be either retail service stations that resell NGV and competitive fuels or fleet customers that consume NGV. These two markets are different: retailers need to set competitive end prices; fleet customers are seeking to minimize costs.

c) Firm NGV gas service typically represents about ten cents per litre of the 25 cents per litre pre-tax retail price of NGV, or about 40 percent of the pre-tax retail price. Compression/dispensing cost, including electrical energy, typically represents another 40 percent, and the retail margin is approximately 20 percent or less. GST is currently the only tax charged on NGV since alternative fuels are exempted from provincial Motor Fuel Tax until 1997. If the other cost components were held constant, a ten percent firm gas price change would result in a four percent retail price change, or about one cent per litre.

Retail service stations are limited in their ability to pass NGV rate increases through to their customers by the prices for gasoline and propane. One major NGV retailer attempted to increase prices by five cents per litre and had to quickly withdraw the price increase due to the strongest public response to price changes it had ever experienced. This response tallies with past market research that describes current NGV users as "dedicated cost savers".

d) Fleet customers have made commitments to NGV based on cost savings, environmental awareness and other factors, and are similarly sensitive to changes in their fuel cost. This segment is heavily targeted by the propane motor fuel distributors, and ultimately NGV must remain competitive with propane.

e) The public network of retail NGV outlets in the BC Gas service area comprises 30 stations in the Lower Mainland, most with compression facilities owned by others, and 12 stations in the Interior, most with compression facilities owned by BC Gas. Many of the stations in the Lower Mainland purchase higher volumes than those in the Interior.

f) NGV firm service rate payers are often competitors in the same market area, and a substantial portion of their NGV resale price is based on the firm gas rate. Therefore it is essential that the rates charged be consistent.

g) Previous market research has shown that owners of vehicles which operate on NGV want the public refuelling network to expand. There is also evidence that prospective NGV customers, who have decided not to convert their vehicles, have made their decision largely, or in part, based on the limited extent of the refuelling infrastructure. Therefore, rate increases should not be so large as to cause the closure of stations in the public refuelling network.

Stations in smaller communities, such as Merritt or Williams Lake, which may not have an adequate local fleet to sustain them, are most vulnerable. These are also critical to the credibility of the overall NGV offering to customers. For example, in BC Gas' 1991 Customer Attitude Survey, when NGV users were asked to name the locations in the Lower Mainland where additional retail outlets were most needed, "Hope" and "Merritt" were the most frequent answers. Locations along key routes, often in smaller communities, are vital to permit a vehicle on NGV to travel the major routes in the Province. Rate changes must not adversely impact these critical station locations more than their capability to pass a rate change on to their customers.

If one accepts that outlying public station locations are essential to the overall credibility of NGV, then it is logical that high volume, centrally-located retail stations should to some extent support low volume, outlying critical locations.

3.0 CURRENT RATE STRUCTURE

The current Divisional structure for firm NGV service is summarized below:

SCHEDULE	DIV.	BASIC CHARGE	MINIMUM CHARGE	DELIVERY CHARGE
2206	LM	$9.28/2 mos.	none	$1.8996/GJ
14	INL	none	$200.00/mo.	$2.0966/GJ
5	COL	none	$200.00/mo.	$1.3566/GJ

In addition to the above a gas commodity charge is included in the rate.

The Inland and Columbia divisions also have special tariffs for fleet service which are not in use. Those schedules can be eliminated to simplify the tariffs.

The largest single customer, with more than twice the volume of the next largest customer, has negotiated a commodity rate reduction with BC Gas that takes effect at volumes greater than 7,500 GJ per month. The rate is filed as Tariff Supplement 25, and the underlying contract runs to 1994.

The current structure could be simplified. Three different tariffs and a tariff supplement have to be applied to what is essentially a small part of BC Gas' total load and to few customers.

4.0 COST OF SERVICE

The fully distributed cost studies did not separate firm uncompressed gas service from compression/dispensing service or VRA service. The rolled-in costs of NGV and VRA services require one to use judgment when applying the results of the

FDC studies to firm uncompressed NGV service.

The NGV Annual report for 1992, which will be filed shortly, has determined that the NGV rate of return on rate base for 1992 was 8.48 percent, compared to the allowed rate of return of 10.31 percent. It is concluded that the margin earned by uncompressed NGV service sufficiently approximates the test year 1992 costs.

5.0 PROPOSED RATE STRUCTURE

Existing NGV tariffs should be replaced with a simpler structure that contains uniform basic charges and uniform delivery charges for all customers. The new NGV schedule will be called Schedule 6. The large volume price reduction, which is part of Tariff Supplement 25, should be incorporated into the NGV schedules to encourage operators to increase their sales volumes. This action would bring all users under a common rate schedule.

5.1 Basic Monthly Charge

The monthly Basic Charge should approach recovering the fixed customer-related component cost. The vast majority of NGV customers consume over 2,000 GJ/year, and all but 11 are over 6,000 GJ/year. However, the typical public station compressor capacity (200 scfm or 340 m^3/hr.) limits peak flows to levels close to large commercial customer usage of 2,000 to 6,000 GJ/yr. NGV firm service customers have similar needs for peak flow capacity, meter sizing, and billing as those for large commercial (Schedule 3) customers. NGV has additional costs for the NGV marketing program and the vehicle conversion grant. Ideally, the basic charge would reflect the full fixed cost component as identified in the FDC studies. However, a large basic charge would have an unacceptable impact on low volume customers, who are often in remote, key locations. Upon study of these impacts, BC Gas proposes that a $35 basic charge be employed. This level of charge moves towards the fixed costs but avoids large increases.

5.2 Delivery Charges

It is recommended that a delivery charge (excluding cost of gas) of $2.00 per GJ be applied within the present Lower Mainland, Inland and Columbia service areas. The basis of this recommendation is that NGV promotional and customer support programs are uniform throughout the service area.

For loads above 4,000 GJ/month, it is proposed that the delivery charge be reduced by 50%. Currently, that charge would be $1.00/GJ, and it would move with the delivery charge established from time to time. The purpose of this large volume delivery charge reduction is to encourage customers to build load. This would also incorporate provisions of Tariff Supplement 25 into the rate for all users, rather than limiting the provisions to one user. Tariff Supplement 25 specifies the lower rate to take effect over 7,500 GJ per two-month period, or 3,750 GJ/month. This is slightly lower than the 4,000 GJ/month block now proposed.

6.0 IMPACT OF THE PROPOSED RATE CHANGES

The proposed NGV firm service rates are:

- $35/month basic charge
- $2.00/GJ delivery charge, 0 - 4,000 GJ/month
- 50% of delivery charge ($1.00/GJ) >4,000 GJ/month
- cost of gas

The effect on revenues and margins for each Division, and for NGV overall, is shown below:

SUMMARY OF DIVISIONAL REVENUES AND AVERAGE MARGINS

Division Item	1992 Pre Phase A	1992 Phase A	1993	1994 Proposed
Lower Mainland				
Load, TJ	747.7	747.7	805.3	805.3
Revenue ($000's)	$2,646	$2,366	$2,697	$2,723
Rev./GJ	$3.54	$3.16	$3.35	$3.38
Margin ($000's)	$1,151	$1,204	$1,425	$1,450
Average Margin	$1.54	$1.61	$1.77	$1.80
Inland				
Load, TJ	111.6	111.6	125.2	125.2
Revenue ($000's)	$378	$365	$445	$438
Rev./GJ	$3.39	$3.27	$3.55	$3.50
Margin ($000's)	$204	$204	$263	$255
Average Margin	$1.83	$1.83	$2.10	$2.04
Columbia				
Load, TJ	1.9	1.9	1.9	1.9
Revenue ($000's)	$5.27	$5.27	$5.96	$7.60
Rev./GJ	$2.77	$2.77	$3.14	$4.00
Margin ($000's)	$2.05	$2.05	$2.58	$4.22
Average Margin	$1.08	$1.08	$1.36	$2.22
Total NGV (excl. Fort Nelson)				
Load, TJ	861.1	861.1	932.4	932.4
Revenue ($000's)	$3,030	$2,736	$3,148	$3,168
Rev./GJ	$3.52	$3.18	$3.38	$3.40
Margin ($000's)	$1,363	$1,414	$1,697	$1,725
Average Margin	$1.58	$1.64.	$1.82	$1.85

Compared to the current 1993 interim rates, the proposed rates would increase NGV revenue 0.65% overall, by 0.95% in the Lower Mainland, and by 27.57% in Columbia, while reducing revenue by 1.59% in the Inland Division.

The increase in Columbia is the most dramatic change that would result from this proposal. This increase is justifiable considering the much lower margins that have been enjoyed there compared to other Divisions. Although the increase is large in percentage terms, it would be less than 3 cents per litre if passed through to retail customers without markup. This should be an acceptable outcome if it is fully explained to those customers in advance.

The impacts on individual customers have been considered. In the Lower Mainland Division, many customers would experience a 2% to 5% increase, whereas in the Inland Division most would have 0% to 3% reductions. This outcome reflects the objective of providing some level of support from high volume customers to the overall network. The exceptions are that the second largest high volume customer would now receive the high volume rate reduction, which would lower the total cost by 26%, and that the smallest volume Inland customer would now experience a 4.8% increase.

Overall, the proposed new rates would achieve the following goals:

- equity between divisions;
- equity for competitors reselling NGV;
- acceptable cost increases, that could be passed to retail customers;
- large volume price break incorporated into standard rate;
- simplicity of rate administration; and
- enhancement of environmental protection.

GAS COST ALLOCATION FOR THE PROPOSED CUSTOMER CLASSES

The material under this Tab discusses the methodology used to establish the gas supply cost component of the rates for each proposed customer class. The gas supply costs for the customer classes are displayed on the table at the end of this Tab.

1.0 LOWER MAINLAND AND INLAND

In the Lower Mainland and Inland service areas, gas supply costs have been allocated to the proposed customer classes using the methodology approved in the Phase A Rate Design Decision. Under that methodology, demand and other fixed gas supply costs are allocated based on coincident peak demand. Commodity and other variable gas supply costs are generally allocated based on annual consumption with the exception that higher cost peaking and storage gas is assigned first on a reasonable basis to the interruptible classes before prorating the remainder to the other rate classes.

There are three significant items in the gas cost allocation to the proposed customer classes. First, new load factors have been derived for customers of the proposed Schedules 2, 3 and 5. Second, the gas costs for residential, commercial and medium industrial in the Lower Mainland have been flowed through on an average basis to this point but will now be flowed through on a class specific basis. Third, the schedules for sales of interruptible gas have been divided into small interruptible (Schedule 7) and large interruptible (Schedule 10). A summary of gas cost changes affecting Lower Mainland and Inland customers moving from the existing to the proposed customer classes is found in Table 1, Page 1.

1.1 Revised Load Factors for the Proposed Schedules 2, 3 and 5

In Phase A of Rate Design, the customer classes in the Lower Mainland were small commercial (0 to 6 TJ/year), large commercial (>6 TJ/year) and small/medium industrial. The respective load factors for those classes were 30.2%, 36.5% and 45.9%. The initial calculations of the load factors for customers of the proposed Schedules 2, 3 and 5 are 27.9%, 33.9% and 44.6%. These load factors are somewhat lower than under the previous customer classes since customers in the consumption range of 2,000 - 6,000 GJ per annum move from small commercial to large commercial. The peak day demand determined by these load factor for Schedules 2, 3 and 5 across both the Lower Mainland and Inland service areas is the same as the peak day demand under existing classes. All load factors were calculated on a basis consistent with Phase A methodology.

The revised load factors and volume forecasts for Schedules 2, 3 and 5 result in a reallocation of gas costs which only affect these customer classes. In other words, the gas costs allocated to other customer groups are essentially unaffected by the shifts amongst the Schedules 2, 3 and 5 customers.

1.2 Rate Class Specific Gas Costs for Lower Mainland Schedules 1, 2, 3 and 5

The customers in the Lower Mainland of the proposed Schedules 1, 2, 3 and 5 have all had the same rates under the existing customer classes (Schedules 2101, 2102, 2207, 2208 and 2209). In Phase A it was anticipated that the Lower Mainland General Service customers (Schedules 2207 and 2208) would eventually be split into small and large commercial with the break being at 6,000 GJ/year annual consumption (similar to the existing Schedules 2.1 and 2.2 in the Inland Division). Since the work had not been completed to separate the General Service customers, and since there were problems with customer misclassification amongst the residential, commercial and medium industrial classes, gas cost flowthrough changes have been calculated on an average basis for these customers.

Under the proposed Schedules 1, 2, 3 and 5 the gas costs are flowed through on a class specific basis. More particularly, the allocated fixed costs are determined by the load factor for each class. For Schedules 2, 3 and 5 the gas cost changes presented on Table 1, Page 1, Column 9 reflect the combined effect of the load factor changes described above and the change from average to class specific gas costs. For the Residential Rate Schedule 1 customers the gas cost increase of $0.043/GJ (Table 1, Page 1, Column 9, Line 3) is only the result of moving from average gas costs, as calculated under the Phase A methodology, to class specific gas costs.

1.3 Gas Supply Costs for Interruptible Sales - Schedules 7 and 10

The interruptible sales volumes will be classified as either Small Interruptible - Schedule 7 or Large Interruptible - Schedule 10. The Phase A methodology did not allocate demand or other fixed gas supply costs to the interruptible classes. This approach is continued under the proposed interruptible schedules.

The gas cost allocation for Large Interruptible - Schedule 10 is already established and will remain unchanged. The methodology assumes that 40% of winter volumes will be taken from peaking and storage sources. The Schedule 10 summer volumes are all from baseload gas supply contracts.

The gas supply cost allocation for Small Interruptible - Schedule 7 for the summer months will be the same as Large Interruptible - Schedule 10. In the winter months the Schedule 7 volumes will be assigned a variable premium to reflect a better quality of service than Schedule 10. This variable premium will be similar to the Schedule 2502 Peaking Credit which was included in the Phase A methodology. This was an amount added to the Schedule 2502 gas supply cost allocation to reflect estimated costs of the better quality of service relative to Schedule 2501. The amount added to Schedule 2502 was credited to the Lower Mainland and Inland firm rate classes.

2.0 COLUMBIA

In the Columbia Division the existing methodology of gas supply cost allocation has been maintained so, in most instances, there is no gas supply cost impact in moving from the existing to the proposed customer classes (see Table 1, Page 2). One exception to this occurs in the proposed Schedule 5 where certain customers have moved from the existing Schedule 2.2 and a gas supply cost decrease of $0.172/GJ is experienced. The decrease results from these customers moving from the Residential/Commercial market segment to the General Service market segment for gas cost purposes.

2.1 Gas Supply Costs for Interruptible Sales - Schedules 7 and 10

Interruptible sales have not been available in the Columbia Division under the existing sales classes. Small Interruptible - Schedule 7 and Large Interruptible - Schedule 10 gas cost allocations are included in the proposed classes in the Columbia service area as in the Lower Mainland and

Inland service areas. The proposed gas supply costs for these classes are equal to the assigned gas cost for the corresponding market segment less any fixed cost allocation. In other words, the gas supply cost for the proposed Schedule 7 is equal to the variable cost for the proposed Schedules 4 and 5. The gas cost for Schedule 10 is equal to the variable cost for the proposed NGV Schedule 6. These gas costs represent a floor for the Company's proposed market pricing of any interruptible sales in the Columbia service area.

BC GAS INC.
RATE DESIGN – PHASE B
EXISTING AND PROPOSED GAS COSTS
FOR THE YEAR ENDED DECEMBER 31, 1993

Line No.	Existing Classifications (1)	Variable Gas Costs ($/GJ) (2)	Fixed Gas Costs ($/GJ) (3)	Total Gas Costs ($/GJ) (4)	Proposed Classifications (5)	Variable Gas Costs ($/GJ) (6)	Fixed Gas Costs ($/GJ) (7)	Total Gas Costs ($/GJ) (8)	Gas Cost Change ($/GJ) Col.(8)-(4) (9)	Seasonal Gas Costs Winter ($/GJ) (10)	Seasonal Gas Costs Summer ($/GJ) (11)
1	**LOWER MAINLAND**										
2											
3	Residential – Rates 2101/2102	$0.9907	$1.8979	$2.8886	Residential – Rate 1	$0.9907	$1.9408	$2.9315	**$0.0429**		
4											
5	General / Industrial – Rates 2207/08/09	0.9907	1.8979	2.8886	Small Commercial – Rate 2	0.9907	2.0982	3.0889	**0.2003**		
6											
7	General / Industrial – Rates 2207/08/09	0.9907	1.8979	2.8886	Large Commercial – Rate 3	0.9907	1.7213	2.7120	**(0.1766)**		
8											
9	Seasonal – Rates 2601/2602	0.9909	0.3877	1.3786	Seasonal – Rate 4	0.9909	0.3877	1.3786	**0.0000**		
10											
11	General / Industrial – Rates 2207/08/09	0.9907	1.8979	2.8886	General Service – Rate 5	0.9907	1.2999	2.2906	**(0.5980)**		
12											
13	NGV/VRA – Rates 2206/2216	0.9907	0.5857	1.5764	NGV/VRA – Rate 6	0.9907	0.5857	1.5764	**0.0000**		
14											
15	Interruptible – Rate 2501	1.0114	0.0000	1.0114	Small Interruptible – Rate 7	1.1117	0.0000	1.1117	**0.1003**	$1.3059	$0.9400
16											
17	Interruptible – Rate 2502	1.1117	0.0000	1.1117	Small Interruptible – Rate 7	1.1117	0.0000	1.1117	**0.0000**	1.3059	0.9400
18											
19	Interruptible – Rate 2501	1.0114	0.0000	1.0114	Large Interruptible – Rate 10	1.0114	0.0000	1.0114	**0.0000**	1.0975	0.9400
20											
21	Interruptible – Rate 2502	1.1117	0.0000	1.1117	Large Interruptible – Rate 10	1.0114	0.0000	1.0114	**(0.1003)**	1.0975	0.9400
22											
23	Large Interruptible – Rate 10	1.0011	0.0000	1.0011	Large Interruptible – Rate 10	1.0011	0.0000	1.0011	**0.0000**	1.0975	0.9400
24											
25											
26	**INLAND**										
27											
28	Residential – Rate 1	0.9344	1.7251	2.6595	Residential – Rate 1	0.9344	1.7252	2.6596	**0.0001**		
29											
30	Small Commercial – Rate 2.1	0.9344	1.7516	2.6860	Small Commercial – Rate 2	0.9344	1.8645	2.7989	**0.1129**		
31											
32	Small Commercial – Rate 2.1	0.9344	1.7516	2.6860	Large Commercial – Rate 3	0.9344	1.5319	2.4663	**(0.2197)**		
33											
34	Large Commercial – Rate 2.2	0.9343	1.4474	2.3817	Large Commercial – Rate 3	0.9344	1.5319	2.4663	**0.0846**		
35											
36	Seasonal – Rate 4	0.9351	0.3506	1.2857	Seasonal – Rate 4	0.9351	0.3506	1.2857	**0.0000**		
37											
38	Large Commercial – Rate 2.2	0.9343	1.4474	2.3817	General Service – Rate 5	0.9343	1.1624	2.0967	**(0.2850)**		
39											
40	Small Industrial – Rate 5.1	0.9345	1.1503	2.0848	General Service – Rate 5	0.9343	1.1624	2.0967	**0.0119**		
41											
42	NGV – Rate 14	0.9350	0.5234	1.4584	NGV – Rate 6	0.9350	0.5234	1.4584	**0.0000**		
43											
44	Small Interruptible – Rate 7	0.9745	0.0000	0.9745	Small Interruptible – Rate 7	1.0748	0.0000	1.0748	**0.1003**	1.2854	0.9117
45											
46	Large Interruptible – Rate 10	1.0074	0.0000	1.0074	Large Interruptible – Rate 10	1.0074	0.0000	1.0074	**0.0000**	1.0770	0.9117

BC GAS INC.
RATE DESIGN – PHASE B
EXISTING AND PROPOSED GAS COSTS
FOR THE YEAR ENDED DECEMBER 31, 1993

Line No.	Existing Classifications (1)	Variable Gas Costs ($/GJ) (2)	Fixed Gas Costs ($/GJ) (3)	Total Gas Costs ($/GJ) (4)	Proposed Classifications (5)	Variable Gas Costs ($/GJ) (6)	Fixed Gas Costs ($/GJ) (7)	Total Gas Costs ($/GJ) (8)	Gas Cost Change ($/GJ) Col.(8)-(4) (9)	Seasonal Gas Costs Winter ($/GJ) (10)	Seasonal Gas Costs Summer ($/GJ) (11)
1	**COLUMBIA**										
2											
3	Residential – Rate 1	$1.8733	$0.3654	$2.2387	Residential – Rate 1	$1.8733	$0.3654	$2.2387	**$0.0000**		
4											
5	Small Commercial – Rate 2.1	1.8733	0.3654	2.2387	Small Commercial – Rate 2	1.8733	0.3654	2.2387	**0.0000**		
6											
7	Small Commercial – Rate 2.1	1.8733	0.3654	2.2387	Large Commercial – Rate 3	1.8733	0.3654	2.2387	**0.0000**		
8											
9	Large Commercial – Rate 2.2	1.8733	0.3654	2.2387	Large Commercial – Rate 3	1.8733	0.3654	2.2387	**0.0000**		
10											
11	Seasonal – Rate 4	1.6650	0.4016	2.0666	Seasonal – Rate 4	1.6650	0.4016	2.0666	**0.0000**		
12											
13	Large Commercial – Rate 2.2	1.8733	0.3654	2.2387	General Service – Rate 5	1.6650	0.4016	2.0666	**(0.1721)**		
14											
15	Small Industrial – Rate 3	1.6650	0.4016	2.0666	General Service – Rate 5	1.6650	0.4016	2.0666	**0.0000**		
16											
17	NGV Fuel Service – Rate 5	1.3973	0.3821	1.7794	NGV Fuel Service – Rate 6	1.3973	0.3821	1.7794	**0.0000**		
18											
19					Small Interruptible – Rate 7	1.6650	0.0000	1.6650	**N/A**		
20											
21					Large Interruptible – Rate 10	1.3973	0.0000	1.3973	**N/A**		

PROPOSED CONSOLIDATED GENERAL TERMS AND CONDITIONS

1.0 SUMMARY

BC Gas is proposing to replace the existing Lower Mainland, Inland, and Columbia divisions General Terms and Conditions with common General Terms and Conditions. The proposed consolidated General Terms and Conditions are found under this Tab.

2.0 BACKGROUND

The current divisional General Terms and Conditions evolved separately reflecting the different management philosophies, operating regimes, billing practices, and other factors specific to those separate companies. With the creation of BC Gas, the management of the Company has sought to achieve the efficiencies inherent in combining the separate divisions into one. This initiative was discussed during the 1992 Revenue Requirement Hearing, particularly in the context of consolidating the divisions for revenue requirement purposes. Though the Commission did not approve consolidation at that time, it referred the matter to the Phase B Rate Design proceeding. Included in the decision was a direction to consider common General Terms and Conditions. As BC Gas consolidates its operations, its regulatory regime, and implements postage stamp margins, it would be inconsistent to maintain separate General Terms and Conditions which set out different requirements and obligations for BC Gas and its customers.

Consolidating the General Terms and Conditions alleviates some of the regulatory, administrative, and operating burden associated with maintaining divisions for regulatory purposes. The present divisional terms and conditions do not, in most cases, differ significantly from each other in content.

Consequently, there is considerable repetition throughout the existing General Terms and Conditions. Maintaining the separate sets of General Terms and Conditions is not necessary and only adds to the potential for confusion among customers and BC Gas staff when discussing issues relevant to the General Terms and Conditions.

The present divisional General Terms and Conditions have evolved over time as a result of amendments and additions. The changes have occurred in isolation and as a result the present tariffs reflect a mixture of legal and technical jargon. The internal consistency and balance has been altered from their original state. An attempt has been made to improve the readability and understandability through the proposed consolidated General Terms and Conditions. In addition, the consolidated General Terms and Conditions have been written in gender-neutral and plain language form.

References to Fees and Charges were moved to a separate section titled "Standard Fees and Charges" in the consolidated General Terms and Conditions to facilitate changes to the fees and charges from time to time. This will reduce the regulatory burden of maintaining and reviewing the terms and conditions and also make the fees and charges levied by the Company clearer to the customer.

In addition to the style and form of the General Terms and Conditions, some changes were made to the substance of the text so as to better reflect the operational realities faced by BC Gas.

3.0 PROCESS

Bonita Thompson, of Singleton, Urquhart, and MacDonald, a lawyer with extensive experience in drafting regulations with an emphasis on clarity and readability, was retained to assist in drafting the document and to provide input regarding the tone and substance of the draft terms and conditions. Her terms of reference included improving the readability, understandability, consistency, and organization of the document. In addition, she was asked to provide general advice on the clauses as they were written. As a result of the recommendations made by Ms. Thompson, a large number of improvements were made to the form and content of the document.

