1.0 BACKGROUND

1.1 Scope of Phase B Hearing

On April 15, 1993 BC Gas Inc. filed an Application for re-design of its Gas Tariff rate schedules for customers served by the Lower Mainland, Inland and Columbia Divisions. During the hearing, BC Gas Inc. completed a corporate reorganization in which all utility assets were transferred to a wholly-owned subsidiary of BC Gas Inc., named BC Gas Utility Ltd. Thus for the remainder of the hearing the Applicant was referred to as BC Gas Utility Ltd. ("BCGUL", "the Utility", "the Company"). In order to minimize confusion, the Applicant generally will be referred to in this Decision as BCGUL rather than BC Gas Inc., except where the parent Company is being referred to.

BCGUL is a natural gas distribution utility in British Columbia which serves approximately 635,000 residential, commercial, industrial and other customers. These represent over 90 percent of the natural gas consumers in the Province. Since the utility was formed in 1988 as a result of the acquisition of the British Columbia Hydro and Power Authority ("B.C. Hydro") Gas Division by Inland Natural Gas Co. Ltd., it has provided gas through its Lower Mainland, Inland, Columbia and Fort Nelson Divisions to consumers extending from Fort Nelson through the Northern Interior, Cariboo, Okanagan, and Kootenay regions to the Lower Mainland.

The Phase B Rate Design Application proposed the consolidation of all Divisions except Fort Nelson for revenue requirement purposes effective January 1, 1993. It also included a proposal to implement "postage-stamp" rates (exclusive of gas costs) for the residential, commercial and small industrial customer classes in the Lower Mainland, Inland, and Columbia areas, and to implement common general terms and conditions of service, thus combining and eliminating certain sales tariffs and rates in each Division. Moreover, rates between and within classes were to be restructured based on various cost studies undertaken by BCGUL. These changes were to be effective January 1, 1994 for residential and commercial customers, and November 1, 1993 for industrial customers.

In addition, the Application proposed establishing a Gas Cost Reconciliation Account ("GCRA"), intended to ensure that BCGUL fully recovered, but did not over-recover its gas costs. BCGUL also proposed a revised Main Extension Policy and Test to assist BCGUL in its decisions whether or not to serve potential new customers who required the extension of mains in order to be served by natural gas.

The hearing also considered whether or not BCGUL should be required to offer a buy-sell alternative for interruptible customers, and if so, under what conditions. Another issue examined in the hearing was the

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appropriate price and priority to be accorded to gas for use at the Burrard Thermal Generating Plant owned by B.C. Hydro.

Finally, in its 1993 revenue requirements application, BCGUL had proposed a Weather Stabilization Adjustment Mechanism ("WSAM") to stabilize the revenues of the Utility from the impacts of abnormal weather. The British Columbia Utilities Commission ("BCUC", "the Commission") approved the withdrawal of the revenue requirements application by BCGUL, and directed BCGUL to propose either a modified WSAM or some other mechanism as part of its Phase B Rate Design Application. BCGUL subsequently requested and was granted approval to remove WSAM from consideration in the hearing.

1.2 Hearing Orders and Dates

Several of the issues dealt with in the Phase B Rate Design Hearing were carried forward from previous BCGUL hearings. Therefore, for convenience, the following section briefly summarizes the relevant events and Orders leading up to the Phase B Hearing.

In November 1992, BCGUL filed a Revenue Requirements Application seeking a 4.36 percent increase in total revenue. The Commission, by Order No. G-114-92 dated December 4,1992, approved a 9.787 percent interim rate increase on gross margin of divisional captive rate schedules for the Lower Mainland, Inland and Columbia Divisions effective January 1, 1993, subject to refund. The WSAM account and the use of a 7.5 percent unfunded debt interest rate were also approved on an interim basis effective January 1, 1993, subject to review at a public hearing.

By Order No. G-15-93 dated March 4, 1993, the Commission set a date for BCGUL to file its Phase B Rate Design Application and for the commencement of the public hearing to be held in Vancouver. On May 11, 1993 with Order No. G-32-93, the BCUC set a date for a pre-hearing conference into the Application.

By Order No. G-33-93 dated May 18, 1993, the Commission approved an application by BCGUL to withdraw its Revenue Requirements Application and ordered the Company to refund its interim rate increase. The Commission also withdrew its interim approval of the WSAM, and directed the Company to propose a modified WSAM or other decoupling mechanism in its Phase B Rate Design Application. The Commission also issued several directions to BCGUL regarding specific accounting treatment of some items and the treatment of existing or proposed deferral accounts.

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Commission Order No. G-38-93 dated May 25, 1993, established hearing dates for the Phase B Rate Design Hearing as well as dates and procedures for filing evidence, information requests and responses. As directed by the Order, regional hearings relating to the proposed consolidation and local concerns were held on June 28, 1993 in Kamloops and on June 29, 1993 in Cranbrook. The hearing then adjourned until July 5, 1993 when it re-convened in Vancouver.

In the Commission's August 5, 1992 Decision regarding a revenue requirements application by the Utility, the Commission had reiterated a previous request that the Company seek to isolate its utility assets so that a clearer picture of the Utility's capital structure would be available at the next hearing. On March 29, 1993, BCGUL applied for an Order permitting the acquisition of all shares of BCGUL by a holding company. The hearing set down under Order No. G-38-93 commenced on June 11, 1993 and concluded with final argument on June 15, 1993. By Order No. G-45-93 dated June 18, 1993, the BCUC approved the corporate reorganization. All necessary approvals of the reorganization were complete prior to the opening of the Vancouver sessions of the hearing on July 5, 1993. By Order No. G-66-93 dated August 12, 1993, the Commission also approved the issuance of one common share by BCGUL to BC Gas Inc. in the amount of $50 million.

1.3 Matters Dealt with by Earlier Orders

In order to allow the Applicant and other parties to proceed with specific issues arising from the hearing, such as the Integrated Resource Plan ("IRP") and industrial gas supply arrangements, the Commission issued Orders relating to these issues in advance of the date of this Decision. For convenience these are listed below.

By Order No. G-68-93 dated August 13, 1993 (Appendix C), the Commission approved the consolidation of the Lower Mainland, Inland and Columbia Divisions for regulatory purposes. The Commission also ordered BCGUL to follow certain accounting practices. No decision was issued on the related matter of postage-stamp rates.

In the hearing, BCGUL requested a quick decision from the Commission regarding certain IRP and Demand-Side Management ("DSM") deferral accounts in order for the Utility to proceed with its IRP and DSM development. By Order No. G-69-93 dated August 13, 1993, the BCUC approved the DSM and IRP deferral accounts, with the exception of those related to a possible new Liquified Natural Gas ("LNG") plant. The approval of the deferral accounts was subject to certain noted changes and amendments (Appendix D). A decision on the deferral accounts for expenditures on proposed feasibility studies related to a possible new LNG plant was deferred until release of the entire Decision.

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By Order No. G-83-93 dated September 21,1993 (Appendix E), the BCUC approved and accepted for filing certain industrial rate schedules subject to certain changes and comments as set out in Attachment "A" to the Order.

1.4 Present Document is Complete Decision

Notwithstanding the issuing of certain Orders in advance of the Decision, the Commission wishes to note that this Decision constitutes the complete Decision. Orders issued previously relating to parts of this hearing form a part of this Decision and are attached to it as Appendices.

The issuance of this Decision completes an important phase in the regulatory evolution of the natural gas industry in British Columbia, a phase that began in the 1980s with the privatization of B.C. Hydro's Lower Mainland Natural Gas Division and the development of competitive markets in natural gas supply. With this Decision, BCGUL's services have now been significantly unbundled, allowing customers a wide range of utility services in a deregulated supply market.

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2.0 CONSOLIDATION AND POSTAGE-STAMP MARGIN ON DELIVERY RATES

2.1 Introduction

As part of its Phase B Rate Design Application (Exhibit 1, Tab 5), BCGUL sought permission to consolidate its Lower Mainland, Inland and Columbia Divisions. In order to assist BCGUL in the preparation of its 1994-1995 revenue requirements application, the Commission issued Order No. G-68-93 on August 13, 1993 (Appendix C). This Order approved consolidation and related specific accounting practices. The following paragraphs provide reasons for the Commission's Decision in the matter of the BCGUL's consolidation application.

2.2 Background

As a condition of the Inland Natural Gas Co. Ltd. purchase of the Lower Mainland Gas Division from B.C. Hydro in 1988, Inland and its Columbia and Fort Nelson Divisions were exempted from traditional regulation of the Commission for three years. A new company, BC Gas Inc., was created in 1989 to amalgamate the Divisions of Lower Mainland Gas, Inland, Columbia and Fort Nelson, all of which, except Lower Mainland Gas, had previously been separate legal entities. Order in Council 953/89 required all the Divisions of BCGUL to continue to maintain separate rate bases, accounts and schedules of divisional rates.

In 1992, after return to normal Commission regulation, BCGUL applied for consolidation of the above Divisions for regulatory purposes such that any change in the overall revenue requirement would be spread equally to all customers. The Commission Decision dated August 5, 1992 accepted a common capital structure and an overall rate of return on common equity, but rejected the request for full consolidation "because there are other aspects and issues which must be addressed and satisfied before total consolidation can be approved" (p. 21). These "aspects and issues" were listed in Exhibit 68 of the 1992 hearing and were re-submitted as Exhibit 9 in the Phase B hearing.

The 1992 Decision further stated (p. 20):

> "The Commission believes that the Phase B Rate Design hearing will provide an appropriate forum for resolution of the consolidation issue. Therefore, the Commission directs BC Gas to file its costs of service studies on a divisional basis for that hearing. In the interim period, the Company is to maintain divisional rates."

In accordance with the above direction, BCGUL filed its rate design application on April 15, 1993, provided divisional cost of services studies and re-applied for consolidation of the Lower Mainland, Inland

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and Columbia Divisions effective January 1, 1993. Fort Nelson was excluded from the consolidation application as BCGUL explained that the municipality wished to remain independent and unconsolidated (T. 93). In various areas of the application, BCGUL addressed and proposed resolutions to the "aspects and issues" described in Exhibit 9.

Effective July 1, 1993, BCGUL was given Commission approval by Order No. G-45-93 to reorganize and separate the utility assets of the Company from other non-utility investments. All four divisions under the jurisdiction of the Commission are now structured under the name of BC Gas Utility Ltd. and BC Gas Inc. has been transformed into a holding company to control all utility and non-utility shares.

2.3 Consolidation

During a regional hearing in Cranbrook on June 29, 1993, three Columbia industrial customers, Crestbrook Forest Industries Limited, Fording Coal Ltd. and Line Creek Resources Ltd., expressed the concern that, if consolidation was the reason that their rates had been reclassified under the proposed Schedule 22, then they would oppose consolidation (T. 151, 208, 221). They believe the Columbia system to be unique with its gas supply sources independent of other BCGUL Divisions (T. 118, 124). Other than the above concern, the witness for Fording stated that he would encourage consolidation if it would eliminate duplication (T. 221). The Commission considers that the Columbia industrial customers' concern relative to the proposed Schedule 22 is a rate design issue and is independent of the consolidation proposal.

BCGUL received general support for consolidation from its interior customers and from the municipalities which it serves (T. 269, Exhibit 14). BCGUL argued that, in order to unify rates and tariffs to the greatest extent possible, consolidation should be the first step and postage-stamping the second and final step (T. 386); the latter, it claimed, would bring benefits of economic neutrality and simplicity (T. 835). The Company also suggested that the results of the Fully Distributed Cost Studies prepared by BCGUL indicated that the costs of serving residential customers in the three Divisions were comparable and therefore the Utility should move toward consolidation and postage-stamp rates (T. 695, Exhibit 1, Tab 5, p. 5).

Dr. Sarikas, a rate design expert witness for BCGUL, testified in favour of consolidation. He stated that the main benefits of consolidation are the elimination of regulatory and administrative burdens, and discrimination in rates (T. 1028). He concluded that consolidation without postage-stamping would not fully achieve the above-described benefits (T. 1038).

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In final argument, Counsel for BCGUL reiterated the evidence of Mr. J.C. Butler and Dr. W.R. Waters in the 1992 hearing with respect to the benefits of consolidation (Exhibit 1, Tab 5, p. 2). He argued that consolidation would reflect the reality of one entity and submitted that postage-stamping should be approved at the same time as consolidation. The Commission believes that the postage-stamping concept is a rate design and policy issue and that it should be dealt with independently from consolidation.

Having carefully considered the evidence presented in favour of consolidation, and accepting that the consolidation proposed by BCGUL is cost-effective, the Commission approves consolidation with certain conditions. The impact of consolidation will be closely monitored by the Commission and if necessary, this approval may be reconsidered in future. In addition, internal divisional accounts must be maintained so that rate base and cost of service can be determined in future rate design applications. Future revenue requirement changes will be applied across-the-board on the gross margin of approved rates. However, BCGUL will be required to demonstrate each time that any rate change will preserve or enhance the revenue to cost ratio for each divisional rate class as determined in this Decision.

2.4 Depreciation Rates

Standardization of depreciation and amortization rates across BCGUL's Divisions is a logical accompaniment to consolidation. **The Commission therefore approves the relatively minor changes required to achieve this purpose as set out by BCGUL in Exhibit 1, Tab 5, Appendix B.**

2.5 Disposition of Deferral Accounts and Deferred Tax Balances

2.5.1 <u>Deferral Accounts</u>

Consolidation logically requires the disposition of certain deferral account balances which are listed by BCGUL in Exhibit 1, Tab 5, pp. 12-13. **The offset of these deferred account balances within Divisions, proposed by BCGUL upon consolidation, is approved. The Commission, however, requires a review report from the internal auditors of BCGUL to verify that the balances of these deferred accounts are accurate and in compliance with Commission directives.**

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2.5.2 Deferred Income Tax Balances and Franchise Fees

BCGUL proposes to dispose of the deferred income tax balances as offsets against franchise fees otherwise payable by some customers in the Inland and Columbia Divisions. Deferred tax balances exist only in the Inland and Columbia Divisions and franchise fees of 3 percent are charged by interior municipalities on the previous year's gross utility revenue collected within the municipality. However these fees, paid by the utility, are currently spread and allocated to all customers within each Division, both inside and outside municipal boundaries.

BCGUL has proposed, in future, to separate franchise fees and to apply them as a surcharge to the bills of only those customers located within the municipal boundaries. In order to mitigate the impact of rate design changes BCGUL applied to offset the franchise fee with a credit from the deferred income tax balance until the latter is depleted. Since deferred income taxes had been collected from all customers, both Commission counsel and counsel for Fording questioned the fairness of applying these funds in a way which benefits customers located within municipal boundaries more than it does those customers outside of municipal boundaries (T. 82). BCGUL argued that its proposal would provide a smooth billing transition for customers located outside municipal boundaries as opposed to the effect of an immediate elimination of the franchise fee coupled with a credit from the deferred tax accounts. BCGUL contended that to simultaneously provide both these credits would create rate instability. BCGUL, however, did agree that removing the costs of divisional attributes such as revenue, cost of gas, franchise fees and deferred tax amortization would provide a common gross margin on which future rate changes could be applied across-the-board on a consolidated basis (T. 91).

The Commission accepts BCGUL's proposal to effectively act as agent to collect franchise fees on revenues generated from customers within related municipal boundaries commencing January 1, 1994. The Commission accepts that showing the collection as a separate charge on customer bills may be postponed until such time as BCGUL's Customer Information System ("CIS") is installed (expected in 1995).

The Commission does not agree that balances from the deferred income tax accounts should be used to offset franchise fees. The deferred income tax balances carried on the Inland and Columbia books were collected prior to 1984 from *all* customers to pay for a future tax liability. Since the Utility has now adopted the flow-through method of income tax accounting (except in the Fort Nelson Division) and this tax liability may not come due in the foreseeable future, the disposition of this deferred fund is possible and should be used to generate benefits for all customers in the specific Divisions. Consequently, the Lower Mainland customers will receive short-term benefits due to the deferred tax credit in the rate base,

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and Inland and Columbia customers at the same time would also receive extra benefits due to the savings in administrative costs as a result of consolidation. The amortization of this fund will also help to achieve future common rate base components in the Division as consolidation is implemented.

In this Decision, the Commission accepts the application of some portion of the deferred income tax balances to offset potential rate inequity or to offset other deferred account balances within a Division, such as described under item 1.(iii) of Order No. G-68-93 for the Columbia Division. The remaining balances should be amortized to lower the overall revenue requirements in the specific Division and can be combined as a credit in rate base for rate setting purposes. In this regard, BCGUL is directed to propose an amortization schedule in its 1994-1995 revenue requirements application.

2.6 Postage-Stamp Margins

In its Application, BCGUL requested Commission approval for both consolidation and postage-stamp margins on the delivery component of its rates to residential and commercial customers in the Lower Mainland, Inland and Columbia Divisions. However, the Commission considers postage-stamping to be a rate design and policy issue to be dealt with independently from consolidation. The Commission notes that BCGUL itself acknowledged that postage-stamp rates are not a prerequisite for consolidation (T. 77) and that postage-stamp margins (exclusive of gas supply cost) are a rate design objective (T. 41), although some of the evidence in support of consolidation is equally applicable for postage-stamp margins.

BCGUL's postage-stamp margin proposal does not extend to industrial customers (T. 343, 455) and the following discussion refers to residential, commercial and general firm service rates. Evidence presented by the Company emphasized that fairness, equity and the spreading of risk were the major reasons for postage-stamp margins, while simplicity and economic neutrality were the less important factors (T. 832). According to BCGUL, its customers perceive their rates to be fair and equitable if they pay the same rates for similar services in all Divisions. Moreover, the Utility's Fully Distributed Cost Studies demonstrate that the revenue to cost ratios of residential and commercial customers, based on its proposal would be similar and within the $\pm$10 percent band of reasonableness (T. 229).

The need for trade-offs between the perceived fairness and simplicity of postage-stamp rates and the need to send correct price signals in the interest of economic efficiency was explored by a number of Intervenors.

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The Commission is of the view that, on balance, where revenue to cost ratios and other conditions are similar, the perceived fairness and simplicity of postage-stamping outweighs the other considerations. However where the nature of the ratebase, the customer makeup, the gas supply administration, the operational characteristics and the overall cost structures between Divisions have historically differed, and there is no anticipation of early closer alignment, postage-stamping may not be appropriate.

In BCGUL's case, both the Lower Mainland and Inland Divisions are facing rapid customer growth. The resulting growth in rate base is not shared by the Columbia Division. Also, because of its grid system design and location, the Columbia Division experiences different operating and maintenance costs. On a broader basis, BCGUL has recognized, and the Commission has confirmed, gas supply cost differences exist between Divisions.

Although consolidation was widely publicized and was generally supported by the interior communities, postage-stamping did not appear to be as well-understood or to be fully supported (T. 151). In fact, the witness for Line Creek Resources Ltd. spoke against postage-stamp rates due to the uniqueness of the Columbia system (T. 208).

