EXECUTIVE SUMMARY

The Application

This Phase 3 Decision completes the public review and determinations related to the BC Gas 1994/95 Revenue Requirement Application. The public hearing of Phase 3 issues took place between June 6 and 17, 1994 with written argument completed on July 11, 1994.

The Phase 3 hearing focussed primarily on BC Gas' first formal Integrated Resource Plan ("IRP") and on related Demand-Side Management ("DSM") issues. The hearing also considered revisions to the Main Extension policy which would be compatible with IRP objectives.

Integrated Resource Plan

BC Gas' IRP presentation covered three general areas. IRP objectives and their selection through the multi-attribute trade-off analysis ("MATA") process; long-run gas demand forecasts, long-run avoided costs and gas supply options; and integration of the DSM resource into supply portfolio options.

Specific Commission approval of BC Gas' IRP is not required by the Commission's Guidelines; however, since plan development is an evolving process, the Commission has provided considerable comment so that its views may be taken into account in ongoing planning and future IRP submissions. The Commission commends BC Gas for its actions in developing its first IRP within strict guidelines and timeframes required by the Commission.

Plan Objectives

The Commission accepts the fundamental objectives set out by BC Gas in its IRP (Exhibit 28). At the same time it reminds BC Gas of the need to ensure that the Utility's Corporate Plan is not inconsistent with its IRP objectives.

The MATA Process and Public Participation in Plan Development

BC Gas' use of a stakeholder collaborative and its application of the MATA process in developing the Company's IRP was the subject of considerable discussion during the hearing. The Commission recognizes BC Gas' efforts to incorporate the views of its stakeholders but requires the Utility to make further efforts as stakeholder consultation continues, to respond to the concerns of intervenors expressed at the hearing.

Long-Term Gas Demand Forecasts

While the Commission accepts BC Gas' current forecast as satisfactory for planning purposes, it expresses concern as to the flexibility of the Utility's end-use gas demand model currently used for forecasting residential and commercial demand. In particular the Utility is required to explore alternative new end-use models, particularly those capable of simulating the impact of alternative DSM strategies and potential conservation opportunities.

Long-Run Avoided Costs ("LRAC")

BC Gas provided, through a consultant study based on earlier Commission guidelines, an updated estimate of the Utility's avoided costs. The study used both "Customer Incremental Avoided Cost ("CIAC") and Total Incremental Avoided Cost ("TIAC") as measures, and presented argument as to the appropriate use of each value.

The Commission accepts the LRAC study as providing a good first approximation of the Utility's avoided costs and provides suggestions as to the appropriate use of the CIAC and TIAC measures in ongoing integrated resource planning.

Supply-Side Planning

BC Gas identified ten individual supply-side options for meeting an annual gas demand which is forecast to grow by as much as 40 percent over the next 20-year period. Peak day demand is projected to grow by as much as 59 percent over the same time frame.

The supply options were grouped into a number of potential portfolios and each portfolio was tested against a base case scenario. The result of these studies showed that Liquefied Natural Gas ("LNG") storage facilities near each of the Lower Mainland and Interior load concentrations would be potentially beneficial means to minimize future gas purchase costs.

LNG Plant Studies

In view of the importance of LNG storage in future gas supply planning, BC Gas requested permission to proceed with plant planning and to establish a related deferral account.

A four-step planning process, to cost $6.57 million in total, was proposed. BC Gas proposed to seek Commission approval to proceed at the completion of each stage of the study.

The Commission approves only the expenditures of $320,000 for the first stage LNG plant study initially and outlines specific study reporting procedures.

Proposed Integrated Resource Portfolio

By combining the best gas supply portfolio options with a range of demand-side planning measures, BC Gas produced an integrated resource plan which it proposed to pursue to meet forecast future gas needs.

The resulting "Proposed Resource Portfolio", with the exception of one item, was supported by a majority of the IRP stakeholder collaborative group.

IRP Deferral Accounts

BC Gas filed a separate application (Exhibit 33) for deferral account treatment of its 1994 and 1995 expenditures on integrated resource planning. The cost of these items is closely related to approved Operation and Maintenance ("O&M") costs which form the basis of the Phase 1 Decision on Revenue Requirements. This relationship is detailed in section 2.6 of the Phase 3 Decision. The specific IRP items on which BC Gas' deferral account request was based are also outlined in section 2.6, as is the specific Decision of the Commission on each item.

In summary, Commission approval is given for the establishment of IRP-related deferral accounts in amounts not to exceed of $448,000 in 1994 and $390,000 in 1995. The circumstances of this year's IRP development and review led to the need for deferred account treatment of various IRP initiatives. However, the Commission expects that the 1996 Revenue Requirement Application will incorporate IRP initiatives into the base O&M and capital budgets of the Utility.

Demand-Side Management

BC Gas proposed a series of DSM programs as part of its proposed resource portfolio. The proposed DSM programs contain both conservation/peak shaving and valley filling/load building components.

Conservation and Peak Shaving

A total of nine conservation/peak shaving programs were projected by BC Gas to reduce forecast growth in gas sales some 24 percent below the level which would otherwise occur over the forecast period. At the same time, peak-day gas volumes were projected to decline some 55 percent below the unrestrained level.

The Commission commends BC Gas on its identification of these conservation programs. In general, the Commission proposes a cautious approach to program implementation with further pilot level or small scale studies, in some cases, before the Utility embarks on significant incentive programs.

The Commission has particular concerns about the ability of the efficient furnace program to perform as forecast and expects BC Gas to continue to work closely with the Ministry of Energy, Mines and Petroleum Resources ("MEMPR") on energy efficiency standards regulations as a possible means to achieve a comparable conservation objective.

Off-Electricity Fuel Substitution

In evaluating the benefits of off-electricity (fuel switching) load building programs, BC Gas assumed that the Burrard Thermal generating station and purchases of Alberta thermally generated energy were the most likely marginal sources of British Columbia Hydro and Power Authority ("B.C. Hydro") energy in the short term. This assumption significantly impacts the measurement of external environmental costs associated with off-electricity fuel switching. During the hearing this proved a contentious issue with the BC Energy Coalition, one of the most active intervenors, which charged BC Gas with ignoring emerging government policies related to the stabilization of greenhouse gases.

The Commission recommends that BC Gas re-examine the range of possible B.C. Hydro and West Kootenay Power Ltd. marginal energy resources and reconsider the net environmental impacts which could result from off-electric fuel substitution.

The Commission concludes that the evidence advanced in the current IRP, with regard to electricity fuel substitution programs, is insufficient to justify BC Gas embarking on these programs at this time.

Monitoring and Evaluation

In pursuit of the proposed DSM programs, BC Gas proposed a number of monitoring and evaluation activities. These include surveys, engineering projections, billing analyses and total building/dwelling metering. An important purpose of the monitoring and evaluation program will be to isolate net DSM program impacts from naturally occurring change. The Commission reiterates its view that the selection and development of an appropriate gas end-use model should be an essential adjunct to the Utility's monitoring and evaluation program.

In addition, the Commission reminds BC Gas that the development of DSM incentive mechanisms will require the parallel initiation of DSM-specific accounting policies.

DSM Programs and Related Deferral Accounts

BC Gas proposed a total of 24 separate DSM programs, each with 1994 and 1995 budget requirements, as set out in Exhibit 33. These programs resulted in the request for deferral accounts totalling $1,745,967 in 1994 and $9,947,406 in 1995. Seven of the proposed programs are applicable to the residential market sector; eight to the commercial sector; four to the industrial sector and four to the Natural Gas for Vehicles market sector. One proposal is non-market specific.

Each of the programs is discussed in detail in Chapter 4.0. A summary of the DSM programs, the associated Action Plan budget and the Commission's views on each program appears in Table 4-1 (pp. 46-54). The Commission's cautious approach to program development, requiring step-by-step evaluation is reflected in its deferral account treatment.

In summary, the Commission approves deferral treatment for programs whose budgetted Action Plan costs total approximately $600,000 in 1994 and $4,600,000 in 1995. The exact deferral amounts allowed must be recalculated by BC Gas to account for differences between the Action Plan Budget and the deferral account requests due to incremental labour or treatment of funds arising out of the negotiated settlement approved in Phase 1.

Main Extension Policy

BC Gas did not bring forward a proposal for a definitive main extension test at the hearing. Instead it proposed to continue to use the interim discounted cash flow test while further examining the full implications of a test more closely aligned with its IRP methodology. Moreover, BC Gas suggested that changes in government policy appeared to be pending, which would impact main extension tests.

BC Gas filed a consultant report (Exhibit 32) which addressed the troublesome and inter-related effects of adopting a realigned main extension test.

The Commission accepts the contents of BC Gas' consultant report (Exhibit 32) as providing sufficient evidence to justify the Utility's cautious approach to proposing a new extension test. Nevertheless the Commission requires BC Gas to bring forward a definitive proposal for a new main extension test, which is more closely aligned with its IRP, by January 31, 1995.

A deferral account request related to the above-described consultant study is not approved by the Commission at this time. The request will be reconsidered on submission by BC Gas of definitive main extension test proposal.

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1.0 BACKGROUND

1.1 BC Gas Utility Ltd.

BC Gas Utility Ltd. ("BC Gas", "the Utility", the "Company" or the "Applicant") is a natural gas distribution utility providing gas sales or transportation service to over 666,000 residential, commercial and industrial customers in British Columbia. BC Gas Utility Ltd. was formed in July 1993, when the gas utility assets were separated from the non-regulated business ("NRB") assets of BC Gas Inc. which had encompassed both regulated utility assets and NRB assets. Subsequent to this change, BC Gas Inc. became the legal name of the holding company which acquired 100 percent of both utility and non-utility assets.

1.2 1994/95 Revenue Requirement Decision Phases

On November 22, 1993, BC Gas filed a 1994 and 1995 Revenue Requirements Application ("the Application") which sought interim and permanent rates for 1994 and 1995, pursuant to Sections 64, 67 and 106 of the Utilities Commission Act ("the Act") for all divisions except Fort Nelson. The Application also sought a 3.63 percent increase on captive rates in 1994 and a further 5.73 percent increase on captive rates for 1995, based in part on forecast total sales and transportation service volumes of 226,892 TJ for 1994 and 227,695 TJ for 1995. An Alternate Dispute Resolution process was used prior to a hearing on the Application to identify, define and eliminate issues which would otherwise have gone to the hearing. A tentative settlement was reached on two major cost items which formed the 1994 and 1995 Revenue Requirements of the Utility. This portion of the Application was dealt with by the Phase 1 Revenue Requirements Decision of June 16, 1994, which approved the negotiated settlement (Exhibit 9).