The General Terms and Conditions as filed provide a significant improvement over the existing divisional terms and conditions and reflect the rights and obligations of BC Gas and its customers.

4.0 SUMMARY OF CHANGES

It is very difficult to compare the existing and proposed documents on a clause by clause basis because the consolidated General Terms and Conditions differ in form and structure from the existing terms and conditions. In order to facilitate such a comparison, BC Gas has prepared the following table (labelled Comparison Table) which cross-references the existing divisional General Terms and Conditions with the proposed consolidated General Terms and Conditions. The column on the far left identifies the consolidated General Terms and Conditions section number and name, and the columns to the right of it identify the page number and/or section number identified in the existing divisional terms and conditions that apply to the same general subject.

The changes in style and form have been discussed above. The majority of changes made to the content of the consolidated General Terms and Conditions were made to ensure a consistent treatment of all customers to the extent possible across all of BC Gas' service areas.

In particular, the application for service requirements and procedures, service connections, meter sets and metering sections were made common for the Lower Mainland, Columbia and Inland service areas. In addition, the bill due dates were standardized to be twenty-one days after the billing date as is specified in the existing Lower Mainland division General Terms and Conditions. The Inland and Columbia division bill due dates are presently thirty days after the meter reading date. The terms and conditions dealing with periodic review and reactivation of a service which are included in the existing Inland General Terms and Conditions would now also apply to the Lower Mainland and Columbia customers under the consolidated General Terms and Conditions.

A standardized Main Extension Test is being developed by BC Gas. The terms and conditions relating to the main extension test will be determined in conjunction with the Integrated Resource Plan and will be filed at that time.

The Lower Mainland divisional terms and conditions relating to rental premises were included in the consolidated General Terms and Conditions and would now also apply to the Columbia and Inland service areas.

The existing Lower Mainland Service Policy for Mobile Home Parks was not included in the consolidated General Terms and Conditions as it is adequately covered in the consolidated General Terms and Conditions under the rental premises and the service lines sections.

Comparison Table

Proposed Consolidated General Terms and Conditions	Existing Divisional General Terms and Conditions				
	Lower Mainland	Inland		Columbia	
	Page	Page	Section	Page	Section
Section 1 Application Requirements	B-2 B-19 B-24	11	1	12 14	2 5
Section 2 Agreement to Provide Service	B-2	11	1	12	2
Section 3 Conditions on Use of Service	B-2	11	1	12	2
Section 4 Periodic Review	N/A	N/A	N/A	14	5
Section 5 Application Fees & Charges	B-2,-4 B-19 B-20	39	22	27	19
Section 6 Security for Payment of Bills	B-12 B-17.1	18	8	15	6
Section 7 Term of Service Agreement	B-11	12	2	13	3
Section 8 Termination of Service Agreement	B-20	13	2	13	3
Section 9 Delayed Consumption	N/A	12	2	14	4
Section 10 Service Lines	B-2 B-3,-4 B-11	14 16 17	4 5 6	14 17 19	4 8 9
Section 11 Meter Sets & Metering	B-12 B-23	27 27 28 28 29	10 11 12 13 14	22 22 23	12 13 14
Section 12 Main Extensions	B-6	17 20	7 9	20 21	10 11
Section 13 Interruption of Service	B-21 B-22	40	24	29.1	22
Section 14 Access to Premises	B-22	29	15	23	15
Section 15 Promotions and Incentives	B-24 B-25	39	23	28 28	20 21

Comparison Table, contd.

Proposed Consolidated General Terms and Conditions	Existing Divisional General Terms and Conditions				
	Lower Mainland	Inland		Columbia	
	Page	Page	Section	Page	Section
Section 16 Billing	B-13	30	17	24	16
Section 17 Advance Billing	B-17.4	N/A	N/A	N/A	N/A
Section 18 Advance Payment Discount Plan	B-17.4 B-18	N/A	N/A	N/A	N/A
Section 19 Back-Billing	B-17.1	35	20	24.2	16.10
Section 20 Equal Payment Plan	B-19	33	18	24.2	16.5
Section 21 Late Payment Charge	B-18.1	34	19	25	17
Section 22 Returned Cheque Charge	B-18.1	34	19	25	17
Section 23 Discontinuance & Refusal of Service	B-20 B-21	37	21	26	18
Section 24 Limitation of Liability	B-21 B-22	37 41	21 25	17 30	8 23
Section 25 Taxes	B-22	42	26	31	24
Section 25 Conflicting Terms & Conditions	B-24	43	29	32	27
Section 25 Authority of Agents of Company	N/A	44	27	31	25
Section 25 Additions, Alterations and Amendments	N/A	43	30	32	28
Section 25 Headings	N/A	N/A	N/A	N/A	N/A

5.0 PROPOSED CHANGES TO SERVICE CHARGES

BC Gas proposes to revise a number of its customer related service charges to better reflect the real cost of providing such services. In particular, revising the Application for Service charges brings the charges more in line with the cost of providing service. A review of other utilities supports this revision.

Table A provides a review of the Application/Connection and Reconnection fees charged by the other British Columbia utilities. Table B summarizes the Application/Connection and Reconnection fees charged by some other major Canadian gas utilities. The activities associated with reconnection of a service after discontinuance at a customer's request are similar to the Application for Service, and the corresponding fees from various utilities are provided for comparison.

BC Gas currently charges $10 for each Application for Service, regardless of whether the application is simply to transfer an existing account from one person to another or to actually install a new service line and meter set. In many situations the $10 collected does not match the BC Gas administrative costs associated with providing the service.

5.1 Cost Analyses

BC Gas devotes considerable resources and incurs significant cost, to process requests to initiate or terminate gas service. However, the nature of the work required to process applications and terminations varies depending upon the circumstances. The following are the three basic application/termination scenarios that develop:

1) <u>Account Transfer - Existing Installation, Service Active</u>
   In this case, the premise is already served with gas and

the gas is flowing at the time a new occupant calls to apply for service. The complete transaction can usually be dealt with over the telephone or at a branch office.

2) <u>Account Transfer - Existing Installation, Service Inactive</u>

In this case, the premise is aready serviced with gas but the gas is not flowing. While the administrative process can be completed over the telephone or at the branch office, BC Gas Customer Service personnel must be dispatched to reactivate gas service, including relighting the gas appliances.

3) <u>New Account - New Service Required</u>
In those situations where natural gas service is not currently available at the premises, a new gas service line installation is required. The customer must sign up for the new installation in person at a branch office.

In each scenario, some or all of the following activities occur:

a) The Applicant's information is obtained either over the telephone or at a branch office.

b) The Applicant's information is keyed into the Company's computer system.

c) An evaluation of the Applicant's credit worthiness is determined and, if any outstanding bills from other accounts exist, collection activities are undertaken before new service is provided.

d) Information regarding the terminating customer is sought, in particular a forwarding address for the final bill is obtained. Billing adjustments are required in some cases.

e) In some cases Customer Service personnel are dispatched to obtain a meter reading on the transfer date; in most situations the final meter reading is estimated.

f) When there is an existing service, but it is inactive, Customer Service personnel are dispatched to reactivate the service and relight the gas appliances. In some cases the gas meter must be reset.

g) In certain cases the account may be temporarily transferred into the landlord's name, for a period of time between tenants.

h) When a new service installation is required, additional information is required for permanent installation records and a site visit prior to installation is necessary for 20-25% of all installations. Following installation of the new service, site records are completed in greater detail.

The activities listed generate costs in the following areas:

- clerical time
- computer system utilization
- customer service personnel and vehicles
- mains and services representatives and vehicles
- associated overhead.

Given the various activities that are required to complete applications/terminations, the following cost estimates for each of the three scenarios has been developed.

Account Transfer - Existing Installation, Service Active

1. <u>Interior Costs</u>

Clerical Time:

Customer Service Representative 3		
OTEU Collective Agreeement	$17.69/hr	
- Group 5 (3 yrs experience)		
Benefits @ 17.3%	$ 3.06	
Concessions @ 15.5%	$ 2.74	
Total	$23.49/hr	
Average total application processing time: .5 hrs =		$11.74
Computer System Utilization:		
On-screen average costs for interior billing system		$ 4.71
Total Interior =		$16.45

2. <u>Lower Mainland Costs</u>

1993 B.C. Hydro customer accounts, service and collection contracts average cost	$ 9.15

3. <u>Weighted Average</u>

Lower Mainland - B.C. Hydro billing system - 72% of customers x $9.15	$ 6.59
Interior billing system - 28% of customers x $16.45	$ 4.62
	$11.21

Account Transfer - Existing Installation, Service Inactive

1. <u>Clerical time & computer system use, same as above</u> $11.21

2. <u>Site Visit</u>

IBEW collective agreement	$21.77/hr	
Benefits @ 20.9%	$ 4.55	
Concessions @ 36%	$ 7.84	
Total	$34.16/hr	
Average service deactivation/reactivation time - 1.0 hr* =		$34.16
Vehicle costs @ $6.10/hr X 1.0 hr =		$ 6.10
Total =		$51.47

* Each time an account has to be reactivated, the cost of deactivating gas service has already been incurred.

New Account - New Service Required

1. <u>Clerical Time</u>

Construction Planning Clerk		
OTEU Collective Agreement	$17.69/hr	
- Group 5 (3 yrs experience)		
Benefits @ 17.3%	$ 3.06	
Concessions @15.5%	$ 2.74	
Total	$23.49/hr	
Average total application processing time: 1.5 hrs =		$35.24

2. <u>Computer System Utilization</u>

On-screen average costs for interior billing system	$ 4.71

3. <u>Site Visit/Confirmation</u> (25% of installations are non-standard)

Mains & Service Representative		
OTEU Collective Agreement	$22.47/hr	
- Group 8 (3 yrs experience)		
Benefits @ 17.3%	$ 3.89	
Concessions @15.5%	$ 3.48	
Total	$29.84/hr	
Average total application processing time: 1.5 hrs =		$44.76
Vehicle cost @ $6.10/hr X 1.5 hrs =		$ 9.15
Total:		$93.86

BC Gas proposes to recover a greater portion of the above costs through increased fees charged for Applications for Service as follows:

	Current Charge	Proposed Charge	Increase
1) Application for Service I - Existing Installation - Account Transfer	$10	$25	$15
2) Application for Service II - New service line installation	$10	$75	$65

During the year ending December 31st, 1992, BC Gas processed approximately 205,000 Applications for Service. Approximately 181,000 of these applications were for account transfers only and 24,000 applications were for new service installations. An increase of $15 per Application for Service I would generate an additional $2.715 million/year assuming 180,000 or more Applications for Service are received in future years. An increase of $65 in Application for Service II, where a new service line and meter set is required, would generate an additional $1.3 million per year assuming 20,000 such installations occurred each year. BC Gas has installed an average of 23,100 new services per year for the years 1990, 1991 and 1992.

The increased revenues arising from these revised charges serve to mitigate the impact of annual bill increases caused by the proposed rate design. The use of these funds is discussed in the "Implementation and Phase-in of the Proposed New BC Gas Rates" section for Residential, Commercial, General Service, and Industrial Customers in Tabs 6, 7, 8 and 9, respectively.

Table A

Review of Application/Connection & Reconnection Fees of Other B.C. Utilities

	4/1/92	4/1/93	4/1/94	4/1/95
B.C. Hydro[1]				
1. New Service Installation (single Phase secondary overhead service connection plus one meter for Residential service).	$75.00	$100.00	$175.00	$250.00
2. Account Charge	$10.00			
3. Reconnection Charge	$64.00			

B.C. Tel[2]

1. New Installation Cost to 1st customer (include pre-wiring & 1st telephone jack)	$ 42.50	+ $ 11.25 each extra phone jack
2. Account Transfer only	$ 23.50	

Rogers Cablevision[2]

1. New home or cable service	$ 73.95
2. Service exists but technician required to reactivate	$ 52.50
3. Cable still active, account transfer	$ 20.95

Pacific Northern Gas

Connection and reconnection charge	$15.00
If customer previously requested termination of service at the same premises	$30.00

Centra Gas (B.C.) Inc.

Reconnection fee[3]	$25.00

Northland Utilities (B.C.) Limited

Reconnection fee[3]	$55.00

---

[1] B.C. Hydro information extracted by B.C. Hydro Electric Tariff Page B-37 Effective 5 September 1991.

[2] B.C. Tel and Rogers Cablevision charges were obtained via telephone calls to each company's Customer Service Departments.

[3] Reconnection fees are associated with resuming service subsequent to a discontinuance at the customer's request.

Table B

Review of Application/Connection & Reconnection[4] Fees by Other Canadian Gas Utilities

Canadian Western Natural Gas Co. Ltd.	
Reconnection fee - Residential	$45.00
Northwestern Utilities Ltd.	
Reconnection fee	$45.00
Centra Gas Manitoba Inc.	
Reconnection fee	$48.00
Consumers Gas	
New account charge	$20.00
Centra Gas Ontario	
Account opening charge	$25.00
Reconnect charge	$25.00
Union Gas	
Connection charge	$24.00
Reconnection charge	$55.00-$90.00
Gaz Métropolitain Inc.	
Reconnection charge	$50.00

[4] Reconnection fees are associated with resuming service subsequent to a discontinuance at the customer's request.

BC GAS PROPOSED CONSOLIDATED GENERAL TERMS AND CONDITIONS

April 1993

BC Gas

Table of Contents

Table of Contents

Definitions

Unless the context indicates otherwise, in the General Terms and Conditions the following words have the following meanings

Adjustment Factor	Means a factor, or combination of factors, which converts gas meter data to gigajoules or cubic metres for billing purposes.
Basic Charge	Means a fixed charge required to be paid by a customer for service during a prescribed period as specified in the applicable rate schedule.
BC Gas	Means BC Gas Inc.
Commercial Service	Means the provision of firm gas supplied to one delivery point and through one meter for use in approved appliances in commercial, institutional or small industrial operations.
Customer	Means a person who is being provided service or who has filed an application for service with BC Gas that has been approved by BC Gas.
Day	Means any period of 24 consecutive hours beginning and ending at 8:00 am. Pacific Standard Time or as otherwise specified in the Service Agreement.
Delivery Point	Means the outlet of the meter set unless otherwise specified in the service agreement.
Delivery Pressure	Means the pressure of the gas at the delivery point.
Gas	Means natural gas or propane.

Gas Service	Means the delivery of gas through a meter set.
General Terms & Conditions	Means these terms and conditions.
Gigajoule	Means a measure of energy equal to one billion joules used for billing purposes.
Heat Content	Means the quantity of energy per unit volume of gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).
Landlord	A person who, being the owner of a property, has leased or rented it to another person, called the tenant.
Main	Means pipes used to carry gas for general or collective use for the purposes of distribution.
Main Extension	Means an extension of one of BC Gas' mains with low, distribution, intermediate or transmission pressures, and includes the installation of any required pressure regulating facilities and upgrading of existing mains, or pressure regulating facilities on private property but does not include the installation of service lines or customer meter sets.
Meter Set	Means an assembly of BC Gas owned metering and ancillary equipment and piping.
Month	Means a period of time, for billing purposes, of 27 to 34 consecutive days.

Other Service	Means the provision of service other than gas service including, but not limited to, rental of equipment, natural gas vehicle fuel compression, alterations and repairs, merchandise purchases, and financing.
Other Service Charges	Means charges for rental, natural gas vehicle fuel compression service, damages, alterations and repairs, financing, insurance and merchandise purchases, and late payment charges, franchise fees, Social Service Tax, Goods and Services Tax or other taxes related to these charges.
Person	Means a natural person, partnership, corporation, society, unincorporated entity or body politic.
Premises	Means a building, a separate unit of a building, or machinery together with the surrounding land.
Rate Schedule	Means a schedule attached to and forming part of the General Terms and Conditions which sets out the charges for service and certain other related terms and conditions for a class of service.
Residential Premises	Means the premises of a single customer, whether single family dwelling, separately metered single-family townhouse, rowhouse, or apartment, or single-metered apartment blocks with four or less apartments.
Residential Service	Means firm gas service provided to a residential premises.
Rider	Means an additional charge or credit attached to a rate.
Service	Means the provision of gas service or other service by BC Gas.

Service Agreement	Means an agreement between BC Gas and a customer for the provision of service.
Service Line	Means that portion of BC Gas' gas distribution system extending from a main to the inlet of the meter set.
Service Related Charges	Include, but are not limited to, application fees, excess service line length charges, franchise fees, and late payment charges, plus Social Services Tax, Goods and Service Tax, or other taxes related to these charges.
Standard Fees & Charges Schedule	Means the schedule attached to and forming part of the General Terms and Conditions which lists the various fees and charges relating to service provided by BC Gas as approved from time to time by the British Columbia Utilities Commission.
Temporary Service	Means the provision of service for what BC Gas determines will be a limited period of time.
Tenant	A person who has the temporary use and occupation of real property owned by another person.
Year	Means a period of 12 consecutive months.

Service Areas

These general terms and conditions refer to the following major service areas: Lower Mainland, Inland and Columbia.

Lower Mainland Service Area

Means the areas including, but not limited to, the following locations and surrounding areas of

Abbotsford
Burnaby
Chilliwack
Coquitlam
Delta

Harrison Hot Springs
Hope
Kent
Langley City
Langley District

Maple Ridge
Matsqui
Mission
New Westminster
North Vancouver City

North Vancouver Dist.
Pitt Meadows
Port Coquitlam
Port Moody
Richmond

Surrey
Vancouver
West Vancouver
White Rock

Inland Service Area

Means the areas including, but not limited to, the following locations and surrounding areas of

Armstrong
Ashcroft
Bear Lake
Cache Creek
Castlegar

Chase
Chetwynd
Christina Lake
Clinton
Coldstream

Nelson
Okanagan Falls
Oliver
100 Mile House
108 Mile House

150 Mile House
Osoyoos
Oyama
Peachland
Penticton

Inland Service Area
(continued)

Collettville
Craigmont
Falkland
Ferguson Lake
Fruitvale
Gibralter Mines
Grand Forks
Greenlake
Greenwood
Hedley
Hixon
Honeymoon Creek
Hudson's Hope
Kamloops
Kelowna
Keremeos
Lac La Hache
Lakeview Heights
Logan Lake
Lumby
MacKenzie
Merritt
Midway
Montrose
Naramata
Prince George
Princeton
Quesnel
Revelstoke
Robson
Rossland
Salmo
Salmon Arm
Savona
Shelley
Sorrento
Spallumcheen
Summerland
Trail
Vernon
Warfield
Westbank
Westwold
Williams Lake
Winfield
Woodsdale

Columbia Service Area

Means the areas including, but not limited to, the following locations and surrounding areas of

Cranbrook
Creston
Elkford
Fernie
Galloway
Jaffray
Kimberley
Sparwood
Yahk

1. Application Requirements

1.1 **Requesting Services** - A person requesting BC Gas

(a) to provide gas service,

(b) to provide a new service line,

(c) to re-activate an existing service line,

(d) to transfer an existing account,

(e) to change the type of service provided, or

(f) to make alterations to an existing service line or meter set

must apply to BC Gas at any of its office locations in person, by mail, by telephone, by facsimile or by other electronic means.

1.2 **Required Documents** - An applicant for

(a) residential service may be required to sign an application and a service agreement provided by BC Gas,

(b) commercial service must sign an application and a service agreement provided by BC Gas, and

(c) service on other rate schedules must sign the applicable service agreement provided by BC Gas.

1.3 **Separate Premises/Businesses** - If an applicant is requesting service from BC Gas at more than one premises, or for more than one separately operated business, the applicant will be considered a separate customer for each of the premises and businesses. For the purposes of this provision, BC Gas will determine whether or not any building contains one or more premises or any business is separately operated.

1.4 **Required References** - BC Gas may require an applicant for service to provide reference information and identification acceptable to BC Gas.

1.5 **Rental Premises** - In the case of rental premises, BC Gas may

(a) require an owner of rental premises or its agent who wishes BC Gas to contract directly with a tenant to enter into an agreement with BC Gas defining the responsibilities of the owner or agent for payment for service to the premises,

(b) contract directly with the owner or agent of the rental premises as a customer of BC Gas with respect to any or all services to the premises, or

(c) contract directly with each tenant as a customer of BC Gas.

1.6 **Refusal of Application** - BC Gas may refuse to accept an application for service for any of the reasons listed in section 23 (Discontinuance of Service and Refusal of Service).

2. Agreement to Provide Service

2.1 **Service Agreement** - The agreement for service between a customer and BC Gas will be

(a) the oral or written application of the customer which has been approved by BC Gas and which is deemed to include the General Terms and Conditions, or

(b) a service agreement signed by the customer.

2.2 **Customer Status** - A person becomes a customer of BC Gas when BC Gas

(a) approves the person's application for service, or

(b) provides service to the person.

A person who is being provided service by BC Gas but who has not applied for service shall be served in accordance with these General Terms and Conditions.

2.3 **No Assignment/Transfer** - A customer may not transfer or assign an agreement for service without the written consent of BC Gas.

3. Conditions on Use of Service

3.1 **Authorized Consumption** - A customer must not increase the maximum rate of consumption of gas delivered to it by BC Gas from that which may be consumed by the customer under the applicable rate schedule nor significantly change its connected load without the written approval of BC Gas, which approval will not be unreasonably withheld.

3.2 **Unauthorized Sale/Supply/Use** - Unless authorized in writing by BC Gas, a customer must not sell or supply gas supplied to it by BC Gas to other persons or use gas supplied to it by BC Gas for any purpose other than as specified in the service agreement.

4. Periodic Review

4.1 **Periodic Review** - BC Gas may

(a) conduct periodic reviews of the quantity of gas delivered and the rate of delivery of gas to a customer to determine which rate schedule applies to the customer, and

(b) change the customer's charge to the appropriate charge, or

(c) change the customer to the appropriate rate schedule.

5. Application Fees and Charges

5.1 **Application Fee** - An applicant for service must pay the applicable application fee set out in the Standard Fees and Charges Schedule.

5.2 **Waiver of Application Fee** - The application fee

(a) will be waived by BC Gas if service to a customer is reactivated after it was discontinued for any of the reasons described in section 13.2 (Right to Restrict), and

(b) may be waived by BC Gas if a landlord requires gas service for a short period between the time a previous tenant moves out and a new tenant moves in.

5.3 **Reactivation Charges** - If

(a) service is terminated

(i) at the request of a customer, or

(ii) for any of the reasons described in section 23 (Discontinuance of Service and Refusal of Service), or

(iii) to permit customers to make alterations to their premises, and

(b) the same customer or the spouse, employee, contractor, agent or partner of the same customer requests reactivation of service to the premises within one year,

the applicant for reactivation must pay, in addition to the application fee in section 5.1 (Application Fee), the greater of

(i) the costs BC Gas incurs in re-activating the service, or

(ii) the sum of the minimum charges set out in the applicable rate schedule which would have been paid by the customer between the time of termination and the time of reactivation of service.

6. Security For Payment of Bills

6.1 **Security for Payment of Bills** - If a customer or applicant cannot establish or maintain credit to the satisfaction of BC Gas, the customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to BC Gas. As security for payment of bills

(a) all customers in the Inland and Columbia service areas who have not established or maintained credit to the satisfaction of BC Gas, may be required to provide a security deposit or equivalent form of security, the amount of which may not

(i) be less than $50, and

(ii) exceed an amount equal to the estimate of the total bill for the two highest consecutive months consumption of gas by the customer or applicant.

(b) residential customers in the Lower Mainland service area who have not maintained a payment history satisfactory to BC Gas will be required to participate in Advance Billing as set out in section 17 (Advance Billing).

(c) commercial service applicants in the Lower Mainland service area who have not established credit satisfactory to BC Gas will be required to select one of the following options

(i) participate in Advance Billing, with no security deposit, or

(ii) provide a security deposit equal to two times the customer's estimated maximum monthly bill if the account is on regular monthly billing, or

(iii) provide a security deposit equal to three times the customer's estimated maximum monthly bill if the account is on regular bi-monthly billing.

(d) commercial service customers in the Lower Mainland service area who have not maintained a payment history satisfactory to BC Gas shall be required to select one of the following options:

(i) participate in the Advance Payment Discount Plan for a minimum of two years, with no security deposit, or

(ii) participate in Advance Billing and provide a security deposit equal to the customer's estimated maximum monthly bill, or

(iii) provide a security deposit equal to two times the customer's estimated maximum monthly bill if the account is on regular monthly billing, or

(iv) provide a security deposit equal to three times the customer's estimated maximum monthly bill if the account is on regular bi-monthly billing.

6.2 **Deposit Not Advance Payment** - A security deposit or equivalent form of security is not an advance payment within the meaning of section 18 (Advance Payment Discount Plan).

6.3 **Interest** - BC Gas will pay interest to a customer on a security deposit at the rate and at the times specified in the Standard Fees and Charges Schedule. If a security deposit is returned to the customer for any reason, BC Gas will credit any accrued interest to the customer's account at that time.

No interest is payable

(a) on any unclaimed deposit left with BC Gas after the account for which it is security is closed, and

(b) on a deposit held by BC Gas in a form other than cash.