The Commission concludes that the Columbia Division is sufficiently different from the Inland and Lower Mainland Divisions that, as a matter of rate design principle, Columbia Division gas delivery charges for residential, commercial and general firm service customers should not be linked to those of Inland and Lower Mainland customers through postage-stamping at this time. As a matter of coincidence, the approved Columbia Division margin may, in fact, be similar from time-to-time but this should not be taken as Commission acceptance of the principle of a postage-stamp rate for the Columbia Division.

The Commission commends BCGUL's decision to exclude the markedly different Fort Nelson Division from the consolidation and postage-stamping application, partly to accommodate the wishes of the municipality.

The Commission approves the adoption of a postage-stamp delivery charge to BCGUL's Inland and Lower Mainland Division residential, commercial and general firm service customers only.

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3.0 RATE DESIGN BASIS

BCGUL presented three technical studies in support of its rate design application. These were a Fully Distributed Cost-of-Service ("FDC") study, a Long-Run Incremental Cost ("LRIC") study, and a Competitive Energy and Price Elasticities of Demand study. Both the FDC study and LRIC study results were presented on a divisional and consolidated basis.

In addition to the evidence put forward by the Applicant, Commission staff retained the firm of Barakat and Chamberlin ("B&C") to review each of these studies for technical correctness and report their findings (Exhibit 20). As well, evidence relating to the cost studies was put forward by Mr. John Todd, a consultant hired by the Consumers' Association of Canada (B.C. Branch) et al. ("CACBC") (Exhibit 52) and Dr. Alan Rosenberg, a consultant hired by the Lower Mainland Large Volume Gas Users' Association (Exhibit 38).

3.1 Cost and Pricing Studies

3.1.1 Fully Distributed Cost of Service Study

The purpose of an FDC study is to identify the embedded cost of service for each customer class and compare these costs to the revenue generated by each class to determine to what extent class costs are recovered through class revenues. This process is undertaken in three steps. First, the rate base and annual revenue requirement is divided into functional categories such as purchased gas cost, transmission cost, distribution cost, etc. Second, each functional amount is divided into classifications indicating that the cost is demand or capacity-related, commodity-related or customer-related. Third, the classified costs are allocated to the appropriate rate classes using allocation factors that reflect the particulars of each rate class. Depending on the cost being allocated, allocation factors may be based on usage volumes, number of customers, or use of capacity.

The BCGUL FDC study used three different methods of allocating capacity costs: peak responsibility, non-coincident peak, and average and excess demand. These three methods were identified by the Applicant, Intervenor and Commission staff expert witnesses as being the most commonly used in the gas industry in North America. All three methods indicated that BCGUL's current rates are less than the allocated historical costs for residential customers in all Divisions, although the revenue to cost ratios for Inland residential customers were within 10 percent of the theoretical ideal of a one-to-one correspondence between costs and revenues. In previous decisions the Commission has accepted a 10 percent band as

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reasonable. Similarly, all three methods indicated that Lower Mainland industrial customers were contributing revenues in excess of the costs allocated to them.

Based on the results of the FDC study, BCGUL has proposed to raise rates to residential customers in the Lower Mainland and Columbia Divisions while simultaneously lowering rates to Lower Mainland industrial customers. However, the Utility has not attempted to match specifically its rate design proposal to any one costing approach.

In general, the experts called to testify on behalf of Intervenors and Commission staff found that the technical approaches used in the BCGUL FDC study were reasonable and consistent with standard industry practice. Some differences of opinion arose with respect to the appropriate treatment of distribution costs. Mr. Todd advocated the allocation of distribution facility costs to interruptible customers using a non-coincident demand methodology. However, Mr. Todd agreed that this method would have little practical effect on the BCGUL proposal since the utility proposes to set the rate for interruptible customers at a discount to the firm rate (T. 3476). Alternatively, Dr. Rosenberg argued that some portion of the distribution system should be treated as a customer cost with the result that smaller customers would be allocated a greater responsibility for these costs (Exhibit 38, p. 11). He did not provide evidence as to the impact this change would have on BCGUL's FDC studies.

3.1.2 Long-Run Incremental Cost Study

In addition to the FDC study, BCGUL also presented an LRIC study in support of its Application. This study used an engineering approach to determine the incremental costs of facilities, exclusive of gas supply costs, associated with serving new or additional customers. It did not examine the incremental costs of serving existing customers. BCGUL indicated that these approaches had been taken since it viewed gas supply costs as information which could give other gas suppliers a competitive advantage (Exhibit 4, Tab A19) and it expected load growth to come from the addition of new customers rather than increased use by existing customers (Exhibit 4, Tab A14)).

The results of the study indicated that LRIC's on a per gigajoule basis are greatest for residential customers and lowest for industrial customers in all Divisions, reflecting the higher portion of distribution and operating and maintenance costs associated with residential customers. A comparison of the estimated LRIC for residential customers to the average margin received from residential customers indicates that current rates will not recover expected future costs. In contrast, the estimated LRIC for commercial and small to medium industrial customers is less than the average margin associated with these customer classes.

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A review of the study by the Commission staff expert witness indicated that the calculations and results presented by BCGUL were reasonable but limited in scope since they did not include costs associated with existing customers (Exhibit 20, p. 16). Similarly, the witness indicated that the exclusion of gas costs from the study left out "an important part of the story" and prevented the study from being used to assess the efficiency aspects of the Utility's rate proposals (Exhibit 20, p. 15). Dr. Rosenberg agreed (Exhibit 38, p. 6). Although the staff witness recognized the difficulties faced by BCGUL in undertaking a gas utility LRIC, and commended the Utility for its attempt (Exhibit 20, p. 1), the witness recommended that the Utility undertake an expanded LRIC which would contain capacity costs related to gas supply. In addition the witness suggested the Company consider developing seasonal LRIC estimates (Exhibit 20, p. 18).

Mr. Todd, CACBC, was also critical of certain aspects of the Utility's LRIC study. He suggested that the results of this study should present the LRIC broken down by demand, commodity and customer categories and that some of the incremental demand costs associated with mains should be allocated to the interruptible class. He suggested that the LRIC study should be linked directly to the expansion plans of the Company so that the avoided cost of incremental reductions in the demand of new and existing customers could be determined. Finally, he indicated that the LRIC would be improved by an attempt to include social costs (Exhibit 52, pp. 16-17).

The Commission recognizes the problems faced by BCGUL in undertaking an LRIC study, particularly as these problems relate to the incremental costs associated with additional use by existing customers. However, the Commission finds limited value in an LRIC study which does not include the capacity costs related to gas supply. Therefore, BCGUL is directed to prepare future LRIC studies on a basis which is consistent with the Commission's directions on the Avoided Cost Study discussed in Section 14.3 of this Decision.

3.1.3 Competitive Energy Study

BCGUL presented a further two-part study in support of its Application: the first part of which compared the price of natural gas to other energy sources and the second part of which estimated the elasticity of natural gas demand with respect to price. Both parts indicated that the market for natural gas could accommodate the rate design proposals being put forward by the Applicant.

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A review of the study by the Commission staff witness did not indicate significant problems with either part.

3.2 BCGUL Rate Design Methodology

BCGUL indicated that the specific rate design proposals put forward by the Utility are supported by the cost studies provided in the Application and that the cost studies acted as a guide to the proposed cost allocation among customer classes. However, no direct matching of the proposed rates to any one cost study can be made (Exhibit 4, Tab B3). This reflects the Company's view that appropriate rate design depends on many factors, including present rate levels and design, value of service or the price of competitive energy, long-run incremental costs, fully distributed costs, perceived equity and fairness, proper economic signals, simplicity, revenue and rate stability and customer reaction to rate levels and rate design (Exhibit 1, Tab 3, p. 5 and Tab 6, p. 10). In addition, it appears that the proposed rates for residential, commercial and general service customers were influenced by the desire to implement uniform postage-stamp margins for these customers.

For all classes of customers requiring firm service, BCGUL proposed to implement a two-part rate structure consisting of a basic charge and a flat commodity charge for each gigajoule of gas delivered to the customer. In addition, the Utility proposed to increase the residential rates in the Lower Mainland and Columbia Divisions to achieve rates that will lead to a revenue margin to cost margin ratio that is on par with that of Inland Division residential rates and will result in a revenue to cost ratio that is within 10 percent of a one-to-one correspondence between cost and revenue margins. The Company proposes to use the increased revenues collected from residential customers to reduce rates to customer classes which are currently over-contributing based on the FDC study.

BCGUL has proposed to introduce three rate groups for firm sales service to non-residential customers. These are small commercial service, large commercial service and general firm service. These rate classes are proposed so that the different cost of gas supply incurred by the Utility in serving these classes can be reflected in rates; however, the basic charge and delivery charge, exclusive of gas costs, will be the same for both small and large commercial customers. As a result of the rate design proposal, bills to small commercial customers will increase in both the Lower Mainland and Columbia Divisions but decline in the Inland Division. Large volume commercial customer bills will decrease in both the Lower Mainland and Inland Divisions.

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3.3 Commission Decision

The FDC studies and the LRIC study were essentially used by BCGUL to determine inter-class cost causation and thereby to guide inter-class rate design. Issues of intra-class rate design are discussed in the sections of this Decision devoted to individual customer classes.

The Commission accepts the results of the FDC study showing that cost causation by customer class supports a shift of revenue responsibility from industrial customers to residential and commercial customers. While the LRIC study was found to have shortcomings as noted in Section 3.1.2, it does directionally support the rate shifts indicated by the FDC study. Therefore, the Commission accepts the specific BCGUL proposal which shifts some of the revenue responsibility from industrial customers to residential and commercial customers. However, as noted in Section 4, measures will be undertaken by the Utility to offset the impacts of this general inter-class rate shift.

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4.0 RESIDENTIAL AND COMMERCIAL RATE DESIGN

4.1 BCGUL Rate Design Proposal

4.1.1 Residential Rate Proposal

Currently, BCGUL's residential and commercial customers are served under a variety of rate schedules depending on the location of the customer. These rate schedules are inconsistent with each other with respect to items such as the level of the basic charge, the level of the commodity charge and the overall structure of the rate. The BCGUL rate design application seeks to simplify and make more consistent the Company's residential and commercial rates. The Company's general intent is to create rates that provide understandable and consistent rate design messages to consumers, while contributing to other objectives such as revenue stability and fairness.

Specifically, BCGUL proposes to establish a residential rate for all Divisions consisting of a $7 per month basic charge and a flat commodity charge (i.e. provides neither discounts nor premiums to different levels of consumption). The level of the commodity charge varies from division to division only to reflect differences in gas supply costs. The delivery charge (the margin required to amortize the investment in infrastructure) would be identical in each Division, in line with the Company's proposal to "postage-stamp" its margins.

In the Company's proposal, the basic charges have been increased by approximately a factor of two, with current charges ranging from $3.52 per month in the Inland Division to $4.64 per month in the Lower Mainland Division. BCGUL stated that the increase in the basic charge, to $7 per month, was appropriate since the Fully Distributed Cost ("FDC") study indicated that customer-related fixed costs were in the order of $11 to $14 per month. Although the proposed $7 basic charge would not recover all customer-related costs, the increase would act to narrow the gap between the current charge and actual costs. In addition, BCGUL indicated that the proposed basic charge was in line with that charged by other gas utilities (Exhibit 1, Tab 3, p. 7).

BCGUL indicated that the shift to a flat delivery charge in those Divisions in which a declining block structure was in place would eliminate a price signal that encouraged increased consumption of natural gas. With respect to the actual level of the delivery charge, BCGUL indicated that the proposed increases to the Lower Mainland and Columbia Divisions' residential rates were appropriate since the FDC study had shown that the revenue margin to cost margin ratios for these customers were unacceptably low (Exhibit 1, Tab 3, p. 8). This argument was accepted by the Commission in Section 3 of this Decision.

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In the hearing, BCGUL recognized that future review of the rate design would probably be required once the Utility had completed its IRP (T. 3501).

4.1.2 Commercial Rate Proposal

For commercial customers, BCGUL is proposing to establish two rate schedules: small commercial service for customers using less than 2000 GJ/year and large commercial service for customers using in excess of 2000 GJ/year. Commercial customers whose load is primarily non-space heating also have an option of the general service rate. The rate design proposal for general service customers is discussed in Sections 9 and 10 of this Decision.

For both small and large commercial customers, BCGUL is proposing to institute a basic charge of $14 per month and a flat commodity charge. As with the residential rate schedules, the amount of the commodity charge will vary only as required to reflect divisional gas costs. In addition, the commodity charge will vary between small and large commercial customers within the same division to reflect the lower unit cost of gas associated with serving large volume customers. The exception is the Columbia Division where a methodology to allocate gas costs between small and large commercial customers has not yet been established. Therefore, for the Columbia Division small and large volume commercial customers are not differentiated.

In the Company's proposal there is a considerable variation in the increase to basic charges which currently range from $4.64 per month in the Lower Mainland Division to $12.91 per month in the Inland Division. Similar to the arguments presented in support of the residential rate design proposal, BCGUL stated that the increased basic charge for commercial customers was appropriate since the FDC study indicated that customer-related costs were in the order of $20 per month (Exhibit 1, Tab 7, p. 9) while the establishment of a flat commodity rate in place of the declining block structure would eliminate an inappropriate price signal.

With respect to the actual level of the commodity charge, BCGUL indicated that its proposal would decrease the commodity charge to Inland commercial customers while increasing it slightly for Lower Mainland and Columbia Division customers. The decrease for Inland commercial customers would bring the revenue margin to cost margin ratio for these customers to lower, more acceptable levels (Exhibit 2, Tab 2B, Section 1, pp. 1-2 and Exhibit 4, Tab B2).

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BCGUL presented evidence to show that taken together, the effect of the increased basic charge and changed commodity level on bills to small commercial customers varied between 5 percent and 41 percent for Lower Mainland customers, between 7 percent and 24 percent for Columbia Division customers, and between -11 percent and -14 percent for Inland Division customers. For large volume customers in both the Lower Mainland and Inland Divisions bills declined (Exhibit 1, Tab 7, pp. 13-14). BCGUL recognized that some of the impacts appeared large when reported in percentage terms but indicated that the actual dollar impacts were not substantial, e.g. less than $10 per month (Exhibit 4, Tab B35, p. 2).

4.1.3 Use of Cost "Offsets"

For both residential and commercial customers, BCGUL proposes to offset rate design impacts through a number of measures. First, BCGUL proposes to apply funds obtained through increases in the connection and reconnection fees to offset the revenue requirement. Second, in the case of Inland and Columbia customers, funds in the deferred income tax account will be applied directly to the residential and commercial revenue requirement consistent with the Commission's directions in Section 2.5.2. Third, 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 Division customers. Fourth, BCGUL proposes to establish common depreciation rates for all Divisions. This will reduce depreciation expense and thus the revenue requirement. Fifth, Inland and Columbia residential and commercial customer rates will also be reduced by the drawdown of deferred income tax balances to pay franchise fees.

In contrast, Lower Mainland customers will be billed a separate charge to recover the revenue loss of $0.41/GJ currently in the deferral account established to capture the difference in margin for the Lower Mainland large volume customers who switched from interruptible sales to interruptible service.

In Section 2 of this Decision the Commission approved BCGUL's application to charge postage-stamp margins for the Lower Mainland and Inland Divisions. In Section 3 of this Decision the Commission approved BCGUL's rate design in terms of the allocation of cost among rate classes. **The Commission also approves of the above-noted proposals of BCGUL to offset in various ways the impacts of the general rate design approved in Section 3, subject to the Commission's comments in Section 2.5.2 with respect to deferred income tax balances and the offsetting of franchise fees.**

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4.2 Rate Design Hearing Issues

4.2.1 Seasonal Rates

The basic direction of the BCGUL residential and commercial rate design was challenged in the hearing by evidence presented by the CACBC, and in cross-examination by various Intervenors and Commission Council. A key issue was whether or not the BCGUL application went far enough toward rates that provide signals that encourage long-run efficiency of the entire gas delivery system. Under cross-examination, BCGUL policy witnesses recognized that they used the LRIC study primarily as a means of ensuring that the allocation of costs between customer classes as indicated by the FDC study was appropriate, but not as a guideline for determining marginal rates within each customer class (T. 613, 695).

Mr. Todd, an expert witness retained by CACBC, presented evidence to suggest that there are means by which BCGUL could design rates within each class that provide efficient price signals while meeting the Utility's allocation of cost recovery requirements between rate classes (Exhibits 52 and 52A). For example, a high demand charge (based on maximum peak usage) would ensure that the costs of future peaking-related expenditures (LNG plant, storage, transmission expansion) are allocated to those most responsible for their occurrence. The residential and commercial customers who use gas primarily for space heating have low load factors (below 35 percent) meaning that they do not come close to fully utilizing the significant investment in capacity that must be made in order to reliably meet their winter requirements. BCGUL faces significant peaking expenditures over the next 20 years. Economic efficiency would suggest that the unit costs of those expenditures should be reflected in the marginal rates facing the residential and commercial customers responsible for the investments' occurrence. In the long-run, society as a whole would be better off, even though some customers, those who do not make cost-effective investments, would see bill increases.

Mr. Todd's evidence was that a demand charge was the best means of providing the correct price signal to residential and commercial customers. However, he noted that metering peak demand would require a massive investment in remetering. As a demand charge proxy, Mr. Todd recommended that BCGUL be required to charge seasonal rates.

> "The only way you get the right price signals going through to customers, to get them to respond to the social and efficiency issues that will be integral to the IRP process is to have rates which pass costs through to them in a way that reflects the costs of the system and the costs to society. That means that since there are demand costs, there should ideally be a demand charge. To the extent that that is not feasible, you should attempt to come as close to your target as possible by setting rates which, shall we say, approximate demand charges. Seasonal rates do that far better than flat rates." (T. 2198)

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Seasonal rates would involve low summer and high winter commodity charges to reflect the cost of future capacity investments to meet the winter demand. While Mr. Todd suggested a ratio of winter:summer rates of about 6:1, he provided a formula in Exhibit 52A which allowed for adjustments of this ratio and the size of the customer fixed charge, in order to reduce the volatility for customer bills and utility revenues. The numbers in Mr. Todd's formula were based on BCGUL's FDC and LRIC studies. In cross-examination, Mr. Todd suggested that there could be a phased-in transition to seasonal rates (T. 2286).

4.2.2. Inverted Rates

Another alternative to BCGUL's flat rate proposal is inverted rates. With inverted rates, the commodity cost increases for consumption in a given time period that exceeds a specified threshold. Dr. Watkins, witness for BCGUL, pointed out that inverted rates were usually justified for one of two reasons: (1) to reflect a situation in which increased consumption causes rising costs (i.e. LRIC above average cost) and (2) to subsidize low consumption customers (i.e. "lifeline rates") (T. 1314).

4.2.3 The Basic Charge

Under cross-examination BCGUL witnesses recognized that the movement to a higher customer fixed charge would reduce the incentive for DSM expenditures (T. 756). This could have adverse effects with respect to economic efficiency because the higher the fixed charge, the more difficult it could be to align the marginal rate for commodity consumption with the delivery system's LRIC. Customers making investments in energy using equipment would therefore not face the true costs to the system of their decisions to consume more or less natural gas.