In the Application, the Utility also requested approval of a revenue stabilization adjustment mechanism ("RSAM") effective January 1, 1994, which would stabilize the Company's margin from variances between the actual and forecast use-per-account for residential and commercial customers during the months of November to March. This part of the Application was dealt with by the Phase 2 Revenue Requirement Decision of August 4, 1994.

Phase 3 of the hearing dealt primarily with the Commission's review of the Utility's Integrated Resource Plan ("IRP") which was filed on March 28, 1994. This Decision on Phase 3 of the BC Gas 1994/95 Revenue Requirements Application completes the Decisions of Phases 1 and 2 to provide the full findings of the Commission on the Application. The phased hearing of the Application stemmed from the unusual situation whereby the three-member panel initiated to review the full Application was reduced to a two-member panel when Commissioner Sleath became unavailable to complete the hearing. Thereafter, Chairperson Jaccard stepped down from the panel for the review of issues in what became Phase 3 of the hearing.

This Phase 3 Decision should be read in concert with the Phase 1 and 2 Decisions to provide a complete account of the disposition of the full Application.

1.3 The Phase B Rate Design Decision

On April 15, 1993, BC Gas Inc. filed an Application referred to as its Rate Design Phase B Application ("Phase B Application") to implement certain rate design changes. Included in that application were issues that were carried over into the hearing which is the subject of this Decision.

In the Phase B Application, the Company proposed certain changes to its existing main extension test. In the subsequent Decision, the British Columbia Utilities Commission (the "Commission"; the "BCUC") approved several aspects of the proposed main extension test and directed the Utility to modify certain other aspects. In response to a request from the Utility contained in a letter dated February 1, 1994, the Commission approved implementation of an interim main extension test that adopted some of the Commissions directives, and directed the utility to file a revised test prior to the anticipated date of the hearing into the 1994/95 Revenue Requirements Application.

The Commission in its Phase B Decision directed the Utility to examine certain issues in the next revision of its IRP, which it was to file by December 31, 1993. BC Gas subsequently requested and received Commission approval for a delay in filing, and accordingly filed its IRP on March 28, 1994.

1.4 Previous Commission Directives on IRP

General Commission directives regarding Integrated Resource Plans were outlined in the BCUC's February 1993 Integrated Resource Planning Guidelines ("IRP Guidelines") which were included as Appendix J of Exhibit 28B. More specific direction was provided to BC Gas in the Commission's Decision on the BC Gas Phase B Rate Design Application ("Phase B Decision").

In the Phase B Decision, BC Gas was directed to provide an estimate of avoided costs consistent with the Long-Run Incremental Cost study which the Utility had filed in that hearing. In doing so, BC Gas was required to specify the costs at each stage of the market, including "...wellhead price, gathering, processing, transmission, distribution and peaking resources." BC Gas was also directed to segregate the costs by class where appropriate and to distinguish between the demand and commodity components.

BC Gas had also applied for deferral accounting treatment of $1.5 million, for feasibility studies related to a potential new Liquefied Natural Gas ("LNG") Plant . The Phase B Decision did not approve the request, but stated that the Commission would reconsider the topic at some later time when in possession of a revised BC Gas IRP.

The Commission also noted in the Phase B Decision that it was unwilling to approve any residential or commercial load building programs without knowledge of the avoided costs and analysis in an IRP context indicating that such a program would be in the public interest.

Finally, in Order No. G-69-93, the Commission ruled on several proposed deferral accounts related to IRP and Demand-Side Management ("DSM"). The Order and the Commission's reasoning with respect to these deferral accounts was attached as Appendix D to the Phase B Decision. The Commission approved the IRP deferral accounts, with the exception of the above noted LNG plant studies, subject to certain comments made in its reasons. The Commission also approved deferral treatment of $1,000,000 for DSM programs.

2.0 INTEGRATED RESOURCE PLAN

BC Gas provided three panels to speak to its IRP. The subjects these panels were to consider were:

- IRP Objectives/Multi-Attribute Trade-off Analysis and Objectives;
- DSM programs, including Natural Gas Vehicles ("NGV") and related deferral accounts; and,
- Gas supply and LNG deferral application/long-run avoided costs/ demand forecasts.

With the exception of certain deferral applications, none of these items require specific Commission determinations, although IRP issues are candidates for Commission review and comment. In particular, issues warranting comment include those where two or more parties' opinions diverged during the hearing (e.g. public participation, the Multi-Attribute Tradeoff Analysis ("MATA"), and fuel switching DSM programs) and those where the Utility had previously been directed to undertake certain actions (determination of Long-Run Avoided Costs and exploring end-use forecasting).

The IRP in general was discussed in testimony and in final submissions, with respect to its relationship to the Corporate Strategic Plan ("Strategic Plan"). The B.C. Energy Coalition ("Energy Coalition") submitted that BC Gas senior management was unclear about the appropriate role of an IRP, which the Energy Coalition submitted should be to serve as a guide for the corporate strategic planning process (written submission, p. 4). Discussion during the hearing did little to clarify the distinction except to suggest that although the perspectives of the IRP and the Strategic Plan are not identical, they may overlap (T4: 417-18). In testimony, BC Gas stated that the Strategic Plan would indicate what the Company's role would be in certain activities, and that the IRP would be what they were encouraging for the industry and the province as a whole. The witness also indicated that there should not be any direct conflicts between the IRP and the Strategic Plan (T4: 414). BC Gas (T16: 1965) argued that the IRP and the Corporate Strategic Plan are complementary and should be consistent, but that neither should be dependent on the other.

The Commission's IRP Guidelines do not provide guidance on the relative roles of the IRP and Strategic Plans, but they do suggest that the IRP process is intended to result in a selection of resources which yields the preferred outcome of expected impacts and risks for society over the long-run (Exhibit 28B, Tab J). The Commission believes that the IRP is more than a document that concerns only what the Company is encouraging for the industry and the province. The IRP, as the guidelines suggest, involves eventual focused action as a result of specific types of analyses relating to resource selection and alternative methods of providing energy services to the Utility's customers. The Commission agrees with both the Energy Coalition and BC Gas that the Utility's Strategic Plan and the IRP should be consistent. If they are not, there will be a serious risk of corporate actions frustrating effective implementation of IRP activities.

2.1 Objectives, MATA and Public Participation

BC Gas attempted to include various degrees of stakeholder input into the development of its IRP objectives, the definition of measures for the objectives and the clarification of stakeholder views on relevant trade-offs among objectives. The Utility employed consultants to assist it in developing objectives that would serve as the basis of the BC Gas IRP. The consultants used both individual interviews and a meeting with the BC Gas IRP stakeholder group ("stakeholder group", "stakeholders") in order to identify the important information that would form part of a useful IRP. Following the meeting and interviews a set of fundamental objectives and means objectives ("sub-objectives") were developed.

Once the fundamental and means objectives were developed, measures which could be used to interpret and evaluate objectives were defined through a workshop with BC Gas staff and with input from the stakeholders.

Finally the trade-offs between objectives were examined through a process referred to as multi-attribute value elicitation or a MATA. The MATA process involved presenting the stakeholder group with a series of questions that involved trade-offs within each category of objectives. The trade-offs contained in the question set involved both monetary and non-monetary values. Where monetary values were considered, the respondents were explicitly asked to answer in terms of appropriate public investments or increases in utility bills rather than in terms of personal willingness to pay. This in the view of the Utility, distinguished the MATA approach from a contingent valuation approach.

Ms. Reardon, on behalf of the Energy Coalition referred to the Commission's June 17, 1994 Decision regarding an application by West Kootenay Power Ltd. ("WKP"), with specific reference to WKP's stakeholder process (T16: 1903-1910). The Energy Coalition acknowledged that BC Gas had made a "good faith effort" to conduct a fair and adequate public process, and offered some suggestions for improvement in the future. These suggestions included increased independence of the stakeholder group, increased efforts to develop techniques that would encourage consensus, stakeholder input into the choice of a facilitator, and increased time for the stakeholder process. The Energy Coalition also recommended that the Commission conduct a workshop on collaborative processes.

Additionally, the Energy Coalition argued that the MATA process contained several weaknesses, some of which related specifically to the amount and type of information included in the process, particularly regarding the environmental impacts of natural gas use. The Energy Coalition submitted that the Commission should encourage the use of monetization based on control cost estimates as a starting point in all future IRPs and that "...the polluter pay principle be incorporated in all resource allocation decisions approved by the BCUC" (T16: 1923).

CAC(BC) et al. ("CAC(BC)") had three criticisms of the public participation aspect of the MATA process. Firstly, there was a lack of criteria for the selection of participants and a lack of direct participation by some parties that CAC(BC) perceived to be potential stakeholders. Secondly, there was the involvement of BC Gas senior management and Commission personnel in discussing IRP objectives with the BC Gas consultants prior to the involvement of the stakeholder group. To correct these flaws CAC(BC) suggested that the IRP public participation process in future should not involve senior utility management until after the stakeholder group had produced its final product. A related suggestion was that a new stakeholder group be convened with new representatives of any organizations represented in the previous group, and that the new stakeholder group should not have access to any material generated by the previous group, at least not initially (T16: 1939-40).

Thirdly, CAC(BC) expressed concern at the perceived similarity between the questions posed to the stakeholders in the MATA process and the "willingness to pay" questions often used in contingent valuation - a methodology criticized by the consultants. In testimony, Dr. McDaniels, one of the consultants for BC Gas, disputed the suggestion that contingent valuation and the MATA approach were essentially the same (T4: 401-4).

In its Phase 3 reply, BC Gas rejected the view that senior management of the Utility should be divorced from the IRP process until after the stakeholder process was complete. The Utility cited the June 17, 1994 Decision of the Commission regarding the WKP stakeholder process, noting that utility management with Commission oversight have responsibility for the Company's IRP and that cannot be delegated to a collaborative process (T16: 1963-64).