6.4 **Refund of Deposit** - When the customer pays the final bill, BC Gas will refund any security deposit plus any accrued interest or cancel the equivalent form of security.

6.5 **Unclaimed Refund** - If BC Gas is unable to locate the customer to whom a security deposit is payable, BC Gas will take reasonable steps to trace the customer; but if the security deposit remains unclaimed 10 years after the date on which it first became refundable, the deposit becomes the absolute property of BC Gas.

6.6 **Application of Deposit** - If a customer's bill is not paid when due, BC Gas may apply all or any part of the customer's security deposit or equivalent form of security and any accrued interest toward payment of the bill. Even if BC Gas applies the security deposit or calls on the equivalent form of security BC Gas may, under section 23 (Discontinuance of Service and Refusal of Service), discontinue service to the customer for failure to pay for service.

6.7 **Replenish Security Deposit** - If a customer's security deposit or equivalent form of security is called upon by BC Gas towards paying an unpaid bill, the customer must re-establish the security deposit or equivalent form of security before BC Gas will reconnect or continue service to the customer.

6.8 **Failure to Pay** - Failure to pay a security deposit or to provide an equivalent form of security acceptable to BC gas may, in BC Gas' discretion, result in discontinuance or refusal of service as set out in section 23 (Discontinuance of Service and Refusal of Service).

7. Term of Service Agreement

7.1 **Initial Term for Residential and Commercial Service** - If a customer is being provided residential or commercial service the initial term of the service agreement

(a) when a new service line is required will be one year, or

(b) when a main extension is required will be for a period of time fixed by BC Gas not exceeding the number of years used to calculate the revenue in the main extension economic test used in section 12 (Main Extensions).

7.2 **Initial Term for Gas Service other than Residential or Commercial Service** - If a customer is being provided gas service other than residential or commercial service, the initial term of the service agreement will be as specified in the service agreement or as specified in the appropriate rate schedule.

7.3 **Transfer to Residential or Commercial Service** - If a customer is being provided gas service other than residential or commercial service and transfers to residential or commercial service, the initial term of the service agreement will be determined by the criteria set out in section 7.1 (Initial Term for Residential and Commercial Service). A customer may only transfer service from one rate schedule to another rate schedule once a year.

7.4 **Renewal of Agreement** - Unless

(a) the service agreement or the applicable rate schedule specifies otherwise,

(b) the service agreement is terminated under section 8 (Termination of Service Agreement),

(c) a refund has been made under section 9.2 (Refund of Charges), or

(d) the service agreement is for seasonal service,

the service agreement will be automatically renewed at the end of its initial term

(e) from month to month for residential or commercial service, and

(f) from year to year for all other types of gas service.

8. Termination of Service Agreement

8.1 **Termination by Customer** - Unless the service agreement or applicable rate schedule specifies otherwise, the customer may terminate the service agreement after the end of the initial term by giving BC Gas at least 48 hours notice.

8.2 **Continuing Obligation** - The customer is responsible for, and must pay for, all gas delivered to the premises and is responsible for all damages to and loss of meter sets or other property of the company on the premises until the service agreement is terminated.

8.3 **Effect of Termination** - The customer is not released from any previously existing obligations to BC Gas under the service agreement by terminating the agreement.

8.4 **Sealing Service Line** - After receiving a termination notice for a premises and after a reasonable period of time during which a new customer has not applied for gas service at the premises, BC Gas may seal off the service line to the premises.

8.5 **Termination by BC Gas** - Unless the service agreement or applicable rate schedule specifies otherwise, BC Gas may terminate the service agreement for any reason by giving the customer at least 48 hours written notice.

9. Delayed Consumption

9.1 **Additional Charges** - If a customer has not consumed gas

(a) within 3 months for Inland and Columbia service areas and within 2 months for the Lower Mainland service area after the installation of the service line to the customer's premises, BC Gas may charge the minimum charge for each billing period after that, and

(b) within one year after installation of the service line to the customer's premises, BC Gas may charge the customer the full cost of construction and installation of the service line and meter set less the total of the minimum charges billed to the customer to that date.

9.2 **Refund of Charges** - If a customer who has paid the charges for a service line under section 9.1(b) (Additional Charges) consumes gas in the second year after installation of the service line, BC Gas will refund to the customer the payments made under section 9.1(b) (Additional Charges). If a refund is made under section 9.2 (Refund of Charges), the term of the service agreement will be one year from the time the customer begins consuming gas.

10. Service Lines

10.1 **Provided Installation** - If BC Gas' main is adjacent to the customer's premises, BC Gas

(a) will designate the location of the service lines on the customer's premises and determine the amount of space that must be left unobstructed around them, and

(b) will install the service line from the main to the meter set on the customer's premises at no additional cost to the customer provided

(i) the service line follows the route which is the most suitable to BC Gas,

(ii) the distance between the property line and the meter measured along that route does not exceed 20 metres, and

(iii) the distance from the front of the customer's building or machinery to the meter does not exceed 1.5 metres

(c) may charge for any non-standard construction costs such as creek crossing, casings, extra depth, etc.

10.2 **Extended Installation** - The customer may make application to BC Gas to extend the service line beyond that described in section 10.1 (Provided Installation), parts (b), (ii) and (iii). Upon approval by BC Gas and agreement for payment by the customer of the additional costs, BC Gas will extend the service line only if it is on the route approved by BC Gas.

10.3 **Customer Requested Routing** - If

(a) BC Gas' main is adjacent to the customer's premises, and

(b) the customer requests that its piping or service line enter its premises at a different point of entry or follow a different route from the point or route designated by BC Gas,

BC Gas may charge the customer for all additional costs as determined by BC Gas to install the service line in accordance with the customer's request.

10.4 **Temporary Service** - A customer applying for temporary service must pay BC Gas in advance for the costs which BC Gas estimates it will incur in the installation and subsequent removal of the facilities necessary to supply gas to the customer.

10.5 **Winter Construction** - If an applicant or customer applies for service which requires construction when, in BC Gas' opinion, frost conditions may exist, BC Gas may

(a) postpone the required construction until the frost conditions no longer exist, or

(b) carry out the construction.

If BC Gas carries out the construction, the applicant or customer may be required to pay all costs greater than the normal construction costs which are incurred due to the frost conditions.

10.6 **Additional Connections** - If a customer requests more than one service connection to the premises, BC Gas may install the additional service lines and may charge the customer for the cost of the additional installations and will bill the additional service connection from a separate meter and account.

10.7 **Easement Required** - If an intervening property is located between the customer's premises and BC Gas' main, the customer is responsible for the costs of obtaining an easement in favour of BC Gas and in a form specified by BC Gas, for the installation, operation and maintenance on the intervening property of all necessary facilities for supplying gas to the customer.

10.8 **Ownership** - BC Gas owns the entire service line from the main up to and including the meter set, whether it is located inside or outside the customer's premises.

10.9 **Maintenance** - BC Gas will maintain the service line.

10.10 **Supply Cut Off** - If the supply of gas to a customer's premises is cut off for any reason, BC Gas is not required to remove the service line from the customer's property or premises.

10.11 **Damage Notice** - The customer must advise BC Gas immediately of any damage occurring to the service line.

10.12 **Prohibition** - A customer must not construct any permanent structure over a service line or install any air intake openings or sources of ignition which contravene government regulations, codes or BC Gas policies.

10.13 **No Unauthorized Changes** - No changes, extensions, connections to or replacement of, or disconnection from BC Gas' mains or service lines, shall be made except by BC Gas' authorized employees, contractors or agents or by other persons authorized in writing by BC Gas. Any change in the location of an existing service line

(a) must be approved in writing by BC Gas, and

(b) will be made at the expense of the customer if the change is requested by the customer or necessitated by the actions of the customer.

11. Meter Sets & Metering

11.1 **Installation** - In order to bill the customer for gas delivered, BC Gas will install one or more meter sets on the customer's premises. Unless approved by BC Gas, all meter sets will be located outside the customer's premises at locations designated by BC Gas.

11.2 **Measurement** - The quantity of gas delivered to the premises will be metered using apparatus approved by Consumer and Corporate Affairs Canada. The amount of gas registered by the meter set during each billing period will be converted to gigajoules in accordance with the Electricity and Gas Inspection Act and rounded to the nearest one-tenth of a gigajoule.

11.3 **Testing Meters** - If a customer applies for the testing of a meter set and

(a) the meter set is found to be recording incorrectly, the cost of removing, replacing and testing the meter will be borne by BC Gas subject to section 24.4 (Responsibility for Meter Set), and

(b) if the testing indicates that the meter set is recording correctly, as defined by the Electricity and Gas Inspection Act, the customer must pay BC Gas for the cost of removing, replacing and testing the meter set as set out in the Standard Fees and Charges Schedule.

11.4 **Defective Meter Set** - If a meter set ceases to register, BC Gas will estimate the volume of gas delivered to the customer according to the procedures set out in Section 16.7 (Incorrect Register).

11.5 **Protection of Equipment** - The customer must take reasonable care of and protect all meter sets and related equipment on the customer's premises. The customer's responsibility for expense, risk and liability with respect to all meter sets and related equipment is set out in section 24.4 (Responsibility for Meter Set).

11.6 **No Unauthorized Changes** - No meter sets or related equipment shall be installed, connected, moved or disconnected except by BC Gas' authorized employees, contractors or agents or by other persons with BC Gas' written permission.

11.7 **Removal of Meter Set** - At the termination of a service agreement, BC Gas may disconnect or remove a meter set from the premises if a new customer is not expected to apply for service for the premises within a reasonable time.

11.8 **Customer Requested Meter Relocation** - Any change in the location of a meter set or related equipment

(a) must be approved by BC Gas in writing, and

(b) will be made at the expense of the customer if the change is requested by the customer or necessitated by the actions of the customer.

11.9 **Delivery Pressure** - The normal delivery pressure is 1.75 kPa. BC Gas may charge customers who require delivery pressure at other than the normal delivery pressure the additional costs associated with providing other than the normal delivery pressure.

12. Main Extensions

Main extension General Terms and Conditions to be determined in conjunction with the Integrated Resource Plan.

13. Interruption of Service

13.1 **Regular Supply** - BC Gas will use its best efforts to provide the constant delivery of gas or the maintenance of unvaried pressures.

13.2 **Right to Restrict** - BC Gas may require any of its customers, at all times or between specified hours, to discontinue, interrupt or reduce to a specified degree or quantity, the delivery of gas for any of the following purposes or reasons:

(a) in the event of a temporary or permanent shortage of gas, whether actual or perceived by BC Gas,

(b) in the event of a breakdown or failure of the supply of gas to BC Gas or of BC Gas' gas storage, distribution, or transmission systems,

(c) in order to comply with any legal requirements,

(d) in order to make repairs or improvements to any part of BC Gas' gas distribution, storage or transmission systems,

(e) in the event of fire, flood, explosion or other emergency in order to safeguard persons or property against the possibility of injury or damage.

13.3 **Notice** - BC Gas will, to the extent practicable, give notice of its requirements and removal of its requirements under section 13.2 (Right to Restrict) to its customers by

(a) newspaper, radio or television announcement, or

(b) notice in writing that is

(i) sent through the mail to the customer's billing address,

(ii) left at the premises where gas is delivered,

(iii) served personally on a customer, or

(iv) sent by facsimile or other electronic means to the customer, or

(c) oral communication.

13.4 **Failure to Comply** - If, in the opinion of BC Gas, a customer has failed to comply with any requirement of BC Gas under section 13.2 (Right to Restrict), BC Gas may, after notice to the customer communicated in the manner specified in section 13.2 (Right to Restrict), discontinue service to the customer.

14. Access to Premises and Equipment

14.1 **Access to Premises** - BC Gas must have a right of entry to the customers premises. The customer must provide free access to its premises at all reasonable times to BC Gas' authorized employees, contractors and agents for the purpose of reading, testing, repairing or removing meters and ancillary equipment, turning gas on or off, completing system leakage surveys, stopping leaks, examining pipes, connections, fittings and appliances and reviewing the use made of gas delivered to the customer, or for any other related purpose which BC Gas requires.

14.2 **Access to Equipment** - The customer must provide clear access to BC Gas' equipment. The equipment installed by BC Gas on the customer's premises will remain the property of BC Gas and may be removed by BC Gas upon termination of service.

15. Promotions and Incentives

15.1 **Promotion of Gas Appliances** - BC Gas may promote, sell, rent, lease, or finance natural gas vehicle equipment, gas appliances and related accessories on a cash or finance plan basis and make reasonable charges for these services as approved by the British Columbia Utilities Commission.

16. Billing

16.1 **Basis for Billing** - BC Gas will bill the customer in accordance with the customer's service agreement, the rate schedule under which the customer is provided service, and the fees and charges contained in the general terms and conditions.

16.2 **Meter Measurement** - BC Gas will measure the quantity of gas delivered to a customer using a meter set and the starting point for measuring delivered quantities during each billing period will be the finishing point of the preceding billing period.

16.3 **Multiple Meters** - Gas service to each meter set will be billed separately for customers who have more than one meter set on their premises.

16.4 **Estimates** - For billing purposes, BC Gas may estimate the customer's meter readings if, for any reason, BC Gas does not obtain a meter reading.

16.5 **Estimated Final Reading** - If a service agreement is terminated under section 8.1 (Termination by Customer), BC Gas may estimate the final meter reading for final billing.

16.6 **Incorrect Register** - If any meter set has failed to measure the delivered quantity of gas correctly, BC Gas may estimate the meter reading for billing purposes, subject to section 19 (Back-Billing).

16.7 **Bills Issued** - BC Gas may bill a customer as often as BC Gas considers necessary but generally will bill on a monthly or bi-monthly basis.

16.8 **Bill Due Dates** - The customer must pay BC Gas' bill for service on or before the due date shown on the bill which will be

(i) the first business day after the twenty-first calendar day following the billing date, or

(ii) such other period as may be agreed upon by the customer and BC Gas.

17. Advance Billing

17.1 **Where Available** - BC Gas may only use advance billing as described in this section for customers being supplied gas in the Lower Mainland service area.

17.2 **When Required** - BC Gas will use advance billing for

(a) a residential service customer who has not maintained a payment history satisfactory to BC Gas, or

(b) a commercial service applicant or customer who has not established or maintained credit satisfactory to BC Gas, or

(c) residential or commercial customers who apply for Advance Billing.

17.3 **Advance Billing** - In advance billing, BC Gas will bill a customer for the required amount one month in advance, based on the estimated monthly bill or one-twelfth of the estimated annual bill for consumption of gas by the customer. BC Gas may amend the required amount of the monthly bill from time to time. Such bills are deemed to have the same force and effect as bills which are based on actual meter readings.

17.4 **Due Date** - A customer billed by advance billing must pay BC Gas' bill for

(a) residential or commercial service, on or before the due date shown on the bill which will be the first business day after the twenty-first calendar day following the billing date; or

(b) customers enrolled in the advance payment discount plan as specified in section 18.5 (Payment).

17.5 **End of Advance Billing** - A customer billed by advance billing, as specified in section 17.2 (When Required), parts (a) and (b), who has paid the amounts due by the required dates during the immediately preceding 2 year period, may request BC Gas to stop billing by advance billing.

18. Advance Payment Discount Plan

18.1 **Where Available** - BC Gas may provide the advance payment discount plan described in this section only to those customers being supplied gas in the Lower Mainland service area.

18.2 **When Required** - BC Gas will use the Advance Payment Discount Plan for

(a) customers receiving commercial service who have not maintained a payment history satisfactory to BC Gas, or

(b) residential or commercial customers who request to enrol in the plan.

18.3 **Pre-authorized payment** - A customer enrolled in the advance payment discount plan will pay BC Gas bills in advance by pre-authorized bank debit and, in that event, the customer is entitled to receive a discount of 3/4 of 1% on the amount billed.

18.4 **Enrolment Procedures** - To enrol in the advance payment discount plan, a customer must

(a) apply to BC Gas, and

(b) arrange payment of any outstanding charges owed by the customer to BC Gas before the application will be accepted.

18.5 **Payment** - For a customer in the advance payment discount plan,

(a) BC Gas will bill the customer in advance under section 17 (Advance Billing), and

(b) the customer must arrange for payment of the bill by pre-authorized debit from the customer's bank account on or before the first business day after the tenth calendar day following the billing date.

18.6 **End of Plan** - A customer billed on the advance payment discount plan may end payment under the plan by giving one month notice to BC Gas as long as participation in the plan is not required under section 6 (Security for Payment of Bills). The customer will continue to be billed by advance billing under section 17 (Advance Billing) .

19. Back-Billing

19.1 **When Required** - BC Gas may, in the circumstances specified herein, charge, demand, collect or receive from its customers in respect of a regulated service rendered hereunder a greater or lesser compensation than that specified in the subsisting schedules applicable to that service.

In the case of a minor adjustment to a customer's bill, such as an estimated bill or an equal payment plan billing, such adjustments do not require back-billing treatment to be applied.

19.2 **Definition** - Back-billing means the rebilling by BC Gas for services rendered to a customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the customer or BC Gas, and may result from the conduct of an inspection under provisions of the federal statute, the Electricity and Gas Inspection Act ("EGI Act"). The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(a) stopped meter
(b) metering equipment failure
(c) missing meter now found
(d) switched meters
(e) double metering
(f) incorrect meter connections
(g) incorrect use of any prescribed apparatus respecting the registration of a meter
(h) incorrect meter multiplier
(i) the application of an incorrect rate
(j) incorrect reading of meters or data processing
(k) tampering, fraud, theft or any other criminal act.

19.3 **Application of Act** - Whenever the dispute procedure of the EGI Act is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

19.4 **Billing Basis** - Where metering or billing errors occur and the dispute procedure under the EGI Act is not invoked, the consumption and demand will be based upon the records of BC Gas for the customer, or the customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by BC Gas. Such estimates will be on a consistent basis within each customer class or according to a contract with the customer, if applicable.

19.5 **Tampering/Fraud** - If there are reasonable grounds to believe that the customer has tampered with or otherwise used BC Gas' service in an unauthorized way, or evidence of fraud, theft or other criminal act exists, then the extent of back-billing will be for the duration of the unauthorized use, subject to the applicable limitation period provided by law, and the provisions of sections 19.8 (Under Billing) to 19.11 (Changes in Occupancy) below do not apply.

In addition, the customer is liable for the direct (unburdened) administrative costs incurred by BC Gas in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by BC Gas on unpaid accounts from the date of the original under-billed invoice until the amount under-billed is paid in full.

19.6 **Remedying Problem** - In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the customer will be promptly notified of the error and of the effect upon the customer's ongoing bill.

19.7 **Over-billing** - In every case of over-billing, BC Gas will refund to the customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Simple interest, computed at the short-term bank loan rate applicable to BC Gas on a monthly basis, will be paid to the customer.

19.8 **Under-billing** - Subject to section 19.5 (Tampering/Fraud) above, in every case of under-billing, BC Gas will back-bill the customer for the shorter of

(a) the duration of the error; or

(b) six months for residential, commercial or irrigation; and

(c) one year for all other customers or as set out in a special or individually negotiated contract with BC Gas .

19.9 **Terms of Repayment** - Subject to section 19.5 (Tampering/Fraud) above, in all cases of under-billing, BC Gas will offer the customer reasonable terms of repayment. If requested by the customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal instalments corresponding to the normal billing cycle. However, delinquency in payment of such instalments will be subject to the usual late payment charges.

19.10 **Disputed Back-bills** - Subject to section 19.5 (Tampering/Fraud) above, if a customer disputes a portion of a back-billing due to under-billing based upon either consumption, demand or duration of the error, BC Gas will not threaten or cause the discontinuance of service for the customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the customer to dispute that portion of the back-billing. The undisputed portion of the bill shall be paid by the customer and BC Gas may threaten or cause the discontinuance of service if such undisputed portion of the bill is not paid.

19.11 **Changes in Occupancy** - Subject to section 19.5 (Tampering/Fraud) above, back-billing in all instances where changes of occupancy have occurred, BC Gas will make a reasonable attempt to locate the former customer. If, after a period of one year, such customer cannot be located, the applicable over or under billing will be cancelled.

20. Equal Payment Plan

20.1 **Definitions** - In this section, "equal payment plan period" means

(a) in the Lower Mainland service area, a period of twelve consecutive months commencing with a normal meter reading date at the customer's premises, and

(b) in the Inland and Columbia service areas, a period of twelve consecutive months commencing with the July billing to the customer.

20.2 **Application for Plan** - A customer may apply to BC Gas at any of its office locations in person, by mail, by telephone, by facsimile or by other electronic means to pay fixed monthly instalments for gas delivered to the customer during the equal payment plan period. Acceptance of the application will be subject to BC Gas finding the customer's credit to be satisfactory.

20.3 **Monthly Instalments** - BC Gas will fix monthly instalments for a customer so that the total sum of all the instalments to be paid during the equal payment plan period will equal the total amount payable for the gas which BC Gas estimates the customer will consume during the equal payment plan period.

20.4 **Changes in Instalments** - BC Gas may at any time, increase or decrease the amount of monthly instalments payable by a customer in light of new consumption information or changes to the rate schedules or the General Terms and Conditions.

20.5 **End of Plan** - Participation in the equal payment plan may be ended at any time

(a) by the customer giving 5 days' notice to BC Gas, or

(b) by BC Gas, without notice, if the customer has not paid the monthly instalments as required.

20.6 **Payment Adjustment** - At the earlier of the end of the equal payment plan period for a customer or the end of the customer's participation in the plan under section 20.5 (End of Plan), BC Gas will

(a) compare the amount which is payable by the customer to BC Gas for gas actually consumed on the customer's premises from the beginning of the equal payment plan period to the sum of the monthly instalments billed to the customer from the beginning of the equal payment plan period, and

(b) pay to the customer or credit to the customer's account any excess amount or bill the customer for any deficit amount payable.

21. Late Payment Charge

21.1 **Late Payment Charge** - If the amount due for service or service related charges on any bill has not been received in full by BC Gas or by an agent acting on behalf of BC Gas on or before the due date specified on the bill, and the unpaid balance is $15 or more for the Inland and Columbia divisions and $30 or more for the Lower Mainland division, BC Gas may include in the next bill to the customer the late payment charge specified in the Standard Fees and Charges Schedule.

21.2 **Equal Payment Plan** - If

(a) the monthly instalment and service related charges due from a customer billed under the equal payment plan set out in section 20 (Equal Payment Plan) have not been received by BC Gas or by an agent acting on behalf of BC Gas on or before the due date specified on the bill, and

(b) the customer's account is in deficit.

BC Gas may include in the next bill to the customer the late payment charge in accordance with section 21.1 (Late Payment Charge) on the amount due. For purposes of this section, an account is in deficit during a period when the amount credited to the customer's account is less than the amount which is payable by the customer for gas delivered and service related charges during that period.

22. Returned Cheque Charge

22.1 **Dishonoured Cheque Charge** - If a cheque received by BC Gas from a customer in payment of a bill is not honoured by the customer's financial institution for any reason other than clerical error, BC Gas may include a charge specified in the Standard Fees and Charges Schedule, in the next bill to the customer for processing the returned cheque whether or not the service has been disconnected.

23. Discontinuance of Service and Refusal of Service

23.1 **Discontinuance With Notice and Refusal Without Notice** - BC Gas may discontinue service to a customer with at least 48 hours written notice or refuse service without notice for any of the following reasons:

(a) the customer has not fully paid BC Gas' bill with respect to services on or before the due date,

(b) the customer or applicant has failed to pay any required security deposit, equivalent form of security, or post a guarantee or required increase in it by the specified date,

(c) the customer or applicant has failed to pay BC Gas' bill in respect of another premises on or before the due date,

(d) the customer or applicant occupies the premises with another occupant who has failed to pay BC Gas' bill, security deposit, or required increase in the security deposit in respect of an other premises which was occupied by that occupant and the customer at the same time,

(e) the customer or applicant is in receivership or bankruptcy, or operating under the protection of any insolvency legislation and has failed to pay any outstanding bills to BC Gas.

23.2 **Discontinuance or Refusal Without Notice** - BC Gas may discontinue or refuse the supply of gas or service to a customer at the customer's premises without notice for any of the following reasons:

(a) the customer or applicant has failed to provide reference information and identification acceptable to BC Gas, when applying for service or at any subsequent time on request by BC Gas,

(b) the customer has defective pipe, appliances, or gas fittings in the premises,

(c) the customer uses gas in such a manner as in BC Gas' opinion

(i) may lead to a dangerous situation, or

(ii) may cause undue or abnormal fluctuations in the gas pressure in BC Gas' gas transmission or distribution system,

(d) the customer fails to make modifications or additions to the customer's equipment which have been required by BC Gas in order to prevent the danger or to control the undue or abnormal fluctuations described under paragraphs (c),

(e) the customer breaches any of the terms and conditions upon which service is provided to the customer by BC Gas,

(f) the customer fraudulently misrepresents to BC Gas its use of gas or the volume delivered,

(g) the customer vacates the premises,

(h) the customer's service agreement is terminated for any reason, or

(i) the customer stops consuming gas on the premises.