4.3 BCGUL's Responses

BCGUL witnesses admitted that low load factor, temperature sensitive customers were incurring high costs to the system because capacity was installed to meet their peak demand, even though that capacity offered much less value to the system in off-peak periods (T. 792, 1755). As a consequence, the BCGUL application includes a proposal for seasonal rates for the general service and industrial customers, and in cross-examination BCGUL witnesses indicated that the Company was not opposed to seasonal rates for residential and commercial customers (T. 793).

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However, BCGUL expressed concerns with the immediate introduction of seasonal rates. First, prior to completion of its IRP, it would be difficult for BCGUL to determine appropriate levels for seasonal rates (Exhibit 3, Tab 1, p. 10). Second, BCGUL would prefer to consult with the public in advance of implementing seasonal rates (T. 1660). Third, BCGUL stated that seasonal rates would increase revenue instability for the Utility and bill instability for customers (T. 1658-1659). Fourth, BCGUL pointed out that the trend to annual average billing for utility customers eliminates the educational benefit of seasonal rates (T. 1741).

BCGUL witnesses did oppose inverted rates. First, they argued that there is currently no evidence that increased consumption of natural gas leads to rising costs of the gas delivery system. Second, BCGUL noted that inverted rates would result in utility revenue and customer bill instability (T. 1659, 1750). Third, BCGUL pointed out that inverted rates may send inefficient signals because low volume customers who consumed only at the peak would end up being significantly subsidized (T. 1750).

With respect to the customer basic charge, BCGUL argued that the proposed increase to this charge better reflected customer-related costs and therefore would send a more appropriate pricing signal than would a lower charge (T. 703).

4.4 Commission Decision

The following refers to the rate design principles applied to both residential and commercial rates. Where comments apply only to one or the other, the distinction will be indicated.

The Commission agrees with BCGUL that the continuation of a declining block structure for either residential or commercial customers is inappropriate. At the same time, the Commission heard evidence in the hearing to suggest that a simple flat rate would not send an appropriate price signal to customers about the costs that their winter peak consumption will cause BCGUL to incur.

Because a key objective of this Commission is to minimize the regulatory costs for customers and participants that result from frequent rate design hearings, the Commission is concerned that this major rate design application lacks an analysis of marginal rate alignment with LRIC, a key issue in economically efficient rate design. This omission was highlighted by the evidence, testimony, cross-examination and final argument of CACBC, but it was also noted by other Intervenors.

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In the following sections, the Commission provides direction to BCGUL for rate design analysis and initiatives to be included in its next revenue requirement application, and makes rulings that take the first steps toward addressing this key rate design issue.

4.4.1 Seasonal Rates

There was general agreement in the hearing that winter consumption of natural gas incurs higher current and future costs to the gas delivery system than does summer consumption. This is especially true in the BCGUL system with its limited storage capability. While the LRIC of winter use of the system will be better understood when the next version of the IRP is completed at the end of 1993, the BCGUL application for general and industrial customer classes recognizes that there is already enough understanding of costs to propose a winter:summer seasonal rate differential of 2:1 for the delivery charge.

A similar differential for the delivery charge for residential and commercial customers would be a first step in the direction of aligning winter rates with the full long-run capacity costs of peak gas consumption. The IRP would then guide future analysis, and possible adjustment, of this differential. BCGUL pointed out that a 2:1 seasonal rate differential, when added to the commodity cost of gas, would lead to winter burner tip prices about 25 percent higher than summer prices (T. 1716).

At the request of Commission Council, and the Commission Panel, BCGUL tested various adjustments to its rate design proposal for residential and commercial customers that included seasonal rates at a 2:1 ratio, inverted rates and a lower basic customer charge (Exhibits No. 41, 42, 43, 44, and 47). These exhibits allowed the Commission to assess the arguments of BCGUL in defence of its application.

First, the Commission agrees with BCGUL that it is preferable that rate design changes be guided by IRP. However, the information provided by the Utility, its rate proposal for general service and industrial customers, the commentary of BCGUL witnesses, and the analysis of Mr. Todd suggest a clear recognition that the high winter consumption of residential and commercial customers is the primary cause of current and future capacity-related investments needed to meet seasonal peaking demands of the BCGUL transmission and distribution system. It is therefore possible to take action now that will be consistent, albeit transitionally, with the outcome of the IRP process.

Second, the Commission also agrees with BCGUL that it is preferable for the public to be consulted and warned in advance of a rate design change such as a shift to seasonal rates. However, as noted, the Commission is concerned that BCGUL chose to omit this issue from this major rate design application. Omission by the Utility is an insufficient reason to neglect rate design instruments that are critical to

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economic efficiency and/or other objectives. Furthermore, the issue of seasonal rates was well canvassed in the hearing.

Third, the Commission notes BCGUL's concern for revenue and customer bill stability. However, the Commission is not convinced that this objective should prevent efforts to send appropriate price signals with respect to the marginal rate facing consumers. Exhibits 42 and 44 suggest that a move to seasonal rates, even with basic charges for residential and commercial customers reduced to $6 and $12, would not lead to dramatic increases in revenue and bill instability compared to the BCGUL proposal. In any case, elsewhere in this Decision the Commission directs BCGUL to propose a weather stabilization mechanism that would protect the Utility from weather induced swings in revenue. The Utility is also directed to explore other mechanisms of decoupling sales from profits. Customers have the option of protecting themselves from seasonal bill impacts by switching to annual billing, a trend which the Utility need not discourage. Annual billing does not change the economics of DSM and, if utility information and billing campaigns are effective, should not reduce customer interest in cost-effective DSM. Moreover, BCGUL noted that the switch to seasonal rates by Canadian Western Natural Gas and Northwestern Utilities led to only a slight increase in bill complaints, which was effectively addressed through an information campaign (T. 1654). Finally, even though the customers it represents are perhaps the most sensitive to higher winter bills, the Commission notes with interest that CACBC was generally favourable to seasonal rates in the interests of long-run economic efficiency (T. 3830).

Therefore, the Commission finds that residential and commercial customers' delivery charges should be set on a seasonal basis such that the rate during the 5 winter months is twice the summer rate. The exact level of the rate will be calculated by BCGUL taking into consideration all other elements of this Decision.

In its next revenue requirements application, BCGUL is directed to present a proposal for intra-class rate adjustments such that marginal winter rates reflect as nearly as possible the LRIC of winter consumption as estimated in BCGUL's IRP. To achieve this, it is understood that the customer fixed charge may diverge significantly from customer-related fixed costs. Furthermore, it is recognized, as noted in Sections 14.6 and 15.2 of this decision, that BCGUL will bring forward a weather stabilization proposal and a general decoupling proposal that will serve to protect the Utility from significant yearly swings in revenue.

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4.4.2 Inverted Rates

The Commission agrees with Dr. Watkins' description of the two possible justifications for inverted rates, these being rising costs and income distribution.

While it has generally been recognized that natural gas prices may be below long-run replacement cost, there is considerable uncertainty about the shape of the long-run cost curve for natural gas. It is increasingly suggested that with the exception of short-term corrections, the production cost of natural gas in North America will not rise significantly for many years, even with dramatic increases in consumption. This argument implies that inverted block rates may not be appropriate, if the goal is to provide a signal for long-run economic efficiency. However, if the natural gas price were to include not-yet-internalized environmental costs, the issue becomes complicated. Depending on how natural gas compares with alternatives (such as efficiency and/or fuel substitutes), there may or may not be justification for inverted rates.

Also, the Commission notes that the CACBC, representing some of the social groups most likely to benefit, did not advocate inverted rates as a means of subsidizing low consumption customers. The Commission is generally of the belief that decisions about income distribution are best left to elected representatives.

4.4.3 The Basic Charge

In determining the appropriate level of the basic charge for both residential and commercial customers, BCGUL emphasized revenue stability and the need to send appropriate price signals (T. 1728). However, as noted above, the Utility did not explore the key issue of economic efficiency from the perspective of customer investments in energy using buildings and equipment: namely, that the marginal rate facing customers should be as close as possible to BCGUL's LRIC. To achieve this end, trade-offs will be required with respect to other objectives of rate making, such as revenue stability, fair allocation of historic costs, etc.

When trying to meet the objective of aligning marginal rates with LRIC, variables that can be adjusted are (1) the basic charge and (2) the intra-marginal rate (this would be the summer rate in a seasonal rate design). Thus, changes to the basic charge may be required, simply to ensure that the Utility recovers its costs, and these changes may require decreases rather than increases, even though the FDC studies indicate that the customer related costs significantly exceed the current basic charge.

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The Commission is therefore unwilling at this time to accept the full increase in the basic charge proposed by BCGUL. The Commission approves a basic monthly charge for residential customers of $6 and for commercial customers of $12.

In its next revenue requirements application, BCGUL is directed to explicitly explain the trade-offs that it is making with respect to the setting of the basic charge and the alignment of marginal rates with LRIC.

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5.0 MAIN EXTENSION POLICY

Currently, BCGUL applies different feasibility tests to proposed main extensions in the Lower Mainland Division than it does to those in the Inland and Columbia Divisions. However, both sets of tests utilize the same general methodology: they subtract the cost of gas from the gross revenue expected from the extension, multiply the difference by a given number of years, and compare the product to the cost of the extension. Differences between the tests lie in the number of years of consumption used, and the use of project specific or divisional average construction costs.

In the BCUC's August 5, 1992 Decision regarding the BC Gas Inc. Revenue Requirements Application, the Commission stated: "A major issue is that if the test is not reasonable, existing customers may end up subsidizing new customers. Another issue is whether the Utility has consistently applied the test" (p. 32). The Commission directed the Utility to file main extension test proposals prior to or concurrent with its Phase B Rate Design Application.

5.1 BCGUL Proposal

In the Phase B Rate Design Application, BCGUL submitted a proposed test based on the Discounted Cash Flow ("DCF") method. As applied by the Utility, the proposed test will discount the gross revenue less the cost of gas over an expected main extension life of 50 years; the test will be based on project specific consumption projections and an after tax discount rate. The cost component of the test consists of the discounted cost of capital expenditures over five years for mains, services, meters and other project specific capital costs. Economic viability of an individual main extension proposal is indicated by a benefit/cost ratio greater than or equal to one, or a corresponding Net Present Value ("NPV") greater than or equal to 0. As proposed by the Applicant, however, the aggregate of all main extensions in a year would have a positive or zero NPV; the factor in the DCF test that would provide a zero or slightly positive aggregate NPV for all main extensions in a given year would be provided by 0.6 benefit/cost ratio as the 'hurdle ratio' for a particular main extension . A witness for the Utility stated that the 0.6 hurdle ratio would be checked periodically, and changed if necessary to ensure that it produced an aggregate benefit/cost ratio of 1 or slightly greater (T. 1548)

The Commission noted that the potential appears to exist for overstating revenues relative to costs. This could arise from forecasting error (T. 1534). It could also arise from the asymmetrical approach to costs and revenues adopted by the Utility which includes 50 years of discounted revenues, and only five years of costs. Utility witnesses stated that the choice of a 50-year revenue stream in the test is based on the time period over which the mains are depreciated, although they agreed that meters are depreciated over

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33 years. No allowance is made for the possibility of improved appliance efficiencies (T. 1558). Finally, the proposed test includes only direct overheads in its costs, whereas the existing tests include full overheads in the cost projections (T. 1459).

When the revenues from the main extension are shown by the test to be insufficient to meet the cost of the main extension, customers may be asked to make a contribution in aid of construction. In situations where the size of the main installed is larger than that necessary to serve existing customers, the Company may waive some or all of any contribution in aid of construction. Moreover, the Company proposes to waive contributions of less than $100 per customer. For required contributions greater than $300, the Utility proposed a Main Extension Surcharge enabling customers to make their payment as part of their regular gas bill payment. If more customers than anticipated connected to the main extension within five years of installation of the new main, the customers who had made contributions in aid of construction would be eligible for pro-rated refunds based on the difference between the original and actual number of customer additions. After a final review of each main extension after five years of use, no further refunds would be made.

In conjunction with the main extension proposal, BCGUL proposed a new mechanism, the Gas System Extension Fund ("GSEF") to "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".

During the hearing BCGUL indicated that it saw the DCF methodology as more or less permanent, but that it will examine the need for altering the test inputs to incorporate social costs and benefits and/or LRIC's, as its IRP process advances (Exhibit 5, Tab B45, T. 1478).

5.2 System Averaging Versus Stand-alone Test

An interesting aspect of the BCGUL main extension proposal was the use of aggregating the proposed main extensions in any given year so that the sum of the main extensions for that year would have an overall benefit/cost ratio of one or slightly greater to be achieved through the use of a hurdle benefit/cost ratio of 0.6. The Company argued that this approach is reasonable because if, in the alternative, every main extension were required to have a benefit/cost ratio at least equal to 1, the result would be a subsidy from new customers to existing customers (T. 3518).

Utility witnesses acknowledged that existing customers might face increased costs as a result of a main extension. For instance, if a main extension was installed to serve a large volume customer who went bankrupt before the Utility has recovered its costs, the existing customers would absorb the deficiency

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(T. 1544). The Utility also recognized that if a main extension attracts more customers than anticipated, those who made an initial contribution in aid of construction would get a refund; however, if fewer customers than anticipated signed up and revenue projections were overstated, existing customers would be required to meet the deficiency. Further, witnesses for BCGUL acknowledged that uncertainty in demand projections could arise out of rate design changes, elasticities, and differences in types of appliances (T. 1534).

The written evidence of the CACBC (Exhibit 52, p. 32) cited the Averch-Johnson effect and the incentives provided to regulated companies under traditional rate base rate of return regulation. It suggested that regulated companies would have an incentive to maximize rate base by, for example, seeking to undertake main extensions even when those extensions were not economic. Moreover, the witness for CACBC stated that a test based on the average or aggregated cost of mains was not consistent with competitive market situations (T. 2323). In the view of the witness, the test should be appropriate on a forward looking basis without regard to the decisions that were made in the past. The witness also stated that social costs and benefits should be included in deciding whether of not to undertake a main extension. Counsel for the CACBC argued that the proposed main extension policy should be allowed on an interim basis, but that the Commission should direct the Utility to return with a revised test that included LRIC's to the system as a whole (T. 3815-3816).

5.3 Gas System Extension Fund

As part of its main extension proposal, BCGUL proposed to establish a GSEF to accumulate funds from a variety of sources to reduce the large contributions in aid of construction required to bring gas service to areas currently not served by BCGUL. Potential sources of funds suggested by the Utility included 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 BCGUL's off-system sales.

The witness for BCGUL acknowledged in the hearing that several of these potential sources of funds, such as refunds, gas supplier incentives, gas sales margins from Rate Schedule 10 customers, and revenues from off-system sales would normally flow back to existing BCGUL customers (Exhibit 5, Tab B17, T. 821-24). In Argument, counsel for CACBC opposed the use of funds that would otherwise constitute a contribution back to the core market (T. 3816).

5.4 Commission Decision

The Commission supports a consistent main extension test for the Lower Mainland, Inland and Columbia Divisions that recognizes the time value of money. The Commission also notes that BCGUL intends to re-examine the inputs to the DCF test and may revise them to incorporate information from the IRP process and other social costing initiatives (T. 1478). However, the Commission sees no reason why some of these factors cannot be accounted for sooner rather than later.

The Commission is of the view that a consistent set of evaluative criteria should be generally applied to BCGUL investments, be these main extensions, an LNG plant, transmission lines, DSM programs or appliance marketing. Therefore, the Commission directs BCGUL for the next revenue requirement hearing to align its main extension test more explicitly with the criteria applied in its IRP. To that end, the Commission accepts the current proposal for a DCF based main extension test with, however, several modifications which are detailed below.

The Commission does not agree with BCGUL's argument that the overall main extension test should be one which achieves a benefit-cost ratio greater than or equal to one based on the aggregate of all main extensions, even if some of the main extensions have a benefit-cost ratio between .6 and 1. There is no obvious public interest justification for main extensions for which the benefit-cost ratio is less than one: these are by definition uneconomic main extensions. A main extension benefit-cost ratio exceeding one should not be seen, in contrast to BCGUL's argument, as a subsidy from new customers to existing customers. BCGUL's argument overlooks the critical rationale for the existence of natural monopolies: economies-of-scale. If a natural monopoly exhibits economies-of-scale (as they do frequently but not always), increases in output should lead to lower costs for all customers, and that is a desirable social outcome. The Utility should not be encouraged by the regulator to, in effect, include uneconomic extensions in order to prevent the realization of economies-of-scale under the auspices that somehow these economies-of-scale effects represent a subsidy from new customers to existing customers.

However, there are several circumstances in which the IRP process, or government policy directives, could lead to subsidies within a main extension policy. For example, the IRP process could provide a non-financial justification that the Commission was ultimately willing to accept. Or, a social costing policy of the provincial government could demonstrate additional benefits of increased gas use relative to the alternatives. Or, the government may issue a direction to the Commission to allow individual main extensions whose benefit-cost ratio was less than one because of other perceived benefits to extended access to natural gas.

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Therefore, the Commission rejects the concept of a hurdle benefit-cost ratio of .6 for individual main extensions. The Commission directs BCGUL to modify its proposed main extension test to use a minimum NPV of 0 or a minimum benefit-cost ratio of 1 as its acceptance criterion for each proposed main extension.

During the hearing, BCGUL presented evidence on why it had chosen a different discount rate for its LRIC study than for its mains extension policy (Exhibit 102). The Commission remains unconvinced that reasons for the difference are valid or that the discount rate chosen for the mains extension policy is appropriate. Moreover, BCGUL's July 1992 IRP adopted discount rates that were also somewhat different than those used in either the LRIC or the main extension test.

The Commission therefore directs the Company to review its choice of discount rate, and support its choice with its updated main extension policy. In the Commission's view, the Company should adopt a consistent set of parameters within its LRIC studies and its IRP - including the appropriate DSM test, such as the Total Resource Cost Test - unless there exists a clear rationale for doing otherwise.

The Commission is concerned with the use of 50 years of revenues in the proposed DCF methodology when evidence in the hearing showed that use per customer may decrease over time and that additional costs for meter renewal may occur sometime after year 30. The Commission is also concerned that the full incremental cost of main extensions be included in the DCF calculation. Finally, the Commission is concerned with the accuracy of main extension cost estimation.

Therefore, the Commission directs BCGUL to make the following adjustments to its proposed DCF method. First, the time horizon for the revenue stream in the DCF calculation should not exceed 33 years, the depreciation life of meters. Second, full overheads should be included in the DCF calculation, not just direct overheads as originally proposed by BCGUL. Third, the Commission also directs BCGUL to carry out and file post-construction audits of its main extensions to ensure that costing methodology and revenue projections are sufficiently accurate.