The Energy Coalition cited and agreed with the Commission's June 14, 1994 WKP Decision where the Commission stated that: "The consultative committee should be given more time, recognizing the iterative process involved in conducting in-depth trade-off analysis of the major packages of resource options. However, public involvement processes must conform to Commission deadlines" (T16: 1903). BC Gas, on several occasions during the hearing, acknowledged concerns about its public involvement process, but indicated that it had a very short deadline set by the Commission (T4: 375-379, T5: 522 and 564). The Energy Coalition acknowledged that BC Gas "... made a good faith effort to conduct a public participation process that is fair and adequate" (T16: 1903). CAC(BC) also complimented the Utility staff who "...devoted enormous effort to a difficult task on a short timeline" (T16: 1932).

With respect to specific objectives, Ms. Reardon for the Energy Coalition questioned whether growth in utility earnings was an appropriate objective for an IRP (T4: 418-24). Counsel for Commission staff also discussed with BC Gas witnesses the validity of using percent annual growth in rate base as an attribute for measuring the financial health of the utility. BC Gas indicated that it was possible for a utility to be healthy without growth in rate base (T5: 620), and that there were examples from the electric utility industry where growth in rate base had been detrimental to the health of the utility (T5: 622).

Commission's Views

The Commission commends BC Gas for its efforts in production of the IRP, submitted as part of the Company's 1994/95 Revenue Requirements Application, which was reviewed during the Phase 3 hearing. The serious attempt by BC Gas to ensure public participation in the IRP process, through a stakeholder collaborative, is supported. The Commission recognizes that many of the flaws identified by intervenors have been caused by a tight Commission deadline. However, the Commission is optimistic that many of these shortcomings can be rectified through ongoing iterative re-examination by the stakeholder collaborative of the various IRP options.

The Commission believes it should give BC Gas feedback at this stage as to the direction the Utility is pursuing on IRP issues. Participant views were well canvassed during three hearing days and in written argument. **The Commission accepts the fundamental IRP objectives set out in Table ES-1 of Exhibit 28 as providing a satisfactory basis on which BC Gas shall continue its IRP development.** However, the Commission does caution the Utility that, in its view, growth in rate base as an attribute for measuring the financial health of the Utility holds the potential for biasing the objective selection of supply and demand-side resources, and therefore is an inappropriate attribute for the Quality Shareholder Return objective.

With respect to public participation, both BC Gas and the Energy Coalition cited comments of the Commission in the June 17, 1994 WKP Decision (pp. 5-6). Those comments are repeated here for convenience:

> "The Commission agrees that the public participation process needs further development, and suggests careful consideration of the following changes. The Commission recognizes that some of the criticisms relate to the deadlines imposed upon WKP by the Commission.
>
> 1. The consultative committee should be converted to function more along the model of a collaborative, with greater independent control over its process. However, participating members of the collaborative must be clearly aware that the outcome of

the collaborative process cannot be binding on the Utility management Ultimately, the Utility management and then the Commission have decision-making responsibility for determining the prudency of the Utility's IRP and the Action Plan contained therein. Neither management nor the Commission can avoid their responsibilities via a collaborative process.

2. The consultative committee should try for consensus. Where consensus cannot be realized, members may write dissenting positions.

3. An independent facilitator should be retained by the consultative committee.

4. The consultative committee should have explicit representation from environmental and other key interests. The individuals providing such representation need not reside in the Utility service area, although this may be preferred.

5. The consultative committee should be given more time, recognizing the iterative process involved in conducting trade-off analysis of the major packages of resource options. However, public involvement processes must conform to Commission deadlines."

The Commission's views on public participation apply no less to BC Gas than to WKP. The Commission also notes that the Utility intends to file its next iteration of its IRP in June 1995, and directs the Utility to consider and make an effort to respond to the concerns of the intervenors as they relate to the IRP development process.

However, the Commission is not directing the Utility to require groups that were represented in the previous stakeholder collaborative to have new representatives, nor to deny the stakeholders access to materials from the previous stakeholder group - material that is now part of the public record. The Utility should make stakeholder group participants aware of the concerns of CAC(BC), and allow those organizations to make their own decision regarding who they wish to participate on their behalf, and what past materials they wish to rely on.

The Commission notes that, although the MATA process worked reasonably well at this early stage, as IRP development becomes more refined greater efforts may be required to incorporate monetized environmental impact measurements, as better data becomes available from a variety of sources. The importance of the use of consistent criteria by different utilities in preparing their IRPs is clearly recognized by BC Gas (Exhibit 28, p. 29) and BC Gas is encouraged to pursue inter-utility activities leading in this direction. Monetization is discussed further in section 3.3.

2.2 Long-Term Demand Forecasts

<u>Modeling</u>

BC Gas is forecasting total natural gas demand by developing an 'expected value' forecast and 65 percent and 90 percent confidence bands around the expected value forecast, or reference case. The forecast of total natural gas demand is used as input to the Gas Supply Optimization Model ("GSOM"). The expected value forecast is the average of many Monte Carlo forecast simulations. The confidence bands provide an estimate of the demand levels within which 65 or 90 percent of the values produced by the Monte Carlo simulations will fall. The expected value forecast anticipated natural gas demand of more than 280 PJ by 2010 compared to 208 PJ in 1993.

The Utility also forecasts residential and commercial natural gas demand by end-use activity using the "Energy 2020" end-use model. The model is based on consumer decision theory and operates on a set of 'logit functions', also referred to as decision curves or trade-off curves. New capital additions and new energy requirements are added to the existing stock of appliances (reduced by equipment retirements and their associated energy requirements) (T12: 1581-92). The Energy 2020 model is described in more detail in Exhibit 28A (Tab C, Appendix B) and the description was elaborated on by BC Gas testimony .

During testimony, BC Gas noted that the Energy 2020 model decision curves relate technology efficiency to capital cost and the decision between efficiency and fuel price. These curves have not been validated for the BC Gas service area nor do they use actual data on appliance costs and efficiency. As noted by BC Gas, the particular relationships in the decision curves are drawn from the experience of the model developers and their studies with other utilities and within academic institutional environments (T12: 1581).

The Commission has concerns about the validity of the Energy 2020 model, particularly given that the fundamental decision choice elements of the model - the decision curves - do not use actual data on appliance costs and efficiency, nor have they been validated for the BC Gas service area. Without data on existing BC Gas equipment stocks, it is unclear how the model could be used to estimate the conservation potential in B.C.

In developing an appropriate end-use model for IRP purposes, the Utility should continue to explore alternative models. Final approval of related expenditures will require BC Gas to demonstrate the usefulness of the chosen model for IRP analysis and demand-side planning.

Identification of Conservation Potential

BC Gas has stated that it has not explicitly measured the conservation potential for natural gas in British Columbia (T11: 1390). The Utility has relied mainly on secondary sources of information and end-use load surveys of a sample of its customers. The Action Plan in the IRP does not contain a project to specify the conservation potential in BC Gas' territory.

BC Gas addressed the importance of identifying potential "lost opportunities" for energy efficiency but the magnitude of the potential in B.C. has not been specifically identified (T11: 1392). BC Gas also emphasized the need for useful information gained from experience with full programs and indicated that reliance on the results of pilot projects could be risky (T11: 1398 and 1399).

The Commission recognizes that utilizing the experiences and knowledge gained in other jurisdictions is a cost effective approach to DSM planning, but market characteristics vary significantly from one jurisdiction to another. Experimenting with full scale programs can be both costly in the short-run and damaging to market potential in the long-run if those experiments fail in a dramatic way. While it is true that experience from full scale programs provides valuable insight, BC Gas runs the risk of losing opportunities that might otherwise be achieved with more specific research of the B.C. market.

The Commission directs BC Gas to include in its evaluation of demand models the ability of the model to simulate and evaluate the impacts of alternative DSM activities by the Utility. The Commission notes that the B.C. Hydro Conservation Potential Review has utilized demand models extensively to determine the levels of conservation available to the utility. The Commission also directs BC Gas to address the issue of how it intends to cost-effectively identify potential "lost opportunities" for efficient use of natural gas in its next IRP.

2.3 Long-Run Avoided Cost Study

As noted in section 1.3, the Commission had previously directed the Utility to file an updated estimate of its avoided costs with its IRP. The Utility hired consultants RCG/Hagler Bailly ("Hagler Bailly") to undertake an avoided cost study for BC Gas consistent with the Commission's previous directions. The consultants' study, titled "Development of Long-Run Avoided Costs for BC Gas Utility Ltd." ("LRAC study") was included in the IRP Technical Appendices (Tab D of Exhibit 28A).

The LRAC study developed avoided cost estimates based on two separate approaches. One was based on the use of forecast tolls for costs to BC Gas upstream of the BC Gas system. This was termed the Customer Incremental Avoided Cost ("CIAC"). The other approach used estimates of proxy investments to represent incremental upstream investments in gas supply , processing and transportation which are not incurred directly by the utility in order to meet additional demand. This approach was termed the Total Incremental Avoided Cost ("TIAC"). BC Gas and the Hagler Bailly representative argued that the TIAC was inappropriate for utility decision-making, and that the CIAC estimate was appropriate for DSM screening, although the CIAC estimate should not be used in other decision-making situations without careful analysis as to its appropriateness. The LRAC study noted however, that "...the TIAC estimates provide information that may be useful as part of investigating BC Gas' options, or when decisions are examined from a broader, societal perspective" (Exhibit 28A, Tab D, p. 5-1). The LRAC study also stated that the use of the TIAC would not result in significantly different conclusions from the CIAC since the two sets of estimates were comparable for all load shapes (p. 5-3).

The CIAC estimates were based on analysis using the "Status Quo" supply portfolio which assumed unlimited gas and capacity available to meet future requirements, even though other supply portfolios - notably the LNG portfolios - were shown to be less costly. BC Gas argued that use of the Status Quo portfolio was acceptable, since once any new LNG facility was at capacity, the avoided cost would return to the same level as in the Status Quo case. However, the Utility also stated that, as other supply plans were developed by BC Gas, the assumptions contained in the Status Quo case should be reviewed.

No intervenors in the hearing took a position on the avoided cost study or the situations where they might find the use of either the CIAC or the TIAC estimates to be appropriate.