23.3 **Application to Former Tariffs** - Section 23.1 (Discontinuance With Notice and Refusal Without Notice), parts (c), (d) and (e), apply to bills rendered under these General Terms and Conditions and under the following former tariffs:

Lower Mainland - Gas Tariff,
Inland - Gas Tariff B.C.E.C. No. 2,
Columbia - Gas Tariff B.C.U.C. No.1,

24. Limitations on Liability

24.1 **Responsibility for Delivery of Gas** - BC Gas, its employees, contractors or agents are not responsible for any loss, damage, costs, injury, including death, incurred by any customer or any person claiming by or through the customer caused by or resulting from, directly or indirectly, any discontinuance, suspension or interruption of, or failure or defect in the supply or delivery or transportation of, or refusal to supply, deliver or transport gas whether caused by the negligence or otherwise of BC Gas, its employees, contractors or agents.

24.2 **Responsibility Before Delivery Point** - The customer is responsible for all expense, risk and liability with respect to

(a) the use or presence of gas before it passes the delivery point in the customer's premises, and

(b) company-owned facilities serving the customer's premises

if any loss or damage caused by or resulting from failure to meet that responsibility is caused, or contributed to, by the act or omission of the customer or a person for whom the customer is responsible.

24.3 **Responsibility After Delivery Point** - The customer is responsible for all expense, risk and liability with respect to the use or presence of gas after it passes the delivery point.

24.4 **Responsibility for Meter Set** - The customer is responsible for all expense, risk and liability with respect to all meters sets or related equipment at the customer's premises unless any loss or damage is

(a) directly attributable to the negligence of BC Gas, its employees, contractors or agents, or

(b) caused by or resulting from a defect in the equipment. The customer must prove that negligence, or defect.

24.5 **Customer Indemnification** - The customer must indemnify and hold harmless BC Gas, its employees, contractors or agents from all claims, loss, damage, costs or injury, including death, suffered by the customer or any person claiming by or through the customer or any third party caused by or resulting from the use of gas by the customer or the presence of gas in the customer's premises, or from the customer or customer's employees, agents or contractors' damaging BC Gas' facilities.

25. Miscellaneous Provisions

25.1 **Taxes** - The rates and charges specified in the applicable rate schedules do not include any local, provincial or federal taxes, assessments or levies imposed by any competent taxing authorities which BC Gas may be lawfully authorized or required to add to its normal rates and charges or to collect from or charge to the customer.

25.2 **Conflicting Terms and Conditions** - Where anything in these general terms and conditions conflicts with special terms or conditions specified under an applicable rate schedule or service agreement, then the terms or conditions specified under the rate schedule or service agreement govern.

25.3 **Authority of Agents of BC Gas** - No employee, contractor or agent of BC Gas has authority to make any promise, agreement or representation not incorporated in these general terms and conditions or in a service agreement, and any such unauthorized promise, agreement or representation is not binding on BC Gas.

25.4 **Additions, Alterations and Amendments** - The general terms and conditions, fees and charges, and rate schedules may, with the approval of the British Columbia Utilities Commission, be added to, cancelled, altered or amended by BC Gas from time to time.

25.5 **Headings** - The headings of the sections set forth in the general terms and conditions are for convenience of reference only and will not be considered in any interpretation of the general terms and conditions.

26. Direct Purchase Agreements

26.1 **Collection of Incremental Direct Purchase Costs** - Where BC Gas incurs any costs relating to implementing, providing or facilitating the direct purchase arrangements of a customer, agent, broker or marketer, BC Gas may collect those costs from the customer, agent, broker or marketer. Such costs may, subject to BCUC approval, include the costs of arranging, acquiring or transporting substitute gas supplies as well as any other costs or obligations relating to the direct purchase arrangement that are incurred by BC Gas. BC Gas can bill the customer for such costs as part of the regular BC Gas bill for service.

26.2 **Direct Purchase Customers Returning to BC Gas System Supply** - Where a customer has acquired gas under a direct purchase arrangement and later wishes to return to the system gas supply of BC Gas

(a) BC Gas may require that the customer provide BC Gas up to one year's written notice before the date on which the customer wishes to return to system gas supply,

(b) BC Gas will supply the customer with system gas when the customer wishes to return to system gas supply if BC Gas is able to secure additional gas supply and transportation to accommodate the customer, and

(c) BC Gas may, subject to BCUC approval, charge the customer for any costs associated with the customer returning to system gas supply. Such costs may include, among other things, the costs of securing additional gas supply and transportation to accommodate the customer. BC Gas can bill the customer for such costs as part of the regular BC Gas bill for service.

Standard Fees and Charges Schedule

Administrative Charges

Application Fee	
Existing Installation	\$25.00
New Installation	\$75.00
Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance
Dishonoured Cheque Charge	\$16.00

Interest on Cash Security Deposits:

Inland and Columbia Service Areas

BC Gas will pay interest on cash security deposits at BC Gas' prime interest rate minus 2%. BC Gas prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by BC Gas' lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the customer's account in January of each year.

Lower Mainland Service Area

BC Gas will pay simple interest on cash security deposits at the rate of interest which BC Hydro's lead bank publishes on January 1st and July 1st of each year as payable on one to two year term deposits of the same amount as the security deposit. For the purpose only of determining the appropriate rate of interest, security deposits of less than \$1,000 shall be deemed to be \$1,000 and security deposits of \$100,000 or more shall be deemed to be \$99,999.

Payment of interest will be credited to the customer's account on 30 June and 31 December of each year, or at the time of the customer's final bill.

Metering Related Charges

Disputed Meter Testing Fees

Meters rated at less than or equal to 14.2 M^3/hour	\$30.00
Meters rated greater than 14.2 M^3/hour	Actual Costs of Removal and Replacement

Rate Schedules

Rate schedules to be inserted upon final determination of the Rate Design Application.

PROPOSAL TO REVISE THE BC GAS MAIN EXTENSION POLICY AND ECONOMIC TEST

1.0 SUMMARY

BC Gas has examined the main extension policy of each Division in the Company and has developed a new policy which will be uniformly applied across all service areas.

Investigations have indicated that using a discounted cash flow (DCF) test is appropriate for BC Gas main extension evaluations.

The test and its application has been developed to satisfy the criterion that existing customers are not unduly burdened but at the same time do not unduly benefit from new main extensions.

2.0 INTRODUCTION

BC Gas is seeking approval for the consolidation for regulatory purposes of the Lower Mainland, Inland, and Columbia Divisions. To ensure consistency with the proposal for uniform delivery charges and common general terms and conditions the Company has reviewed the existing gas main extension policies and economic tests to determine if they are compatible with the proposed consolidation. In addition, the review of the main extension policies and tests was undertaken to address concerns expressed by the Commission in its August 5th, 1992 Decision regarding the Revenue Requirement

Application of BC Gas. Specifically, the Commission identified two issues:

1. If the current main extension tests are not reasonable, existing customers may be subsidizing new customers; and

2. Whether the Company has been applying the tests on a consistent basis.

Prior to reviewing the current main extension policies and tests, and making any new proposals, a discussion of the need for a main extension test is useful. BC Gas is the sole distributor of natural gas in its service area which comprises a significant portion of the Province of British Columbia. Being the sole distributor creates a situation where residential, commercial, and most industrial customers in the Company's service area must obtain natural gas distribution service from BC Gas. In those situations where the provision of service requires the installation of new gas distribution mains a consistent economic test should be in place to ensure that both existing and new customers are treated fairly.

In this application, the Company will demonstrate why it is desirable to change the current tests. The Company proposes the following changes to the gas main extension policy and test:

1. Implementation of a uniform main extension policy and economic test for residential, commercial and general service customers for the Lower Mainland, Inland and Columbia service areas.

2. Utilization of a Discounted Cash Flow (DCF) test that recognizes the time value of money and the expected useful life of the capital investment.

3. Estimation of future revenue based upon such factors as the size of the premises to be served, local yearly average temperatures and the number of appliances installed.

4. Use of project specific construction cost estimates for each proposed main extension.

5. Provision of service to large industrial firm customers on a stand alone basis. Customers with large firm loads will be expected to cover all costs of service.

6. Establishment of a Gas System Extension Fund (GSEF) that will accumulate revenues to assist with the extension of gas service to unserved areas within the BC Gas service area.

In the process of developing the main extension policy and economic test, BC Gas has considered the concerns expressed by the Commission regarding the economics of main extensions, the ongoing desire for natural gas service in a number of British Columbia communities not currently served, and the policies and tests utilized by other gas utilities.

2.1 Review of Current BC Gas Main Extension Policies and Economic Tests

2.1.1 Differences Between Divisions

At the time of its inception in 1988, BC Gas inherited four different geographically based divisions, three from the Inland Natural Gas Company and one from the former BC Hydro Gas Division. Within these four divisions were three different main extension tests.

The gas main extension policies and tests for the Lower Mainland, Inland, and Columbia Divisions were developed throughout the history of those Divisions and have remained unchanged since the formation of BC Gas. Variations exist with regard to the revenue margin used in the calculations, the determination of main extension costs and the time period for the test. In addition, none of the current tests recognizes the time value of money. The following table summarizes the current main extension tests for each division.

MAIN EXTENSION TESTS		
DIVISION	**REVENUE CALCULATION**	**CAPITAL COST METHODOLOGY**
Lower Mainland	Gross revenue less the cost of gas multiplied by 5 years consumption	Project Specific
Inland & Columbia	Gross revenue less the cost of gas multiplied by 6 years consumption	Divisional Average Construction Costs

The variation in the number of years of consumption used in each Division, the difference in capital cost methodology, and the use of a relatively unsophisticated economic test as a substitute for more advanced methods of financial analysis may raise concerns about the reasonableness of the main extension tests. Potential customers in the Lower Mainland service area, where a shorter period is used to determine revenue, do not receive the same treatment as Inland and Columbia customers and may be required to make contributions in aid of construction not required by Inland and Columbia customers. As well, the use of average costs in the Inland and Columbia Divisions compared to project specific costs in the Lower Mainland creates inequities in the treatment of customers between Divisions. However, the Inland and Columbia Divisions have recently begun a transition to project specific costing for main extensions.

2.1.2 Commission Concerns

Interest in the main extension policy was expressed by the Commission during past Inland Natural Gas Co. Ltd. hearings. The Commission supported the broad based service policy of Inland Natural Gas but expressed reservations about the economic consequences of the Company's main extension policies. The predominant Commission concern was that under existing main extension tests, the true cost impact of new main extensions on existing customers could not be determined. The use of a (DCF) test has the advantage over the current tests of considering the time value of money as well as the entire lifecycle of the investment. Accordingly, DCF has the potential to provide more reasonable test results than the current tests.

Another concern expressed by the Commission related to the consistency demonstrated by the Company in applying the main extension economic tests. The Company strives to treat potential customers fairly when evaluating main extension applications to ensure consistency. In the Inland and Columbia Divisions, a standard main extension policy is referred to by all company personnel when completing and processing main extension applications. In the Lower Mainland Division, consistency is achieved through the use of the Sales Function and Procedures Manual. Upon approval of the proposed main extension policy, the Company will prepare and issue a standard procedure manual for the Lower Mainland, Inland, and Columbia service areas.

2.1.3 BC Gas Objectives

It always has been, and will continue to be, a Company objective to provide broad based gas service in all areas that

BC Gas currently serves. In addition, it is the intention of BC Gas to extend service to communities not presently receiving gas service, providing that such service is practical and does not put undue burden on the existing customer base or company finances.

The new main extension policy will govern the extension of gas service within and beyond the area currently served by the Company.

2.2 Main Extension Policy and Test Design Considerations

In the process of developing a new main extension policy and test for the Company a number of important issues were considered.

2.2.1 Revenue

To be effective, a uniform test must be able to take into consideration the significant differences between various parts of the service areas. The test should recognize that individual customers' annual consumption of natural gas can vary considerably as a result of larger premises, more gas appliances in use, and colder winter climates. The annual consumption of potential customers has a direct impact on the revenue the Company will receive over the life of the capital investment and should be a key consideration in the main extension application.

2.2.2 Costs

To be consistent with the determination of future revenues, the estimate of construction costs should be project specific to the greatest extent possible. Consideration should also be given to the impact each new main extension has on the Company's overall system capacity and the periodic need for major system delivery improvements. The Work Management System will enable BC Gas personnel to accurately estimate construction costs based on the most up to date costing information available.

2.2.3 <u>Economic Development</u>

The widespread availability of natural gas service can be a significant factor in the economic development of the Province of British Columbia. The BC Gas Competitive Energy and Price Elasticities of Demand Studies filed with the Rate Design Phase B application indicate that natural gas rates are less than the prices of the competing fuels such as electricity, propane, and furnace oil for residential and commercial customers in most of the BC Gas service area. Communities with natural gas service are in a better position to compete for and attract new industry that is sensitive to energy costs. Furthermore, residential and commercial customers in the communities served with natural gas enjoy the benefits of lower energy costs.

2.2.4 <u>Environmental Considerations</u>

Natural gas is gaining prominence world wide for its clean burning characteristics as compared to fuels such as oil, wood, and coal. As such, it is desirable to promote the widespread use of natural gas for environmental reasons.

2.2.5 <u>Time Value of Money</u>

The investment in additional gas distribution mains is no different than any other business investment involving a trade-off between current dollar outlays and future benefits. To the extent that the current tests do not consider the time value of money, the future benefits of a particular main extension may not be accurately stated.

2.2.6 <u>Contributions</u>

A main extension that fails to pass the economic test may still be constructed if contributions covering the revenue shortfall are available. Potential sources for contributions are customers on the proposed main extension, property owners whose lots will now have access to gas service, developers, governments, and the electric utility if sufficient electric load reduction is projected.

3.0 SELECTION OF TEST

Selection of a test included a review of tests used by other utilities in Canada and the United States. Most of the effort revolved around the identification of an existing or new test method that would address the concerns of the Commission but would also be easy to apply and satisfy the needs of prospective gas customers.

3.1 Review of Test Methods

The main extension policies prevailing among gas distribution companies fall into three broad categories:

1. A "free footage" test in which main will be extended up to a threshold distance (e.g 30 metres) at no charge to the customer. An example is San Diego Gas and Electric which allows a free footage of 75 feet for customers who meet certain base load requirements.

2. A widely used method compares the revenue estimate (such as 2 year's gross revenue or 6 year's net revenue) with the cost of the main extension. Three different versions of this method are currently used by BC Gas.

3. The third method can be classified as a "Return on Investment" method. Revenues and costs are evaluated using one of several rate of return methods, such as:

- discounted cash flow
- internal rate of return
- return equal to allowable return on rate base.

The extension policies currently used by gas distribution companies in Canada and the U.S differ widely. The differences are products of local conditions, such as geography, gas supply, costs, and regulatory concerns. The American Gas Association did a survey of main extension tests throughout North America and concluded that there was no correlation between the methodology and the size of company.

Pacific Northern Gas uses a main extension test in which "the after tax fifth year return is calculated as a percent of fifth year rate base, to determine whether the projected return on rate base meets or exceeds the Company's allowed rate of return" (Page 1, PNG Policy).

The Ontario Energy Board (OEB 134, June 1, 1987) directed Ontario utilities to develop a three-stage process for extension feasibility analysis. The first stage is a discounted cash flow (DCF) analysis of any given project. The second stage is designed to quantify public interest factors not considered at stage one. The third stage takes into account all other public interest factors plus stage one and two.

4.0 PROPOSED MAIN EXTENSION POLICY AND ECONOMIC TEST

The proposed policy of the Company will be to extend gas service as widely as possible without creating an undue cost or benefit to the Company's existing customers. If the aggregate of all main extensions in a particular year provides a zero or positive net present value, existing customers will not be affected by the construction of those main extensions. The main extension test will be used to identify uneconomic main extensions and calculate required contributions. The DCF method has been selected for the proposed main extension test to be implemented. The improved accuracy of the DCF test outweighs the difficulties caused by its complexity. A general discussion of the DCF test follows and details are included in the Appendix.

4.1 Revenue Calculations

The DCF model will discount the revenue expected over the life of the proposed main extension and will take into consideration the following:

1. Consumption projections will be project specific and will consider whether the premises to be served are newly constructed or existing premises, the level of saturation of gas appliances over time, and the type of premises being served (eg. single family dwellings, townhomes, manufactured homes, commercial building or industrial sites).

2. Whether the customers are actually committed to taking gas service now (ie. signed service contracts) and if not, when they will connect in the future

3. The normal temperatures experienced in the area of the province where the main extension is proposed.

4. A discount rate based on BC Gas' approved cost of capital, adjusted to an after tax rate.

Using the appropriate tariff, projected consumption will be translated to a revenue stream which will be discounted to a present value. The revenue calculation is net of the cost of gas. In those cases where a substantial portion of the future revenue to be received will come from only one of the customers to be served, the Company may require certain minimum annual payments from that particular customer as part of the contract for service to ensure the financial viability of the investment.

4.2 Cost Calculations

Cost estimates for a proposed main extension will be determined using the Company's Work Management System and will be project specific to the extent possible. In some cases the size of the main to be installed may be larger than that necessary to serve the customers. The installation of larger mains may be required to meet future growth in areas beyond that served by the proposed main extension. This is often the case when extending gas mains into large new subdivisions or when an opportunity exists to reinforce the distribution system by connecting to another existing section. In these cases, the Company may waive all or a portion of the required contribution in aid of construction determined in the economic test.

4.3 Contributions in Aid of Construction

In those situations where the proposed main extension does not meet the test, the customer(s) to be served will be asked to make a contribution in aid of construction. When multiple customers will be served by the proposed extension, each customer will be required to provide a contribution on a fair and reasonable basis. The Company proposes to waive contributions less than $100 per customer given the administrative burden associated with processing contributions.

Should customers in addition to those projected in the original application connect to the main extension within five years from the date of initial installation, the original contributors will be eligible for a pro-rated refund of their contribution. The refund will be calculated by determining the reduced revenue shortfall that will result in the DCF test over the life of the main extension and will be distributed on the basis of their original contributions. In those situations where the increased revenue to be realized from the additional customer(s) does not completely eliminate the need for a contribution, the new customer(s) will be required to contribute to the revenue shortfall. No refund will be applicable for customer additions to further main extensions that are connected to the main for which the contributors made their original payments. In addition, no interest will be paid on the refund of contributions and the refund will not exceed the amount of the original contribution.

The Company will conduct a final review of each main extension at the end of the first five years of use and will make no refunds after that review is completed.

To assist those customers required to make a contribution, the Company proposes to implement a Main Extension Surcharge mechanism that, when the new Customer Information System (CIS) is in place at BC Gas, will enable potential customers to make their contribution in aid of construction as part of their regular monthly gas bill payment. The main extension surcharge amount would be determined so that the total required contribution, including interest, would be paid within a 36 month period. The Main Extension Surcharge would only apply in those situations where the required contribution per customer is in excess of $300 and the customer would be subject to the Company's normal credit terms and conditions.

5.0 IMPACT OF PROPOSED TEST

BC Gas has reviewed actual main extensions constructed in 1992 in the Lower Mainland, Inland, and Columbia Divisions that were approved under the existing tests and subjected them to the proposed DCF test. Table 1 below indicates the number of main extensions constructed in 1992 that met, and did not meet, the proposed DCF test, those requiring contributions in aid of construction under the DCF test, and under the existing tests, and the difference between the contributions required under the existing tests and the proposed DCF test.

TABLE 1	EVALUATION OF ACTUAL 1992 MAIN EXTENSIONS UNDER THE PROPOSED DISCOUNTED CASH FLOW TEST						
Division	# Of Main Extensions Analyzed	# of Main Extensions Meeting DCF Test	# of Main Extensions Requiring Contri-butions Under DCF Test	# of Main Extensions Requiring Contributions Under Existing Tests	Contri-butions Required Under DCF Test	Contributions Collected Under Existing Tests	Difference
Lower Mainland	304	285	19	76	$94,000	$385,000	($291,000)
Inland	594	558	36	56	$47,000	$122,300	($75,300)
Columbia	33	28	5	14	$11,000	$75,000	($64,000)

It is important to recognize that the DCF model includes the cost for the gas services and meters in addition to the cost of the gas main. The current 5 and 6 year net revenue tests only address the cost of the gas main in their calculations.

6.0 UNSERVED AREAS

BC Gas receives, on an on-going basis, requests from both residents and elected officials, to provide natural gas service to areas currently not served by the Company. The availability of natural gas could help these communities to attract new industries and provide lower energy costs for existing businesses and residents. Some of the communities currently not served include such towns as Clearwater, Invermere and Golden in the Interior, and Belcarra in the Lower Mainland. While most of these communities have building densities that could economically justify the installation of gas mains within the town limits, the distances between those communities and the nearest point of the existing gas distribution infrastructure makes the overall extension uneconomic. In previous years, funding from the Federal and Provincial governments had helped BC Gas to serve previously uneconomic locations, however, funding is not currently available.

BC Gas proposes to establish a Gas System Extension Fund (GSEF) that would accumulate funds from various sources to assist in reducing the large contributions in aid of construction that are required to bring gas service to the unserved areas. Specifically, the fund would be used towards the cost of the gas system infrastructure necessary to bring gas from the nearest point on the Company's existing system to the boundary of the community to be served. Potential sources of funding are new government contributions, refunds, gas supplier incentives, regional district tax levies, a portion of the gas sales margins from Rate Schedule 10 customers, and some of the revenue from BC Gas' off-system gas sales. The Company proposes to explore with the Commission the inclusion of funds in the GSEF.

The GSEF is based upon the establishment of similar funds by gas utilities in North Carolina that were ordered on April 9, 1992 by the North Carolina Utilities Commission to establish such funds consisting of customer surcharges and supplier refunds. The order resulted from legislation enacted by the North Carolina General Assembly on July 8, 1991. Details regarding the North Carolina Special Natural Gas Expansion Fund are included in the Appendix.

BC Gas proposes to periodically submit for Commission approval expansion projects that would utilize funds from the GSEF to make up revenue short-falls that are not adequately met by customer contributions and other sources of funding. While the project selection criteria must still be determined, the likely criteria would include the required contribution per customer, total project cost, type and quantity of fuel displaced, economic benefits, and environmental issues.

The Company proposes to maintain the GSEF until such time as all major unserved communities in the BC Gas service area are provided with gas service. It is estimated that approximately $50 million will be required to meet the revenue shortfall necessary to complete the remaining 80 main extension projects that did not qualify for Provincial Gas Extension Program funds prior to the discontinuance of that program.

7.0 SUMMARY

To ensure consistency with the BC Gas application to consolidate the Lower Mainland, Inland, and Columbia Divisions, the Company has reviewed the main extension policies and tests that currently exist for each Division. The review was also undertaken to address Commission concerns regarding the reasonableness of the tests.

The review has indicated a uniform test throughout the three service areas that uses a discounted cash flow test will provide fair treatment to both existing and potential customers. In the proposed test the aggregate of all main extensions in a year are to have a positive or zero net present value. Extending gas service to currently unserved areas will require the accumulation of funds from various sources to meet the significant revenue shortfalls that would be experienced by the Company in providing service.

APPENDIX

MAIN EXTENSION TEST

TO FOLLOW

GAS COST RECONCILIATION ACCOUNT (GCRA)

On December 22, 1992 BC Gas applied to the BCUC to establish, effective January 1, 1993, a Gas Cost Reconciliation Account. This application was approved on an interim basis in BCUC Order No. G-5-93, Item 2. The December 22, 1992 Application also sought to use a gas cost recovery methodology from a previous application dated July 15, 1992, for the period from July 15, 1992 to December 31, 1992. BC Gas withdraws this aspect of the December 22, 1992 Application relating to the July 15, 1992 to December 31, 1992 period. The following material is substantially the same as the December 22, 1992 Application with respect to the GCRA from January 1, 1993 on.

The purpose of the GCRA is to ensure that the rates for gas sales fully recover, but do not over-recover, the gas costs incurred by the utility, independent of weather conditions and variations which may occur from time to time in the various gas cost components. BC Gas is proposing a mechanism that will deal with all of the utility's gas supply costs, both fixed and variable, and that will streamline for regulatory and accounting purposes the appropriate recovery of those costs in rates.

1.0 BACKGROUND

The current methodology of flowing through gas cost changes is a continuation of the approach used by Inland over many years when gas prices were regulated. Gas costs during that period were predictable and subject to few adjustments. Adjustments that were needed were dealt with expeditiously by way of a flow-through application. As Inland, and now BC Gas, have moved towards greater reliance on deregulated gas purchasing, the complexity of gas cost forecasting has increased and with it the frequency of adjustments to rates due to gas cost changes.