BCGUL requested that the Commission approve the GSEF in principle, so that the Utility could then explore with the Commission the types of funding that could be included in the fund. The Commission is not convinced that funds, such as refunds or some percentage of revenues for Rate Schedule 10 customers or off-system sales, that would otherwise flow to existing firm customers should be used to

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construct uneconomic main extensions into currently unserved areas. The remaining sources of revenue cited by the Utility, such as new government contributions or regional district tax levies, do not require the establishment of the GSEF since they would normally be offered and administered on a program or region specific basis. Therefore, if any level of government wishes, as a policy decision, to contribute to the extension of gas service to areas where it would otherwise be uneconomic, it is not precluded from doing so. The function of an economic test is to encourage the Utility and community residents to make rational economic choices. The use of a fund to divert revenues from existing customers to currently unserved areas can only blur those choices. **The Commission therefore denies the establishment of a Gas System Extension Fund.**

Nevertheless, the Commission supports the provision of cost-effective energy services to customers in areas currently unserved by natural gas. The Commission also notes that the IRP process now underway at British Columbia utilities does not focus only on specific supply or project alternatives, but includes examination of alternatives to the project as well. **The Commission encourages BCGUL to take a similar approach to requests for gas service from presently unserved communities and to examine, with those communities, alternative means of providing them with least-cost energy services.** These alternatives could involve non-traditional forms of energy delivery, or innovative forms of financing. An example of the latter is the BCGUL proposal to allow customers to pay contributions in aid of construction in their gas bills. The Commission has supported such financings previously so that customers minimize their upfront expenses and enjoy energy savings immediately.

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6.0 NATURAL GAS FOR VEHICLES

6.1 BCGUL Proposal

The BCGUL proposal for Natural Gas For Vehicles ("NGV") rates contains two significant changes from existing rates. First, BCGUL proposes a single rate to be called Schedule 6 for all three Divisions, replacing the existing separate divisional rate schedules of Schedule 2206 (Lower Mainland), Schedule 14 (Inland) and Schedule 5 (Columbia). The Company justifies this proposal on the basis of simplicity and notes that NGV sales are a small part of the total load and that few customers are involved.

The second significant change from existing rates is the introduction of a second step in the rates whereby delivery changes are reduced by 50 percent for volumes above 4,000 GJ/month. The Company wishes to encourage customers to build load and notes that this type of reduced rate is currently offered to the largest single customer through a negotiated tariff which expires in 1994. BCGUL now proposes this volume incentive be offered to all Schedule 6 customers.

The Commission notes that little interest was shown by Intervenors in NGV rates. Commission Counsel did review the step rate concept; as a result BCGUL clarified that only two Lower Mainland customers would currently qualify for the rate reduction for volumes in excess of 4,000 GJ/month (T. 1922). The Company speculated that customers such as BC Transit might look more favourably at NGV if the volume discount were embedded in a tariff rather than subject to negotiation (T. 1927). BCGUL argued that having standard provisions in the tariff was more equitable to large volume customers than negotiations would be (T. 1928, 3525), nevertheless the Company conceded that these large volume customers would have a strong bargaining position (T. 1929).

6.2 Commission Decision

6.2.1 Postage-Stamping

As stated in Section 2.6 of this Decision, while the Commission does not accept postage-stamping for the Columbia Division as a rate design principle, this does not preclude Columbia rates from matching those in the other Divisions from time-to-time in specific circumstances. In the case of NGV rates proposed for Schedule 6, the Commission notes that despite the relatively large 27.5 percent increase in revenue that they generate in the Columbia Division, the Columbia revenue is only 8.3 percent of costs excluding the cost of gas (Exhibit 4, Tab B2). Finally, the Commission notes that revenues for Columbia are less than 1 percent of the total NGV revenues. Considering all of these factors, the Commission agrees with

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BCGUL that simplicity of rate administration should be the determining factor. **On this basis the Commission approves the concept of a single NGV tariff as proposed with Schedule 6.**

6.2.2 Volume Discount

The Commission is not persuaded by BCGUL's arguments about building load and the difficulty of negotiating a competitive fuel rate for large customers. The Commission believes that the proposed discount is inconsistent with flat rates proposed for delivery service in all other rate schedules. In view of the fact that only two customers presently qualify for the discount, the task of conducting equitable negotiations should not be onerous. Furthermore, the Commission remains unconvinced of the need for volume discounts to public refuelling stations, so long as adequate profit margins to these retailers are provided for in the BCGUL wholesale rates. **In summary, BCGUL is directed to file Schedule 6 for approval in a form which deletes the volume incentive but otherwise reflects the rates in the Application.**

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7.0 UNBUNDLING OF INDUSTRIAL SERVICES

The Commission, at p. 26 of its March 11, 1993 Decision on Domestic Natural Gas Supply Rules, had directed that each local distribution company ("LDC") should present appropriate tariff proposals for unbundled transportation service at its first available rate design hearing. BCGUL responded in this Application with specific tariffs for unbundling previously available peaking/backstopping tariff Schedule 13 into new tariffs for peaking (Schedule 13) and backstopping (Schedule 14). BCGUL also filed tariff Schedule 32 for a Gas Balancing Service to be used by large volume transportation customers (Schedule 22) who did not wish to daily balance.

In response to a Commission staff information request, BCGUL also filed methodologies to unbundle three other services on an interruptible basis: Gas Banking, Storage Service and Delivered Storage Service (Exhibit 5, Tabs 16-38). BCGUL noted that these services were not part of its application (T. 1996). During the hearing, Commission Counsel canvassed the customer panels as to their interest in the availability of these three unbundled interruptible services, but little interest was expressed. The Inland Industrial customer panel expressed limited interest, primarily for captive customers and with respect to banking service, but did not appear to be familiar with BCGUL's specific proposals in Volume 5 (T. 3151-3155). The Lower Mainland Large Volume Interruptible customer panel expressed no interest in any of these three services (T. 3358). Mobil Natural Gas Canada Ltd., which had been an advocate of unbundling in both this hearing and previous BCGUL hearings going back to the BCGUL Phase A Rate Design hearing which concluded in January 1992, went on record in final argument supporting the BCGUL unbundled tariff proposals and agreed that unbundling of storage on a firm basis was not practical (T. 3758).

The Commission concludes that the BCGUL filed tariffs for Schedules 13, 14 and 32 have responded appropriately to industrial customer requirements at this time. Specific conclusions with respect to these Schedules are discussed in detail in subsequent sections of this Decision. The Commission will expect BCGUL to continue to be responsive to customer requirements for unbundled service and, to the extent further unbundling is both desired and feasible, the Commission will consider appropriate future applications for approval.

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8.0 INDUSTRIAL SALES SCHEDULES

During the course of the hearing, BCGUL is understood to have held discussions with industrial customers outside the formal hearing process in an attempt to improve mutual understanding of the proposed industrial tariffs and to avoid debate within the hearing over relatively minor issues. As a result, BCGUL undertook a number of amendments to the industrial tariffs in the original application, with the final filing being dated July 20, 1993. Where the Commission refers to various Schedules in the following text, the reference is to this updated filing. The Commission accepts that the Schedules will be effective November 1, 1993 as requested by BCGUL unless otherwise noted.

8.1 Schedule 10: Large Volume Interruptible Sales

Schedule 10 and the underlying market pricing concepts were approved by the Commission in the Phase A Decision of February 21, 1992. In this application BCGUL has made only one significant change from the currently approved Schedule. That change involves the introduction of a Priority 1 designation which provides for negotiation of price and curtailment terms.

Schedule 10 pricing for Priority 2 is currently established annually and fixed for a one-year term with an exclusivity requirement that the customer buy all of its interruptible gas from the Utility. During the hearing Commission Counsel asked the customer panels if they would be interested in the option of indexed pricing for Schedule 10 which would entail use of an index such as "Inside FERC" to establish prices, probably on a monthly basis. Customers generally preferred the cost stability which came with prices fixed for a one-year period, but some felt an indexed price option would be worthwhile (T. 3359, 3627). The Commission believes that in keeping with deregulation trends, as much flexibility as possible should be provided to industrial gas purchasers. Therefore, the Commission directs BCGUL to fully investigate an optional pricing methodology which is based on an appropriate index and could be selected by a customer on an annual basis as an alternative to fixed prices. The Utility should consider customer needs and the impact that an indexed price may have on total Schedule 10 sales revenues.

Concerns were expressed about the exclusivity provision under Schedule 10, especially as it relates to indexed pricing (T. 3629). Considering this issue, the Commission believes that it is appropriate to attach an exclusivity condition to prices which are fixed annually since both parties, buyer and seller, are agreeing on a contract based on their assessments of risk and return. It would be inappropriate to permit buyers to buy elsewhere whenever the market price went lower and/or supplies were readily available while still requiring BCGUL to deliver when prices are higher in the marketplace. While the arguments for exclusivity are less strong with indexed pricing, the Commission believes that Schedule 10, Priority 2

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service should be uniform except only for the pricing option chosen and that an annual commitment to buy all the customer's interruptible gas from the Utility is consistent with the priority of service under Schedule 10. Moreover, the Commission notes that Schedule 14 provides interuptible gas at an indexed price without exclusivity. **Other than directing BCGUL to file a proposal for indexed pricing, in all other respects the Commission approves Schedule 10 for filing.**

8.2 Schedule 13: Interruptible Peaking Sales

Few concerns were expressed about this Schedule with the exception of the proposed rate which is calculated as the residential burner tip rate minus the large industrial transportation margin. In the event BCGUL has no gas available, there is a provision to enable it to purchase gas at a cost above its normal peaking costs and to pass on this purchase cost to the customer. The Commission supported the concept of market-based pricing for peaking gas in the Phase A Rate Design Decision and continues to do so. In response to concerns raised about the increase in the rate, BCGUL explained that the previous rate was based on a peaking contract which is no longer in effect (T. 2573). The Commission accepts this explanation and agrees that deriving the current rate from the residential rate is a reasonable proxy for the market price of gas where the curtailment priority is just below firm and the availability is on a same-day basis. The Commission notes that the alternative of a market indexed price is offered in Schedule 14 but requires more notice, so the price and availability levels are consistent. **The Commission approves Schedule 13 for filing, and accepts that the rate will be subject to adjustments depending on the residential cost of gas.**

8.3 Schedule 14: Interruptible Backstopping Sales

BCGUL has unbundled backstopping to create this new Schedule. The Commission believes that Schedule 14 provides a useful option with its indexed pricing for customers seeking short-term interruptible gas supplies over a defined period, when the need can be identified sufficiently in advance to fit into the normal nominating process.

The only concern raised with this Schedule related to the 90-day letter of credit which, it was suggested, was too onerous. In the absence of any evidence of hardship being created by the 90-day requirement and recognizing that Schedule 14 could conceivably be used to purchase gas over an extended period of time where a customer liked the indexed price and associated priority, the Commission accepts the BCGUL proposal. **The Commission approves Schedule 14 for filing.**

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9.0 INDUSTRIAL & GENERAL SERVICE BURNER TIP SERVICE SCHEDULES 4, 5, 7 AND 8

BCGUL proposed four distinct bundled or burner tip schedules for industrial customers: Schedule 4 for seasonal service, Schedule 5 for small volume firm service, Schedule 7 for small volume interruptible service and Schedule 8 for large volume interruptible service. There were no significant concerns expressed about any of these four schedules during the hearing. With respect to the provision of Schedule 8, this was introduced at the request of the industrial customers to provide them a burner tip rate option in the event they decide against taking on the administrative tasks inherent in the unbundled tariffs.

In examining the ratio of revenue to cost for Schedule 5 customers (under the peak responsibility method) the Commission is concerned that in comparison to other firm rates the Schedule 5 ratio of 134 percent is too high. The Commission believes that this should be corrected and this matter is discussed in detail in conjunction with delivery charges for Schedule 25 in a following section, under Transportation Schedules. The Commission notes BCGUL's intention to complete the installation of demand meters for Schedule 5 customers as soon as possible and urges early completion of this program and the initiation of appropriate demand charges as soon as possible.

The Commission approves BCGUL's proposed Schedules 4, 5, 7 and 8 for filing, subject to adjustment of Schedule 5, 7, and 8 delivery charges and subject to the lowering of the Schedule 8 access threshold. Each of these matters is discussed in detail in a subsequent portion of this Decision. The Commission accepts that rates under Schedule 4 will be subject to adjustment depending on the residential cost of gas.

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10.0 INDUSTRIAL & GENERAL SERVICE TRANSPORTATION SCHEDULES 25, 27, 22 AND 32

BCGUL is proposing firm and interruptible transportation schedules in two categories: General Service (Schedules 25 and 27) and Large Volume Industrial Service (Schedules 22 and 32) defined by a volume threshold which BCGUL proposed to be 20,000 GJ/month. Because of the emphasis on large-volume customer interests by Intervenors, little attention was directed to General Service Rate Schedules 25 and 27 during the hearing. However, in setting the delivery charges, BCGUL has used the approach of discounting from the General Service firm rate in Schedule 25 to arrive at the other rates. It is therefore necessary that any review of Schedule 25 delivery charges consider all related Transportation Schedules. **More generally, the Commission approves the suggestion made by BCGUL in final argument (T. 3538) and directs that the minor wording refinements made in the updated filing of Schedule 22 also be incorporated into Schedules 25 and 27 where appropriate.** Incorporation of these changes is assumed in the following discussion.

10.1 Transportation Rates

Intervenor cross-examination of the Applicant at the hearing touched on each of the key aspects of Schedule 22 rates, namely the basic monthly charge, the proposal for two levels of service, the amount and seasonal nature of delivery charges, the charges for unauthorized overrun gas ("UOR") and the demand surcharge.

10.1.1 Monthly Charges

With respect to basic monthly charges, the Commission accepts that these are cost-based and set reasonable minimum limits for access to the services provided. The Commission also notes that for General Service, these charges have been reduced from previous levels. **Therefore, the Commission approves the basic charges proposed for Schedules 25, 27 and 22.**

10.1.2 Level 1 Versus Level 2 Service

BCGUL in its application proposed two levels of service for Schedule 22 and 27 transportation customers. Level 1 customers would be subject to curtailment only in the event of system capacity limitations. The latter are defined in the Schedules as criteria "established from time to time by BC Gas' Systems planning department", or additionally, as constraints which "may occur on the basis of day to day operating conditions." Level 2 service proposed discounted delivery charges in return for the customer

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providing access by BCGUL to the customer's interruptible gas for peak-shaving purposes. Should a Level 2 shipper fail to provide gas on more than two days per year, the customers would be automatically elevated to the more expensive Level 1 rate.

Intervenors protested that to obtain Level 2 rates for direct purchase gas would virtually require a firm gas supply. They claimed that these conditions tended to "tilt the playing field" in favour of BCGUL's Schedule 10 supplies, since Schedule 10 customers were not subject to being elevated to Level 1 rates. The Commission concludes that only one level of service should be provided, with curtailment based only on capacity constraints. The contribution to BCGUL's peak shaving supplied from the proposed interruptible Level 2 service customers is unlikely to be large. Moreover, if BCGUL wants access to gas owned by transportation customers as contemplated under Level 2, it can negotiate the purchase at a price which is both acceptable to the customer and consistent with LRIC pricing objectives, considering the cost of competitive supply or DSM alternatives.

The Commission directs that Schedules 27 and 22 be revised to provide a single level of service which is subject to curtailment only for capacity reasons. In approving this change the Commission is also aware of the BCGUL concern about Schedule 22A customers possibly changing nominations from firm to interruptible since, in reality, capacity constraints in the portions of the Utility's system serving many of these customers are unlikely. The Commission notes that the Inland Industrial customers agreed that it was reasonable to maintain firm nominations generally at a level that applied when their agreements were signed (T. 3083) and expects that they will do so without explicit changes to Schedule 22 wording. However, if this becomes a problem in future, BCGUL can submit appropriate revisions for Commission consideration.

10.1.3 Delivery Charges

With respect to the proposal for seasonal delivery charges, the Commission finds this approach consistent with pricing signals based on long-run incremental costs. **The Commission approves the seasonal delivery charge concept for Schedules 25, 27 and 22.**

With respect to the amount of delivery charges, the Commission is less satisfied. For firm service under Schedule 25 the ratio of revenue to cost of service using the peak responsibility method is as high as 134 percent for the Lower Mainland Division (Exhibit 4, Tab B2). For firm service customers, the Commission considers this to be too far beyond the "band of reasonableness" which was described by a number of expert witnesses as $\pm$ 10 percent during the hearing (e.g. T. 1041-1045). Commission staff have determined that it is possible to lower the Schedule 25 revenue to cost ratio by some 10 percent, and

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at the same time maintain revenue neutrality by also adjusting Schedule 27 and 22 rates, using BCGUL "discount from firm" methodology as set out in Exhibit 5A, Tab B8.

Increasing the incentive adjustment (described in Note 3 of the above-noted Exhibit) from $0.10/GJ to $0.15/GJ leads to a single, "capacity curtailed only" rate very similar to that originally proposed by BCGUL for Level 2 service. The resulting rates, and their relationship to those originally proposed by BCGUL are demonstrated in Table 10.1 following. The overall effect of these changes would be revenue neutral to BCGUL and would deal with two concerns simultaneously, namely the high Schedule 25 rate and the need for an appropriate rate for capacity-only interruptions to fall somewhere between the Level 1 and 2 rates originally proposed by BCGUL. Such a rate is appropriate in view of the improved level of service resulting from removal of automatic access by BCGUL to the shipper's interruptible supply.

In developing these revised rates, the BCGUL approach of maintaining an approximate 2:1 winter:summer ratio has been maintained for the firm rate, with interruptible discounts mainly from the winter rate. The Schedule 22 summer rate is also now consistent with BCGUL's proposed Schedule 22A rate of $.55/GJ. The Commission believes that the elimination of Schedule 32 monthly charges as discussed in a following section is another reason to set the single-level Schedule 22A rate at $.55/GJ since 22A customers will have both improved transportation access and improved balancing service relative to that currently provided by this Schedule. **In conclusion, the Commission directs that Schedules 5/25, 7/8/27, 22 and 22A delivery charges be revised as set out in Table 10.1 following.**

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Table 10.1

Delivery Charge Revisions
Schedules 5/25, 7/8/27, 22, 22A

SCHEDULE		BCGUL PROPOSED		BCUC REVISED
5/25	Winter	1.50		1.35
5/25	Summer	.75		.70
5/25	Average	1.125		1.025
		LEVEL 1	LEVEL 2	CAP.CURT.only
7/8/27	Winter	1.20	.95	.95
7/8/27	Summer	.75	.70	.70
7/8/27	Average	.975	.825	.825
22	Winter	.95	.75	.80
	Summer	.70	.50	.55
	Average	.825	.625	.675
22A	(Interruptible)	.55	.38	.55

Notes:

1. Average rate calculated on the basis that 5 winter month volume equals 7 summer month volume.

2. Discount methodology for revised rates:

a) proposed average firm rate = **$1.125**

discount to reduce firm rate = .10

discount for alternate fuel = .05

discount to consider capital cost and operating cost of backup fuel (incentive adjustment) = .15

b) resulting average small volume interruptible rate = **.825**

discount for daily balancing and grouping = .15

c) resulting average large volume interruptible rate = **.675**

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10.1.4 Unauthorized Overrun Charges/Demand Surcharges

Changes to UOR charges proposed by BCGUL for Schedule 22 have the effect of reducing customer charges when gas up to 5 percent in excess of the authorized amount is taken. However, the charges are increased for takes above the 105 percent level. The Commission believes the new charges are directionally correct as they recognize customer difficulty in controlling takes precisely, while increasing penalties for inordinate takes of unauthorized gas. Similarly, the revised demand surcharge conditions have been relaxed with widening of the tolerance band from 102.5 percent to 110 percent. In addition, provision has been made for a 100 GJ cushion and the retention of two days grace for exceeding the tolerance band before the demand surcharge applies.