The Commission accepts the LRAC study as a good approximation of the avoided costs of the Utility at this time. The estimation of both the CIAC and the TIAC provides some degree of sensitivity analysis to the avoided cost component of the DSM benefit/cost tests. BC Gas should, in the view of the Commission, use the best alternative supply portfolio as the basis for estimating the CIAC in future calculations. In the estimations provided in this IRP, such a calculation would have been based on the best LNG portfolio, rather than the Status Quo portfolio. However, the Commission recognizes that there were time constraints, and that the results BC Gas provided would not be materially different at the end of the study period, if calculated using a different portfolio.

The Commission recognizes the uncertainty in the calculation of the TIAC estimates, but sees validity in their use in some instances, for example where a societal perspective is being considered, as the LRAC study acknowledged. The Commission also derives some comfort regarding the proxy nature of the TIAC estimates from the relatively close fit between the final CIAC and TIAC figures. In summary, BC Gas is to be commended on its work to date in this area, and should continue to refine both the CIAC and the TIAC estimates for future IRPs.

The choice between CIAC or the TIAC as the avoided cost for economic assessment of DSM programs involves a consideration of the particular DSM load shape strategy. A distinction can be made on the basis of the direction of change in load intended by a DSM program; an increase in load utilizes current capacity and may cause incremental investments from distribution upstream to production. CIAC could be relied upon for assessment of strategic conservation, peak shaving and valley filling and TIAC could be relied upon for assessment of strategic load building. Cogeneration could be assessed using CIAC rather than TIAC if that cogeneration will be on interruptible service.

The Commission directs BC Gas to consider further the alternative uses of CIAC and TIAC in its next IRP.

2.4 Supply-Side Planning

BC Gas projects a 20-year growth in annual load from the current 167 PJ to 234 PJ (high forecast) or 213 PJ (low forecast). Its peak day demand is projected to grow from 1,014 TJ/day to 1,612 TJ/day (high forecast) or 1,449 TJ/day (low forecast) over the same 20-year period.

To meet this load growth the Company identified ten individual supply options including peaking/seasonal contracts, Canadian and U.S. underground storage and various LNG or propane/air plant possibilities. These sources were grouped into seven potential supply portfolio options which were then analysed to compare them with a base-case status quo alternative (Exhibit 28B, Tab H, pp. 45-48). The analysis determined the net present value of savings in gas purchase costs over the 20-year period which would result from the adoption of each supply portfolio option.

The analysis incorporates a number of simplifying assumptions but in BC Gas' view provide satisfactory guidance, for planning purposes, as to the general direction the Utility should take in its supply-side gas purchase planning (Exhibit 28B, Tab H, p. 8).

The results of the above-described analyses clearly demonstrate the important role played by proposed new LNG plants in the least-cost management of the Utility's gas purchases.

The Commission believes that BC Gas has done a satisfactory job of evaluating its supply-side resources. Apparently this view is shared by the registered intervenors who raised no concerns about supply planning. However, the Commission does have some specific concerns related to the Gas Supply Optimization Model ("GSOM"). The first concern is that the GSOM requires trial and error manipulation of supply alternatives compared to the preferred approach of determining the optimal amount of each alternative from a menu of all alternatives. BC Gas has anticipated this concern in its IRP when it states:

> "BC Gas plans to more fully evaluate alternative long term planning models which might also incorporate demand side programs into the resource stack and evaluate resources in a multi-attribute IRP framework." (Exhibit 28, p. 80)

The Commission supports this plan and directs BC Gas to complete the analysis as soon as possible and preferably in time to adopt the use of an improved model to develop its next IRP.

A second concern with GSOM relates to the inputs to the model in terms of some of the specific cost assumptions which have been used and some of the benefits which have been ignored. For example, an assumption has been made that no additional storage projects will be developed other than those now under construction; the LNG cost estimates are very preliminary; and, the factors that have been used to escalate capital costs, pipeline charges, and gas costs should be based on a consistent forecast of future inflation but this may not always be possible. The Commission is concerned that these assumptions in combination may have overstated the relative value of an LNG portfolio. On the other hand, potential benefits such as reliability, security of supply, and operating flexibility of an LNG plant have not been quantified. The Commission notes that the Company plans further studies of at least some of these factors for its next IRP (Exhibit 28, p. 80).

Recognizing that variability in some or all of these input assumptions could significantly impact the outcome of an IRP analysis, the Commission will require BC Gas to include some additional uncertainty analysis in future IRPs to quantify the effect of varying these and other cost and benefit assumptions.

The Commission notes with satisfaction that BC Gas will continue to monitor future potential developments, such as the Southern Crossing project, which could have a fundamental impact on the Utility's supply-side resource planning options.

2.4.1 LNG Plant Studies Deferral Account

BC Gas applied, in Exhibit 30, for approval of expenditures to commence feasibility studies on a new LNG plant. The Company proposed to conduct the studies in four phases for the purposes of regulatory oversight, with each phase requiring separate approval. The first phase approval is for an expenditure of $320,000 in 1994 for the purpose of evaluating preliminary siting options, sizing, and environmental considerations. Total cost for all four phases is estimated to be $6.57 million. The Company proposes that costs including AFUDC be collected in a deferral account, and upon termination or completion, be amortized in the customers' rates over ten years and that deferred charges be included in rate base.

In its October 25, 1993 BC Gas Phase B Rate Design Decision, the Commission had denied a previous application for a similar deferral account on the basis that BC Gas had not established in an IRP framework that a new LNG plant was necessary. While BC Gas' gas supply planning does not yet integrate the analysis of demand-side resource options, these options have now been considered in sufficient detail that the need for more detailed feasibility studies regarding an LNG plant can be determined.

The Commission observes that no concerns were raised about the application by any of the intervenors. Northwest Pipeline Corporation and Williams Storage Company who wish to build an LNG project to serve the BC Gas market provided final argument in support of the application (T16: 1948-1952).

BC Gas testified that despite all of the uncertainties about the costs for a new LNG plant, it believed that its planning analysis which showed a supply portfolio containing an LNG plant to be the most beneficial was conservative for two reasons. Firstly, the analysis used the highest capital costs for an LNG plant from the range of estimates, and secondly the analysis showed the net present value of the portfolio to be relatively insensitive to these costs so that even if they were understated by 50 percent, for example, such a portfolio would still be the most beneficial (T13: 1624-1626).

The Commission also accepts that qualitatively at least, a new LNG plant could reduce the need to add other capacity to the BC Gas system, as well as improving security of supply and improving operating flexibility. These benefits have not been quantified in the IRP analysis but tend to offset the Commission's concerns about the potential variability of GSOM inputs which may have tended to underestimate the LNG portfolio costs as discussed in section 2.4 of this Decision.

The Commission is now satisfied that there is sufficient certainty about the costs and benefits of a new LNG plant to warrant proceeding with the phase 1 feasibility study, and approval to begin phase 1, as described in Exhibit 30, is granted. Before considering approval of further phases, the Commission will require BC Gas to update and upgrade estimates for both costs and benefits and to complete the variability analysis required by section 2.4 of this Decision.

While the sequence of activities proposed by BC Gas in the four phases of the studies does appear logical, the Commission is concerned that the $2.32 million expenditure in phases 1 and 2 would be at risk if the public consultation in phase 3 were to be unsuccessful in obtaining an approved site. **In order to mitigate this concern, BC Gas will be required to provide the Commission with sufficient**

information so as to provide it with greater confidence about the Company's ability to obtain site approvals as the studies proceed. After phase 1, BC Gas will be required to report its progress at least quarterly and prior to committing to major expenditures throughout the study period and not just at the end of each phase as proposed in the application.

2.5 Integrated Resource Portfolio Selection

From its analysis of individual gas supply options and supply-side portfolio groupings, taken together with the potential contribution from DSM programs, BC Gas presented two possible integrated resource portfolios described in Exhibit 28, pp. 94 and 95.

The first of these, entitled "Stakeholder Consensus Portfolios", contained 17 individual resource options. As its caption implies, it was a consensus portfolio supported by all the participants in the stakeholder collaborative. In addition, BC Gas presented a slightly different resource portfolio entitled "Proposed Resource Portfolio"; this latter contained 25 individual resource items. The "Proposed Resource Portfolio" was supported in its entirety by a majority of the collaborative stakeholders, with the exception of one resource item, cogeneration.

Each of the above-named resource portfolios was evaluated by BC Gas against a base-case benchmark portfolio, capable of meeting future forecast peak day demand, designated the Status Quo case. The Status Quo case essentially assumed that all additional peak day load would be supplied from new Canadian baseload gas contracts; that current underground storage sources would remain available; and, that BC Gas' existing LNG plant would continue in service.

BC Gas' analysis, comparing the potential rate impact of each of the above-described portfolios with that of the Status Quo base-case, yielded the following results:

- Adoption of the "Stakeholder Consensus Portfolio" would lead to a net present value ("NPV") rate reduction of $81 million compared with the Status Quo case over a 20-year period.

- The Proposed Resource Portfolio showed a $69 million NPV rate reduction potential over the same time period.

It should be noted that, in arriving at both of these portfolios, other attributes than rate impact were considered, such as the Total Resource Cost ("TRC") test and the MATA ranking of resource alternatives.

It is the "Proposed Resource Portfolio" which is proposed by BC Gas in its IRP planning. The DSM components of this portfolio are reviewed in detail in Chapters 3.0 and 4.0, below.

2.6 IRP Deferral Accounts

BC Gas filed a separate application (Exhibit 33) for deferral accounting treatment of expenditures for various IRP and DSM related costs. This application is tied to several other items in the hearing, the Operating and Maintenance ("O&M") Settlement in Phase 1, the IRP Action Plan, the DSM program descriptions and various information requests. Schedules B1 and B2 of Exhibit 33, which list the IRP and DSM items for which deferral treatment is requested, are attached as Appendix A to this Phase 3 Decision.