Along with the trend to deregulated gas purchasing, gas purchase costs have moved from largely variable commodity prices to market based pricing that rewards higher load factors. Previous take-or-pay arrangements have been largely replaced by fixed cost obligations. As one of the first changes in this regard, Westcoast rates moved to a fixed/variable allocation methodology with the overwhelming majority of pipeline tolls put on a demand basis. More recently, the utility has been active in obtaining more cost effective peaking and storage gas, but with costs containing a high component of fixed charges. Lastly, since November 1, 1991 the cost of the utility's baseload gas for the Inland and Lower Mainland Divisions has also contained a fixed producer demand cost component.

The Rate Design Phase A hearing dealt with the utility's allocation of gas costs on the basis of coincident peak demands by its various customer classes. The Phase A allocation process assumed normal weather conditions.

This Application seeks to stabilize permanently the recovery of gas costs in the utility's rates for gas sales. The GCRA is intended to deal with the recovery of gas costs only.

2.0 MECHANICS OF THE GAS COST RECONCILIATION ACCOUNT

2.1 Applicability

The proposed GCRA (Attachment 1) will be set up to capture differences in gas costs from forecast and to record all differences from forecast in the recovery of those costs from the utility's gas sales. This will require separate accounting of the fixed and variable components for the combined gas purchases for the Inland and Lower Mainland Divisions and separate purchases of the Columbia and Fort Nelson service areas.

On the cost side, the GCRA will accumulate unforecast changes in gas costs, such as in:

- demand charges for gas supply and pipeline transportation;
- producer credits for use of pipeline capacity, Volume Incentive Adjustment and any Gas Inventory Charges;
- Pipeline (Westcoast, ANG and Northwest) fuel use and cost of fuel;
- U.S./Canadian dollar exchange rates associated with gas supply or pipeline costs;
- commodity purchase volume and price variances affecting average commodity costs, such as variances in volume due to other than normal weather patterns or variances in the cost of baseload gas that may be subject to arbitration
- arrangements to purchase peaking supplies or spot gas not known when the forecast was prepared.

Secondly, the GCRA will accumulate unforecast changes in the recovery of gas costs on the basis of the standard cost of gas assigned to each customer class under normal weather, based on the Phase A methodology. These will include:

- changes in sales volumes by class, resulting in a change in gas cost recovery;
- contributions by interruptible and off-line sales, towards recovery of the utility's gas costs.

2.2 Annual Gas Cost Forecast

For the initial year, BC Gas proposes to use the forecast unit gas costs consistent with the April 27, 1993 update to the 1993 Revenue Requirement Application. Thereafter, gas costs will be forecast annually on the basis of a calendar year. This would be very similar to previous forecasts prepared for flow through purposes. The most significant variation will be that changes in pipeline tolls or fuel costs can be accommodated on a forecast basis.

As in the past, the forecast will be allocated to each customer class in the manner determined under Phase A or as applicable to the Columbia and Fort Nelson service areas. In this manner, the annual forecast will be the basis for the gas cost component of the sales rates for the upcoming year without further planned adjustment. Under routine circumstances, rates for gas cost recovery would be adjusted only once, effective each January 1. Included in these rates would be any cost components required to recover a forecast deficiency from the previous year.

2.3 Accounting Treatment

i) <u>Gas Costs</u>

Beginning January 1, 1993, gas purchase costs incurred, excluding costs inventoried to storage, will be charged to the GCRA. Gas volumes withdrawn from storage for system supply would be deducted from the inventory account at the average cost of inventory and also charged to the GCRA. Costs will be segregated between fixed and variable components.

ii) <u>Fixed Cost Recovery</u>

Fixed costs will be charged to cost of gas and credited to the GCRA based on actual sales volumes per rate class times the forecast unit fixed costs.

The variation between actual fixed costs incurred and the fixed costs allocated to core customers on a unit basis will remain in the deferral accounts.

iii) <u>Variable Cost Recovery</u>

Variable costs will be charged to cost of gas and credited to the GCRA based on actual sales volumes per rate class times the forecast unit variable cost.

The variation between the actual variable unit cost and the budgeted variable unit cost will remain in the deferral accounts.

iv) <u>Core Market Contribution Credit</u>

It is proposed that non-margin gas sales revenues from interruptible customers, off-system sales and other non-core customers will provide a credit to fixed gas costs and will remain in the deferral account. To the extent such revenues are not included in the forecast, the amount of the credit will tend to provide a positive bias towards the recovery of fixed gas costs.

2.4 Allocation to Rates of Deficiencies or Over-Recoveries

Most fixed and variable gas costs are pooled and allocated across the core market rate classes within the Inland and Lower Mainland service areas. Deficiencies or over recoveries of fixed and variable costs recorded in the GCRA will be allocated back to customers in a manner consistent with the Phase A methodology. To the extent there are variances in gas costs assigned by service area, the under and over recoveries will be allocated to customers within each service area.

For the Columbia and Fort Nelson service areas deficiencies or over recoveries of costs will be allocated back in a manner consistent with the existing methodology.

2.5 Mid-Year and End-of-Year Adjustments

It is the utility's objective to minimize the accumulation of significant GCRA deficits. Monthly monitoring of variations to forecast will be used to provide an early warning of any mismatch between gas costs and the recovery of these costs. Ideally, changes in various costs and recoveries will tend to balance out over the year. However, when weather induced changes in gas cost recovery such as in 1992, or changes in Westcoast tolls, for example, cause significant unforecast balances to accrue in the GCRA, a mid-year adjustment to the gas cost recovery may be required to minimize the deferral amounts.

BC Gas proposes to refund positive gas cost recovery balances should they become significant. In general, this will ensure that customers who over-contributed towards gas costs receive appropriate credit. In order to minimize administrative costs in relation to benefits and to assist in stabilizing rates, it is proposed such refunds be made only in instances where a forecast positive balance at year end exceeds a prescribed amount, and be subject to maintaining a minimum balance for stabilization. For the Inland and Lower Mainland service areas, it is proposed that refunds be made when the forecast credit balance exceeds $10 million and be subject to maintaining a minimum $5 million balance in the account. Refunds would be made to current customers in the form of a credit on their gas bill. Credit balances not refunded would be carried forward, and would assist in stabilizing future rate changes.

For the Columbia and Fort Nelson service areas it is proposed that separate limits of $500,000 and $30,000 respectively be set for these service areas subject to maintaining balances of $250,000 and $15,000 respectively.

2.6 Quarterly Reporting

BC Gas proposes to file statements of account with the Commission on a quarterly basis. The reports to the Commission will ensure the Commission is informed of the status of the GCRA, and permit scrutiny of variances from forecast. Reports will be filed within 45 days of the end of each quarter.

2.7 Annual Reconciliation

The year-end under/over recovery in costs will be summarized by way of an annual reconciliation that BC Gas proposes be filed with the Commission by February 15, following each year ending December 31. The annual reconciliation will confirm the amount of any positive or negative balance in the GCRA.

3.0 NEED FOR GCRA

The need for a GCRA has been driven by the need to stabilize the Company's revenues and earnings and to ensure fairness in the recovery of fixed gas costs from customers. The design of the GCRA must also respond to the growing complexity of gas supply and transportation arrangements, and the increased frequency of changes in costs of the diversified gas supply mix. Specifically, the GCRA will provide the following:

3.1 Reduce the Impact of Weather Swings

As previously detailed in the July 15th Application, the utility and core market customers are currently exposed to the over and under collection of fixed gas supply costs due to weather swings.

The GCRA will permit the Company to fairly collect its gas supply costs from customers. The GCRA provides a relatively simple mechanism that accrues under or over recoveries of gas costs. Over the longer term, the customer should be indifferent as warmer and colder year gas cost adjustments balance out. After a cold year the Company proposes to refund significant over collections of gas costs, providing relief to customers for the higher bills they would have paid.

3.2 Account for the Impact of Colder, Warmer or Other Unusual Weather on Average Commodity Prices

The annual forecast of gas commodity costs presumes normal weather patterns. The forecast draws on various gas supply sources at commodity costs which may range from approximately $0.90/GJ to $4.00/GJ. To the extent weather is colder or warmer than normal, average gas commodity costs may be higher or lower to the extent the higher cost gas is drawn on.

A similar situation exists with respect to baseload supply. While in 91/92 and 92/93 most baseload contracts have had similar gas purchase prices, for 93/94 and following years there may be a greater variety of prices. Weather patterns will therefore also affect the average commodity cost of baseload supply.

By including variable costs in the GCRA, the Company will ensure that any commodity cost benefits during a warm year will be used to partially offset under recoveries of fixed costs. During a cold year, this offset will operate to somewhat reduce over recoveries of fixed costs. The result is fair to the Company and its sales customers.

3.3 Accommodate Variations in Baseload Supply Costs Not Known When Forecasts are Prepared, and Unforecast Purchases of Peaking or Spot Gas

There may be occasions when commodity costs are not fully known when forecasts are prepared. On at least two occasions in recent years, commodity costs were being negotiated after November 1 or were the subject of arbitration proceedings. The new baseload agreements also provide for arbitration if the parties fail to reach pricing agreement. The GCRA will act as a deferral mechanism to account for differences between prices included in rates and those determined under arbitration.

There may be occasions when additional short term supplies are purchased that are not known at the time of the forecast, including costs that may be associated with any penalty for gas taken. Benefits and costs from such arrangements will accumulate in the GCRA.

3.4 Optimize the Balance between Fixed and Variable Costs

Within the various supply arrangements there is a mix between those costs that are fixed and those that are a function of the amount of gas purchased. By allowing for recovery of both sets of costs an optimal balance between those two categories can be established. This will also provide the utility the opportunity to pursue all avenues for generating additional revenues designed to offset the costs of the overall portfolio. For instance, off-line sales can be optimized based upon variable costs of gas on a daily basis.

3.5 Accommodate Other Variations in Transportation Costs and in U.S./Canadian Dollar Exchange Rates

Changes in Westcoast, ANG and Northwest pipeline tolls are beyond the utility's control, and may be subject to interim rates or delays beyond the effective date of rate changes. All such changes would be captured in the GCRA.

BC Gas proposes to forecast pipeline tolls for each year, with the GCRA in effect picking up adjustments from forecast.

Costs of Jackson Prairie Storage, Northwest Pipeline tolls and U.S. gas supply are denominated in U.S. dollars. The GCRA will protect the utility and customers from changes in U.S./Canadian dollar exchange rates on these gas costs, which are also beyond control of the Company. U.S. dollar costs of gas will be offset by offline sales denominated in U.S. dollars.

3.6 Minimize Regulatory Applications for Gas Cost Changes

Under the deregulated gas purchasing environment, changes in the Company's gas costs are becoming more frequent. The diversity of the supply portfolio will tend to cause the need for more frequent adjustments than in the past, although in general they may be individually of a lower magnitude. The most significant changes occurring during the gas year will continue to relate to pipelines including Westcoast, ANG and Northwest. By permitting the Company to forecast such costs, the GCRA will minimize unnecessary changes in rates during the year.

3.7 Simplify Administration of Deferrals

A single GCRA mechanism will replace the various gas cost deferral accounts presently in effect and eliminate the need to initiate additional deferral accounts.

This would not lessen the need to track gas costs and to compare year to date actual with forecast. It would simply allow the process to be rationalized and maintained in the most efficient manner.

3.8 Accommodate Phase A Flow Through Principles

The GCRA mechanism will be used to track both fixed and variable recoveries of gas costs. This will permit unabsorbed or overrecovered demand costs to be allocated back to customer classes based upon the methodology approved under Phase A. Similarly, under/over recovered variable costs can be allocated back to customers on a volumetric basis.

Annual vs Monthly Adjustment

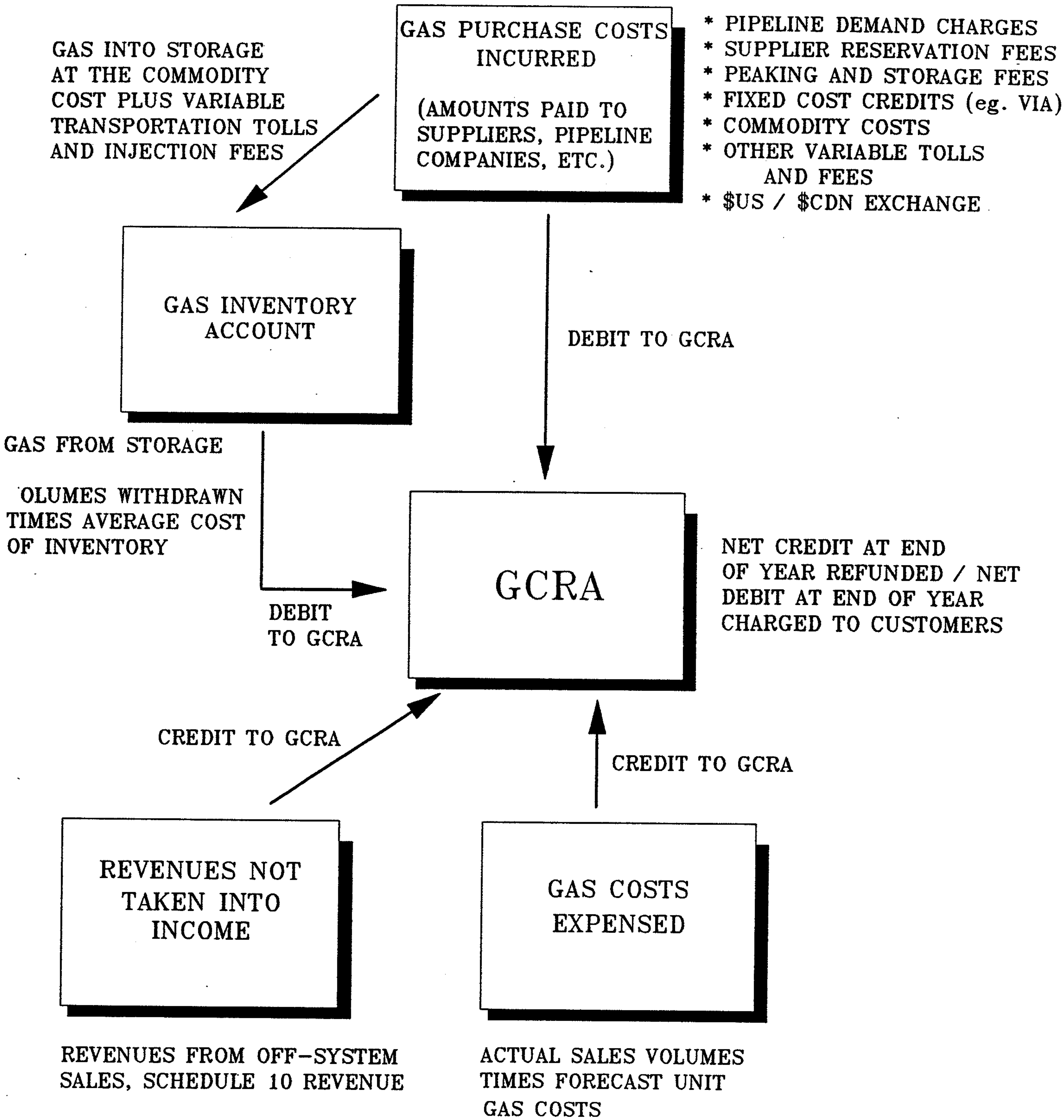
The high percentage of fixed gas costs incurred by BC Gas and the seasonality in the utility's firm sales market make it necessary to levelize the cost of gas recovery across a full year. Monthly adjustment mechanisms typically deal only with gas price adjustments. Monthly gas cost adjustments are therefore less relevant than the need to ensure equity in the recovery of annual costs. There are precedents for seasonal recovery of gas costs using a deferred account mechanism, however these precedents are generally predicated upon seasonal rates. Under current circumstances, it is the Company's view that gas cost recovery is more appropriately calculated on an annual basis.

<u>Summary</u>

The principle that a distribution utility should remain whole with respect to its gas costs is reflected in the acceptance by numerous regulatory authorities in North America of various gas cost recovery mechanisms, each to a degree tailored to meet local circumstances. This principle is also well established in Canada, and with the exception of BC Gas, the major publicly owned distribution utilities have mechanisms that ensure appropriate gas costs are charged to sales customers. The result is fair and equitable to both customers and the utility. The distribution utilities referred to include the following:

LDC	RECONCILIATION PERIOD	METHOD IN EFFECT SINCE
Canadian Western	Seasonal	1974 - 1979 and Since Nov 1, 1987
Centra Gas - Alberta	Annual	January 1, 1990
Centra Gas - Manitoba	Annual	Last 2 years
Centra Gas - Ontario	Annual	Last 2 years
Consumers Gas -	Annual	Since deregulation
Gaz Métropolitain	Monthly	Since 1988
Northwestern	Seasonal	Assumed similar to Canadian Western
Union Gas	Annual	Since 1980

MECHANICS OF THE
GAS COST RECONCILIATION ACCOUNT



BUY-SELL ARRANGEMENTS FOR INTERRUPTIBLE CUSTOMERS

By letter dated April 21, 1993 to Mr. Comfort of Eastern Natural Gas Management (B.C.) Ltd., the Commission indicated that buy-sell arrangements for interruptible customers could be canvassed during the Phase B Rate Design Hearing of BC Gas. While BC Gas does not advocate buy-sell arrangements for interruptible customers, the material under this Tab sets out the proposal of BC Gas respecting the method by which buy-sell arrangements for interruptible customers might be implemented, if it is determined that BC Gas should implement such arrangements.

1.0 METHODOLOGY

Interruptible sales customers of BC Gas who choose to enter into buy-sell agreements will retain brokers or agents who will arrange for the customer, or a group of customers to purchase gas directly from producers or other suppliers. The broker must also arrange for the gas to be gathered, processed and transported to the appropriate BC Gas interconnection point (e.g. Huntingdon for the Vancouver area). BC Gas will purchase the customer's gas and deliver it to the customer through the BC Gas system.

The pricing concept under a buy-sell arrangement is that the gas utility pays a price for gas acquired from the customer which equals the price which the gas utility would have paid for the system gas which would have been used to provide gas service to that customer. In buy-sell arrangements for interruptible customers BC Gas proposes to pay the same amount as the average forecast commodity cost paid by BC Gas to its system gas suppliers for sales to interruptible customers including the Westcoast commodity tolls associated with firm Westcoast service (the "Interruptible Reference Price"). This amount will be reduced by the extra costs incurred for the interruptible buy-sell arrangements including incremental Gas Inventory Charges ("GIC") and also adjusted for the loss of Volume Incentive Adjustment ("VIA") credits and cost of service credits under the existing baseload contracts.

Interruptible customers will continue to be billed for their gas from BC Gas in the usual manner. Since BC Gas will pay the same amount as the forecast commodity cost paid by BC Gas to its system suppliers (adjusted for changes in GIC and VIA), the total gas costs incurred by BC Gas will not change and therefore the sales tariffs will remain the same. The broker provides the customer with a rebate based on the difference between the Interruptible Reference Price and the purchase price under the supply contract that the broker has arranged.

1.1 Priority

BC Gas will continue to provide service to buy-sell interruptible customers on the same priority basis as its other interruptible sales customers. On days when the buy-sell supply is interrupted, BC Gas will backstop the buy-sell supply, on a 'best efforts' basis, from the BC Gas system supply pool. Buy-sell customers will be charged for this backstopping service as set out in section 1.5 below.

1.2 Delivery Points

The delivery point for interruptible buy-sells will be the interconnection points between the BC Gas system and the Westcoast system (i.e. Huntingdon or Savona).

1.3 Daily Volume

The Maximum Daily Volume ("MDV") in a buy-sell interruptible supply contract with BC Gas will be established at the average forecasted daily volume for the customer or the customer group served by that buy-sell contract (i.e. the total forecasted annual volume divided by 365).

1.4 Interruptible Reference Price

The Interruptible Reference Price will be established each contract year commencing November 1. It will be based on the forecast commodity cost to be paid by BC Gas to system suppliers for sales to interruptible customers. The price will be adjusted for changes in approved Westcoast commodity tolls.

Since the costs vary significantly between summer and winter, BC Gas proposes a seasonal Interruptible Reference Price. Based on the 1992 - 1993 contract year, the Interruptible Price Factors would be:

Price Factor	Summer(1)		Winter(2)	
	Huntingdon ($/GJ)	Savona ($/GJ)	Huntingdon ($/GJ)	Savona ($/GJ)
Unit Commodity Charge(3)	0.879	0.879	1.140(4)	1.140(4)
Westcoast Commodity Tolls(5)	0.012	0.008	0.012	0.008
Interruptible Reference Price	0.891	0.887	1.152	1.148

(1) April 1 to October 31
(2) November 1 to March 31
(3) Paid for each unit of gas delivered to BC Gas plus any units delivered to Westcoast for fuel gas; excludes Westcoast commodity tolls
(4) Average commodity cost includes baseload, storage and peaking gas commodity costs
(5) Based on average 1993 approved Westcoast tolls and assumes a heat content of 38.6 MJ/m^3.

1.5 Backstopping

On any day when BC Gas orders the interruptible buy-sell supply and this supply fails to arrive at the interconnection point, BC Gas will backstop the buy-sell interruptible supply from its system supply pool if system supply gas for interruptible customers is available. BC Gas will charge Schedule 13 rates for this backstopping.

Buy-sell interruptible customers will not be charged for backstopping on days that they are curtailed by BC Gas.

1.6 Contract Term

BC Gas proposes that buy-sell interruptible customers must remain on a buy-sell arrangement on a year to year basis with a minimum one year term commencing November 1 of any year. The November 1 to October 31 term is consistent with the existing BC Gas gas supply arrangements and also with the contract term for interruptible sales customers.

2.0 EFFECT ON CORE MARKET CUSTOMERS

If gas is supplied to interruptible customers under buy-sell arrangements on the basis set out above there should not be an immediate impact on the gas supply costs for core market customers. However, in the longer term, buy-sell arrangements for interruptible customers may increase the gas supply costs for core market customers. To the extent that gas is supplied to interruptible customers from buy-sell arrangements rather than from system gas supply, there will be less gas taken in off-peak periods from system gas suppliers. The reduction in the volume taken from system gas suppliers during off-peak periods will reduce the purchase load factor for gas supplied to the core market under system gas supply arrangements. As the forecast load factor decreases the load factor for purchases under buy-sell arrangements for the core market will also decrease.

There is a relationship between the price paid for gas and the load factor at which the gas is purchased. Although it is not possible to quantify the potential detriment to core market customers, a reduction in the purchase load factor in the gas purchase contracts used to supply the core market will likely have the long term effect of increasing the costs of gas supply to the core market.

BURRARD THERMAL PRICING

The material under this Tab addresses the price to be charged to B.C. Hydro for natural gas supplied pursuant to The Amended and Restated Burrard Thermal Interruptible Gas Purchase Agreement made as of the 29th day of September, 1988 (the "Burrard Agreement"). A copy of the Burrard Agreement is found under Tab A.

1.0 PHASE A DECISION

The Commission's Decision of February 21, 1992, at pages 25 and 26, addressed the pricing for gas supplied to the Burrard Thermal electrical generating plant of B.C. Hydro ("Burrard Thermal" or the "Burrard Thermal Plan"). At page 26 the Decision states that "the Commission believes that the "commodity cost" of $.89/GJ derived by BC Gas is inconsistent with the definition in the Burrard Agreement. A more appropriate price might be the minimum price in Schedule 10 or the minimum price accepted at an auction."

At page 26 of the Decision the Commission ordered BC Gas to submit "a commodity cost which conforms to the intent of the Burrard Agreement and, in the interim, the current commodity cost of $.93/GJ is to be continued". Commission Order No. G-22-92 required BC Gas to comply with the orders and directions incorporated in the Commission Decision. That Order also provided that the Commission would accept amended Gas Tariff Rate Schedules which conformed to the Decision.

As part of its July 15, 1992 filing responding to matters in the Phase A Decision, BC Gas addressed the issue of the appropriate pricing for gas supply to Burrard Thermal. Included under Tab B are copies of pages 2-8 and 2-9 from the July 15, 1992 filing. At Tab C is an August 7, 1992 letter from B.C. Hydro responding to the July 15, 1992 filing. Commission Order No. G-91-92, dated September 29, 1992, addressed the July 15, 1992 filing of BC Gas. As part of Order No. G-91-92 the Commission ordered:

> "3. BC Gas is to include further material on both pricing and priority of service to B.C. Hydro's Burrard Thermal Plant in the Phase B hearing application. In the meantime, a deferral account should be maintained to account for the difference between current and proposed pricing."

For gas supplied under the Burrard Agreement BC Gas has been billing B.C. Hydro a commodity price of $.93/GJ as required by the Commission's February 21, 1992 Decision. B.C. Hydro paid the amount billed until October, 1992 when B.C. Hydro unilaterally withheld payment and unilaterally and retroactively adjusted the commodity price to $.88/GJ. B.C. Hydro has also adjusted downward subsequent billings.

As required by Commission Order No. G-91-92 BC Gas has maintained a deferral account to account for the difference between the two prices. As of the end of April 1993, the difference between those two prices is approximately $800,000. That amount has not been paid since B.C. Hydro has unilaterally withheld payment.