Intervenors generally accepted that the basic concepts behind the proposed UOR charges and demand surcharges were sound. They did suggest, however, that the resulting customer costs were punitive (T. 3619). The Commission accepts the BCGUL argument (T. 3564) that since customers have valued the availability of winter gas at $85/GJ where they have bought-out of 50 percent curtailment, the UOR charges which range up to about $20/GJ are not excessive. Since the charges for the first 5 percent band are based on Rate Schedule 1 gas costs, the Commission accepts that these UOR charges may be subject to future adjustments.

The demand surcharge would only be effective at some level above the $85/GJ curtailment buyout charge or else customers would be paying the surcharge in preference to buying out curtailments. The Commission continues to believe, as it stated at p. 46 of its February 21, 1992 Decision with regard to Schedule 22, that given the importance of industrial customer curtailment in BCGUL's portfolio of peak shaving resources, a substantial demand surcharge is required as an additional disincentive to customers insufficiently deterred by UOR charges. **Considering the additional flexibility, such as widening of the demand surcharge tolerance band, included in the revisions proposed by BCGUL, the Commission approves both the Schedule 22 UOR charges and the demand surcharge provisions with one minor exception. While the Commission recognizes the historic origin of the $19.93/GJ and other charges for UOR over 5 percent, the Commission believes that rounding of these charges to the nearest dollar would now be appropriate. In addition, the Commission directs BCGUL to make the UOR charges in the other Industrial Rate Schedules consistent with those in Schedule 22.**

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10.2 Large Volume Tariff Issues: Schedules 22 and 32

10.2.1 Balancing

Other than Schedule 22 transportation rates, the Schedule 22 requirement for daily balancing was probably the major concern raised by industrial Intervenors during the hearing. By Order No. G-91-92, the Commission had approved daily balancing under Schedule 22 for the five winter months November 1992 to March 1993. The Order required BCGUL to file a report which would review the cost of, and experience with, daily balancing during this period and which would consider options for cost recovery. The requested report was filed during the hearing and, at the same time, BCGUL introduced Schedule 32 Large Volume Gas Balancing as an unbundled substitute for daily balancing under Schedule 22. Balancing under Schedule 22 is now proposed to be required each day of the year but at reduced charges in summer months based on Schedule 7 commodity charges.

The position adopted by Intervenors generally was that the Commission should only approve charges for balancing that were cost based and that, in any event, the daily balancing requirements under Schedule 22 were too onerous (T. 3621). The Inland customers preferred the alternative of the gas balancing service provided by Schedule 32, although the Lower Mainland customers thought it was unnecessary since they opposed daily balancing in any form for their service area (T. 3759).

The importance of accurate nominations and daily balancing by large-volume industrial customers was demonstrated by BCGUL in its Gas Balancing Report, filed during the hearing as Exhibit 51. This Exhibit detailed the adverse financial consequences for the Utility resulting from losses on Schedule 10 sales and unnecessary costs incurred from over-nominations during the 1992/93 winter, when the form of daily balancing then in effect did not provide sufficient inducements to encourage accurate nominating by Schedule 10 customers. Based on this evidence, the Commission concludes that daily balancing is appropriate for large volume customers. **The Commission agrees with those Intervenors who found Schedule 22 daily balancing provisions onerous when compared with the balancing service and charges offered under Schedule 32, especially considering the very generous 20 percent tolerance zone in Schedule 32. Despite the Commission's general belief that LDC's should unbundle services wherever possible, in the case of BCGUL it appears that some simplicity could be gained and that no useful flexibility would be lost, if the gas balancing service provisions under Schedule 32 were rolled into Schedule 22. These provisions would replace Section 8.0 beginning on p. 22.13 of Schedule 22. BCGUL agreed that this was a reasonable alternative (T. 2532). The**

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Commission therefore approves the requirement for daily balancing under Schedule 22 on this basis and orders the withdrawal of Schedule 32.

The Commission concludes that additional administration charges of $175/month for gas balancing (as proposed for Schedule 32), will not be necessary with the incorporation of these services into Schedule 22. The Commission also notes that BCGUL has agreed that it would adopt any renomination provisions adopted by Westcoast Energy Inc. (T. 2433). Such a provision would have the effect of further reducing the cost of daily balancing and the Commission would encourage BCGUL to make such renominations available when possible.

Commodity charges as proposed by BCGUL in Schedule 32 for gas balancing are developed on the basis of a proxy for market value using the cost of gas component from seasonal rates (Schedule 4) as the summer charge and the cost of gas component from residential rates (Schedule 1) as the winter charge. While the Commission has some reservations about the use of cost-based rates to establish market value, the resulting differentials between the balancing charges and the interruptible rates appear reasonable. For example in the Lower Mainland the balancing charge exceeds Schedule 10 rates by $1.33/GJ in the winter and $.28/GJ in the summer. The differentials for other Divisions are similar. The Commission notes that depending on the relationship of market pricing to costs in future, it may be more appropriate to simply adopt a suitable markup above interruptible rates in order to determine balancing charges.

The Commission is cognizant of the preference for predictable costs expressed by customers. Moreover, since some 90-95 percent of delivered volumes will be delivered within the 20 percent tolerance band, (Exhibit 51) there is little need for exact pricing signals, nor should customer costs be significantly impacted by the BCGUL proposals. **The Commission concludes that the commodity charges proposed by BCGUL for balancing service (pp. 32-36 of Schedule 32) are reasonable and are therefore approved for incorporation into Schedule 22.**

10.2.2 Large Volume Firm Rates: Schedules 22, 22A and 22B

BCGUL proposed that existing large volume transportation customers in the Inland and Columbia service areas ("interior customers") maintain their existing rates, but generally adopt terms and conditions similar to those in Schedule 22. These existing rates would not be available to new interior customers or for significant load increases by existing interior customers. BCGUL proposed that the tariffs be named Schedules 22A (Inland) and 22B (Columbia) to indicate the similarity to Schedule 22. The rationale was that since virtually all of these interior customers moved their direct purchase gas on firm service, and used only small amounts of interruptible gas, they differed significantly from Lower Mainland large

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volume customers, who had historically been interruptible sales or service customers only and had no firm gas sales or transportation. Under these circumstances, considering that most of these interior customers had either individually negotiated rates (Inland by-pass customers) or a uniquely linked rate design (Columbia customers) and few if any were likely to be requiring load increases, closed rates were argued to be appropriate. BCGUL also proposed that any new customers requiring firm transportation could negotiate an appropriate rate under Schedule 22 at a cost which covered BCGUL costs, valued customer peak shaving contributions if applicable and made some contribution to the Utility profit.

Industrial Intervenors representing interior customers argued against the proposals to close Schedules 22A and 22B and negotiate firm rates under Schedule 22, reasoning that they would become "stigmatized" by such action and that as a result, their rates might be eliminated by future Commissions (T. 3599). They also proposed that a preferable alternative for new customers or major load increases would be to retain existing rates but introduce an initial price adjustment to allow for BCGUL costs or peak shaving benefits. BCGUL countered that such an approach was no different from its negotiated rate proposal under Schedule 22 except that payments would be made initially rather than over time, through rates (T. 3856).

In the particular case of Schedule 22B, applicable to Columbia Division customers, there was general agreement that the grandfathering of existing rates should apply only until December 31, 1993. During this period BCGUL and the Columbia customers propose to negotiate revised rates, and give consideration to the incorporation of BCGUL proposals for Schedule 22 terms and conditions, while still recognizing Columbia Division differences. There was some minor disagreement on this latter point, with Counsel for Fording attempting to debate specific terms and conditions for Schedule 22B during the hearing. On the other hand, Counsel for Crestbrook and Line Creek expected the proposed rate negotiations to deal with all matters, including terms and conditions. In any event, the parties were consistent in the request that matters unresolved as of December 31, 1993 be referred to the Commission for resolution.

In considering the matter of closing Schedules 22A and 22B, the Commission is aware of the many special circumstances and negotiated agreements underlying the existing rates for these interior customers. The Commission rejects the "stigma" argument and agrees with BCGUL that the initial contribution concept differs from negotiated rates only as to timing of charges. **The Commission therefore approves the closing of Schedules 22A and 22B subject to continuation of the negotiations proposed for Schedule 22B over the period ending December 31, 1993. The Commission also approves the concept of negotiated rates for future firm customers under Schedule 22 as proposed by BCGUL with the comment that such rates could be structured in a number of ways.** Some possibilities include demand-commodity rates, initial contributions to cover capital costs, or the use of a rider to collect capital contributions over time in

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addition to some basic rate. The Commission believes that any such rate must consider long-run incremental costs, but otherwise BCGUL is encouraged to be flexible as to the tariff structure so long as the time value of money is considered.

10.2.3 Large Volume Customer Definition

The volume threshold of 20,000 GJ/month was proposed by BCGUL as the basis for being considered a large volume customer and, hence, having access to bundled interruptible service under Schedule 8 or firm or interruptible transportation service under Schedule 22. The latter can be used in combination with either firm or interruptible gas purchased directly, or may be used with interruptible gas purchased from BCGUL under Schedule 10.

The main opposition to the 20,000 GJ/month threshold level was from Eastern Natural Gas Marketing Ltd. ("ENGM") which wishes to offer gas administration services such as nominations and daily balancing or even the direct purchase of gas to a number of customers who use somewhat less gas than 20,000 GJ/month. ENGM's suggested alternative was that the limit be reduced to an annual minimum of 144,000 GJ or an average of 12,000 GJ/month (T. 3670). BCGUL indicated that this would result in an additional 20 customers becoming eligible for large volume rates (Exhibit 108). The Company further indicated that while there was no administrative or operational reason why they could not accommodate 60 rather than 40 customers, the effect on the rate shift had not been examined (T. 2916, 3565). It is important to remember that BCGUL's overall targetted revenue from all its customers is itself an estimate, based on the Utility's evaluation of the choices expected to be made by those customers when the newly designed tariffs are available. Commission staff have determined that if all customers eligible were to move to Schedule 22 the maximum rate shift would be $800,000. However, if the nine eligible firm service Inland customers did not move (since with Schedule 22A closed, for firm service there would only be a $.15/GJ advantage over Schedule 25) and if half of the Lower Mainland customers chose Schedule 8 instead of the combination of Schedule 10/22, then the rate shift would be reduced to only $270,000.

The Commission is concerned about additional rate shifts to the residential and commercial customer classes, but also would like to see LDC's provide larger customers with a variety of options in keeping with deregulation objectives. In this case, the Commission believes that the rate shifts involved may be relatively small overall but that the value to individual industrial and institutional customers could be significant. **The Commission therefore directs that the large volume threshold definition should be established at an annual average of 12,000 GJ/month.**

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10.3 Complaints Deferred to Phase B

The Commission had advised in Order No. G-15-93 that two complaints relating to general service and industrial tariff matters which had been raised by B.C. Health Services Ltd. and separately by Inland Natural Gas Marketing Ltd. would be referred to the Phase B Rate Design Hearing. These complaints related primarily to the level of fixed charges in the BCGUL transportation tariffs. **In view of the significant revisions to the BCGUL tariffs filed in the hearing and in view of the fact that the level of fixed charges was addressed as an integral part of the hearing review, the Commission considers these complaints to have been addressed by the various findings elsewhere in this Decision.**

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11.0 OTHER RATE DESIGN ISSUES

11.1 Termination of Tariffs

This subject was not addressed by Intervenors during the hearing. The Commission has reviewed BCGUL's application and finds it acceptable (Exhibit 1, Tab 2, pp. 6-7). **The Commission therefore approves the termination of these tariffs effective the date of implementation for new tariffs, namely November 1, 1993 for industrial and general service tariffs and January 1, 1993 for residential and commercial tariffs.**

11.2 Deferral Account for Lost Industrial Margin

Because the reduction in Industrial margin is to be effective November 1, 1993 and offsetting increases to residential and commercial customers are not to be effective until January 1, 1994, there is a potential for the rate design to reduce revenues. The Commission notes that this subject was not addressed by Intervenors during the hearing. The Company proposed (Exhibit 1, Tab 2, p. 7) and reiterated in final argument (T. 3588-3589) that this account was necessary to provide revenue neutrality and proposed to amortize the deferral balance by way of charges to the Industrial customers over the 12 months commencing November 1, 1993. **The Commission has reviewed the matter and now approves the establishment of a deferral account in principle, but will review the disposition of this account by way of a future Commission Order, most likely in conjunction with the review of the Company's 1994 revenue requirements.**

11.3 Consolidated General Terms and Conditions

Each division of BCGUL currently uses different General Terms and Conditions for incorporation into its gas customer contracts. This condition results largely from historic differences between the predecessor companies.

The Commission, in its Decision following BCGUL's 1992 Revenue Requirement hearing, referred consideration of common General Terms and Conditions to the Phase B Rate Design Hearing. As part of its application to the Phase B hearing BCGUL formally applied for approval of consolidated General Terms and Conditions which were submitted in Exhibit 1, Tab 12. The section of the terms and conditions dealing with Main Extensions has not been completed pending the outcome of the Utility's Integrated Resource Plan and any relevant direction from the Commission in the current hearing Decision.

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The proposed General Terms and Conditions provoked relatively little discussion during the hearing. The large volume industrial customers objected to the unlimited right of BCGUL under Section 13.2, to curtail gas to any of its customers in the event of failure of BCGUL's gas supply for *any* reason, arguing that this should not include the case of failure to deliver gas by the Utility's own suppliers. However, the Commission rejects this argument and is satisfied that a utility must have the final decision on emergency curtailment but will use these broad powers responsibly.

The Commission believes the adoption of consolidated General Terms and Conditions is a logical accompaniment to consolidation for rate making purposes. Adoption of simplified and clearer Conditions should improve customer understanding and simplify contract administration by the Utility. **The Commission therefore approves adoption of the proposed consolidated General Terms and Conditions.**

11.3.1 Service Charges: Connection and Reconnection Fees

The proposed new General Terms and Conditions contain a supplemental schedule of standard fees and charges related to connection fees and disputed meter testing charges.

BCGUL proposes to set the fee for Account Transfers (whether service is active or inactive) at $25 and proposes a fee of $75 for new installations. In its application the Utility demonstrates that the former charge is close to the average cost of servicing active and inactive account transfers. The "new installation" charge moves much closer to full cost recovery than the formerly charged $10 fee, but still falls short of full cost recovery.

The Commission accepts that the proposed change in service charges is directionally correct, is satisfied that the charges are reasonably consistent with comparable charges of other Canadian utilities, and approves the application as filed.

11.4 BCGUL Application for Hearing Cost Recovery

By an August 9, 1993 letter addressed to the Commission, BCGUL requested permission to recover Phase B Rate Design hearing costs in the amount of $487,179, plus $52,944 of capitalized FDC modelling costs. These costs excluded any consideration of Commission costs arising from the hearing or any consideration of participant funding by the Utility which might arise from a Commission award under Section 133 of the Utilities Commission Act ("the Act").

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In the letter, BCGUL also requested approval to amortize the costs commencing January 1, 1994, over a 3-year period, distributed volumetrically to all rate schedules except special tariffs. The letter was accompanied by an expenditure summary showing the derivation of the requested amount. A subsequent letter (August 17, 1993), filed at the Commission's request, provided further details.

While the Commission is prepared to approve BCGUL's request on this occasion, it believes that in future the Utility should be required to demonstrate that equally careful cost control has been exercised in the matter of hearing expenditures as in any other area of the Company's operations. Therefore, at the time of filing an application, BCGUL is directed to submit for Commission approval a budget estimate of the expected hearing costs. The Utility will then be required to justify any significant variation at the time of filing for cost recovery.

The Commission approves BCGUL's application for hearing cost recovery, as filed. In addition, the Commission directs BCGUL to initiate a system of pre-hearing budgets of expected future hearing costs so as to provide benchmarks for hearing cost control.

11.5 Participant Funding

The Act was amended earlier this year to include Section 133.1 which reads as follows:

> "(1). The Commission may order a participant in a proceeding before the Commission to pay all or part of the costs of another participant in the proceedings.
>
> (2). If the Commission considers it to be in the public interest, the Commission may pay all or part of the costs of participants in proceedings before the Commission that were commenced on or after April 1, 1993 or that are commenced after the coming into force of this sub-section.
>
> (3). Amounts paid for costs under sub-section (2) must not exceed the limits prescribed for the purposes of this section."

In response to the legislative amendment, the Commission developed a draft policy for participant funding which was circulated to interested parties for comment. The Commission has received detailed responses and is in the process of revising the draft policy.

In the instance of this hearing the Commission has received only one request for participant funding. That request has come from Counsel representing CACBC. **The Commission panel is not in a position at this time to determine the appropriate participant funding for this hearing. If any future Commission determination on participant funding for this hearing assigns costs to BCGUL, the Utility will be permitted to recover those monies in customer rates.**

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12.0 BURRARD AGREEMENT TARIFF

12.1 Background and Commission Jurisdiction

The Amended and Restated Burrard Thermal Interruptible Gas Purchase Agreement ("Burrard Agreement") is a tariff under which BCGUL sells gas to B.C. Hydro for use in its Burrard Thermal Generating Plant. The Burrard Agreement was briefly considered in a previous Commission Decision dated February 21, 1992 into the matter of BCGUL's gas cost allocation methodology. In that Decision, due to a lack of evidence during the hearing, the Commission chose to make an interim ruling which resulted in the commodity cost as defined in the Burrard Agreement being frozen at its then current rate of $.93/GJ. The difficulty that the Commission experienced in determining the appropriate pricing level is apparent from its statement that: "A more appropriate price *might* be...at an auction." The Commission ruling directed BCGUL to submit a more appropriate price for approval by April 30, 1992.

Subsequent to the February 1992 Decision, there was an exchange of correspondence on this matter involving BCGUL, B.C. Hydro and the Commission. Some of this correspondence has been filed by BCGUL as evidence in this hearing (Exhibit 1, Tab 16). As follow-up to the February 1992 Decision, BCGUL filed an application dated July 15, 1992 which dealt with a number of issues including the Burrard Agreement. After receiving Intervenor views on that application, the Commission dealt with it by Order No. G-91-92 dated September 29, 1992.

In that Order the Commission directed that both pricing and priority for service to B.C. Hydro's Burrard Thermal plant were to be addressed in BCGUL's Phase B hearing application. Hence, all parties including B.C. Hydro were put on notice in September of 1992, that the Burrard Agreement would again be the subject of a Commission hearing. Notwithstanding this notification and B.C. Hydro's subsequent correspondence on the matter (Exhibit 1, Tab 16), B.C. Hydro chose not to file evidence or present witnesses at the Phase B hearing. Rather, B.C. Hydro elected to cross-examine BCGUL witnesses and make final argument, opposing the adoption of BCGUL's application in regard to the Burrard Agreement, questioning the Commission's jurisdiction to deal with this matter and making application for the reconsideration of the February 21, 1992 Decision.