In Exhibit 33, BC Gas applied for deferral accounting treatment of $886,000 for IRP related projects in 1994, and $640,000 in 1995. Costs for Integrated Resource Planning at BC Gas were considered in the negotiated settlement agreement (Exhibit 9) for the 1994 and 1995 Revenue Requirements of the Company. The settlement agreement included $574,000 for "defined required incremental activities" ("DRIA") for 1994, which included incremental wages and salaries for the Integrated Resource and Demand Planning ("IRDP") Department. The costs included under the DRIA for 1994 then became part of the ongoing O&M expenditures for the 1995 revenue requirements. The settlement agreement also stated that the parties had agreed to the establishment of deferral accounts for costs for outside consulting services and consultation to the IRDP Department in 1994 and 1995, and that ongoing internal expenditures would be provided within the base O&M formula.

BC Gas stated that:

> "All incremental labour costs in the deferral account request are to cover the expenses for consultants and/or contract work, and are incremental to the DRIA amount and operating and maintenance expenses which were part of the settlement and approved by the Commission in the May 2, 1994 hearing." (Exhibit 85, p. 2)

The Commission notes that both Exhibit 33 and Exhibit 85 indicate that the deferral accounts requested assume that any remaining funds approved in Commission Order No. G-69-93 are no longer available. The Commission confirms that its approval of any IRP and DSM deferrals in this Decision are based on a similar understanding.

The individual action plan costs for which deferral treatment is requested are discussed below. **The circumstances of this year's IRP development and review led to the need for deferral account treatment of various IRP initiatives. However, the Commission expects that the 1996 Revenue**

Requirement Application will incorporate IRP initiatives into the base O&M and capital budgets of the Utility.

2.6.1 IRP Filing

BC Gas has requested $50,000 for each of 1994 and 1995 for filing its Integrated Resource Plan. **The Commission considers the filing of an IRP to be of such a fundamental nature to the operation of a utility that it expects such activities to be funded out of normal O&M budgets. Therefore the request for deferral of $50,000 in each year is denied.**

2.6.2 Public Involvement

BC Gas requested a total of $173,000 for 1994 and $210,000 for 1995 for public involvement. These totals are comprised of the following individual items:

	1994	1995
Stakeholder group	$128,000	$165,000
Advisory panels	40,000	40,000
IRP joint workshops	5,000	5,000

The Commission agrees with the need for stakeholder involvement and, further, sees potential benefits to joint IRP workshops. The anticipated budget for the latter item is, in any event, very small. However, the Commission is not convinced of the need for advisory panels. Although there may be benefits to seeking out trade allies, it is unclear that these are best obtained through advisory panels with the costs visited on ratepayers. The incorporation of customer groups in advisory panels appears potentially to overlap with the IRP stakeholder collaborative for which the budget appears generous. **Therefore the Commission approves deferral treatment of only the costs of the stakeholder group and the IRP joint workshops, not to exceed $133,000 for 1994 and $170,000 for 1995.**

2.6.3 Monitoring and Evaluation

BC Gas applied for deferral treatment of $50,000 in 1994 and $160,000 in 1995 for data collection and analysis related to DSM program monitoring and evaluation. Also, $500,000 per year was included for demand metering in the capital budget approved by the negotiated settlement. The Utility requested deferral of $35,000 for 1994 for development of a DSM data analysis model ("DAS"), and $10,000 in 1994 and $20,000 in 1995 for incremental labour to operate the DAS model; these incremental labour amounts were not included in the Utility's IRP Action Plan budget (Exhibit 33). The total amounts requested were $95,000 in 1994 and $180,000 in 1995 for monitoring and evaluation of its DSM programs.

The Commission approves deferral treatment of those costs related to DSM program monitoring and evaluation, and the development of the DAS model, excepting for the incremental labour costs. Therefore, the Commission is approving a total not to exceed $85,000 for 1994 and $160,000 for 1995 for DSM program monitoring and evaluation.

2.6.4 Supply-Side Resources

In addition to the costs for LNG plant feasibility studies which are discussed in section 2.4.1, BC Gas requested deferral treatment of $40,000 to complete a study quantifying "qualitative issues such as security of supply and risk" (Exhibit 28, p. 107). **The Commission considers continuous evaluation of these factors fundamental to the operation of any utility. Deferral treatment of $40,000 for this supply study, which the Commission expects to be funded out of normal O&M budgets, is therefore not approved.**

2.6.5 Resource Integration

The Utility requested deferral treatment of $213,000 for 1994, and $105,000 for 1995 for evaluation of alternative end-use computer models developed for IRP and to develop models appropriate for BC Gas. The total amounts included the following specific items:

	1994	1995
Evaluate Options (end-use/Resource Optimization Model)	$ 10,000	$ 0
Develop and implement model	160,000	0
Update and support model	0	20,000
Incremental labour expense of a computer modeler to collect and input data and operate proposed model	43,000	85,000

The Commission is convinced by the arguments of BC Gas that its existing Gas Supply Optimization Model ("GSOM") is primarily a gas dispatch model and is not ideal for the IRP analysis which it is also required to perform (T6: 963-4).

The request for deferral treatment to evaluate the options, develop and implement the model, and update and support the model, as requested in the Action Plan budget (Exhibit 33) is approved. However, the Commission is not convinced that the incremental labour expense is required, especially since a major intended benefit of a new model would be greater ease of use and

efficiency in IRP analysis. Therefore, the $43,000 in 1994 and $85,000 in 1995 are not approved for deferral.

Given the importance of the choice of a model or models on its resource planning process, the Commission directs the Utility to provide the consultants' report on the evaluation of alternative models to Commission staff and members of its current stakeholder group. BC Gas indicated during the hearing that evaluation criteria had not been developed at that point (T6: 694). The evaluation criteria that BC Gas uses in order to examine alternative models should be included in the report.

2.6.6 Energy Aware Guide

BC Gas indicated in its IRP (Exhibit 28, p. 109) that it was co-sponsoring a B.C. "Energy Aware Guide to Community Planning" with other utilities and community agencies. Following completion of the guide, scheduled for April/June 1994, BC Gas suggested that it may be involved in co-sponsoring workshops aimed at "improving energy efficiency in municipal and building design" (Exhibit 28, p. 109). BC Gas requested deferral treatment of $10,000 in 1994 for co-sponsoring the Energy Aware Guide, and $30,000 in each year if 1994 and 1995 for co-sponsoring the workshops.

The Commission approves the deferral of $10,000 of 1994 costs for co-sponsoring the Guide, but is not ready to approve the co-sponsoring of workshops. Although the Commission is supportive in general of efficient energy use, and is aware of the implications that municipal and building design can have on energy use, the specifics of such workshops are too vague for approval at this time.

2.6.7 Community Integrated Energy

BC Gas indicated that it was co-sponsoring a feasibility study "to determine the potential for district heating as it affects community integrated energy planning in the Lower Mainland and Vancouver Island" (Exhibit 28, p. 109). The Company has requested deferral treatment of $20,000 in each of 1994 and 1995. The Commission sees the potential for identifying options for providing cost-effective energy services to some communities through such analysis, as it alluded to in its BC Gas Phase B Rate Design Decision (p. 31). **Therefore, the Commission approves the deferral of $40,000 in total for studies on community integrated energy planning.**

2.6.8 IRP Related Studies

BC Gas also requested deferral accounting treatment of $20,000 in 1994 for a discount rate study, and $20,000 in each of 1994 and 1995 for continuing Long-Run Avoided Cost ("LRAC") analysis.

The Commission received a BC Gas report on discount rates during the hearing (Exhibit 34), and is satisfied with expenditures in this area. **Therefore, the deferral amount of $20,000 requested for the study on discount rates is approved.**

The Commission notes that $45,000 of the approximately $200,000 for LRAC studies, approved in the Phase B Rate Design Decision, was unspent. However, the Commission also wishes the Utility to develop its own expertise for updating and refining its LRAC estimates. **Therefore, the Commission approves an amount not to exceed $40,000 for LRAC studies.**

Finally, in the absence of any detailed justification, the $25,000 request for deferral treatment in each of 1994 and 1995 for "miscellaneous consulting for IRP related activities" is denied.

2.6.9 Technology Development and Transfer

BC Gas indicated in its IRP that it intended to file a "Technology Action Plan" approximately two months after the receipt of this Decision (Exhibit 28, p. 108). In the meantime, the Company has applied in Exhibit 33 for deferral account treatment of some $175,000 for activities which it states are closely related to IRP. Schedule D of Exhibit 33 lists the proposed activities and provides a brief qualitative summary of benefits. The Company stated that in the event that technologies to which they contributed were successful, there would be no direct repayment to the Utility (T6: 697-698). The Company also stated that in a more general sense, it is presently unsure of its role in technology development (T4: 412-413).

The Commission is surprised that BC Gas would bring forward a deferral account proposal which had just been eliminated one month earlier in the settlement of O&M. What the Commission finds more surprising is that BC Gas would characterize the proposal as part of its IRP, and then fail to apply any of the appropriate benefit/cost measures such as the TRC or Rate Impact Measure ("RIM") tests.

Recognizing the need to give some direction to BC Gas in regards to what it considers an appropriate role in technology development for the Utility, the Commission advises that it agrees that there is a value to the customers for the Utility to monitor technological developments and to be positioned to adopt them when they are market ready. The Commission assumes that this type of monitoring role, normal to any utility, is provided for in the O&M Settlement. On the other hand, the Commission does not believe that customers should be required to fund activities such as those listed in Schedule D of Exhibit 33 unless the appropriate benefit/cost measures can be demonstrated.

In light of the absence of an appropriate justification, the Commission denies the application for the $175,000 deferral account request at this time. In the event BC Gas wishes to pursue its intention to file a "Technology Action Plan", the Commission will expect that plan to provide the missing cost/benefit analyses and justification.

3.0 DEMAND-SIDE MANAGEMENT ISSUES

3.1 Conservation and Peak Shaving

BC Gas proposed a total of nine individual strategic conservation and peak shaving Demand-Side Management ("DSM") programs which are forecast to reduce growth in sales demand by 4,868 TJ (24 percent) and to reduce growth in peak demand by 69 TJ (55 percent) by the year 2001.

The Commission commends BC Gas on the breadth and depth of its proposed conservation and peak shaving programs and concludes that a reasonable balance has been achieved amongst the key criteria of market penetration, cost effectiveness and equity. Subsequent evaluations will be relied upon by the Commission to determine if the planned results have been achieved.