2.0 FEBRUARY 16, 1993 APPLICATION

As a result of the refusal of B.C. Hydro to pay $.93/GJ, BC Gas applied by letter dated February 16, 1993 for Commission approval to file an amendment to the Burrard Agreement. A copy of the February 16, 1993 Application is under Tab D. In reply to the February 16, 1993 Application, B.C. Hydro filed a letter dated March 23, 1993, a copy of which is under Tab E.

In response to the March 23, 1993 letter of B.C. Hydro, BC Gas submits (using the same numbering as in that letter):

1. Contractual and Jurisdictional Issues

BC Gas does not dispute that the Burrard Agreement is a contract. However, the Burrard Agreement is also a rate schedule. B.C. Hydro specifically agreed on page 2 of its August 7, 1992 letter (Tab C) that the Burrard Agreement is a tariff. In its Application of February 16, 1993 BC Gas does not seek to have the Commission interpret a contract nor does it seek to sue B.C. Hydro under the contract. BC Gas seeks only to have the Commission approve an amendment to one of its rate schedules. The Commission has jurisdiction to approve the amendment and B.C. Hydro has not taken the position that the Commission does not have jurisdiction.

2. The Burrard Agreement

B.C. Hydro argues that the Burrard Agreement is a cost based contract and that the cost is $.88/GJ. B.C. Hydro submits that stipulating a $.93/GJ price would violate paragraph 3.03 of the Burrard Agreement. B.C. Hydro fails to recognize that the Commission has already ordered that the price should be $.93/GJ. The February 16, 1993 Application of BC Gas does not seek to stipulate a price but rather seeks only to amend a rate schedule in order to have the rate schedule conform to an outstanding Order of the Commission.

3. The Rate Design Hearing

B.C. Hydro refers to evidence during the Phase A Rate Design Hearing of BC Gas. The submissions of B.C. Hydro are an attempt to re-argue Phase A issues. B.C. Hydro does not address the fact that the Commission has ordered a price of $.93/GJ and that BC Gas is only seeking to amend a rate schedule in order to have the rate schedule conform to an outstanding Commission Order.

4. BC Gas' Revenue Requirement Hearing

In its submissions under item 4 of the March 23, 1993 letter B.C. Hydro also attempts to re-argue Phase A issues. B.C. Hydro again fails to address the fact that the Commission has ordered a price of $.93/GJ and that BC Gas is only seeking to amend a rate schedule in order to have the rate schedule conform to an outstanding Commission Order.

5. Domestic Natural Gas Supply Contracts Hearing

In its submissions under item 5 of the March 23, 1993 letter B.C. Hydro further attempts to re-argue Phase A issues. B.C. Hydro continues with its failure to address the fact that the Commission has ordered a price of $.93/GJ and that BC Gas is only seeking to amend a rate schedule in order to have the rate schedule conform to an outstanding Commission Order.

3.0 CONCLUSION

The March 23, 1993 submission of B.C. Hydro does not address the fact that the Commission, in its February 21, 1992 Decision, ordered that a price of $.93/GJ be charged by BC Gas to B.C. Hydro for gas supply under the Burrard Agreement. If B.C. Hydro did not agree with that Decision of the Commission then B.C. Hydro should have sought a reconsideration of the Decision or have otherwise appealed the Decision.

Having been ordered to charge a price of $.93/GJ it is not open to BC Gas to agree to a lower price. B.C. Hydro paid $.93/GJ until October 1992 when B.C. Hydro unilaterally refused to pay that amount and unilaterally adjusted its payments to reflect a price of $.88/GJ.

The Commission has jurisdiction to approve the rate schedule amendment sought by BC Gas and the amendment should be so approved. B.C. Hydro should then make payment of the amount due. The difference between the two prices will be recorded in a deferral account and it will be open to B.C. Hydro to make submissions regarding the disposition of that deferral account.

AMENDED AND RESTATED
BURRARD THERMAL INTERRUPTIBLE GAS PURCHASE AGREEMENT

THIS AGREEMENT made as of the 29th day of September, 1988 is an amendment and re-statement of an agreement made as of July 15, 1988 between the parties noted below.

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a crown corporation established pursuant to an Act of the Province of British Columbia and continued under the Hydro and Power Authority Act, RSBC, 1979, ch.188

("**Hydro**")

OF THE FIRST PART

AND:

B.C. GAS INC. , a body corporate under the laws of the Province of British Columbia, having its registered office at 2800 - 595 Burrard Street, Vancouver, British Columbia, V7X 1J5

(the "**Company**")

OF THE SECOND PART

W H E R E A S:

A. By separate agreement made as of the 15th day of July, 1988 (the "Asset Transfer Agreement") Hydro agreed to sell to the Company and the Company agreed to purchase from Hydro certain assets upon the terms more specifically set out therein;

B. For the purposes of this Agreement, all capitalized words shall have the same meaning given to those words in the Asset Transfer Agreement, unless otherwise defined herein; and

C. Hydro owns and operates the Burrard Thermal electrical energy generating station for the production of electrical energy and requires an interruptible supply of natural gas to fuel its operation of Burrard Thermal.

NOW THEREFORE THIS AGREEMENT WITNESSETH, that in consideration of the mutual covenants and agreements in herein contained, the parties hereto mutually covenant and agree that:

1.0 DEFINITIONS

Where used herein or in any amendment hereto, unless the context otherwise requires, each of the following words shall have the meaning set forth as follows:

(a) **"Burrard Thermal"** means the Burrard Thermal electrical energy generating station owned and operated by Hydro and situate at Port Moody, British Columbia;

(b) **"Commodity Cost"** means the field commodity cost of natural gas negotiated by the Company from time to time for the purposes of this Agreement, the current cost of which is $1.03 per gigajoule;

(c) **"Commodity Tolls"** means the commodity charges prescribed by the toll schedules of Westcoast Energy Inc. ("Westcoast") as approved from time to time by the National Energy Board ("NEB") and applicable to the gas supplied or delivered hereunder.

(d) **"Contract Year"** means each successive twelve-month period of the Term commencing 8:00 a.m. PST September 30, 1988;

(e) **"Demand Tolls"** means the demand charges prescribed by the toll schedules of Westcoast as approved from time to time by the NEB and applicable to the gas supplied or delivered hereunder.

(f) **"Period of Interruption"** means the period during which Hydro is required by the Company to cease or curtail the use of natural gas under this Agreement;

(g) **"Seasonal Gas"** means that natural gas which can be purchased by the Company over and above its system requirements up to the limit nominated in its natural gas supply agreements with third parties; and

(h) **"Term"** means that period described in section 7.01.

2.0 INTERRUPTIBLE NATURAL GAS SUPPLY

2.01 The Company shall sell and deliver to Hydro natural gas for use in Burrard Thermal and Hydro shall take and pay for such natural gas upon the terms and conditions herein contained.

2.02 The supply and delivery of natural gas hereunder is interruptible service. The obligations of each of Hydro and the Company hereunder are in addition to the obligations of each under the Burrard Thermal Firm Gas Purchase Agreement, made as of July 15, 1988.

2.03 Natural gas supplied hereunder shall be subject to the terms and conditions from time to time contained in the Company's gas tariff except where the terms of this Agreement are inconsistent with the Company's gas tariff in which event the terms of this Agreement shall prevail.

3.0 CHARGES

3.01 Hydro shall pay the Company for the services provided hereunder the total of:

(a) the Commodity Cost;

(b) for Seasonal Gas, the applicable Westcoast Commodity Tolls;

(c) for natural gas other than Seasonal Gas, the applicable Westcoast Demand and Commodity Tolls;

(d) taxes directly on the charges under subsections 3.01(a), (b), (c), (e) and (f) herein, including social services tax;

(e) such additional variable costs of the Company necessary for the supply of natural gas hereunder; and

(f) 25 cents per gigajoule of natural gas supplied and delivered hereunder.

3.02 The Company undertakes to negotiate with third parties to obtain natural gas to be supplied under this Agreement at the lowest possible cost to Hydro.

3.03 Except with respect with to Commodity Costs in contracts for the supply of natural gas negotiated with third parties and approved by Hydro, the Commodity Cost shall be adjusted from time to time during the Term, so that the Commodity Cost provided hereunder is no greater than the Commodity Cost for any other sales customer of the Company.

3.04 Any credits obtained by the Company from Westcoast, or any other monetary benefits which may be obtained by the Company, other than payments made pursuant to sections 3.01 and 3.05 herein, relating to costs paid by Hydro shall be credited to Hydro.

3.05 Hydro may, at any time and from time to time, upon reasonable notice, direct the Company to cease the supply of natural gas purchased by the Company, for the period of time stated in the notice, and to commence delivery of natural gas purchased by Hydro, for which services Hydro will pay the Company the total of:

(a) the applicable Westcoast Demand and Commodity Tolls, unless otherwise paid directly by Hydro;

(b) taxes directly on the charges under subsections 3.05(a), (c) and (d) herein, including social services tax;

(c) such additional variable costs of the Company necessary for the delivery of natural gas hereunder; and

(d) 25 cents per gigajoule of natural gas transported and delivered hereunder.

In addition Hydro shall reimburse the Company for all costs, expenses and liabilities (net of credits or other monetary benefits) associated with the cessation of the supply of natural gas purchased by the Company pursuant to contracts negotiated with third parties and approved by Hydro.

3.06 Subject to section 8.0, and notwithstanding the occurrence of an event of Force Majeure claimed by Hydro, during each Contract Year the minimum aggregate annual payment by Hydro to the Company for the supply or delivery of natural gas pursuant to subsections 3.01(f) or 3.05(d), as the case may be, shall be Five Million ($5,000,000) Dollars regardless of the quantity of natural gas supplied or delivered to Hydro within any Contract Year.

3.07 Following each Contract Year, the Company will prepare and deliver to Hydro an accounting with respect to each of subsections 3.01(a) to (f) and 3.05(a) to (d) herein and will include in such accounting a request for payment of the amount, if any, of any deficiency in the minimum aggregate annual payment requirement. Hydro will pay the amount of any such deficiency within twenty-one days of its receipt of the accounting and, in the event the deficiency is not paid when due, the late payment specified in section 10.02 shall apply to the unpaid deficiency.

4.0 USE

4.01 The Company shall provide to Hydro, as soon as possible and not later than October 30, 1988, estimates of the minimum and expected annual Seasonal Gas available in each of the three Contract Years following the execution of this Agreement and shall provide similar such estimates on or before May 1, 1989 and on May 1st of each year thereafter.

4.02 The Company shall make available to Hydro not less than 20 petajoules of natural gas during each Contract Year.

4.03 If in any Contract Year Hydro does not use all 20 petajoules of natural gas made available by the Company pursuant to section 4.02 herein, such shortfall may be taken in the four following years provided that:

(a) 20 petajoules for the current Contract Year has first been taken;

(b) thermally equivalent volumes carried over from the fourth previous Contract Year are taken next; and

(c) thermally equivalent volumes carried over from the third, second and first previous Contract Years are taken next.

When taking natural gas pursuant to this section, Hydro shall pay to the Company the amounts set out in subsections 3.01(a) to (e) inclusive if the natural gas is purchased by the Company, or subsections 3.05(a) to (c) inclusive if the natural gas is purchased by Hydro; but need not pay the amounts in subsections 3.01(f) and 3.05(d).

4.04 Natural gas supplied or delivered hereunder shall be considered, for billing purposes, as having passed through the Company's gas metering station on the Burrard Thermal property after natural gas supplied to Hydro by the Company under the Burrard Thermal Firm Gas Purchase Agreement made as of the 15th day of July, 1988, or any agreement which succeeds or replaces the Burrard Thermal Firm Gas Purchase Agreement.

4.05 If in any Contract Year the Company is in breach of section 4.02 herein and Hydro elects to prorate, pursuant to section 8.0 herein, the minimum aggregate annual payment of five million dollars to reflect the reduced supply of natural gas made available by the Company, the difference between 20 petajoules of natural gas and such reduced supply of natural gas may be taken in the four following years as provided in subsections 4.03(a) to (c) inclusive. When taking natural gas pursuant to this section, Hydro shall pay to the Company the amounts set out in subsections 3.01(a) to (f) inclusive if the natural gas is purchased by the Company, or subsections 3.05(a) to (d) inclusive if the natural gas is purchased by Hydro.

5.0 CONNECTION

The point of delivery shall be at the outlet of the Company's gas metering station on the Burrard Thermal property.

6.0 CURTAILMENT

6.01 The supply and delivery of natural gas provided herein is on an interruptible basis and may be interrupted or curtailed by the Company at any time and from time to time only if such interruption is reasonably required by the Company. The Company undertakes to use its best efforts to minimize any period of interruption required by the Company for the maintenance, repair or construction of the Company's facilities.

6.02 The Company may give Hydro notice (which in the Company's discretion may be oral, including notice by telephone to the Burrard Superintendent, or written) to cease or curtail the use of natural gas under this Agreement, which notice shall be not less than six hours in advance of the period of interruption, and Hydro shall, in accordance with the notice, cease or curtail such use before commencement of the period of interruption as specified in such notice, and shall not begin to use natural gas again or to use natural gas beyond the curtailed amount until so authorized by the Company. If the Company has a reasonable expectation that it may exceed its Westcoast contract demand, the Company may give Hydro notice, as provided herein, to cease or curtail the use of natural gas under this Agreement, in which case such notice shall not be less than two hours in advance of the period of interruption.

6.03 Subject to regulatory approvals which apply from time to time, the priority for the interruption or curtailment in the supply or delivery of natural gas under this Agreement shall be as follows:

(a) (i) the Company's requirements to refill storage capacity equivalent to its existing storage facilities;

(ii) the supply or delivery of natural gas under interruptible sales and service agreements, and renewals thereof, with customers who have entered into interruptible agreements prior to the date of this Agreement including any such agreements converted into sales and/or service agreements following the date of this Agreement; and

(iii) the supply or delivery of natural gas under interruptible sales or service agreements, and renewals thereof, with customers who have entered into interruptible agreements subsequent to the date of this Agreement, which agreements, insofar as they relate to the natural gas market in the Lower Mainland, in the aggregate provide for the delivery and/or sale of five petajoules of natural gas,

shall have priority over the supply or delivery of natural gas to Hydro under the Agreement;

(b) the supply or delivery of natural gas to Hydro under this Agreement shall have priority over:

(i) the Company's requirements to refill storage capacity in excess of an amount equivalent to its existing storage facilities; and

(ii) the supply or delivery of natural gas under interruptible sales or service agreements, and renewals thereof, with customers who have entered into interruptible agreements subsequent to the date of this Agreement, which agreements, insofar as they relate to the natural gas market in the Lower Mainland, are for the supply or delivery of natural gas in excess of five petajoules;

(c) for natural gas taken in any year following termination of this Agreement by virtue of either section 4.03 or 4.05 herein, the Company's requirements to refill storage capacity equivalent to existing storage facilities and the supply or delivery of natural gas in (a)(ii) and (iii) herein shall have priority; and the interruption or curtailment in the supply or delivery of natural gas to Hydro shall be on a basis equal to all other interruptible gas customers of the Company. In any year, other than a Contract Year, Hydro shall have no right to take greater than 20 petajoules of natural gas under this Agreement.

6.04 In the event a system emergency on the Hydro electrical system is declared by Hydro, then for the duration of such system emergency Hydro shall have priority for the interruptible supply or delivery of natural gas over those requirements and interruptible agreements referred to in section 6.03. For natural gas taken by Hydro under this section, Hydro shall pay a rate or rates which equal the rate or rates that would otherwise have been paid to the Company by those customers of the Company whose supply or delivery of natural gas is interrupted or curtailed due to the declaration by Hydro of a system emergency on the Hydro electrical system. When interrupting or curtailing other customers of the Company under this section, to the extent permitted by good utility practice, the Company shall use its best efforts to minimize the cost to Hydro under this section.

6.05 If Hydro fails to comply with a Company direction to cease or curtail the use of natural gas as set out in section 6.02, Hydro shall pay for each unit of gas taken in excess of the curtailed level the rate set out in Company's Rate Schedule 2501 as amended from time to time, or a successor schedule, for takes by a customer beyond a curtailed level, which rate is presently $18.84 per gigajoule. Notwithstanding the foregoing, Company may immediately discontinue the supply of natural gas to Hydro in the event of a failure by Hydro to cease or curtail the use of natural gas as set out in section 6.02.

7.0 TERM

Subject to section 8.0, this Agreement shall commence at 0800 PST on July 16, 1988 and shall terminate and be of no further force or effect at 0800 PST on September 30, 1998, provided that such termination shall be subject to the rights and remedies of both parties accruing to the date of termination such right and remedies shall survive such termination.

8.0 NON-PERFORMANCE

In the event that the Company is unable to fulfill its obligations under section 4.02 herein, Hydro's only recourse shall be to elect to terminate this Agreement or elect to pro rate the minimum aggregate annual payment of five million dollars to reflect the reduced supply of natural gas.

9.0 CHARTS

Hydro shall, at the request of the Company:

(a) (i) change charts at 0800 PST on the first day of each month and at 0800 PST on any day a chart change is required,

(ii) enter all the information required to complete the reverse side of each chart as it is removed from the meter,

(iii) send all completed charts to the Company in a manner specified by the Company except for those charts removed during the final four (4) days of each month which will be picked up by a representative of the Company on the first working day of the following month,

(iv) wind the clock mechanism, ink and service the recorder pens, and report forthwith mechanical failure to the Company,

(v) take readings of front and rear dials at 0800 PST on each working day and telephone them to the Company by noon the same day,

(vi) advise the Company as soon as possible of any actual or anticipated abnormal change in Hydro's rate of consumption of gas; or

(b) permit the Company to maintain on Hydro's premises aforesaid, the necessary communication circuit and other facilities for the purpose of telemetering Hydro's gas consumption.

10.0 ACCOUNTS

10.01 Bills will be rendered by the Company to Hydro on a monthly basis in respect of natural gas actually used at Burrard Thermal. The due date for payment of bills shown on the face of the bill is twenty-one days following receipt of the bill. Hydro shall pay to the Company at a Company office located within the Lower Mainland designated by the Company from time to time for such purpose the full amount on the bill.

10.02 If the amount due on any bill has not been paid in full on or before the due date shown on such bill, and if the unpaid balance is $30 or more, a further bill will be rendered to include the overdue amount plus a late payment charge of 1-1/2% (equivalent to 19.6% per annum when compounded monthly). Notwithstanding the due date shown, to allow time for payments made to reach the Company's payment processing centre and to coordinate the billing of late payment charges with scheduled billing cycles, the Company may, in its discretion, waive late payment charges on payments not processed until a number of days after the due date.

11.0 SUSPENSIONS

If as a result of any emergency or force beyond the reasonable control of either party herein or strike, lockout or other such disturbance of either party (the "Force Majeure"), either party is or was wholly or partly unable because of the Force Majeure, to perform an obligation arising from this Agreement and claims that a Force Majeure is occurring or has occurred and reasonably establishes that fact, then the performance of the obligation shall be deemed to be suspended provided always that:

(a) the suspension shall be of no greater scope and no longer duration than the Force Majeure,

(b) the non-performing party shall make its best efforts to counter the Force Majeure or to otherwise remedy its inability to perform the obligation,

(c) a performance required at a time other than when the Force Majeure is occurring shall not be excused by the Force Majeure, and

(d) an obligation to make a payment when due shall not be excused by the Force Majeure.

12.0 INDEMNITY

12.01 Subject to the Financial Administration Act S.B.C. 1981, c.15, as amended, and the Hydro and Power Authority Act R.S.B.C. 1979, c.188, as amended and the regulations thereunder:

(a) Hydro shall be liable for and shall indemnify and save harmless the Company, its employees and agents, from and against any and all damage, loss, cost and expense which the Company, its employees or agents, may suffer or incur; and

(b) Hydro shall indemnify and save harmless the Company, its employees and agents, from and against all claims, demands, costs, actions and causes of action whatsoever (including assessments by the Workmen's Compensation Board of British Columbia) which may be brought or made against the Company, its employees or agents, in either case caused by, arising out of, or connected in any way with any of Hydro's equipment or any use thereof or disturbing element caused, permitted or introduced by Hydro or Hydro's equipment, or caused by, arising out of or connected in any way with any action, effect or use of gas after the same shall have been delivered to Hydro.

12.02 Hydro, its employees or agents, will not be liable to the Company pursuant to paragraph 12.01(a) for any loss of revenue or profits or other indirect, consequential or financial loss whether such loss is caused by an act or omission of Hydro, its employees or agents, later found to be negligent or otherwise.

13.0 MISCELLANEOUS

13.01 The Company will prepare and maintain records related to the supply and delivery of natural gas hereunder, which records will be open to audit examination by Hydro during regular business hours of the Company during the term of this Agreement and for a period of one year after the termination of this Agreement.

13.02 No waiver of or failure by the Company to enforce any right or to exercise any remedy provided in the Agreement shall affect or prejudice the rights and remedies of the Company in respect of any future or other breach of the Agreement by Hydro or in respect of any matter for which the Company may be entitled to discontinue the supply of natural gas.

13.03 Any notice report or other document that either party may be required or may desire to give to the other shall be in writing, unless otherwise provided for, and will be deemed to be validly given to and received by the addressee, if served personally, on the date of such personal service or, if delivered by mail, telex or facsimile copier, when received:

(a) if to the Company:

B.C. Gas Inc.
#2300, 1066 West Hastings Street
Vancouver, B.C.
V6E 3G3

Attention: Secretary

(b) if to Hydro:

British Columbia Hydro and Power Authority
970 Burrard Street
Vancouver, B.C.
V6Z 1Y3

Attention: Comptroller

or at such other address as either party may from time to time designate by notice in writing to the other.

13.04 Notwithstanding section 12.03, notice of interruption or curtailment of the supply of natural gas shall be given in accordance with the provisions of section 6.02 of this Agreement.

13.05 This Agreement is subject to the Company obtaining and maintaining any regulatory approvals that may be required.

13.06 A party shall not commence any legal proceedings against the other party in respect to the interpretation or enforcement of this Agreement unless and until it has first taken all reasonable steps to resolve the matter in issue with the other party, and included in such reasonable steps is the right of a party to submit any dispute, with the other party, arising out of this Agreement to a single arbitrator in accordance with the provisions of the Commercial Arbitration Act or any re-enactment or amendment thereof.

13.07 Notwithstanding any statutory limitation to the contrary, a party shall not commence any action, arbitration or other proceeding between the parties after the expiry of a period of two years after the issue in dispute arose.

13.08 Upon execution by the parties, this Agreement replaces and supersedes the prior Agreement made as of the 15th day of July, 1988 between the parties.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed as of the day and year first above written.

THE COMMON SEAL OF **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY** was hereto affixed in the presence of:	)	C/S
Authorized Signatory	)	
THE COMMON SEAL OF **B.C. GAS INC.** was affixed hereto in the presence of:	)	C/S
Authorized Signatory	)	

WPD-H/MG/2-2

Burrard Commodity Pricing (Decision p. 26)

The Commission orders BC Gas to submit for approval by April 30, 1992, a commodity cost which conforms to the intent of the Burrard Agreement and, in the interim, the current commodity cost of $.93/GJ is to be continued.

BC Gas has had a number of discussions with BC Hydro concerning the commodity cost for the amended and restated Burrard Thermal Interruptible Gas Purchase Agreement made September 29, 1988 and as amended ("Burrard Agreement"), but has not been able to reach an agreement. BC Gas submits that the Burrard Agreement commodity cost for interruptible sales should be the average commodity price under BC Gas' long term supply contracts. However, BC Gas believes the price and the priority of service are linked, since the access to valley gas by Burrard affects the amount and availability of gas for the auction and for off-system sales. Arrangements for an auction and off-system sales were not contemplated at the time the Burrard Agreement was drafted, resulting in ambiguity regarding the respective priorities of gas moving to Burrard, or to contractual or auction arrangements. At the time of the hearing, questions about the priority of Burrard gas relative to auction sales were not resolved. If Burrard is to receive gas at a price equal to the commodity price under the long term supply contracts, then the priority to Burrard should be at a level which does not adversely affect the auction of gas or contractual sales of gas off the BC Gas system.

The Burrard Agreement is a rate schedule under Section 67 of the Utilities Commission Act filed as BC Gas Lower Mainland Division Tariff Supplement NO. 11 ("Burrard Agreement Tariff"). The BCUC may choose to set a market price that it considers more appropriately obtains an adequate core market contribution, such as the price set for Schedule 10 interruptible sales. The Burrard Agreement Tariff also recognizes that priorities can be the subject of regulatory decisions, in order to maximize public interest (Clause 6.03).

BC Gas' objective in clarifying the priority of service is to realize as great a contribution as possible to the Core Market. This can only be achieved by giving the potential off-system sales customers and auction gas customers as much certainty as possible that gas will be available, but this must be balanced by the needs of Burrard Thermal. BC Gas' suggestion (laid out in our Auction proposal, page 12) is to give Burrard priority over the Auction and off-system sales on a monthly basis, but to give the various interruptible sales schedules and the Auction priority over Burrard on a daily basis. The best result would be for Burrard Thermal to be required to indicate its reasonable needs, recognizing that ambiguity reduces value to the Core Market. The effective date and pricing level of any revised commodity price to Burrard Thermal, as well as the priority of service, should be the subject of a future hearing.