In the matter of the issue of its jurisdiction over the Burrard Agreement, the Commission is now in a different position than it was following the Phase A hearing, when no evidence was presented and it did not hear full argument on this issue. Having held a public hearing and having heard evidence, cross-examination and argument, the Commission believes that it is now in a position to determine an appropriate tariff rate

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pursuant to Sections 67(2) and 70(1) of the Act. The Commission concludes that it has jurisdiction to consider revisions to this tariff.

The Commission acknowledges B.C. Hydro's request at the hearing that the February 21, 1992 Decision, as it relates to the Burrard Agreement, be reconsidered (T. 3801) and BCGUL's position that it does not oppose such a reconsideration (T. 3938). **In the circumstances and given the evidence and argument on the issue at the Phase B hearing, the Commission is prepared to reconsider the February 21, 1992 Decision with respect to Burrard Thermal pricing, and herein presents its Decision on that Reconsideration Application.**

12.2 Price and Priority

There has been no evidence to suggest that a commodity cost as defined in the Burrard Agreement other than the commodity component of BCGUL's average field purchase price should be included in the price charged to B.C. Hydro. In the case of the period following November 1, 1991, this price would have been approximately $.88/GJ. BCGUL proposed this price in their Phase A hearing application and B.C. Hydro has repeatedly endorsed this proposal.

However, in the Commission's view, the price for interruptible gas sold under the present market pricing regime, which includes Schedule 10 sales to on-system customers and off-system sales, is tied directly to priority of supply. For example, the Commission has approved off-system sales prices below Schedule 10 interruptible prices on the basis that this gas is only made available in the off-system market after the Schedule 10 customers have received their nominated volumes. Similarly, the Commission believes that if B.C. Hydro is charged a price of $.88/GJ, which is below the price of any Schedule 10 or off-system volumes, then that price should receive a level of priority consistent with that low price.

The Commission is not persuaded by the arguments of B.C. Hydro that only price should be reconsidered. The Commission notes that the definition of rate in Section 1 of the Act includes "charge", "practice", and "contract of a public utility or corporation relating to a rate". Similarly, the definition of service as contemplated under Section 70(1) "includes the use and accommodation provided". **The Commission concludes that in reviewing the rate charged for service under the Burrard Agreement, price and priority can, and should, be considered together.**

12.3 Key Issues Related to BCGUL Request for Tariff Change

In deciding upon the priority matter, the Commission recognizes that there is an issue as to whether B.C. Hydro should have access to what has been referred to as the "Inland Valley" (under baseload

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supply contracts), and also an issue as to what amount of gas BCGUL should be allowed to inject into storage before making deliveries to B.C. Hydro under the Burrard Agreement.

With regard to the Inland Valley, the Commission understands the arguments put forward by BCGUL about circumstances at the time the Burrard Agreement was signed precluding access to the Inland Valley (T. 2951-2952). However, in determining what is a fair and reasonable rate now, the Commission believes that present circumstances are more relevant. In approving BCGUL's current gas cost allocation methodology, the Commission has accepted that the gas supply for the Inland and Lower Mainland customers is managed as a single supply. In the present circumstances the Commission believes that there is no longer an "Inland Valley" or "Lower Mainland Valley". **Therefore, the Commission concludes that for the purposes of assigning priority, the volume of gas to be considered is the total valley under the baseload supply contracts for the Inland and Lower Mainland customers.**

In the matter of the priority of storage injection, the Commission believes that since under the present gas cost allocation methodology, the firm customers in the Inland and Lower Mainland service areas have been assigned all of the storage service costs and all of the demand charges for the baseload gas supply used to fill storage, then they should receive first priority access to the valley gas for the purposes of filling storage. In the alternative, if B.C. Hydro or any other interruptible customer was prepared to pay a price for this storage injection gas which exceeded its replacement cost to the firm customers, then they could purchase it on a priority basis. However, in the event that such customers expect to pay only the incremental commodity cost as does B.C. Hydro, priority access is not appropriate.

BCGUL in its application (Exhibit 1, Tab 17) has made a number of requests relative to the appropriate priority for sales under the Burrard Agreement. BCGUL proposes that in addition to ensuring that the minimum annual quantity of 20 petajoules is delivered, it will provide priority to B.C. Hydro for the Lower Mainland Valley under baseload supply contracts after storage has been refilled and the 5 petajoules of growth in interruptible sales contemplated by clause 6.3(a)(iii) of the Burrard Agreement have been made available for both interruptible sales in the Lower Mainland service area and off-system sales. The Commission notes that however it is defined, the 5 petajoule limitation on interruptible sales growth limits the strict application of the principle that higher price equals higher priority.

The BCGUL proposal also requires monthly nominations by B.C. Hydro. Once authorized by BCGUL, this monthly quantity will be deemed to have been delivered whether taken or not. This procedure will enable BCGUL to maximize off-system sales on a monthly basis since Hydro's requirements will be known.

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12.4 Commission Decision

The Commission notes that in translating the proposed priority principles into specific tariff amendments, BCGUL has adopted the position that B.C. Hydro should not have access to the Inland Valley. This position is evident in the revised definition of "seasonal gas" in Section 1.0 of the proposed tariff amendment. As concluded above, the "Inland Valley" concept is not appropriate in view of the single gas supply approved by the Commission for Inland and Lower Mainland customers.

A second concern that the Commission has with the specific wording in the revised tariff relates to the nominating provisions. The Commission believes that some additional flexibility should be included, so that if in future shorter nominating periods become practical, they can be accommodated. For example, if off system sales occur on a shorter term basis than one month, a shorter nominating period would be appropriate.

In view of the above general concerns, the Commission is unable to approve the BCGUL proposals for a tariff change involving revised priority as filed. Specifically, considering the proposal on p. 4 of Tab 17 in Exhibit 1 (as revised July 23, 1993), the following changes are required:

> In point 3., there is no need to limit the interruptible sales to the Lower Mainland; it should also be made clear that the 5 petajoule sales apply only after fulfillment of the 20 petajoule obligation; and
>
> In point 4., the Lower Mainland reference should be deleted i.e., "remaining valley gas" refers to the combined Inland and Lower Mainland valley.

BCGUL should apply to the Commission for timely approval of a tariff which is revised in accordance with the general and specific concerns noted above. This should be effective November 1, 1993, consistent with the implementation of other Industrial tariff revisions.

Finally, in the matter of price, and considering the amended priority provisions approved above, the Commission approves a commodity cost as defined in the Burrard Agreement of $.88/GJ effective November 1, 1991. From November 1, 1993 onwards, the commodity cost should be the average commodity portion of the gas purchase price in the field paid by BCGUL. The deferral account previously required with respect to the $.93/GJ is no longer required and should be closed out. Since BCGUL has advised that B.C. Hydro has paid $.88/GJ for volumes delivered since November 1, 1991, no significant reconciliation should be necessary (T. 2404, 2938, 3572).

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13.0 BUY-SELL ARRANGEMENTS FOR INTERRUPTIBLE CUSTOMERS

Tab 15 of Exhibit 1 sets out a proposal for implementing buy-sell arrangements for interruptible customers which BCGUL filed in response to a suggestion from the Commission. The BCGUL proposal was advanced as a framework for consideration rather than as a fully-developed rate schedule. Similar to buy-sells for small firm customers that resulted from the Commission's March 11, 1993 Decision on Domestic Natural Gas Supply Rules, BCGUL proposed to buy gas at the interconnection point to its system from an agent acting for a customer who wished to arrange a direct supply of gas and to resell the gas to the customer under its regular sales schedules. During the hearing, BCGUL expanded its proposal so that the buy-sell customer would buy gas at Schedule 14 prices when the customer's own supplies were not available for longer periods.

BCGUL did not advocate or oppose the proposal in principle but argued that small interruptible transportation service under Schedule 27 removed the need for it (T. 3538). There was Intervenor evidence (T. 3438-9) that some small interruptible customers such as greenhouse operators, might find the daily nominating and monthly balancing requirements of Schedule 27 onerous compared with using Schedule 7 to access direct purchase gas under a buy-sell arrangement. The Lower Mainland Large Industrial Gas Users indicated a lack of knowledge about how interruptible buy-sell would work but supported the availability of competitive options (T. 3802).

Discussion about the proposal centered on the reference price that BCGUL would pay for gas at the interconnect to its system. An essential part of BCGUL's proposal was that this price would be the average forecast variable cost paid by BCGUL under its other supply arrangements, less administration charges and other costs or lost credits that may result from reduced purchases under base load system supply contracts. The Utility argued this would leave the gas supply costs to firm system sales customers unaffected by the initiation of buy-sells (T. 3584).

The Canadian Industrial Gas Marketing Association ("CIGMA") felt the reference price should equal the gas cost embedded in the interruptible customer's sales rates. The Commission's Phase A Rate Design Decision dated February 21, 1992, concluded that interruptible sales should be priced in such a way as to maximize the benefit to firm sales customers. As a result, the gas component of interruptible sales rates are set at levels expected to be competitive for that quality of supply and are generally higher than the variable or commodity costs associated with the gas supply. CIGMA viewed the BCGUL proposal to use the lower variable cost as requiring the interruptible buy-sell customer to pay a higher transportation rate than would a comparable system sales or transportation service customer with a resulting subsidy of the Utility's firm sales customers (T. 3694). Moreover, CIGMA suggested that firm sales customers should

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not be affected if BCGUL marketed the displaced interruptible sales volume outside of its service area. However, the evidence of BCGUL (T. 2103) was that B.C. Hydro's Burrard Thermal Plant would have priority access to this increased volume of valley gas and such sales to Burrard Thermal make no contribution to firm sales customers.

The Commission supports making the range of services available to customers as wide as practical, but considers that the interruptible sales and transportation services approved in this Decision provide competitive sales and transportation service options to all interruptible customers. Schedule 27 in particular enables smaller volume interruptible users to buy gas direct. Although the combination may be somewhat less convenient than bundled burner tip sales under Schedule 7, Schedule 27 does provide for monthly balancing and grouping of several customers for purposes of day-to-day supply administration.

CIGMA's arguments related to reference price are persuasive and the Commission agrees in principle that the margin from valley gas sales in the competitive marketplace which result from buy-sell displaced gas should make a contribution to system firm customers equivalent to that available before implementation of buy-sells, were it not for the special conditions of the Burrard Agreement. However, so long as the Agreement is in force, the net impact of interruptible buy-sells would be likely to increase the costs borne by firm system sales customers, many of whom will in any case experience higher rates as a result of other changes approved by this Decision.

On balance, the Commission does not consider that it would be in the public interest to require the development of a buy-sell alternative for interruptible customers at this time. However, this decision should be re-examined at such time as the Burrard Agreement has either expired in 1998 or has been revised by agreement between BCGUL and B.C. Hydro so that it no longer precludes off-system sales in place of displaced interruptible sales. The Commission is aware of options being considered that would result in a revision of the existing contract commitments.

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14.0 INTEGRATED RESOURCE PLAN AND DEMAND-SIDE MANAGEMENT

14.1 Integrated Resource Plan Background

Integrated Resource Planning is now well established for electric utilities, and is becoming more established for gas utilities throughout North America. In July 1992, BCGUL filed its draft Least Cost Integrated Resource Plan, described by the Utility as a first attempt at IRP and in the covering letter BCGUL noted its intention to develop a revised IRP.

In February 1993, the BCUC issued its Integrated Resource Planning Guidelines ("the Guidelines") which aimed to provide guidance for utilities in their processes of developing IRPs. The Guidelines stated that the IRP process also provides a framework that helps to focus public hearings on utility rates and energy project applications. Some of that focus on rates from the perspective of IRP is noted in Section 4 of this Decision.

On February 25, 1993, subsequent to issuance of the Guidelines, the Commission held a workshop on the barriers to DSM and IRP. The purpose of that workshop was to discuss the financial and regulatory barriers to DSM and IRP, and methods or changes that might potentially be used to overcome those barriers.

On March 4, 1993, the BCUC sent a letter to utilities, including BCGUL, stating that work plans for completion of their IRPs should be provided to the Commission by April 16, 1993, and that draft IRPs should be submitted by December 31, 1993, unless the Commission directed specific utilities to do otherwise. BCGUL, which had filed its draft IRP in July 1992, was specifically directed to revise its filing by April 30, 1993. In response, BCGUL filed its April 30 IRP document (Exhibit 19), which included its workplan and applications for several related deferral accounts.

The direction and progress of BCGUL's IRP were examined in the Phase B Rate Design Hearing. In Exhibit 19, BCGUL had applied for deferral accounts relating to most significant expenditures of its proposed IRP process. A portion of this Decision, relating to the IRP and DSM related deferral Accounts, was released earlier under Order No. G-69-93 (Appendix D). The Commission's views on specific aspects of the Company's IRP plans can be found in that Appendix.

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14.2 Rate Design and Integrated Resource Planning

In its Application, the Company indicated the link between appropriate pricing and DSM (Exhibit 1, Tab 3, p. 6). A Company witness stated that the first order of business was to get the right pricing signals out, but that if consumers did not respond appropriately to the pricing signals, then DSM measures would have to be taken (T. 785-786). A Company witness also agreed that the price signals should be consistent with the principles and analysis that are contained in its IRP (T. 612).

The evidence of CACBC stated that cost effective energy efficiency could not be accomplished unless both consumers and producers were motivated by appropriate incentives, which required designing rates that reflected the total social costs of energy consumption. Efficient pricing was considered to be "the most effective instrument in the DSM arsenal" (Exhibit 52, p. 34).

A key objective in coordinating rate design and IRP is to set the marginal rates facing consumers to reflect LRIC. In this way, the market failure effects of natural monopoly are minimized: consumers face marginal costs just as they would in competitive markets so that the price structure, at least, is not a barrier to economic efficiency. Of course, the goal of setting marginal rates at LRIC is constrained by other objectives of rate making, such as full cost recovery, revenue stability, rate predictability, etc.

In Section 4 BCGUL is directed to present in its next revenue requirements application a proposal for intra-class rate adjustments such that marginal winter rates reflect as nearly as possible the LRIC of winter consumption as estimated in BCGUL's IRP.

14.3 Avoided Cost Study

A significant amount of hearing time involved discussions of the Company's avoided cost for IRP purposes and the Long-Run Incremental Cost study prepared for its Rate Design Application. Concern was raised during the hearing that the LRIC study did not include the cost of gas supply and social costs, as noted under Section 3.1.2 of this Decision. The Commission staff witness suggested that each of the various segments of the gas industry - the producer segments, the transmission pipeline segment and the distribution segment - provided price signals to the segment downstream of it and that the price signal could be used as a proxy for marginal costs. Thus, in her view, an LRIC study should include estimates of incremental production, transmission and distribution and other LDC costs (T. 2158-2159).

A BCGUL witness agreed that it would be difficult for the Commission to come to decisions on items such as DSM or mains extension proposals in the absence of an estimate of full avoided cost (T. 1238).

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The witness also stated that the avoided cost provided in this application included LRIC's associated with "two of the four cost components, that is transmission distribution of the utility and the customer specific charges" (T. 1243). The closest the Company had come to providing avoided costs associated with pipeline and peaking resources was filed in its 1992 IRP but it had not been segregated by customer class. The fourth component of the cost structure, the commodity cost, would have to be determined by the marginal cost in the market (T. 1244). BCGUL agreed that an avoided cost estimate by customer class including costs related to customers, the Utility, the Westcoast transmission line and others could be prepared this fall when gas supply contract negotiations would be complete, and once the Westcoast five-year plan was released (T. 1242-1243).

As noted by Company witnesses, the peak demand is what drives Westcoast facilities that relate to the Lower Mainland. Some of the resources that BCGUL uses to meet peak demand, such as seasonal gas and peaking gas, indirectly rely on continual expansion of Westcoast which may entail a higher unit cost than is reflected in Westcoast tolls (T. 1303-1305).

The CACBC witness, Mr. Todd, stated that the only way to get the right price signals to customers, such that they would respond to the social and efficiency issues integral to the IRP process, is to have rates that reflect the costs of the system and the costs to society (T. 2198, 3948).

The Commission considers an avoided cost estimate to be a fundamental element of an integrated resource plan and of rate design. As stated by the Commission staff witness, "...while an avoided cost and marginal costs or long run incremental costs can't be identical, they should be consistent in the overall planning process, both the rate planning and the resource planning process" (T. 2130). Both the Commission staff witness and the witness for CACBC stated that, in theory, such a study should include both utility and upstream system costs (T. 2159, 2301). The witnesses agreed that there could be practical difficulties at present in determining and using the upstream incremental costs in setting rates (T. 2157, 2301). However, the Commission staff witness also acknowledged that as gas IRP was becoming more established, many utilities were working on developing a more complete view of marginal costs (T. 2175).

Therefore, the Commission directs BCGUL to provide with its revised draft IRP an estimate of avoided costs consistent with its LRIC, which specifies the costs at each stage of the market, including wellhead price, gathering, processing, transmission, distribution and peaking resources. BCGUL is advised to draw on the experience of other utilities and jurisdictions where possible, and make necessary simplifying assumptions when required. Where alternative assumptions appear equally appropriate,

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the Utility is encouraged to develop alternative avoided cost values under these different assumptions. The costs should be segregated by class, where appropriate, and should distinguish between the demand and commodity components of those costs. In order not to delay a revised avoided cost study, BCGUL need not attempt to incorporate social costs at this time.

14.4 Integrated Resource Plan and Demand-Side Management Deferral Accounts

Prior to its filing of the Phase B Application, BCGUL applied on April 30, 1993, for a Commission Decision with respect to a number of proposed deferral accounts related to the Utility's IRP, DSM and commercial marketing programs deferral accounts. Consideration of these applications was deferred by the Commission to the Phase B Hearing. A consolidation of the requested deferral accounts was filed during the hearing as Exhibit 60.

Because of the need for an early decision on these accounts, the Commission considered the matter and issued Order No. G-69-93 on August 13, 1993 (Appendix D). This Order disposed of all requested deferral accounts with the exception of an account requested to permit preliminary surveys and investigations for a new LNG plant. Order No. G-69-93 was accompanied by an appendix which set out the reasons for the Commission's Decision with respect to all accounts except that requested for the LNG plant preliminary investigation, which is discussed in the following section.

14.5 Liquified Natural Gas Plant Deferral Account

In its April 30, 1993 IRP filing (Exhibit 19), BCGUL requested authority to establish a deferral account covering the cost of studies to determine the feasibility of constructing a new LNG plant. Exhibit 19 (Tab 3), identified costs of $1.9 million and $0.6 million, respectively for Phases I and II of the studies to be executed during 1993. The budget for Phase III of the studies, to be undertaken in 1994, was $3.7 million. Subsequently, during the Phase B rate design hearing, the amount of the 1993 deferral account request was reduced to a total of $1.5 million for Phases I and II (Exhibit 60).

The application identified the Phase I and II activities as preliminary siting and environmental studies and public consultation. The Utility's draft IRP of July 1992 identified a new LNG plant as potentially the second best supply-side option after Fraser delta underground storage with indicated gas cost savings of $242 million over 20 years on a NPV basis.