Although these programs were not contested by intervenors, an examination of the BC Gas design criteria, stakeholder portfolios and specific program parameters reveals areas of concern.

The Commission is especially concerned about the ability of the Efficient Furnace Program to perform as forecast. The Commission directs BC Gas to continue to work with the Ministry of Energy, Mines and Petroleum Resources in the development of energy efficiency standards regulations and to achieve an effective fit of this policy alternative with the BC Gas DSM programs.

In the case of a number of the programs, the Commission proposes a cautious approach to full scale implementation. It believes this is best obtained by awaiting evaluation of the Greater Vancouver Regional District ("GVRD") pilot project, and possibly other pilot scale programs, before a commitment is made to major incentive investments. This approach is reflected in the Commission's disposition of the DSM deferral account applications in Chapter 4.0 where the DSM action plan measures are discussed in detail.

3.2 Off-Electricity Fuel Substitution

<u>Position of the Utility</u>

BC Gas utilized benefit and cost data for the year 1994 to evaluate its electricity fuel substitution programs based upon its experience with some of these programs during the past few years (Exhibit 27, Tab 11, pp. 1-2). A modified 1995 cost of new electricity supply was used as the short-run cost of B.C. Hydro electricity avoided through fuel substitution (Exhibit 89). Burrard Thermal and Alberta purchases were considered as possible marginal sources of electricity for purposes of identifying external costs of air emissions in the short-run (Exhibit 70). BC Gas also considered high-efficiency "generic" combined cycle gas turbines, with best-available-control-technology, as B.C. Hydro's possible longer term, marginal resource. The three thermal resources were assumed by B.C. Hydro to be "the marginal source of electricity for the last 1000 GW.h of demand served in each year" (Exhibit 70). One thousand GW.h of electricity is roughly equivalent to 3,600 TJ of natural gas. BC Gas chose to use only the Burrard Thermal Plant as the electricity generation resource in its assumption of "zero net emissions" that could result from its 1435 TJ of electricity fuel substitution, (T11: 1355).

BC Gas entered two exhibits that identified the relative environmental impact of using natural gas directly in water and space heating appliances compared with using natural gas in the Burrard Thermal Plant, including a modification to include selective catalytic conversion. These exhibits indicated that electricity fuel substitution programs could save significant levels of greenhouse gas emissions to the year 2010. (Exhibits 69 and 77, T10: 1312-13).

The short-run perspective led BC Gas to allege that, for purposes of evaluating its fuel substitution programs, externality costs of using natural gas directly in water and space heat appliances and some commercial processes are no greater than the externality costs of using natural gas at the Burrard Thermal Plant to generate electricity (T10: 1308, T11: 1359). BC Gas felt that this could be a conservative assumption given that the information in Exhibit 77 suggests comparatively less conversion efficiency is currently feasible with thermal generation than with end-use appliances. However, BC Gas also agreed that the highest, cost effective, end-use efficiency should be the basis for the economic evaluation of fuel substitution programs (T1: 386-88).

Intervenor Views

The Energy Coalition cited the IRP guidelines of the Commission and focussed on guidelines Nos. 1 and 10 which include references to both stated and emerging government policies (Exhibit 28B, Exhibit 65, T10: 1212). In the view of the Energy Coalition, the BC Gas IRP is inconsistent with the IRP guidelines because of the failure of the IRP to address the implications of existing government policies on air emissions and for its failure to treat, as a risk factor, the likelihood of regulatory changes in this area in the future. The Energy Coalition referred to international and Canadian agreements containing various commitments with regard to greenhouse gas emissions and argued that the provinces should take a proactive role regarding these challenges (Exhibit 65). They further argued that the stabilization of greenhouse gas emissions by the year 2000 should be an objective of the BC Gas IRP.

The Energy Coalition characterized BC Gas' strategic load building in the following way:

> "In other words, to prevent an increase in rates caused by implementing programs which prevent or reduce pollution, increased gas sales which increase pollution are being proposed." (Exhibit 65 pp. 19 and 20)

With regard to the position advanced by BC Gas that the electricity substitution programs are assumed to result in zero net emissions, the Energy Coalition concluded that:

> "BC Gas should be required to withdraw the strategic load building programs from the IRP unless and until BC Gas completes the analysis of the incremental electric resources which its proposed programs would displace, and can demonstrate that there are actual environmental benefits." (Exhibit 65, p. 22)

The Energy Coalition advocated a comparison of the emissions of the current electrical system to those of the proposed fuel substitution program and identified the air emissions from natural gas associated with the electricity substitution programs. Although the Energy Coalition admitted the possibility of beneficial environmental impacts if an incremental electric resource is a fossil fuel generation plant, they stated that, if the incremental resource is a renewable or a DSM conservation program, environmental impacts of fuel substitution would be adverse (Exhibit 65, p. 14). In this regard they referred to the future electricity resource options that B.C. Hydro could consider beyond the year 2004 (Exhibit 75, p. 21). In this context the Energy Coalition argued for "a formal inter utility multi-stakeholder collaborative to address the fuel substitution issue from an IRP perspective (T16: 1930).

The Energy Coalition also stated that the polluter-pay principle should be applied to the BC Gas IRP suggesting that all of the customers of BC Gas should pay for the additional costs of conservation efforts "above gas cost savings" and that this would ensure that the cost of preventing the life cycle environmental impacts of the resource will be included in the price of the commodity. In this regard, the Energy Coalition advocated the monetization of environmental impacts and the inclusion of these values in the assessment of DSM programs (T10: 1258, Exhibit 65, p. 20).

<u>Commission Determinations</u>

In the short-term, the issue centers upon the uses of the Burrard Thermal Plant and the persistence of purchases from Alberta. The role of the Burrard Thermal Plant is documented in the Commission's Recommendation to Government with regard to a B.C. Hydro Energy Removal Certificate, dated June 30, 1992, where, at page 68, five functions of the plant are listed (T10: 1272):

"(i) Supply emergency generation capability close to the system load centre during transmission outages, storms etc.

(ii) Provide a source of electricity if major new projects are delayed.

(iii) Back-up B.C. Hydro's hydroelectric generating resources in low water years.

(iv) Provide voltage support for the Lower Mainland area.

(v) Firm up energy export contracts, whether or not it actually contributes to export energy."

Therefore, it is not clear that the Burrard Thermal Plant will run less often without the space and water heat load that could switch to natural gas. Based upon the above, the BC Gas view of the Burrard Thermal Plant as the marginal resource is unsubstantiated.

The Alberta purchases currently under contract will provide firm energy but no capacity and will last only until 1995/1996 (Exhibit 75, p. 32). Fuel substitution of space and water heating loads to natural gas would free up some dependable electricity capacity during winter peak but, as such, could have no practical effect upon the Alberta purchases.

In the longer term, the issue is the electrical resource mix and the probable order of dispatch. The following is a tabulation derived from Exhibit 75 at pp. 17 and 32 of B.C. Hydro's 1994 Electricity Plan showing anticipated changes to firm committed supply between 1994 and 2004:

1.	Power Smart (excludes approximately 400 GW.h substitution to natural gas)	2,654 GW.h
2.	Self generation by customers	1,910 GW.h
3.	Firm Hydro	2,000 GW.h
4.	Resource Smart	370 GW.h
5.	Burrard Upgrade	1,140 GW.h
6.	Alcan (net)	1,120 GW.h
7.	Alberta purchases, a reduction of	(715) GW.h
	TOTAL INCREMENT	8,479 GW.h

The Columbia River Treaty downstream benefits are not included above because of the current uncertainty with regard to the manner in which those benefits will be returned to B.C.

In the above, "Self generation by customers" could be derived from high-efficiency gas turbines used to cogenerate heat and electricity, but B.C. Hydro may have only minimal ability to affect the dispatch of this resource as it applies to the self-generating customers' own needs. In the long-term, high-efficiency gas turbines may offer advantages, but B.C. Hydro does not characterize this resource as its long-term marginal source of supply (Exhibit 75, p. 29).

The Commission concludes that it is not appropriate to use the short-term or the longer term thermal resources as the exclusive basis for determining the avoided environmental impacts of fuel substitution from electricity to natural gas. Future resource options beyond the year 2004 for B.C. Hydro are too uncertain at this time to be relied upon for evaluating environmental impacts of fuel substitution programs. B.C. Hydro's 1994 Electricity Plan provides specific information regarding the incremental sources of generation committed to by that utility during the intermediate term of 1994 to 2004, and this could serve as the basis for a weighted average measure of environmental impacts during this time frame and a surrogate for the longer term.

BC Gas is directed to explore this concept further in its next IRP and to compare the environmental impacts of electricity generation that are avoided with the environmental impacts that are incurred with the substitution of natural gas for electric space and water heating and commercial process applications. B.C. Hydro's resource options beyond the year 2004 could be used as the basis for sensitivity testing.

As discussed in the June 17, 1994 Decision of the Commission, West Kootenay Power Ltd. ("WKP"), identified several alternative resource portfolios that could satisfy its needs during the years 1994 though 2013. The final form of the WKP IRP is due to be filed with the Commission by February 28, 1995 and should at that time provide a basis for an assessment of air emissions impact of fuel substitution relevant to that utility.

The Commission agrees with the position of the Energy Coalition that the emerging government policies with regard to the stabilization of greenhouse gas emissions should be taken into account in the BC Gas IRP, and the Utility is directed to do that, both in its sub-objectives and the risk assessment components of the next IRP.

The Commission finds that the evidence advanced in the current IRP, with regard to electricity fuel substitution programs, is insufficient to justify BC Gas embarking upon these programs.

3.3 Monetization of Externalities

BC Gas explained during the hearing that it had incorporated environmental externalities in its stakeholder group through the MATA process, which was discussed in section 2.1. The Energy Coalition argued that the social costing methodology - the MATA process - of BC Gas was flawed; that the Commission should encourage the monetization of externalities using the "cost of control" method for evaluating alternative resources; and that the "polluter pays" principle should be incorporated into all resource allocation decisions (T16: 1923).