BChydro

proud of our Service

Darlene Barnett
Corporate Secretary
Tel (604) 623-3600
Fax (604) 623-4467

7 August, 1992

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: R.J. Pellatt
Commission Secretary

Dear Sirs:

Re: B.C. Gas Inc. Responses Dated July 15, 1992 to Matters in the Rate Design Phase A Decision Pursuant to BCUC Order No. G-22-92 Dated February 21, 1992

We are in receipt of the above document and wish to respond specifically to the B.C. Gas Response in Tab 2, pages 8 and 9:

The Burrard Agreement is very clear on the appropriate commodity cost and B.C. Hydro submits that the Burrard Agreement commodity cost for interruptible gas purchases should be the field commodity cost of $0.88/GJ as negotiated by B.C. Gas for the gas contract year November 1, 1991 to October 31, 1992. B.C. Gas has submitted that the $0.88/GJ commodity cost negotiated under the B.C. Gas long term supply contracts should also be applicable to Burrard. B.C. Hydro agrees with B.C. Gas on this point.

However, B.C. Hydro does not agree that the commodity cost included in the total charge that Burrard pays for Seasonal Gas is dependent on changes to or subject to reaching agreement on the interpretation of any specific contract condition. The minimum annual payment of $5 million, volume, transportation cost, and curtailment priority were some of the contract terms considered when B.C. Hydro agreed to the charges in Clause 3.0 of the Burrard Agreement. B.C. Hydro agreed to conditions in the Burrard Agreement in order to obtain the lowest commodity cost negotiated by B.C. Gas. B.C. Hydro cannot agree to a different commodity cost imposed on Burrard without "off-setting" changes to other contract conditions that were negotiated as part of the Burrard Agreement. B.C. Hydro submits that the commodity cost in the Burrard Agreement is an integral part of the total package of terms and conditions negotiated with the cost of gas. The sanctity of an existing contract should be honoured.

When the Burrard Agreement was negotiated, the issue of priority was, and continues to be of major importance to B.C. Hydro, and is certainly recognized in Clause 6.0 of the Burrard Agreement. Burrard's priority, ahead of future interruptible gas sales of B.C. Gas, was negotiated by B.C. Hydro in Clause 6.0 as part of the Burrard Agreement. B.C. Hydro agrees with B.C. Gas that Burrard usage may have an effect on auction or off-system sales, and B.C. Hydro has proposed to B.C. Gas a procedure as per the attached letter to enable an auction process to proceed. B.C. Gas has not discussed with B.C. Hydro its Auction Proposal as submitted in its response to the Commission. The Auction Proposal is unclear on how priorities will change in the transition from daily to monthly requirements. B.C. Hydro is also concerned that the Auction Proposal will impact adversely on the operation of Burrard, especially when Burrard requirements in the "shoulder months" are very likely to exceed the available Seasonal Gas supply even without any auction or off-system sales.

We agree with B.C. Gas that the Burrard Agreement in its entirety is a "tariff". Although the B.C. Gas proposed redefinition of the commodity cost and a new priority may be beneficial to its customers, B.C. Hydro submits that deletion of other Burrard Agreement obligations such as the $5 million minimum annual payment and lower transportation rates would certainly be beneficial to B.C. Hydro customers.

We request the Commission to continue to recognize the priority negotiated by the parties in the Burrard Agreement and support our proposal to B.C. Gas as outlined in our 2 July 1992 letter to enable B.C. Gas to initiate the Auction Process.

Yours sincerely,

for D.M. Barnett

DMB:ic
Attach.

cc: K. Epp

BChydro

proud of our Service

2 July 1992

Mr. W. G. Bierlmeier
Vice President, Gas Supply
B.C. Gas Inc.
3777 Lougheed Highway
Burnaby, B. C.
V5C 3Y3

Dear Mr. Bierlmeier:

As indicated in our meeting of 24 June 1992 regarding the priority of Seasonal Gas supply to Burrard, it is our position that the supply to Burrard must take priority over gas sold on the auction process. However B.C. Hydro proposes the following procedures for a trial period of one year to enable the auction process to proceed:

1. B.C. Gas will, on or before the seventh day of each month, provide B.C. Hydro with a forecast of Seasonal Gas available for the following calendar month.

2. B.C. Hydro will provide B.C. Gas with a forecast of Seasonal Gas requirements on or before the seventeenth of each month for supply to Burrard for the following calendar month.

3. The surplus Seasonal Gas above the Burrard monthly forecasted requirement may be offered by B.C. Gas for the auction process.

4. B.C. Hydro will use reasonable efforts to take the forecasted requirement of Seasonal Gas within the range of 80 to 120 per cent of the forecasted requirement.

5. Should the actual Seasonal Gas take occur outside the 80 to 120 per cent range B.C. Hydro will provide B.C. Gas with reasons why B.C Hydro plans changed. Some of the reasons that we expect could include:

   a. Force Majeure or emergency conditions including unanticipated local operating contraints.

   b. A major loss of system load or an unforecasted major increase in demand.

c. New system studies indicating that the System Marginal Cost of energy have changed substantially in relation to the cost of Burrard generation on Seasonal Gas.

d. An unexpected change in system supply due to high runoff or lack thereof.

e. Undue adverse financial impact on B.C. Hydro if the operation at Burrard is not changed.

f. Regulatory requirements such as curtailment under our Emissions Permits.

We anticipate that major changes from forecasted monthly required amounts will normally be infrequent. We are prepared to work with B.C. Gas to allow B.C. Gas to maximize its revenues on unused Seasonal Gas but at the same time we cannot jeopardize our contractual rights to gas for Burrard generation.

Yours truly,

K.M. Lum, P. Eng.
Manager
Power Systems Contracts

cc: K. Epp

BC Gas Inc.
1066 West Hastings Street
Vancouver, British Columbia
Canada V6E 3G3

Tel (604) 443-6607
Fax (604) 443-6789

David M. Masuhara
Vice President
Legal and Regulatory Affairs

BC Gas

February 16, 1993

British Columbia Utilities Commission
Box 250
Sixth Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sirs:

Re: British Columbia Hydro and Power Authority and Commission Order G-22-92

Commission Order G-22-92 ordered BC Gas to comply with the orders and directions incorporated in the Commission's Decision of February 21, 1992. At pages 25 and 26 of the February 21, 1992 Decision the Commission discussed pricing for the Burrard Thermal electrical generating plant of British Columbia Hydro and Power Authority ("B.C. Hydro"). The final paragraph of the part of the Decision which deals with pricing for Burrard Thermal states:

> "The Commission orders BC Gas to submit for approval by April 30, 1992, a commodity cost which conforms to the intent of the Burrard Agreement and, in the interim, the current commodity cost of $.93/GJ is to be continued".

By letter dated April 30, 1992 BC Gas reported to the Commission regarding its discussions with B.C. Hydro respecting the pricing, priority of service and availability of gas to Burrard Thermal. On July 15, 1992 BC Gas filed with the Commission responses concerning matters arising from the February 21, 1992 Decision including a response relating to the pricing for Burrard Thermal. At page 2-8, under Tab 2 of that filing, BC Gas stated:

> "The Burrard Agreement is a rate schedule under Section 67 of the Utilities Commission Act filed as BC Gas Lower Mainland Division Tariff Supplement NO. 11".

By letter dated August 7, 1992 B.C. Hydro wrote to the Commission respecting the July 15, 1992 filing. In the August 7 letter B.C. Hydro stated:

> "We agree with BC Gas that the Burrard Agreement in its entirety is a "tariff"."

By Order G-91-92 dated September 29, 1992 the Commission ordered BC Gas to include further material on both pricing and priority of service to the Burrard Thermal Plant in the Phase B hearing application. The Order stated:

> "In the meantime, a deferral account should be maintained to account for the difference between current and proposed pricing".

For gas delivered to B.C. Hydro under the Amended and Restated Burrard Thermal Interruptible Gas Purchase Agreement (the "Burrard Agreement") BC Gas has been billing B.C. Hydro a commodity cost of $.93/GJ as set out in the Commission's Decision of February 21, 1992. B.C. Hydro paid as billed until October 1992 when B.C. Hydro unilaterally withheld payment on the basis that B.C. Hydro was retroactively adjusting back to November 1, 1991 the commodity cost from $.93/GJ (as set out on page 26 of the February 21, 1992 Decision) to $.88/GJ. B.C. Hydro has also adjusted downward subsequent billings.

BC Gas has indicated to B.C. Hydro that if B.C. Hydro does not agree that the amount of $.93/GJ set out in the February 21, 1992 Decision is to be the price paid by B.C. Hydro, then B.C. Hydro should apply to the Commission for a revision. B.C. Hydro has responded by indicating that it will only pay $.88/GJ and that BC Gas should apply to the Commission.

Order G-22-92 provided that "The Commission will accept, subject to timely filing, amended Gas Tariff Rate Schedules and Tariff Supplements which conform to the Commission's February 21, 1992 Decision". BC Gas did not file amendments relating to the Burrard Agreement as B.C. Hydro was paying the commodity cost of $.93/GJ set out in the Commission's Decision. However, as B.C. Hydro now refuses to pay that price and as it has retroactively adjusted its payments back to November 1, 1991, BC Gas hereby applies, pursuant to Order G-22-92, to file the attached amendment to the Burrard Agreement. The amendment conforms with the Commissions's

Decision of February 21, 1992 and, as set out above, both BC Gas and B.C. Hydro agree that the Burrard Agreement is a tariff.

Yours truly,

D.M. Masuhara

cc: Mr. P.D. Swoboda
B.C. Hydro

and requires an interruptible supply of natural gas to fuel its operation of Burrard Thermal.

NOW THEREFORE THIS AGREEMENT WITNESSETH, that in consideration of the mutual covenants and agreements in herein contained, the parties hereto mutually covenant and agree that:

1.0 DEFINITIONS

Where used herein or in any amendment hereto, unless the context otherwise requires, each of the following words shall have the meaning set forth as follows:

(a) **"Burrard Thermal"** means the Burrard Thermal electrical energy generating station owned and operated by Hydro and situate at Port Moody, British Columbia;

(b) **"Commodity Cost"** means the field commodity cost of natural gas negotiated by the Company from time to time for the purposes of this Agreement, or such other cost as determined by the British Columbia Utilities Commission. For the period from November 1, 1991 until further order of the British Columbia Utilities Commission the commodity cost is $0.93 per gigajoule; C

(c) **"Commodity Tolls"** means the commodity charges prescribed by the toll schedules of Westcoast Energy Inc. ("Westcoast") as approved from time to time by the National Energy Board ("NEB") and applicable to the gas supplied or delivered hereunder.

(d) **"Contract Year"** means each successive twelve-month period of the Term commencing 8:00 a.m. PST September 30, 1988;

(e) **"Demand Tolls"** means the demand charges prescribed by the toll schedules of Westcoast as approved from time to time by the NEB and applicable to the gas supplied or delivered hereunder.

BChydro proud of our Service

Thom M. Thompson
Vice-President
Corporate and Aboriginal Affairs
Tel: 623-3878
Fax: 623-4014

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Box 250
Vancouver, B.C.
V6Z 2N3

23 March 1993

BRITISH COLUMBIA UTILITIES COMMISSION
RECEIVED
MAR 26 1993
COMMISSION SECRETARY'S OFFICE

Attention: Mr. R.J. Pellatt,
Commission Secretary

Dear Sirs:

Re: B.C. Gas/Commission Order G-22-92

Further to our letter of 23 February, 1993, we wish to respond in detail to B.C. Gas's letter to the Commission of 16 February, 1993.

B.C. Hydro unequivocally opposes the Order sought. The ramifications of such an Order would be considerable. The Order will affect all customers who purchase from a regulated utility by way of contract. There are also jurisdictional issues raised.

Firstly, we wish to ensure that no false impression is left by Mr. Masuhara's letter to the Commission of 16 February, 1993. At page two thereof he states that: 'B.C. Hydro has responded by indicating ... that BC Gas should apply to the Commission'. By this response we were suggesting that B.C. Gas apply to the Commission to confirm that $.88/GJ is the proper price under the Burrard Agreement.

We wish to make the following submissions:

1. Contractual and Jurisdictional Issues:

The Burrard Thermal Interruptible Gas Purchase Agreement is a contract. It has been filed with and approved by the B.C.U.C. The British Columbia Court of Appeal in the case of Crestbrook Pulp And Paper Co. v. Columbia Natural Gas Ltd. (1978) 87 D.L.R. (3d) 248, stated at page 253:

> "While a contract may be filed and approved as part of a rate schedule, it does not thereby lose its identity as a contract: see ss. 23, 39 and 53 and also the definition of "rate" in s. 1. Similarly, if a utility sues a customer for the price of gas sold, the basis of its claim is the contract of sale and not a provision of the Act."

It follows from this that the Burrard Agreement in question retains its character as a contract. A contract requires agreement of the parties. We respectfully submit that for the Commission directly or indirectly to alter, amend or obviate specific provisions of this contract, destroys the character of the Agreement as a contract. We further respectfully submit that if the Commission is inclined to disapprove or vary any provisions of the contract, then it can and should only do so when there is an application for the same before it. There was no such application in the B.C. Gas Rate Design hearing. This is discussed more fully below.

The Commission stated at p. 25 of its 21 February 1992 Decision in this matter:

> "... the price paid for interruptible gas is equal to BC Gas' commodity cost of gas in the field (T. 2018). The Burrard Agreement was approved as part of the sale of the Lower Mainland Gas Division and <u>is beyond the Commission's purview until it expires.</u>" (Emphasis added)

The Commission went on to state at p. 26:

> "When the Burrard Agreement was entered into, all natural gas costs were streamed on a single variable cost basis for each customer class. The commodity cost identified in the Burrard Agreement was the total cost of gas for industrial purposes at the time. <u>However, the Utility no longer buys its gas on a streamed basis. Therefore the Commission believes that the "commodity cost" of $.89/GJ derived by BC Gas is inconsistent with the definition in the Burrard Agreement.</u> A more appropriate price might be the minimum price in Schedule 10 or the minimum price accepted at an auction." (Emphasis added)

The Commission then made the order in question.

With great respect to the Commission, we make the following submissions:

(a) It is inconsistent for the Commission to state that the Agreement is beyond its purview until it expires, and then go on to make orders which are contrary to that Agreement. It is acknowledged by all parties that $.93/GJ is not the price provided for by the Agreement.

(b) The issue of what price conforms to the intent of the Agreement is a matter for the parties to that Agreement or, in their stead, a Court or an arbitrator. We would again refer the Commission to the <u>Crestbrook</u> case, above-noted, at p. 255 where the British Columbia Court of Appeal stated:

> "I should note that another way in which Columbia's argument was put was to this effect: Columbia says that it charged the proper rate; Crestbrook says it did not; the issue is, what is the rate, and so the dispute relates to the essence of rate-making, which is under the supervision of the Commission. I cannot accept this. This dispute is not over rate-making. The rate was "made" by the contract and its acceptance for filing. The dispute is over the interpretation and implementation of the contract."

The Court of Appeal determined that issues of contractual interpretation were for the Court rather than the Commission. Here, the questions of the intent of the parties and a price which conforms to the Agreement, are matters for a Court or arbitrator.

(c) While it may be correct that costs are no longer streamed for each customer class, costs are still streamed but on the basis of the nature of supply, viz. firm or interruptible. Therefore, with all respect to the Commission, it is incorrect to say that "the Utility no longer buys its gas on a streamed basis".

(d) In its 15 July, 1992 response to matters in the Rate Design Phase A Decision, B.C. Gas confirms that the commodity cost for interruptible sales should be the average commodity price under B.C. Gas long term supply contracts. (p. 2-8). B.C. Gas's concern was mainly with the proposed auction and priorities in relation thereto. There was no issue taken with price per se.

2. <u>The Burrard Thermal Interruptible Gas Purchase Agreement:</u>

The Commission should be mindful of the terms of the Agreement in question. We append a copy of that Agreement for your ease of reference. Some of the relevant provisions are ss. 3.01, 3.02, 3.03, 3.06, 7.0 and 13.05.

Ss. 3.01 clearly establishes that the contract is a cost, rather than market value, based contract. Under ss. 3.02 and 3.03, B.C. Gas must negotiate for supply at lowest possible cost to B.C. Hydro. The commodity cost to B.C. Hydro must be no greater than the commodity cost for any other sales customer of the company. Everyone is agreed that that cost, in this case, is $.88/GJ. (This is discussed below.) Stipulating a $.93/GJ price would violate paragraph 3.03 of the Burrard Agreement.

The term of the contract is until September 30, 1998 and normally the contract would not be subject to revision, unless the parties agreed, prior to that time.

The Burrard Agreement is, of course, a "package". It is an integrated whole and if one of its provisions is to be arbitrarily altered or reinterpreted, then that logically has consequences for the other provisions. While it may seem that the price of gas is in question under the Burrard Agreement, we point out that s. 3.06 of the Agreement calls for a minimum $5 million payment to B.C. Gas regardless of quantity taken. Obviously, this provision, amongst others, must then also be altered by the Commission. Otherwise the effect is to increase costs borne by B.C. Hydro's customers.

Under s. 13.05 the Agreement is subject to the company maintaining regulatory approval. It is arguable that if the Commission in effect alters or reinterprets one provision of the contract, regulatory approval for the contract has not been maintained, and the contract falls.

3. <u>The Rate Design Hearing:</u>

The following aspects of the Rate Design Hearing are material:

(a) There was no evidence at all submitted to indicate $.93/GJ was the correct gas cost under the Burrard Agreement;

(b) At no time was the cost of gas under the Burrard Agreement questioned by any person, whether the Applicant, an Intervenor, or Commission Counsel, during the Hearing;

(c) All B.C. Gas cost allocations submitted in evidence were based on the Burrard Agreement cost of gas of $.88/GJ;

(d) B.C. Gas agreed at the Hearing that the correct cost of gas under Burrard Agreement was properly $.89/GJ. One presumes that the figure of $.89/GJ, rather than $.88/GJ, was merely a slip by Counsel. B.C. Gas accordingly sought approval of $.88/GJ for Burrard Agreement gas.

We quote from B.C. Gas's Counsel's submissions at pp. 2018 and 2019 of the Transcript:

> "Moving to the Burrard Thermal interruptible price, this is a matter that really hasn't been discussed in the evidence, at least in the oral evidence, Mr. Chairman, and I just raise it as a point for the Commission to keep in mind. The Burrard Thermal interruptible gas purchase agreement is a tariff under the provisions of the Commission, under the Act, and it has a price which says that Burrard Thermal shall pay the commodity cost of gas, which is related to the field commodity price.

In the past that price has been based on the 93-cent a gigajoule charge which was in the old CanWest/Westcoast/BC Gas arrangements. BC Gas has continued to bill Burrard Thermal based on that 93-cent price, but the new commodity price as indicated in the material before you is, because Burrard Thermal only takes gas out of the valley, the long-term valley, is about 89 cents. Now, that has yet to be translated into a price change to Burrard pending your decision. It's BC Gas's view that the contract does provide that Burrard Thermal should get the 89-cent price, but I suppose until that's blessed by the Commission as part of this flow-through it has yet to occur.

... that 93-cent price in effect disappeared on October 31st, November 1st. You'll note in the material before you in Exhibit 5 that all of the cost allocations have been undertaken on the basis that Burrard Thermal has the 89-cent price. If you approve the cost allocations as set out in Exhibit 5 then Burrard Thermal I think would automatically get that 89-cent price." (Emphasis added)

The above-noted was the sole reference at the Hearing to the Burrard Agreement price of gas. There was no application before the Commission for any alteration or reinterpretation of the Burrard provisions.

4. B.C. Gas's Revenue Requirements Hearing:

We wish to point out the position B.C. Gas takes respecting unilateral revisions of agreements. At Transcript pp. 724 and 725, Mr. Weafer, on behalf of the Lower Mainland Large Gas Users Association, and Mr. Lloyd, on behalf of B.C. Gas, had this exchange:

"MR. WEAFER: Q: Well, the question, Mr. Lloyd, was there anything preventing BC Gas from going to PCEC and saying, we're looking at the agreement, we're negotiating the final terms of the agreement in 1991 and signing it in 1991, we would like to extract a higher wheeling toll. Could you have done that---?

MR. LLOYD: A: I don't think you could have done it. That would have been just irresponsible. I mean, there's -- PCEC's out there building a pipeline to move gas to Vancouver Island in 1991 on the basic understanding of an agreement that was reached in principle in 1989. That would just be atrocious to treat them like that, to say, well, now that you're going to start building the pipeline, we're going to -- ."

And at p. 727, the same individuals had the following exchange:

"MR. WEAFER: Q: What I'm trying to compare is whether you can still negotiate a toll with PCEC in the interests of the customer base of B.C. Gas based on 1991 dollars, in terms of constructing that bypass pipeline?

MR. LLOYD: A: And the answer to that is clearly no. <u>You cannot reopen an agreement to change the fundamental economics of it.</u>" (Emphasis added)

It is B.C. Hydro's respectful submission that the same principle should apply to the Burrard Agreement.

5. <u>Domestic Natural Gas Supply Contracts Hearing:</u>

We point out that in this hearing, at p. 19 of its submission and final argument dated 28 January, 1993, B.C. Gas stated:

"That the Commission should do nothing which in any way interferes with, restricts the operation of, or displaces the gas supply arrangements which exist between BC Gas and its present suppliers."

We respectfully submit that the same should apply with the Burrard Agreement, which exists between B.C. Gas and its purchaser. Clearly if the Commission is to amend or reinterpret individual provisions of such agreements, then this affects more than merely B.C. Hydro and the Burrard Agreement. The Commission's decision in this matter respecting B.C. Hydro will be a major precedent and a signal to other parties with such contractual arrangements with a utility.

In summary, B.C. Hydro opposes the Order sought because:

1. The Burrard Agreement is a contract. Specific provisions cannot be amended without consequences for other provisions. The Commission has conceded that the Burrard Agreement is beyond its purview until its expiry period. Matters of interpretation of the Agreement, or the intent of the Agreement, are matters for a Court or an arbitrator. For the Commission to impose a $.93/GJ price would violate s. 3.03 of the Burrard Agreement.

2. Sanctity of contract is important. For the Commission to reinterpret or amend the Burrard Agreement in this fashion has important implications for many others who contract with utilities. B.C. Gas has recognized

the sanctity of contracts at its Revenue Requirements Hearing and the Domestic Natural Gas Supply Contracts Hearing.

3. No evidence was given and no application was made respecting the Burrard Agreement during the Rate Design Hearing, B.C. Hydro therefore, had no reason to be an active participant at the Hearing. All B.C. Gas cost allocations were based on the cost of gas being $.88/GJ. B.C. Gas agreed that the correct cost was $.89/GJ (and probably its Counsel actually meant $.88/GJ), and no one asserts that the cost in the Agreement is currently $.93/GJ.

All of which is respectfully submitted.

Yours truly,

Thom M. Thompson

BURRARD THERMAL PRIORITY

As noted under Tab 16, as part of Order No. G-91-92 the Commission directed BC Gas to include material relating to priority of service to the Burrard Thermal Plant in the Phase B application material. Representatives of BC Gas and B.C. Hydro have had discussions in an attempt to resolve the issue of priority but those discussions have not led to agreement. The material in this Tab sets out the position of BC Gas respecting Burrard Thermal priority.

1.0 THE BURRARD AGREEMENT

Article 6.0 of the Burrard Agreement pertains to curtailments and interruptions of the supply and delivery of natural gas to the Burrard Thermal Plant. Section 6.03 specifies the priority for the interruption or curtailment in the supply or delivery of natural gas. In the view of BC Gas section 6.03 of the Burrard Agreement, as presently worded, provides B.C. Hydro with an entitlement to all Lower Mainland "valley gas" under the baseload contracts after sales to interruptible customers in the Lower Mainland service area and after the requirements of BC Gas to refill storage capacity equivalent to the storage capacity which existed at the time of the execution of the Burrard Agreement in 1988.

The effect of the present provisions of section 6.03 of the Burrard Agreement is that the supply of gas to Burrard Thermal has priority over deliveries required to refill additional storage capacity which BC Gas has acquired since 1988 and also has priority over deliveries under off-system sales which may be available to BC Gas.

BC Gas has sought to have B.C. Hydro provide BC Gas with monthly nominations of the amount of gas that will be taken by the Burrard Thermal Plant. B.C. Hydro has indicated that it is prepared to provide monthly nominations but has refused to commit itself to the nominations provided. B.C. Hydro wishes to be able to vary its consumption, notwithstanding a nomination that might be provided, without any financial cost to B.C. Hydro. In effect B.C. Hydro has taken the position that it is entitled to take any amount of valley gas for the Burrard Thermal Plant at any time it wishes. The effect of such a position is that the ability of BC Gas to make off-system sales is seriously affected as BC Gas cannot reliably forecast the amount of gas which will be available for off-system sales since the volume of gas taken by Burrard Thermal can vary significantly.