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The Commission believes it would be inappropriate to spend significant funds exploring this option before demand-side and other supply options have been documented and reviewed in BCGUL's updated IRP. **The application to establish a deferral account in the (1993) amount of $1.5 million for LNG plant feasibility studies is therefore denied at this time. The Commission is prepared to re-visit the topic at a later date, if necessary, when in possession of BCGUL's updated IRP.**

14.6 Other Integrated Resource Plan Issues

BCGUL witnesses suggested that increased market penetration of natural gas appliances would result in improvements to residential load factors, with long-run cost reduction benefits to all residential customers. The Utility was not able to produce evidence in support of this assertion. The evidence that was tabled (Exhibits 77, 103) showed that while some appliances may improve load factor, others may have a negligible effect. In the latter case, efforts to promote such appliances must first clearly demonstrate that there are long-run benefits. As noted before, this requires analysis that charges such appliances with the full long-run unit avoided costs that their market penetration incurs.

The Commission notes that it is not prepared to approve any residential or commercial load building programs without substantial avoided cost and IRP analysis indicating that such a program is in the public interest.

A second issue relating to IRP is that of utility incentives for promoting DSM or of decoupling utility profits from commodity sales. CACBC concluded in its written evidence that "an essential step in achieving societal conservation goals is to bring the company's incentives in line with the interests of society" (Exhibit 52, p. 34). It further stated that the principle component in a solution to the problem of providing appropriate incentives to the utilities is to decouple profits from sales, and that while decoupling is helpful in encouraging utilities to pursue DSM, other more direct incentives can be effective complements to decoupling (Exhibit 52, pp. 34-36).

The Commission wishes to examine the issue of incentives for DSM, including full revenue decoupling, as potential methods of removing barriers to IRP and DSM that may be sustained by inappropriate utility incentives under current regulation. Therefore, as noted in Section 15.2, regarding the Weather Stabilization Adjustment Mechanism, BCGUL is directed to come forward with a proposal for full decoupling to be filed in time to be considered at the next BCGUL revenue requirements hearing.

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14.7 Next Integrated Resource Plan Filing

From the evidence in the hearing, including the work to be done as proposed under the IRP deferral account application, it was apparent that BCGUL is planning significant effort on its IRP. A Company witness stated that late 1993 was an expeditious time for providing an avoided cost estimate by customer class, and that putting together an IRP for December was probably achievable (T. 1243).

Some Intervenors expressed concern that an overly ambitious schedule might detract from the quality of the IRP. The Barakat and Chamberlin report (Exhibit 20) by the Commission staff witness stated that the Company's workplan and schedule were "ambitious" and that its plans to complete and file its final IRP by mid-December of this year were overly optimistic. The report expressed concern that if the schedule were followed too rigidly, it might not allow adequate time to ensure quality studies. Counsel for CACBC also argued that they would prefer to see BCGUL prepare a quality IRP even if that involved taking slightly longer to prepare (T. 1126).

The Commission believes that an IRP framework is essential if it is to properly evaluate the Utility's plans and financial needs related to expansion of its facilities. Therefore, the sooner the Company can provide such an IRP framework the better. The Commission also agrees that an IRP is an on-going process and is always subject to refinement and new information. Nevertheless, the quality of an IRP must be sufficiently high that it is in fact useful for evaluating alternative means of satisfying customer demands for energy services.

Therefore, the Commission directs the Utility to file an updated draft IRP by December 31, 1993. This IRP should incorporate the best information and analysis available at the time it is prepared. Where the quality of the information or analytical techniques are not adequate to meet the Utility's standards or those suggested by the BCUC Guidelines, BCGUL should use its best estimates at the time, indicate the reasons for the deficiency and the possible range of alternative estimates, and provide a description or explanation of the steps that the Utility is undertaking to correct the deficiencies. BCGUL should also provide a schedule at that time wherein the identified problems are expected to have been overcome.

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15.0 OTHER ISSUES

15.1 Gas Cost Reconciliation Account

15.1.1 Background

The BC Gas Rate Design Phase A Decision dealt with the allocation of gas costs on the basis of coincident peak demands by the various customer classes assuming normal weather conditions. The Gas Cost Reconciliation Account ("GCRA") is proposed in the Phase B application as one mechanism which attempts to stabilize the recovery of gas costs through the Utility's gas sales rates. This mechanism is proposed to be effective January 1, 1993 and has received interim approval from the Commission to accumulate balances from that date.

15.1.2 Purpose

With the deregulation of gas purchasing, the complexity of gas cost forecasting for the Utility has increased, resulting in more frequent adjustments to rates due to changes in gas costs. Another impact experienced by the Company is the movement of gas purchase costs from largely variable commodity prices to market based prices that reward higher load factors, and thus now contain a high component of fixed costs. The GCRA is intended to capture the differences between forecast gas costs and the actual recovery of those costs from the Utility's gas sales.

The purpose of the GCRA is to ensure that the rates set for gas sales fully recover, but neither over nor under recover, the gas costs incurred by the Utility.

15.1.3 Operation

The Utility proposes that beginning January 1, 1993, the gas purchase costs incurred, excluding the cost of gas inventoried from storage, would be debited to the GCRA; the cost of gas volumes withdrawn from storage for system supply would be deducted from the inventory account at the average cost of inventory and also debited to the GCRA. Costs would be segregated as between fixed and variable components.

The GCRA would be credited with the forecast unit costs; that is, the actual units multiplied by the forecast costs. Thus, the GCRA would accumulate the variation between actual fixed costs incurred and fixed costs allocated to core customers on a unit basis, and also the variation between the actual variable unit cost and budgeted variable unit cost. Non-margin sales revenue from interruptible customers, off-system sales

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and other non-core customers would be a credit to fixed gas costs and would accumulate in the GCRA. Forecasts would be prepared annually and form the basis for the gas cost component of the sales rate for the following year. Rates for gas cost recovery would be adjusted annually, effective January 1, including any cost components required to recover a deficiency from the previous year.

Exhibit 39 shows an example of the operation of the GCRA in situations of 10 percent higher and 10 percent lower than forecast sales. Where sales are higher than forecast, a credit balance would result in the GCRA and where sales are lower, a debit balance. Similarly, where gas costs are higher than expected, a debit balance would result and where lower, a credit balance. The result of the GCRA is therefore to partially stabilize the Utility's gross margin, by stabilizing that portion of the margin which relates to gas costs. A more comprehensive stabilization of the gross margin also would require stabilization of the gas sales component through the use of a WSAM.

15.1.4 Disposition

To minimize the accumulation of significant balances in the GCRA, the Utility proposes to monitor monthly variations from forecast; the Company believes that the costs and recoveries will balance out over the year, except where WEI toll changes or weather induced changes cause significant unforecast balances to accumulate. Exhibit 78 shows the operation of the GCRA for the Lower Mainland and Inland service areas projected for the year ended December 31, 1993; the exhibit shows credit balances in the GCRA during the colder months and debits during the warmer months, netting out to a small credit balance projected at December 31, 1993.

The Company proposes to refund positive GCRA balances if they become significant. For the combined Lower Mainland and Inland service areas, it is proposed that when a credit or debit balance in the GCRA exceeds $10 million it would be refunded or charged to customers, subject to maintaining a $5 million balance in the account. The $5 million balance would operate as either a debit or credit balance which would be neither refunded nor charged to customers, but held in the account for stabilization of future gas cost changes (T. 3528-3529). For the Columbia service area, refunds or charges would be made when the GCRA balance exceeds $500,000, subject to maintaining a balance of $250,000; for the Fort Nelson service area, the balance would be refunded or charged when it reached $30,000, subject to a minimum balance of $15,000 (Exhibit 1, Tab 14, pp. 6-7).

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15.1.5 Reporting Requirements

To help monitor balances accumulating in the GCRA, the Company would file quarterly statements with the Commission. An annual reconciliation of the year-end over or under recovery of gas costs would be filed with the Commission by February 15 of each year.

15.1.6 Intervenor Response

In general, the Intervenors appeared to support the GCRA as a mechanism to stabilize the Utility's recovery of gas costs. There were certain concerns raised, however, as to the specifics of the proposal.

Representatives from CIGMA expressed concern that the GCRA may distort transportation rates under buy-sell arrangements in relation to unbundled transportation service; the Commission agrees with the Company's argument that the GCRA would not distort transportation rates as it is a credit or debit to the gas component of the rates, not the transportation margin (T. 3896).

CIGMA representatives were also concerned that the GCRA would mask price signals if the account is cleared only once per year and then limited to a minimum balance, and further, that delays in clearing the account would reduce the chances of refunding money to the customers from whom it was collected. CIGMA believes that the GCRA would be an impediment to a competitive market (T. 3699). The Commission accepts the Utility's argument that the minimum balances proposed for the GCRA are not of an amount that would be significant enough to suppress market signals when compared to the total gas costs of the Utility. Further, the Commission believes that while it would ultimately be more equitable to refund balances to the customers from whom they were collected, it is not possible to implement an effective GCRA that would track refunds to this level of detail; the Commission also accepts that the proposed GCRA ideally will tend to balance out over a year and thus would not operate efficiently if the balance were to be cleared more frequently.

Although a Company witness stated that adjustments more frequent than once per year would be unlikely (T. 1856), BCGUL, in its application, proposed mid-year adjustments when necessary to clear significant unforecast balances in the GCRA (Exhibit 1, Tab 14, p. 6). The Commission notes that the term 'significant' is imprecise, and that the quarterly variance reports will provide the actual GCRA balance so that should a mid-year adjustment appear warranted, it may be brought to the attention of BCGUL.

The issue of interest accruing on the GCRA balance was also raised. The Commission accepts the Utility's argument that the GCRA is a component of the rate base, as a reduction where the GCRA is in a

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credit balance or an increase where it is a debit balance, and so no interest should accrue. Customers would benefit or be charged as rates are adjusted through the rate base.

Commission counsel questioned BCGUL witnesses on whether the existence of the GCRA would reduce BCGUL's incentive to manage its gas supply to minimize its gas costs. The BCGUL witnesses offered several reasons why the Company would continue to attempt to minimize its gas supply costs even with the GCRA in place: corporate pride, customer reaction to rate increases, and continued overview of gas supply contracts and the gas supply portfolio by the Commission. BCGUL counsel, in argument (T. 3530) also noted that competitive gas markets are also factors that help to minimize gas supply costs. The Commission accepts that these incentives exist.

15.1.7 Commission Decision

The Commission approves the BCGUL application for a Gas Cost Reconciliation Account, as summarized above, to be effective January 1, 1993.

BCGUL agreed during the hearing that the GCRA mechanism involves some transfer of risk from shareholders to ratepayers (T. 1879) and that the attendant reduction of volatility of BCGUL earnings will be looked upon favourably by investment analysts (T. 1867-1868). The Commission may want to consider this reduction in risk in the next BCGUL revenue requirements hearing.

The Commission notes that one of the incentives mentioned by BCGUL witnesses is the continued overview of its gas supply contracts and portfolio by the Commission. **In order for this overview to be effective, the Commission directs BCGUL to provide, in the quarterly status reports proposed by the Applicant (Exhibit 1, Tab 14, p. 7), a detailed breakdown of the variances and an explanation of each detailed variance that makes up the GCRA balance.**

Finally in the discussion of the GCRA (T. 1621-1623, Exhibit 39), BCGUL illustrated how the GCRA alone provided some earnings stability, but less than if used in conjunction with the WSAM proposed earlier and subsequently withdrawn by BCGUL. As noted in the following section, the Commission expects BCGUL to continue to examine the WSAM, as well as other, perhaps more comprehensive decoupling mechanisms.

15.2 Weather Stabilization Adjustment Mechanism

BCGUL, in its November 23, 1992 Revenue Requirements Application, applied for approval of a Weather Stabilization Adjustment Mechanism ("WSAM") to mitigate the impact of abnormal weather on

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the revenues of the Utility. Under the proposed mechanism, BCGUL would place in a WSAM deferral account any over or under recovery of the commodity margin related to temperature-sensitive consumption due to weather that was more than $\pm$ 5°C colder or warmer than normal in any month. The WSAM would apply only to residential and commercial customers during the months of October to May.

By letter on May 13, 1993, BCGUL requested that it be allowed to withdraw its Revenue Requirements Application including the WSAM. The Commission approved the request by Order No. G-33-93, and directed BCGUL to propose the implementation of a weather stabilization mechanism - either a modified WSAM or other mechanism - as part of the Phase B Rate Design Hearing.

Subsequently, in a letter dated June 9, 1993 (Exhibit 16) and in a motion during the hearing (T. 242-245), BCGUL proposed that decoupling and WSAM be withdrawn as issues in the Rate Design Hearing because the Company was still actively considering the long-term implications of decoupling and WSAM. The proposal included a commitment by the Company to proceed with the development of a BCGUL position on decoupling and/or WSAM, and to report monthly on its progress. The process would culminate in a one-day workshop in early autumn at which BCGUL would present its position on decoupling and/or WSAM, and seek consensus of the interested parties in such a mechanism. If consensus was not reached, the issue would be brought to the Commission and possibly proceed to some form of hearing.

No intervenors in the Rate Design Hearing expressed an objection to the BCGUL motion, although some intervenors expressed the desire to see the issue dealt with quickly. The Commission accepted the BCGUL application to have decoupling and WSAM withdrawn, although it also decided that Intervenors would be permitted to cross-examine on the general concepts of weather stabilization and decoupling during the Phase B hearing. In accepting the BCGUL motion during the hearing, the Commission made the following comments:

> "...the Commission notes that the August 1992 Decision encouraged BC Gas to come forward at the earliest possible occasion with the weather stabilization mechanism. Almost a year has passed and the company still does not have a proposal that is ready to present to the Commission and the public. The Commission also notes that over this time period new concerns have emerged. Interest has grown at the Commission and in other regulatory jurisdictions in a range of mechanisms that remove any impediments to utilities pursuing the goals of conservation and efficient use of energy.
>
> In this context a weather stabilization mechanism is but one of several mechanisms of what can be referred to as decoupling of sales revenues from profits." (T. 716, 717)

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Having accepted the BCGUL motion during the hearing, the Commission now directs the Company, at a minimum, to implement a WSAM on January 1, 1994. Furthermore, as noted in Section 14.6, the Utility is also directed to come forward with a broader proposal for full decoupling to be filed in time for consideration at its next revenue requirements hearing.

15.3 Management Information System

Due to the withdrawal of the BCGUL 1993 revenue requirements application, the review of the Management Information System at BCGUL was deferred to the Phase B Rate Design hearing by Order No. G-33-93. While Deloitte & Touche, consultant for Commission staff, has been reviewing the progress of the Customer Information System ("CIS"), decisions by the Company on key aspects such as contractor selection have yet to be determined and are most likely to occur in November, 1993 or later.

The Commission during the hearing accepted BCGUL's request to defer the overall review of the Management Information System until the next rate case. Nevertheless, the Commission may, depending on the review by Deloitte & Touche, and subsequent Intervenor submissions, order a separate hearing later in 1993 to deal with specific issues and decisions relating to the CIS (T. 3463-3467).

DATED at the City of Vancouver, in the Province of British Columbia this day of October, 1993.

Dr. M.K. Jaccard
Chairperson

F.C. Leighton
Commissioner

E.C. Sleath
Commissioner

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Appendix D

BC GAS 1993 RATE DESIGN HEARING PHASE B

APPENDIX 1
INTEGRATED RESOURCE PLAN AND DEMAND-SIDE MANAGEMENT DEFERRAL ACCOUNTS

AUGUST 13, 1993

1.0 INTRODUCTION

BC Gas Utility Ltd. ("BC Gas", "the Utility", "the Company" or "the Applicant") is the gas distribution utility subsidiary of BC Gas Inc. BC Gas provides gas distribution services to approximately 635,000 residential, commercial and industrial customers in over 100 communities throughout British Columbia.

The Phase B Rate Design Hearing was held under Order No. G-38-93 and examined issues related to Rate Design, Integrated Resource Planning ("IRP") and Demand-Side Management ("DSM") as well as corporate reorganization and consolidation. The Hearing was held in Kamloops, Cranbrook and Vancouver.

In final argument, counsel for the Applicant requested an early decision on the request for several deferral accounts which BC Gas had requested in its April 30, 1993 application for Deferral Accounts related to its IRP (Exhibit 19, "April 30 IRP" or "Workplan"). Therefore, this Appendix of the Decision specifically deals with those IRP and DSM related deferral accounts. This Appendix of the Decision also deals with BC Gas Applications for deferral accounts related to certain Commercial Marketing programs which had been applied for prior to the April 30 IRP, and had not been previously decided upon by the British Columbia Utilities Commission ("BCUC", "the Commission"). The April 30 IRP workplan also requested approval of expenditures for studies concerning the feasibility of a new Liquified Natural Gas ("LNG") Plant. These expenditures will be the subject of a later part of this Decision.

A summary of all IRP Deferral Accounts requested, including those related to Commercial marketing programs and a new LNG Plant, was filed as part of Exhibit 60 during the hearing. This Appendix therefore will examine and decide upon all of the requested deferral accounts shown in that summary (attached for convenience as Attachment 1 to this Appendix), with the exception of those related to new LNG Plant feasibility studies. Thus the Commission, in this portion of the Decision, will decide on an amount requested of $2,072,500 in IRP deferral accounts and an additional $313,005 requested for deferral accounts related to other programs.

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2.0 IRP BACKGROUND

Integrated Resource Planning is now well established for electric utilities, and is becoming more established for gas utilities throughout North America as well. In July 1992, BC Gas filed its draft IRP; this was described by BC Gas as a first attempt at IRP and, in the covering letter, BC Gas noted its intention to develop a revised IRP 'over the next few months'.

In February 1993, the Commission issued its Integrated Resource Planning Guidelines ("the Guidelines") which aimed to provide guidance for utilities in their processes of developing IRPs. The Guidelines stated that the IRP process also provides a framework that helps to focus public hearings on utility rates and energy project applications. Some of that focus on rates from the perspective of IRP has been in evidence in this hearing.

On February 25, 1993, subsequent to issuance of the Guidelines, the Commission held a workshop on the barriers to DSM and IRP. The purpose of that workshop was to discuss the financial and regulatory barriers to DSM and IRP, and methods or changes that might potentially be used to overcome those barriers. One issue raised in the workshop was the concern over the risk of non-recovery of IRP and DSM expenditures. In general, the Commission is of the opinion that utilities should be neither penalized nor rewarded for engaging in IRP or DSM or both, and mechanisms such as deferral accounts that minimize the risk of non-recovery of costs benefit both utilities and ratepayers. On the other hand, the Commission is also of the view that it is the responsibility of the utility to ensure and demonstrate that its IRP and DSM expenditures are well thought out and not extravagant in their approach to achieving their IRP and DSM goals. In other words the utilities must be willing and able to demonstrate prudency and cost-effectiveness in their IRP and DSM expenditures.

On March 4, 1993, the BCUC sent a letter to utilities, including BC Gas, stating that work plans for completion of their IRPs should be provided to the Commission by April 16, 1993, and that draft IRPs should be submitted by December 31, 1993, unless the Commission directed specific utilities to do otherwise. BC Gas, which had filed a draft "Least Cost Integrated Resource Plan" in July 1992 was specifically directed to file a revised draft IRP by April 30, 1993. In response, BC Gas filed its April 30 IRP document (Exhibit 19), which included its workplan and deferral account applications.