BC Gas agreed during the hearing that, had more time been available, it would have been useful to provide people with alternative strategies for assigning values to externalities - including standard environmental economic approaches - as well as the actual ranges of values that had been used in other jurisdictions (T4: 394-5). However, BC Gas also argued that there is no objective measure of an externality cost, and that even if one decided that control costs were a sensible measure, the conceptual underpinnings and the relevance of those values was a matter of judgment (T5: 624). The Draft Energy Strategy of the B.C. Energy Council referred to in the hearing by the Energy Coalition (Exhibit 43), also notes that the Energy Council favours a "multi-attribute/multi-objective approach" to resource acquisition, over monetization.

Commission Determination

The Commission is unable to determine how many of the difficulties with the MATA process were caused by the severe time constraint imposed by the Commission, and how many were caused by problems with the MATA framework itself. The incorporation of externalities into an IRP is inexact, and the adoption of monetization could lead to an inappropriate perception that the externality values attached to various resources were more precise than warranted. As suggested by the comments of a BC Gas witness (T4: 394), there are various methods of trying to incorporate externality values into an IRP, examples include: monetization; MATA as employed by BC Gas; and the multiple accounts analysis discussed by the Commission in its June 17, 1994 Decision on the WKP IRP. As the Commission stated in the WKP Decision (p. 10), no social costing methodology is free of problems.

The Commission has suggested, in section 2.1, that greater efforts may be required to incorporate monetized estimates of environmental costs into its resource evaluation process as more reliable values become available. However, the Commission is not suggesting that a strict monetization approach should be adopted by the Utility. **Therefore, BC Gas is directed to work with its stakeholder group on this issue and to report progress in its next filing of its IRP.**

3.4 Monitoring and Evaluation

Monitoring and evaluation of Demand-Side Management programs link several areas of a utility's Integrated Resource Plan. BC Gas states that its monitoring and evaluation will be focused on several activities, or objectives:

- estimating the impact of DSM programs on annual energy use, peak use and load shape;
- identifying areas to improve implementation of DSM programs;
- providing information on customer needs and values;
- estimating end-use consumption and load shape, and identifying trends over time;
- determining market saturation and penetration by end-use and conservation measures;
- development of customer behaviour models for forecasting and predicting the impact of new technologies and programs; and
- supporting other studies and actions that require demand-side customer information.
(Exhibit 28, pp. 77-78)

BC Gas noted that monitoring and evaluation activities are often segregated into discrete activities such as impact evaluation, process evaluation, market evaluation, and general monitoring. The Utility also stated that monitoring could be segregated into three levels, with each subsequent level containing more detail and accuracy. Thus, the first level would be the most general level and would depend primarily on customer surveys, engineering estimates and billing analysis. The second level would include the elements of the first, plus total building/dwelling metering, while the third level would include end-use metering. BC Gas has indicated that its monitoring plan in this IRP is focused on the second level of monitoring (Exhibit 28B, Tab G). None of the intervenors in this hearing addressed the monitoring and evaluation program proposed by BC Gas (T16: 1971).

BC Gas indicated that as this IRP contained its first DSM plan, it was too early to accurately quantify DSM related uncertainties. Because of this near-term uncertainty, BC Gas recommended a five-year amortization period for the DSM programs contained in this IRP, and suggested that the amortization period would be reassessed as programs were evaluated (Exhibit 28, p. 53). The Company also notes that monitoring and evaluation directly addresses the issue of uncertainty with regard to DSM, and recognizes that information that reduces uncertainty has value and can be itself a useful resource for other purposes. The Utility is also aware that it is essential to identify the information requirements for monitoring and evaluation early in the design stage to ensure effectiveness and cost efficiency (Exhibit 28B, Tab G). **The Commission will be relying on DSM program evaluations for its**

determination of the appropriateness of DSM expenditures. Recovery in rates of DSM costs for continuing programs will depend upon measurement of performance as evidenced by credible evaluations that identify, among other things, the extent of market penetration, program impacts, cost performance, persistence of effects and reasons for non-participation.

BC Gas also stated that it had not yet considered the development of an accounting policy that related to the treatment of DSM program expenditures. At this early stage of DSM program development, this is understandable. However, the Commission wishes to advise BC Gas that it considers accounting and cost control systems relating to DSM program expenditures to be an important component of evaluation and monitoring. Cost control systems might include such items as the treatment of non-recurring program research and development costs, portfolio level costs that are not attached to a single program, or the appropriate period for the amortization of the costs of particular DSM programs. The Commission intends to take steps to examine this issue in the future with all B.C. utilities. Therefore, appropriate amortization periods for DSM expenditures will be determined by the Commission at a later date.

BC Gas further stated during the hearing that it would have been inappropriate and "probably ill-designed" to have proposed DSM incentive mechanisms while the Utility was still developing its programs and its evaluation and monitoring processes (T11: 1419-20). The Commission notes that, in the Commission's Phase 2 Decision concerning this Application, BC Gas has been directed to develop and submit a proposal on a DSM incentive mechanism to the BCUC by December 31, 1994. If a DSM incentive mechanism is implemented for BC Gas in the future, DSM evaluation procedures that are rigorous, reliable, and cost effective will be required for the determination of incentive levels as well as program design.

BC Gas has indicated that its goals for monitoring and evaluation will be based on the needs of other functional areas in the Utility, for uses such as establishing a base case forecast and identifying energy efficiency opportunities, for input as data into end-use modeling, and for other areas such as rate design, main extension and avoided cost refinements (Exhibit 28B, Tab G). **The Commission therefore directs BC Gas to address the integration of its DSM evaluation results with other IRP components, such as objectives, load forecasting and DSM program redesign, in its next IRP filing.**

BC Gas also agreed in its testimony that the BC Gas estimates of the DSM program impact would be engineering estimates, and would not include the impact of natural change in the market. The Company also stated that natural change and net program impacts were areas that would be targeted in the monitoring and evaluation component. The Commission agrees with BC Gas in its intention to apply its evaluation results to identification of the natural change in consumption patterns as represented in the pre-DSM load forecast. The Commission notes that end-use models can assist in the estimation of natural change in demand. However, the Commission also reiterates its concern with the current state of the end-use model employed by BC Gas and the model's reliance on data that is not specific to British Columbia. The development of end-use modeling capabilities with data and applicability specific to BC Gas customers, assisted wherever possible by evaluation and monitoring data, is encouraged, in order for BC Gas to be able to develop estimates of the natural change.

BC Gas forecast the costs for both its short-run and longer-run monitoring and evaluation plan. For the years 1994 through 1995, approximately $560,000 was included for specific programs in the Action Plan Budget. Deferral treatment of program specific monitoring and evaluation costs is incorporated in the treatment of all costs for each program, as discussed in Chapter 4.0. Additionally, BC Gas budgetted $1,245,000 for demand meters, data collection, analysis and modeling, of which BC Gas requested deferral treatment for $95,000 in 1994 and $180, 000 in 1995. The Commission is approving $85,000 for 1994 and $160,000 for 1995 as discussed in section 2.6.3.

4.0 DSM PROGRAMS AND DEFERRAL ACCOUNTS

In Appendix D of the BC Gas 1993 Phase B Rate Design Decision, the Commission reproduced the reasons for its approval for BC Gas to defer costs of DSM programs that the Utility had incurred to December 31, 1993. With regard to the BC Gas commercial sector fuel substitution programs the Commission said:

> "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."

In the current hearing, BC Gas applied for deferral of costs of its DSM programs for 1994 and 1995 and recommended a five-year amortization of these costs (Exhibit 28, p. 53, Exhibit 33). BC Gas also indicated its preference for rate base treatment of all of its DSM costs (T11: 1450).

In addition to stakeholder input, BC Gas relied on two common benefit/cost tests in its DSM analysis: the TRC and the RIM. The TRC is an estimation of the ratio of benefits to costs of a DSM program from the perspective of all utility customers, excluding externality (non-market) costs. The RIM test is an estimation of the ratio of benefits to costs of a DSM program from the perspective of a utility ratepayer who is not participating in the program; in other words the RIM test reflects the impact of the DSM program on unit rates. These and other benefit/cost tests are described in the BC Gas IRP (Exhibit 28B, Tab E).

All DSM programs included in the BC Gas proposed resource portfolio passed the TRC, but some of those programs did not achieve consensus within the stakeholder group (Exhibit 27, Section A, Tab 6 and Exhibit 28, pp. 46 and 47). A consensus was not reached with regard to four programs that demonstrated RIM benefit to cost ratios significantly lower than one. These were the Home Visit program, the Home Improvement program, the Apartment Hot Water Saver program and the Efficient Boiler program. All four programs ranked in the top seven in the MATA analysis, out of 30 supply and DSM program options considered by the stakeholder group.

<u>Commission Comments</u>

The Energy Efficiency Standards Regulations under the Energy Efficiency Act of B.C. were not mentioned in the design framework, but the proposed DSM programs do appear to have taken those regulations into account (Exhibit 80). The DSM programs that were reviewed by the stakeholder group included measures that were pre-screened using stringent benefit/cost criteria (T11: 1430-32).

Pre-screening of resource options may contribute to a more efficient consultation with stakeholders, but care must be taken not to screen out options using only one attribute that could be offset by the merits of other attributes. The customer payback test should not be used to eliminate measures from further consideration but it is a useful device in the design of a balance between an equitable distribution of costs as indicated by the RIM and marketability. Moreover, when consensus cannot be achieved within a stakeholder group the reasons for disagreement should be clearly set out in the IRP. This is useful information to the Commission.

Where feasible programs should attempt to channel costs of DSM measures back to program participants to limit RIM disparities. Financing programs are one example of limiting costs to non-participating customers. With regard to electricity fuel substitution programs, the Commission determined, in section 3.2 of this Decision, that the evidence advanced by BC Gas was insufficient to justify BC Gas embarking upon these programs. **Effective immediately, no further commitments to expenditures are to be made under off-electricity fuel substitution programs but already expended costs of existing programs are approved for deferral.**

BC Gas labour costs that are incremental to those approved in Phase 1 of this proceeding will not be approved for recovery through DSM deferral accounts. Exhibit 33 (Schedules B1 and B2) identify reduction for "DRIA and other" funding already provided through the Phase 1 settlement. BC Gas is to recalculate the "DRIA and other" offsets based on the Commission's findings on the proposed DSM deferral accounts.