Pursuant to the methodology adopted in Phase A, the difference between the price realized by BC Gas for off-system sales and the cost of gas sold off-system is recorded in the Gas Cost Reconciliation Account and thereby flows to the benefit of the firm customers of BC Gas. It is the position of B.C. Hydro that there should be no difference between the price of gas supplied under the Burrard Agreement and the cost of that gas. To the extent that the supply of gas to Burrard Thermal precludes off-system sales, the firm customers of BC Gas are detrimentally affected as they lose the benefit of the "profit" on such off-system sales. The refusal of B.C. Hydro to commit to a nomination procedure could result in circumstances where BC Gas is unable to make an off-system sale due to uncertainty over the volumes which will be taken by Burrard Thermal but Burrard Thermal then does not take the gas. The result is that a benefit to the firm customers has been lost even though Burrard Thermal has not made use of the gas.

2.0 PROPOSED REVISIONS TO THE BURRARD THERMAL AGREEMENT

Section 6.03 of the Burrard Agreement states that the priority for the interruption or curtailment in the supply or delivery of natural gas under the Burrard Agreement is "Subject to regulatory approvals which apply from time to time". The Burrard Agreement is a tariff and is subject to revision by the Commission. The wording of section 6.03 of that agreement specifically contemplates the involvement of regulatory authorities in establishing the priority for interruptions or curtailment of supply of gas to Burrard Thermal.

The arrangements under which BC Gas purchases gas have changed since the Burrard Agreement was executed in 1988. The importance of storage has increased for BC Gas and its customers. Off-system sales at a price higher than cost are now available. The Burrard Agreement should be amended to reflect the present gas supply circumstances.

BC Gas hereby applies for the Commission's consent to file amendments to the Burrard Agreement, the Burrard Agreement being a rate schedule of BC Gas, originally approved and accepted for filing pursuant to Order-in-Council No. 1829/88.

The present wording of section 6.03 of the Burrard Agreement does not distinguish between "supply" and "delivery". The priority provisions should be amended to recognize that B.C. Hydro has the ability to purchase gas directly. BC Gas can provide "delivery" priority for gas purchased directly by B.C. Hydro. However, the Burrard Agreement should be amended with respect to the "supply" of gas in order to ensure that the firm customers of BC Gas, who have allocated to them the fixed costs associated with the supply of gas, receive an appropriate benefit, either by way of savings resulting from the use of storage or from off-system sales.

The amendments to the Burrard Agreement sought by BC Gas will have the following effect:

1. BC Gas will continue to make available a minimum annual gas supply of 20 petajoules.

2. All requirements of BC Gas to refill storage capacity will have priority over the supply of natural gas to Burrard Thermal.

3. The 5 petajoules of growth in interruptible sales contemplated by clause 6.3(a)(iii) of the Burrard Agreement will be made available for both the growth of interruptible sales in the Lower Mainland service area and off-system sales.

4. Burrard Thermal will have priority for the Lower Mainland baseload contract natural gas which is available after items 2 and 3 above ("remaining valley gas"), provided that such volumes are nominated each month. Subsequent to receipt of the nomination from Burrard Thermal, BC Gas will provide the authorized volume. The ~~nominated~~ authorized volume shall be deemed to have been delivered for the purposes of calculating transportation charges.

5. BC Gas will schedule the supply of gas to ensure that B.C. Hydro receives~~, to the extent that there is remaining valley gas,~~ the authorized volume ~~nominated~~ for that month. BC Gas will decide the daily priority between supply to Burrard Thermal and supply to others.

BC Gas will provide specific wording for the amendments to the Burrard Agreement at an early date.

AMENDED AND RESTATED
BURRARD THERMAL INTERRUPTIBLE GAS PURCHASE AGREEMENT

THIS AGREEMENT made as of the 29th day of September, 1988 is an amendment and re-statement of an agreement made as of July 15, 1988 between the parties noted below.

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a crown corporation established pursuant to an Act of the Province of British Columbia and continued under the Hydro and Power Authority Act, RSBC, 1979, ch.188

(**"Hydro"**)

OF THE FIRST PART

AND:

B.C. GAS INC., a body corporate under the laws of the Province of British Columbia, having its registered office at 2800 - 595 Burrard Street, Vancouver, British Columbia, V7X 1J5

(the **"Company"**)

OF THE SECOND PART

W H E R E A S:

A. By separate agreement made as of the 15th day of July, 1988 (the "Asset Transfer Agreement") Hydro agreed to sell to the Company and the Company agreed to purchase from Hydro certain assets upon the terms more specifically set out therein;

B. For the purposes of this Agreement, all capitalized words shall have the same meaning given to those words in the Asset Transfer Agreement, unless otherwise defined herein; and

C. Hydro owns and operates the Burrard Thermal electrical energy generating station for the production of electrical energy and requires an interruptible supply of natural gas to fuel its operation of Burrard Thermal.

NOW THEREFORE THIS AGREEMENT WITNESSETH, that in consideration of the mutual covenants and agreements in herein contained, the parties hereto mutually covenant and agree that:

1.0 DEFINITIONS

Where used herein or in any amendment hereto, unless the context otherwise requires, each of the following words shall have the meaning set forth as follows:

(a) **"Burrard Thermal"** means the Burrard Thermal electrical energy generating station owned and operated by Hydro and situate at Port Moody, British Columbia;

(b) **"Commodity Cost"** means the field commodity cost of natural gas negotiated by the Company from time to time for the purposes of this Agreement, or such other cost as determined by the Commission. For the period from November 1, 1991 until further order of the Commission the commodity cost is $0.93 per gigajoule;

(c) **"Commodity Tolls"** means the commodity charges prescribed by the toll schedules of Westcoast Energy Inc. ("Westcoast") as approved from time to time by the National Energy Board ("NEB") and applicable to the gas supplied or delivered hereunder;

(d) **"Commission"** means the British Columbia Utilities Commission or successor regulatory commission having similar authority;

(e) **"Contract Year"** means each successive twelve-month period of the Term commencing 8:00 a.m. PST September 30, 1988;

(f) **"Demand Tolls"** means the demand charges prescribed by the toll schedules of Westcoast as approved from time to time by the NEB and applicable to the gas supplied or delivered hereunder;

(g) **"Period of Interruption"** means the period during which Hydro is required by the Company to cease or curtail the use of natural gas under this Agreement;

(h) **"Seasonal Gas"** means that natural gas which can be purchased by the Company over and above its system requirements up to the limit nominated for the Lower Mainland in its baseload natural gas supply agreements with third parties; and

(i) **"Term"** means that period described in section 7.1.

2.0 <u>INTERRUPTIBLE NATURAL GAS SUPPLY</u>

2.01 The Company shall sell or deliver to Hydro natural gas for use in Burrard Thermal and Hydro shall take and pay for such natural gas upon the terms and conditions herein contained.

2.02 The supply or delivery of natural gas hereunder is interruptible service. The obligations of each of Hydro and the Company hereunder are in addition to the obligations of each under the Burrard Thermal Firm Gas Purchase Agreement, made as of July 15, 1988.

2.03 The supply and delivery of natural gas hereunder shall be subject to the terms and conditions from time to time contained in the Company's gas tariff except where the terms of this Agreement are inconsistent with the Company's gas tariff in which event the terms of this Agreement shall prevail.

3.0 **CHARGES**

3.01 Hydro shall pay the Company for services relating to natural gas supplied hereunder the total of:

(a) the Commodity Cost;

(b) for Seasonal Gas, the applicable Westcoast Commodity Tolls;

(c) for natural gas other than Seasonal Gas, the applicable Westcoast Demand and Commodity Tolls;

(d) taxes directly on the charges under subsections 3.01(a), (b), (c), (e) and (f) herein, including social services tax;

(e) such additional variable costs of the Company necessary for the supply of natural gas hereunder; and

(f) 25 cents per gigajoule of natural gas supplied hereunder.

3.02 The Company undertakes to negotiate with third parties to obtain natural gas to be supplied under this Agreement at the lowest possible cost to Hydro.

3.03 Except as otherwise approved by the Commission and except with respect to Commodity Costs in contracts for the supply of natural gas negotiated with third parties and approved by Hydro, the Commodity Cost shall be adjusted from time to time during the Term, so that the Commodity Cost provided hereunder is no greater than the Commodity Cost for any other sales customer of the Company.

3.04 Any credits obtained by the Company from Westcoast, or any other monetary benefits which may be obtained by the Company, other than payments made pursuant to sections 3.01 and 3.05 herein, relating to costs paid by Hydro shall be credited to Hydro.

3.05 Hydro may, at any time and from time to time, upon reasonable notice, direct the Company to cease the supply of natural gas purchased by the Company, for the period of time stated in the notice, and to commence transportation and delivery of natural gas purchased by Hydro, for which services Hydro will pay the Company the total of:

(a) the applicable Westcoast Demand and Commodity Tolls, unless otherwise paid directly by Hydro;

(b) taxes directly on the charges under subsections 3.05(a), (c) and (d) herein, including social services tax;

(c) such additional variable costs of the Company necessary for the delivery of natural gas hereunder; and

(d) 25 cents per gigajoule of natural gas transported and delivered hereunder.

In addition Hydro shall reimburse the Company for all costs, expenses and liabilities (net of credits or other monetary benefits) associated with the cessation of the supply of natural gas purchased by the Company pursuant to contracts negotiated with third parties and approved by Hydro.

3.06 Subject to section 8.0, and notwithstanding the occurrence of an event of Force Majeure claimed by Hydro, during each Contract Year the minimum aggregate annual payment by Hydro to the Company for the supply or delivery of natural gas pursuant to subsections 3.01(f) or 3.05(d), as the case may be, shall be Five Million ($5,000,000) Dollars regardless of the quantity of natural gas supplied or delivered to Hydro within any Contract Year.

3.07 Following each Contract Year, the Company will prepare and deliver to Hydro an accounting with respect to each of subsections 3.01(a) to (f) and 3.05(a) to (d) herein and will include in such accounting a request for payment of the amount, if any, of any deficiency in the minimum aggregate annual payment requirement. Hydro will pay the amount of any such deficiency within twenty-one days of its receipt of the accounting and, in the event the deficiency is not paid when due, the late payment specified in section 10.2 shall apply to the unpaid deficiency.

4.0 USE

4.01 The Company shall provide to Hydro, as soon as possible and not later than October 30, 1988, estimates of the minimum and expected annual Seasonal Gas available in each of the three Contract Years following the execution of this Agreement and shall provide similar such estimates on or before May 1, 1989 and on May 1st of each year thereafter.

4.02 The Company shall make available to Hydro not less than 20 petajoules of natural gas during each Contract Year.

4.03 If in any Contract Year Hydro does not use all 20 petajoules of natural gas made available by the Company pursuant to section 4.02 herein then, after deduction of any amount of natural gas authorized by the Company under section 6.03C but not taken by Hydro, the shortfall may be taken in the four following years provided that:

(a) 20 petajoules for the current Contract Year has first been taken;

(b) thermally equivalent volumes carried over from the fourth previous Contract Year are taken next; and

(c) thermally equivalent volumes carried over from the third, second and first previous Contract Years are taken next.

When taking natural gas pursuant to this section, Hydro shall pay to the Company the amounts set out in subsections 3.01(a) to (e) inclusive if the natural gas is purchased by the Company, or subsections 3.05(a) to (c) inclusive if the natural gas is purchased by Hydro; but need not pay the amounts in subsections 3.01(f) and 3.05(d).

4.04 Natural gas supplied or delivered hereunder shall be considered, for billing purposes, as having passed through the Company's gas metering station on the Burrard Thermal property after natural gas supplied to Hydro by the Company under the Burrard Thermal Firm Gas Purchase Agreement made as of the 15th day of July, 1988, or any agreement which succeeds or replaces the Burrard Thermal Firm Gas Purchase Agreement.

4.05 If in any Contract Year the Company is in breach of section 4.02 herein and Hydro elects to prorate, pursuant to section 8.0 herein, the minimum aggregate annual payment of five million dollars to reflect the reduced supply of natural gas made available by the Company, the difference between 20 petajoules of natural gas and such reduced supply of natural gas may be taken in the four following years as provided in subsections 4.03(a) to (c) inclusive. When taking natural gas pursuant to this section, Hydro shall pay to the Company the amounts set out in subsections 3.01(a) to (f) inclusive if the natural gas is purchased by the Company, or subsections 3.05(a) to (d) inclusive if the natural gas is purchased by Hydro.

5.0 CONNECTION

The point of delivery shall be at the outlet of the Company's gas metering station on the Burrard Thermal property.

6.0 CURTAILMENT AND PRIORITY

6.01 The supply and delivery of natural gas provided herein is on an interruptible basis and may be interrupted or curtailed by the Company at any time and from time to time only if such interruption is reasonably required by the Company. The Company undertakes to use its best efforts to minimize any period of interruption required by the Company for the maintenance, repair or construction of the Company's facilities.

6.02 The Company may give Hydro notice (which in the Company's discretion may be oral, including notice by telephone to the Burrard Superintendent, or written) to cease or curtail the use of natural gas under this Agreement, which notice shall be not less than six hours in advance of the period of interruption, and Hydro shall, in accordance with the notice, cease or curtail such use before commencement of the period of interruption as specified in such notice, and shall not begin to use natural gas again or to use natural gas beyond the curtailed amount until so authorized by the Company. If the Company has a reasonable expectation that it may exceed its Westcoast contract demand, the Company may give Hydro notice, as provided herein, to cease or curtail the use of natural gas under this Agreement, in which case such notice shall not be less than two hours in advance of the period of interruption.

6.03 Subject to regulatory approvals which apply from time to time, the priority for the interruption or curtailment in the supply of natural gas under this Agreement shall be as follows:

(a) (i) refilling of storage by the Company;

(ii) the supply of natural gas under interruptible sales and service agreements, and renewals thereof, with customers who have entered into interruptible agreements prior to the date of this Agreement including any such agreements converted into sales and/or service agreements following the date of this Agreement; and

(iii) the annual aggregate supply of up to five petajoules of natural gas on an interruptible basis by the Company under arrangements entered into subsequent to the date of this Agreement, shall have priority over the supply of natural gas to Hydro under this Agreement;

(b) the supply of natural gas to Hydro under this Agreement, provided Hydro provides nominations to the Company pursuant to section 6.03C herein, shall have priority over:

(i) the supply of natural gas on an interruptible basis by the Company under arrangements entered into subsequent to the date of this Agreement when the annual aggregate amount supplied under those arrangements exceeds five petajoules of natural gas;

6.03A Subject to regulatory approvals which apply from time to time, the priority for the interruption or curtailment in the delivery of natural gas under this Agreement shall be as follows:

(a) (i) the Company's supply or delivery of natural gas to storage if such supply or delivery requires use of the Company's transmission or distribution system;

(ii) the supply or delivery of natural gas under interruptible sales and service agreements, and renewals thereof, with customers who have entered into interruptible agreements prior to the date of this Agreement including any such agreements converted into sales and/or service agreements following the date of this Agreement; and

(iii) the annual aggregate supply or delivery of up to five petajoules of natural gas on an interruptible basis by the Company to customers located on the Company's transmission or distribution system under arrangements entered into subsequent to the date of this Agreement,

shall have priority over the supply of natural gas to Hydro under this Agreement;

(b) the delivery of natural gas to Hydro under this Agreement shall have priority over:

(i) the supply or delivery of natural gas on an interruptible basis by the Company to customers located on the Company's transmission or distribution system under arrangements entered into subsequent to the date of this Agreement when the annual aggregate amount supplied or delivered under those arrangements exceeds five petajoules of natural gas;

6.03B For natural gas delivered in any year following termination of this Agreement by virtue of either section 4.03 or 4.05 herein, the Company's supply or delivery of natural gas to storage and the supply or delivery of natural gas referred to in (a)(ii) and (iii) shall have priority over the delivery of natural gas to Hydro. In any year, other than a Contract Year, Hydro shall have no right to take greater than 20 petajoules of natural gas under this Agreement.

6.03C By the twentieth day of each month Hydro shall provide to the Company a nomination in writing of the volume of natural gas which Hydro wishes to take under this Agreement in the next month. The nomination shall be separated between natural gas to be supplied by the Company and natural gas to be transported and delivered by the Company. By the twenty-eighth day of each month the Company shall provide to Hydro a notice in writing which sets out the volume of natural gas available to Hydro in the next month (the "Authorized Volume"). The Company shall schedule its supply and delivery of natural gas so as to make available to Hydro in the next month the Authorized Volume. If Hydro fails to take in the next month any portion of the Authorized Volume then Hydro shall pay to the Company, for each gigajoule of the Authorized Volume not taken, 25 cents per gigajoule and taxes, including social services tax. The payment by Hydro shall be considered a payment under subsection 3.01(f) if it relates to natural gas to be supplied by the Company or a payment under subsection 3.05(d) if it relates to natural gas to be transported and delivered by the Company.

6.04 In the event a system emergency on the Hydro electrical system is declared by Hydro, then for the duration of such system emergency Hydro shall have priority for the interruptible supply of natural gas over the supply by the Company under subsection 6.03(a) and for the interruptible delivery of natural gas over the delivery by the Company under subsection 6.03A(a). For natural gas taken by Hydro under this section, Hydro shall pay a rate or rates which equal the rate or rates that would otherwise have been paid to the Company by those customers of the Company whose supply or delivery of natural gas is interrupted or curtailed due to the declaration by Hydro of a system emergency on the Hydro electrical system. When interrupting or curtailing other customers of the Company under this section, to the extent permitted by good utility practice, the Company shall use its best efforts to minimize the cost to Hydro under this section.

6.05 If Hydro fails to comply with a Company direction to cease or curtail the use of natural gas as set out in section 6.02, Hydro shall pay for each unit of gas taken in excess of the curtailed level the rate set out in Company's Rate Schedule 7 as amended from time to time, or a successor schedule, for takes by a customer beyond a curtailed level. Notwithstanding the foregoing, Company may immediately discontinue the supply of natural gas to Hydro in the event of a failure by Hydro to cease or curtail the use of natural gas as set out in section 6.02.

7.0 **<u>TERM</u>**

Subject to section 8.0, this Agreement shall commence at 0800 PST on July 16, 1988 and shall terminate and be of no further force or effect at 0800 PST on September 30, 1998, provided that such termination shall be subject to the rights and remedies of both parties accruing to the date of termination such right and remedies shall survive such termination.

8.0 **<u>NON-PERFORMANCE</u>**

In the event that the Company is unable to fulfill its obligations under section 4.02 herein, Hydro's only recourse shall be to elect to terminate this Agreement or elect to pro rate the minimum aggregate annual payment of five million dollars to reflect the reduced supply of natural gas.

9.0 **CHARTS**

Hydro shall, at the request of the Company:

(a) (i) change charts at 0800 PST on the first day of each month and at 0800 PST on any day a chart change is required,

(ii) enter all the information required to complete the reverse side of each chart as it is removed from the meter,

(iii) send all completed charts to the Company in a manner specified by the Company except for those charts removed during the final four (4) days of each month which will be picked up by a representative of the Company on the first working day of the following month,

(iv) wind the clock mechanism, ink and service the recorder pens, and report forthwith mechanical failure to the Company,

(v) take readings of front and rear dials at 0800 PST on each working day and telephone them to the Company by noon the same day,

(vi) advise the Company as soon as possible of any actual or anticipated abnormal change in Hydro's rate of consumption of gas; or

(vi) permit the Company to maintain on Hydro's premises aforesaid, the necessary communication circuit and other facilities for the purpose of telemetering Hydro's gas consumption.

10.0 ACCOUNTS

10.01 Bills will be rendered by the Company to Hydro on a monthly basis in respect of natural gas actually used at Burrard Thermal. The due date for payment of bills shown on the face of the bill is twenty-one days following receipt of the bill. Hydro shall pay to the Company at a Company office located within the Lower Mainland designated by the Company from time to time for such purpose the full amount on the bill.

10.02 If the amount due on any bill has not been paid in full on or before the due date shown on such bill, and if the unpaid balance is $30 or more, a further bill will be rendered to include the overdue amount plus a late payment charge of 1-1/2% (equivalent to 19.6% per annum when compounded monthly). Notwithstanding the due date shown, to allow time for payments made to reach the Company's payment processing centre and to coordinate the billing of late payment charges with scheduled billing cycles, the Company may, in its discretion, waive late payment charges on payments not processed until a number of days after the due date.

1.0 SUSPENSIONS

If as a result of any emergency or force beyond the reasonable control of either party herein or strike, lockout or other such disturbance of either party (the "Force Majeure"), either party is or was wholly or partly unable because of the Force Majeure, to perform an obligation arising from this Agreement and claims that a Force Majeure is occurring or has occurred and reasonably establishes that fact, then the performance of the obligation shall be deemed to be suspended provided always that:

(a) the suspension shall be of no greater scope and no longer duration than the Force Majeure,

(b) the non-performing party shall make its best efforts to counter the Force Majeure or to otherwise remedy its inability to perform the obligation,

(c) a performance required at a time other than when the Force Majeure is occurring shall not be excused by the Force Majeure, and

(d) an obligation to make a payment when due shall not be excused by the Force Majeure.

12.0 INDEMNITY

12.01 Subject to the Financial Administration Act S.B.C. 1981, c.15, as amended, and the Hydro and Power Authority Act R.S.B.C. 1979, c.188, as amended and the regulations thereunder:

(a) Hydro shall be liable for and shall indemnify and save harmless the Company, its employees and agents, from and against any and all damage, loss, cost and expense which the Company, its employees or agents, may suffer or incur; and

(b) Hydro shall indemnify and save harmless the Company, its employees and agents, from and against all claims, demands, costs, actions and causes of action whatsoever (including assessments by the Workmen's Compensation Board of British Columbia) which may be brought or made against the Company, its employees or agents, in either case caused by, arising out of, or connected in any way with any of Hydro's equipment or any use thereof or disturbing element caused, permitted or introduced by Hydro or Hydro's equipment, or caused by, arising out of or connected in any way with any action, effect or use of gas after the same shall have been delivered to Hydro.

12.02 Hydro, its employees or agents, will not be liable to the Company pursuant to paragraph 12.01(a) for any loss of revenue or profits or other indirect, consequential or financial loss whether such loss is caused by an act or omission of Hydro, its employees or agents, later found to be negligent or otherwise.

13.0 <u>MISCELLANEOUS</u>

13.01 The Company will prepare and maintain records related to the supply and delivery of natural gas hereunder, which records will be open to audit examination by Hydro during regular business hours of the Company during the term of this Agreement and for a period of one year after the termination of this Agreement.

13.02 No waiver of or failure by the Company to enforce any right or to exercise any remedy provided in the Agreement shall affect or prejudice the rights and remedies of the Company in respect of any future or other breach of the Agreement by Hydro or in respect of any matter for which the Company may be entitled to discontinue the supply of natural gas.

13.03 Any notice report or other document that either party may be required or may desire to give to the other shall be in writing, unless otherwise provided for, and will be deemed to be validly given to and received by the addressee, if served personally, on the date of such personal service or, if delivered by mail, telex or facsimile copier, when received:

(a) if to the Company:

B.C. Gas Inc.
1111 West Georgia Street
Vancouver, B.C.
V6E 4M4

Attention: Vice President, Gas Supply

(b) if to Hydro:

British Columbia Hydro and Power Authority
970 Burrard Street
Vancouver, B.C.
V6Z 1Y3

Attention: Comptroller

or at such other address as either party may from time to time designate by notice in writing to the other.

13.04 Notwithstanding section 13.03, notice of interruption or curtailment of the supply of natural gas shall be given in accordance with the provisions of section 6.02 of this Agreement.

13.05 This Agreement is subject to the Company obtaining and maintaining any regulatory approvals that may be required.

13.06 A party shall not commence any legal proceedings against the other party in respect to the interpretation or enforcement of this Agreement unless and until it has first taken all reasonable steps to resolve the matter in issue with the other party, and included in such reasonable steps is the right of a party to submit any dispute, with the other party, arising out of this Agreement to a single arbitrator in accordance with the provisions of the Commercial Arbitration Act or any re-enactment or amendment thereof.

13.07 Notwithstanding any statutory limitation to the contrary, a party shall not commence any action, arbitration or other proceeding between the parties after the expiry of a period of two years after the issue in dispute arose.

13.08 Upon execution by the parties, this Agreement replaces and supersedes the prior Agreement made as of the 15th day of July, 1988 between the parties.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed as of the day and year first above written.

THE COMMON SEAL of BRITISH)
COLUMBIA HYDRO AND POWER)
AUTHORITY was hereunto affixed)
in the presence of:)
) C/S
____________________)
Authorized Signatory)

THE COMMON SEAL of B.C. GAS)
INC. was hereto affixed in the)
presence of:) C/S
)
____________________)
Authorized Signatory)