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3.0 IRP DEFERRAL ACCOUNTS

As noted above, the amounts applied for with respect to IRP Deferral accounts are summarized in Attachment 1. The individual IRP and DSM proposals for which deferral accounting treatment is requested are described in Exhibit 19. The proposals were also discussed in Information Responses from the Applicant and during the hearing with the IRP Panel (T. 1267 to T. 1287). In Exhibit 4, Tab B49, BC Gas stated that BC Gas intended to file a revised IRP regardless of whether or not it received approval for the deferral accounts requested, but that the deferral accounts were necessary to assure "...the quality of the enhancements to the IRP, in accordance with IRP guidelines and BCUC suggestions....".

The Company's deferral account requests are discussed below in the order in which they appear in Attachment 1 to this Decision, with the exception of the DSM expenditures which will be discussed separately following this section, and the LNG feasibility studies Phases I and II which will be considered in the complete Decision.

3.1 End Use Modelling

The Company has budgeted $45,500 for end use modelling. In an Information Response (Exhibit 4, Tab B56), BC Gas described the company's discussions and evaluations of end-use models. The answer indicated that the Company had not come to a decision on which end use model or models to use in the residential and commercial sectors, although its estimate of costs in Exhibit 19 indicated that the budget of $45,500 was based on the purchase of off-the-shelf models such as the REEPS and COMMEND models, and on having them modified to meet the specific requirements of BC Gas.

When questioned during the hearing about whether the budget remained appropriate given that the evaluation of end-use models was still in progress, the BC Gas witness stated that he was satisfied that the budget was appropriate "for the time period which was envisaged which was for 1993" (T. 1273).

Commission staff engaged an independent consulting firm, Barakat & Chamberlin, Inc., to review BC Gas' rate design cost studies as well as the information presented in Exhibit 19. The Barakat & Chamberlin report (Exhibit 20) noted that BC Gas had budgeted $9,000 of the total budget for customization of the off-the shelf end-use models, and stated that "Our consulting experience tells us that $9,000 is a very small amount in this regard".

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Commission's Views

The Commission shares Barakat & Chamberlin's view that the portion of the budget for adapting off-the-shelf end use models to BC Gas' specific needs seems insufficient to accomplish the task, which is to integrate functional end use models into the Company's planning processes.

3.2 Multi-Attribute Analysis

Exhibit 19 (Tab 6) states that the Company engaged Constable Associates Consulting Inc. to review multi-attribute analysis in the context of IRP and consult with key stakeholders to develop a list and weighting procedure for key attributes to be used in comparing resources as suggested in the Commission's Guidelines. BC Gas applied for a deferral account of $20,000 for this task. The Commission is satisfied that this expenditure is appropriate.

3.3 Demand-Side Management

In Exhibit 19 (Tab 3), BC Gas applied for a total of $1,078,000 for DSM expenditures. These proposed expenses were detailed in Exhibit 19, Tab 7 - the DSM Development Plan. The amount was revised to a total of $1,105,000 in the final summary in Exhibit 60 due to an addition error in one of the items in the total, as was pointed out during the hearing (T. 1276).

Commission's Views

In general, the Commission is encouraged by BC Gas' DSM efforts although clearly there are some areas where additional information and research is required to better focus efforts to maximize benefits to the utility and its customers. The Commission remains uneasy about the lack of empirical evidence, in the form of studies or experience from other utilities, that BC Gas was able to bring forward in support of its DSM programs.

For instance, in its Application (Exhibit 1, Tab 6, page 6), BC Gas makes the statement that "The most effective tools for environmental protection are adequate public education and fostering an ethic of efficient energy use...." The company reiterates this statement in Exhibit 4, Tab B26. However, in Exhibit 4, Tab B64, the Company states that "At present BC Gas does not have any studies or evidence that indicate that general education programs have any impact on customer energy use behaviour...." Further, one BC Gas witness stated that "Now, with empirical data if the reference there is specific reports that show

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that public education with regard to energy conservation and such matters is the best. I don't have specific reports". The witness continues, saying that the Company is relying on the experience of managers and employees dealing with customers (T. 1662).

Similarly, with respect to its proposed industrial energy audit program, BC Gas states that "Although, BC Gas does not have specific studies which show the impact of an Energy Audit Program on customer energy use behaviour, because of the unique needs and criteria of industrial customers, the effectiveness of an audit program would vary in different circumstances" (Exhibit 4, Tab B65).

In this regard, the Commission would caution BC Gas against relying too heavily on assumptions based on intuition or on inferences from employees' experience when designing DSM programs. The Commission is concerned that DSM budget allocations based on these unsystematic techniques could be less than optimal. Among other tools, BC Gas should utilize the systematic, hindsight evaluations of the DSM experience at other utilities, whenever possible. Also, any audit programs, customer surveys and customer monitoring should be directly linked to end use modelling efforts, so that the information from these efforts provide crucial data for the end use models.

The Commission is aware from the comments of a BC Gas witness (T. 1220) that BC Gas is attempting to gather the additional information necessary to develop and refine its DSM programs through some of its DSM research proposals. The Commission encourages the Company's work in this area. Nevertheless, at the present time, the overall package of DSM proposals appears somewhat unfocused.

A second concern of the Commission is the lack of an estimate of avoided cost, based on all of the relevant costs, which would enable it to determine whether or not a proposed DSM measure is economically beneficial. BC Gas agreed that it would be difficult for the Commission to make decisions about various DSM programs without an estimate of long run avoided costs, although BC Gas witnesses enumerated several difficulties or concerns about the Company's ability to provide such an estimate (T. 1238-1245).

3.4 "ROM" Model Development

As noted in Exhibit 19 (Tab 8), BC Gas currently employs a Gas Supply Optimization Model ("GSOM") for selecting its optimal mix of resources. The GSOM model uses a general linear programming formulation. The Company, in using the GSOM to evaluate alternative resource stacks against a range of forecasts in preparing its June 1992 Draft Least Cost Integrated Resource Plan (1992 LCIRP), identified several shortcomings of the GSOM. The $165,000 budgeted for the ROM model is intended to modify

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the GSOM model to accommodate IRP requirements. The BC Gas witness stated that he was satisfied that the $165,000 budget was adequate (T. 1280).

During the hearing, the Company's witnesses indicated that alternative models had been looked at, but that BC Gas had decided to modify the GSOM for cost reasons and because planning staff were already familiar with the GSOM (T. 1280-T. 1282). However, BC Gas did not specify what other types of models had been examined. In response to a Commission Staff Information Request (Exhibit 4, Tab B67), BC Gas had stated that it was unaware of any off-the-shelf models similar to the ROM although it had recently become aware of a potential alternative model and had requested further information. The Company also stated that "Experience rather than evidence per se" has led to the conclusion that building on existing models is a quicker and cheaper way to integrate its resource optimization (Exhibit 4, Tab B67).

Commission's Views

BC Gas has offered little or no evidence of the range of alternative models assessed or on the suitability of a general linear programming model for incorporating demand-side options into the resource stack or for evaluating resources into a multi-attribute IRP framework. The Commission has serious doubts about the suitability of the proposed ROM to accomplish its intended task. It is the opinion of the Commission that BC Gas should examine a wide range of alternatives to integrate supply and demand analysis, in a way which would tie together the results of the GSOM and BC Gas' intended end use modelling efforts to provide the critical information necessary for development of an IRP.

3.5 DSM Benefit/Cost Tests

BC Gas budgeted $17,000 for RCG/Hagler to develop a series of cost/benefit tests for analyzing the costs and benefits of DSM programs. Based on the evidence presented (Exhibit 3, Tab 8, p. 3) the Commission understands that these tests are complete and that the $17,000 represents actual costs.

3.6 IRP Public Information and Consultation

BC Gas has proposed several public consultation processes: a strategy for IRP public consultation (Exhibit 19, Tab 10); the design and possible establishment of a public involvement process to address greenhouse stabilization policy as it affects the B.C. natural gas industry (Exhibit 19, Tab 11); and a two

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or three phase public involvement program to determine the feasibility and siting of a potential new LNG plant (Exhibit 19, Tab 3).

In response to a staff information request, the Company in Exhibit 4, Tab B53 stated that the LNG feasibility study is very specific, whereas the IRP public consultation process is more general. BC Gas also indicated that it would integrate its public consultation efforts where synergies exist. The Barakat and Chamberlin report (Exhibit 20) complimented the Company on its strategy for public consultation and noted that it appeared to be a "sincere effort to attract meaningful input from the general public and traditional intervenor groups".

BC Gas has budgeted $495,000 for the IRP public involvement and consultation process (T. 1251, Exhibit 60).

Commission's Views

While pleased to see this level of commitment from the Applicant to public participation, the Commission is concerned about the significant amount of $495,000 requested for the strategy for IRP public involvement - excluding any additional costs attributable to the LNG feasibility studies or the greenhouse gas policy public involvement process.

The Commission is concerned that BC Gas' focus on several public processes at the same time may dilute the Company's efforts, and decrease the success of all of them, while also straining the ability of the interested public to participate in several simultaneous gas-related collaboratives. The Commission is of the view that synergies will be most apparent where they have been designed into the process, and such synergies are not apparent in the various BC Gas public involvement processes.

3.7 Greenhouse Gas Study

BC Gas and Westcoast Energy Inc. ("Westcoast") agreed to "jointly support the design and possible establishment of a multi-party public involvement process to address the issue of greenhouse gas stabilization policy as it affects the natural gas industry in B.C." (Exhibit 19, Tab 11). In response to a Commission staff Information Request (Exhibit 4, Tab B68) BC Gas indicated that there are several other public processes taking place. However, the Company also stated that the proposed public process would be unique in that it would be industry led, it would focus specifically on the B.C. natural gas industry, and it would attempt to identify practical measures through which the natural gas sector could contribute to the stabilization of greenhouse gas emissions.

BC Gas has budgeted $20,000 for its portion of the initial design phase of the potential greenhouse gas public involvement process.

Commission's Views

Greenhouse gas emissions are a serious concern, and the Commission appreciates BC Gas' intention to address this issue. However, in spite of the unique aspects of the proposal, there does appear to be the potential for significant overlap between the BC Gas/Westcoast public process and other processes attempting to deal with the issue of greenhouse gas emissions. More fundamentally, there is also the potential for overlap with BC Gas' other IRP related public process, as well as the work of the B.C. Energy Council and the B.C. Roundtable on the Economy and the Environment. As noted in the previous section, the Commission is concerned that several overlapping public processes may reduce the efficiency and success of them all, while straining the ability of the interested public to participate. In the Commission's view, there is little need for starting yet another collaborative in this area, at least until it has been identified as a priority by those stakeholders involved in the IRP collaborative.

An additional concern is the pervasive character of the greenhouse gas issue. The Commission is of the view that the focus of public involvement and education should be broad based, looking at all energy forms and even beyond the energy sphere.

3.8 Quantification and Monitoring of Externalities

In its June 1992 LCIRP, BC Gas included a study (Appendix E) entitled "Evaluation of External Costs Associated with Natural Gas Use" by G.E. Bridges and Associates Inc. Exhibit 19 (Tab 3) included a deferral amount for externalities quantification and monitoring of $10,000, an amount noted as being one half of the G.E. Bridges and Associates expenditures to date. These expenditures are for work that is now complete, and the Commission accepts them valid.

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3.9 End Use Survey

BC Gas identified $160,000 in Exhibit 3, Tab 7 for end use surveys for residential and commercial customers. As described by BC Gas witnesses (T. 1271), the customers surveys will form part of a monitoring study. The main purpose of the monitoring study is to collect data and provide analysis for input into end use forecast models, input into DSM program design, and DSM program evaluation (Exhibit 4, Tab B54). From the evidence presented by the Applicant, these efforts, and the associated expenditures are necessary for its IRP to proceed expeditiously.

3.10 Monitoring Study Strategy Document

BC Gas, in Exhibit 3, Tab 7, indicated that it wished to add $35,000 to the deferral account application for outside consultants in order to accelerate development of the Monitoring Study Strategic Document. The Monitoring Study Strategic Document will include objectives and deliverables of the monitoring study, discussion of research methods for the monitoring study, sampling strategies, time frames and a budget for the monitoring study. BC Gas indicated that the additional $35,000 was to accelerate development of the Monitoring Study Strategic Document (Exhibit 4, Tab B54).

The Commission, with consideration of the above comments, approves the BC Gas Application for deferral of the IRP accounts, as summarized in Exhibit 60, with the exception of the LNG deferral accounts and subject to the following comments and adjustments:

The sum of the deferral accounts budgeted for end use modelling and ROM development appears to be, in total, a reasonable amount. However, BC Gas has not shown that the amount allocated for end use model development is sufficient to complete the models to a functional degree. Conversely, BC Gas has not demonstrated that the ROM development is the most cost effective means of developing a model that will adequately integrate supply and demand resources in an IRP context. BC Gas was able to offer little evidence that it had considered alternatives other than building upon its existing GSOM model, or that the chosen approach was the most cost-effective. Therefore, the Commission would support a shifting of budget between these two items.

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The DSM deferral accounts are approved to a total of $1,000,000. The Commission is of the view that there are sufficient opportunities for further economies and synergies between programs, and that approximately ten percent of the requested amount can be removed from the budget without undue harm to the overall objectives. The Commission is especially concerned that large funds could be allocated to industry audits without first ensuring that such audits are an effective means of encouraging cost-effective conservation. A similar concern holds for education programs.

The Commission noted the supportive comments made by the independent consultant hired by Commission staff regarding the Company's public participation plans. Moreover, the Commission agrees with BC Gas that there is no need for a collaborative to oversee studies of technical and economic DSM potential (T. 1264-T. 1266). However, it is the Commission's opinion that where BC Gas has proposed several public consultation processes, only one well focused collaborative is necessary. In the Commission's view that collaborative should begin as soon as possible and take as its initial focus the questions of the avoided cost of gas, and scenarios of achievable DSM potential. Given that this should result in significant economies, the total public participation budget is reduced to $395,000. In this same regard, the Commission approves the $20,000 expenditure for the design of a greenhouse gas study, but is not convinced of the value at this time of a further collaborative, when so many other bodies are studying the same issue. Thus further expenditures, beyond the initial $20,000 approved here, will be at risk.

Finally in this area, the Commission experienced considerable frustration in the hearing at its inability to determine the long run avoided cost of gas to BC Gas customers under alternative supply and demand scenarios, with the calculations and cost assumptions clearly laid out. Many, if not all of the items applied for in this application are of little use without the long run avoided cost information necessary to evaluate demand-side versus supply side resources. Therefore it is important that the long run avoided cost be estimated as soon as possible, preferably by an independent consultant who would be credible to all parties in an IRP collaborative as noted above. This study should be undertaken immediately, and the results must precede the next rate application.

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While the exact budget allocation for estimating avoided costs should be determined by BC Gas, approximately $200,000 could be made available from the deductions suggested above from the DSM and Public Participation areas.

Finally, the Commission is concerned about the Utility's DSM focus being weighted heavily toward education programs, and has not been convinced of their effectiveness. The Commission will review the DSM programs and budget allocations very carefully to ensure that the Company's DSM efforts are as cost-effective as possible. The Commission is aware of a number of generic program categories other than education programs that may be useful in some circumstances. One example is utility loans recovered through bill savings. Another example is grants.

The Commission will also be reviewing the cost-effectiveness of DSM programs through their benefits to customers and society, as demonstrated through an IRP process that appropriately incorporates the long run avoided cost of supply resources.

4.0 DEFERRAL ACCOUNTS APPLIED FOR RELATED TO OTHER PROGRAMS

Prior to the filing of Exhibit 19 on April 30, 1993, BC Gas had applied for other deferral accounts related to certain marketing programs. The Commission had not responded to these previously for several reasons: the postponement of the Phase B Rate Design Hearing until the present time; the absence of avoided cost tests indicating the benefits of the proposed programs, without which the Commission could not adequately assess the programs; potential overlap of programs with those requested in the April 30 IRP and Deferral Account filing; and the withdrawal of the BC Gas Revenue Requirements Application.

As shown in Appendix 1, the Applicant has budgeted $313,005 for these programs in 1993. Of that amount, BC Gas had spent $88,185 in the first quarter of this year. The Company had also spent $104, 135 to the end of 1992 (Exhibit 4, Tab B53).

4.1 Commercial Water Heater and Commercial Booster Water Heater Programs

To review briefly, on March 2, 1992 BC Gas applied for cost deferral for two DSM programs: fuel substitution pilots for commercial water heating and commercial booster water heating. In its Revenue Requirements Decision of August 5, 1992 (p. 55), the Commission stated that it would examine the programs further in the Phase B Rate Design hearing. In the interim, the Commission allowed the deferral

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of costs for the fuel substitution pilots, but noted that cost recovery could still be denied following the Rate Design hearing. Examination of the programs in a subsequent Rate Design hearing did not occur.

4.2 Multi-Family Space Heating and Commercial Fuel Substitution Programs

On December 31, 1992 BC Gas applied for deferral account treatment of two additional commercial DSM projects that had been identified in its Revenue Requirement Application, but had not previously been included in an application for a deferral account. These programs were a Multi-family Space Heating Incentive program and a Commercial Fuel Substitution Program.

Commission Views

The Commission believes that DSM programs should in future be justified on the basis of the appropriate cost/benefit tests using accepted long run avoided costs. It is the opinion of this Commission that in general the benefits of load building and fuel substitution programs have not been sufficiently justified to warrant their long term continuation in the absence of such tests.

While the Commission will approve the expenditures on the above programs as requested to December 31, 1993, it will be reluctant to approve any such expenditures beyond that date without further demonstration of their benefits in the manner suggested above. If the Company wishes to continue these programs beyond 1993, it must adequately justify the benefits accruing from the programs in the context of an IRP based on long run avoided costs. Otherwise, funds that the Company spends on such programs will be at risk beyond the end of this year.

ABBREVIATIONS APPENDIX F
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A. Organizations

"BCUC", "the Commission"	The British Columbia Utilites Commission
"BCGUL", "the Utility", "the Company"	BC Gas Utility Ltd.
"B.C. Hydro"	British Columbia Hydro and Power Authority
"CACBC"	The Consumers' Association of Canada (B.C. Branch) et al
"CIGMA"	The Canadian Industrial Gas Marketing Association
"Crestbrook"	Crestbrook Forest Industries Ltd.
"ENGM"	Eastern Natural Gas Management (B.C.) Ltd.
"Fording"	Fording Coal Ltd.
"Line Creek"	Line Creek Resources Ltd.
"Westcoast"	Westcoast Energy Inc.

B. Terms

"CIS"	Customer Information System
"DCF"	Discounted Cash Flow
"DSM"	Demand-Side Management
"FDC"	Fully Distributed Cost-of-Service
"GCRA"	Gas Cost Reconciliation Account
"GSEF"	Gas System Extension Fund
"IRP"	Integrated Resource Plan
"LDC"	Local Distribution Company
"LNG"	Liquified Natural Gas
"LRIC"	Long-Run Incremental Cost
"NGV"	Natural Gas for Vehicles
"NPV"	Net Present Value
"UOR"	Unauthorized Overrun
"WSAM"	Weather Stabilization Adjustment Mechanism

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