4.1 Proposed Residential Programs

<u>Efficient Furnace Program</u>

BC Gas proposes a rebate to customers of $450 to encourage the installation of high-efficiency condensing furnaces in new homes and replacement furnaces in existing homes. These furnaces have an efficiency as high as 94 percent (Exhibit 80) compared with the minimum quality new furnace efficiency around 78 percent. The program would also include a $40 per unit incentive provided to dealers for advertising programs.

BC Gas noted that past high-efficiency furnaces suffered from problems with respect to corrosion of heat exchangers and noise. Problems with installations also existed.

The Commission believes that BC Gas should be satisfied that high-efficiency furnaces are problem-free furnaces before it offers inducements to its customers to choose them. The Commission notes that this type of market introduction in advance of legislation, proved successful in triggering provincial efficiency legislation in the case of refrigerators sponsored by Power Smart. It therefore does not wish to discourage further activity on this initiative provided furnace design problems are resolved by the manufacturing industry.

The Commission is also concerned that the TRC of 1.01 is barely break-even, the RIM is 0.4 and the likelihood of free riders is high. The Commission wishes to encourage those conservation programs with air emission benefits when the TRC is beneficial. However, in this case the quality of the technology is not assured and the conservation benefits are modest. **BC Gas should eventually reconsider this program, perhaps reducing the rebate to customers, or allowing the rebate with partial repayment by customers through their bills. The Commission is supportive of the $40 per unit incentive to dealers to encourage the sale and stocking of high-efficiency furnaces in the BC Gas service market. This incentive would assist in ensuring that the option of high-efficiency furnaces will be made available to consumers.**

Program Thermostat Savings Plan

The Program Thermostat Savings Plan is to offer a bill-stuffer and voucher valued at $50 for either the purchase or installation of a qualifying programmable set-back thermostat. The retail units and trade units range in price between $50 and $160.

BC Gas acknowledges many uncertainties with respect to this program including participation rates, persistence of installation and use, energy savings, peak savings and manufacturer perceptions. In spite of these uncertainties BC Gas calculates a TRC of 3.93 and a RIM of 0.76. The free rider estimates associated with vouchers are very high.

The Commission believes that BC Gas should obtain more information on the characteristics of programmable thermostat use compared to customer actions to reduce gas consumption by setting back standard thermostats at night and during the day when premises are unoccupied. For example, some households set back their thermostats at night and leave them set back until they return from work the following evening. If this type of action were prevalent, the introduction of programmable thermostats could have the perverse effect of increasing energy consumption in the morning peak period.

The Commission encourages BC Gas to undertake a pilot study, possibly larger than that proposed, of a limited number of customers to review their use patterns with existing thermostats, compared with the use of programmable thermostats. Until greater information is known with

respect to use, the Commission is concerned that the $50 vouchers may be costly, include a large element of free rider participation, and fail to achieve conservation/peak shaving objectives.

BC Gas Home Visit Program

The BC Gas Home Visit program proposes to offer homeowners a $70 saving on the supply and installation of hot water saving and energy saving devices by a qualified contractor. The cost is shared with the participant, $70 from BC Gas and $118 from the participant. The incremental cost is recovered through the gas bill, offering a customer payback in the first year. This program is aimed at the homeowner who is not comfortable with the installation of low-flow shower heads, faucet aerators, hot water pipe insulation and programmable thermostats. The contractor would also provide a "walk through" audit of the home encouraging other energy saving measures. The three-year program is estimated to have a TRC of 3.3 and a RIM of .64.

The Commission is concerned that this program is costly and includes a sizable contribution by BC Gas unless the $70 contribution were recovered in participant rates. The use of low-flow showerheads, faucet aerators, and hot water pipe insulation has existed for several years. Many customers who feel comfortable with the reduced water levels have installed these devices. The Commission is also concerned that the extent of savings from this program are largely unknown (Exhibit 28B, Tab F, p. 22). **Even though the Commission encourages programs with conservation benefits, it has severe reservations that the TRC expectations are optimistic and customer paybacks may not be achieved. Consequently, any expenditures on this program after 1994 are at risk until the benefits of the program are better know.**

BC Gas Home Improvement Program

The Home Improvement program is intended to offer prime rate financing (up to $5,000 for a term of five years) and an incentive of $500 to residential customers who include energy efficiency measures when doing home renovations. This program is intended to piggy-back with the Power Smart home improvement program. The benefit/cost test results provide only modest benefits with a TRC of 1.27 and a RIM of .62. The customer payback is 6.8 years and the loan volume over the three years of the gas finance plan is projected to total over $4 million. Moreover, if the average loan amount increases to over $3,000, the TRC will drop below one. **The Commission is concerned that this program may not pay back high benefits to the participants or the Utility.** There is likely to be a very large free rider element associated with this program, particularly with such a long customer pay back period. The program also seems to suffer from a high overhead compared to value of products delivered. BC Gas may wish to be less aggressive with this program so that only the financing component could be offered initially, or the interest rate on financing could move toward cost recovery.

GVRD Pilot Project

The GVRD Pilot Project is a partnership between BC Gas, B.C. Hydro, the GVRD, and the Cities of West Vancouver, North Vancouver and Vancouver. The pilot program encourages water and energy conservation through the professional installation of water and energy saving devices to 2,500 single and multi-family units with metering facilities. The pilot project is planned for the summer of 1994. The program has a very high benefit/cost rating with a TRC of 4.09, but with a RIM of 0.44.

The Commission believes that this low cost program will provide a great deal of information to BC Gas to assist the Utility in refining the merits of other programs related to conservation of hot water. Consequently, the Commission approves deferral treatment of expenditures related to this program.

Residential Water Heater Conversion Program

The Residential Water Heater Conversion program is an existing strategic load building program which has been in operation for several years. The program offers rebates for conversion of water heaters to natural gas from electricity, oil or propane. Rebates form the greatest program cost and effective April 1, 1994 would be $150 per conversion. After September 30, 1994, all of the rebate will be paid by BC Gas and none by other utilities. BC Gas also pays contractors a $20 incentive payment for each conversion. The TRC and RIM test results are both positive at 1.66 and 1.37 respectively. The customer payback is approximately 0.5 years if the conversion occurs at the time of failure of the existing water heater.

Although this programs shows positive TRC and RIM test results, the Commission views it as primarily an off-electric fuel substitution program. The Commission's views on such programs were set out in section 3.2. On that basis, therefore, **the Commission denies deferral of further expenditures on this program.** However, a future version of this program which restricted itself to conversions to natural gas from oil or propane, may be acceptable, and future BC Gas proposals will be considered by the BCUC.

Areas for Further Investigation

BC Gas also applied for deferral treatment of expenses for various activities or studies listed as "Areas for Further Investigation" in each of the residential, commercial, industrial and Natural Gas Vehicle ("NGV") markets. In the residential sector, the activities were as diverse as load research studies of decorative gas fireplaces, to participation in the R-2000 Home program, to studies of furnace tune-ups, to name a few. The total amounts for which deferral treatment was requested for such residential sector studies was $140,061 in 1994 and $111,180 in 1995. **The Commission believes that, although these may be beneficial activities to undertake, such activities are most appropriately funded as part of the normal operating and maintenance expenditures of the Utility. Therefore, specific deferral treatment of these expenditures is denied.**

4.2 Proposed Commercial Programs

Efficient Boiler Program

BC Gas has proposed an Efficient Boiler program which would offer an incentive rebate of $2 per 1000 Btu or $16 per 1000 Btu for mid-efficiency or high-efficiency boilers respectively. The program is aimed at achieving peak load reductions and strategic conservation, and the incentives are designed to overcome market barriers such as high first cost, product availability and reliability concerns based on earlier products (T11: 1458). Reliability concerns would be addressed by a joint industry/BC Gas training program to ensure effective installation and maintenance. The program also addresses a potential lost opportunity. BC Gas estimates a TRC test result of 2.91 and a RIM test result of 0.74. However, the relatively high TRC result was based to a large extent upon the success of the training program. Participant payback was estimated at 1.14 years, and free ridership was estimated to be 33 percent (Exhibit 88). Moreover, although the program did not obtain consensus from the IRP stakeholder group, it did achieve a MATA ranking of 6.

The Commission approves the deferrals of expenditures for the Efficient Boiler program, although it has reservations concerning the incentive levels and the degree of risk of the program. BC Gas should consider an increase in its evaluation budget, accompanied by an offsetting decrease in the incentive levels.

Apartment Hot Water Saver Program

The Apartment Hot Water Saver program is a strategic conservation program aimed at reducing energy consumption in apartment buildings by providing building operators with free, low-flow showerheads and faucet aerators. Domestic hot water load is expected to decrease by 28 percent as a result. The TRC test result is 3.72; the RIM test result is 0.52; and, the participant payback is 0.7 years. The program achieved a high MATA ranking (five), although it did not obtain stakeholder consensus.

The Commission notes the high risk that savings from this program may not be as great as anticipated due to uncertainties in program delivery, installation, measure persistence, annual savings, and free ridership (Exhibit 28B, Tab F, p. 55). **Given these uncertainties, the Commission directs BC Gas to re-evaluate this program after the GVRD pilot project results are available. The Commission will require further justification for this program if it is to extend past 1995.**

Firm to Interruptible Service Conversion Program

The Commercial Firm to Interruptible program is a peak shaving program designed to eliminate peak demand of large commercial firm service (Rate 5) customers by offering an incentive equal to 50 percent of the cost of a propane or propane/air backup fuel supply. The potential market is limited (approximately 11 customers) by the small number of Rate 5 customers. The participant payback is good at 1.8 years. The TRC and RIM test results are both very good at 8.1 and 4.19 respectively. The program also obtained the consensus support of the stakeholder group, although the MATA ranking was very low.

Recognizing the beneficial TRC and RIM test results and the approval of the stakeholder group, **the Commission approves BC Gas' request for deferral account treatment of costs for this program.** The high cost of capacity to meet peak load requirements is likely to provide additional opportunities for load shedding during peak periods.

Multi Family New Construction Program

The BC Gas Multi Family New Construction program is a load building program intended to promote natural gas for space heat and domestic water heating. The program would offer builders and developers an incentive to offset the incremental costs of installing natural gas equipment in new apartments. The program is designed to capture water heating and heating of corridor pressurization air as well as space heating load in order to keep the load profile as flat as possible. A builder developer could combine this program with the Efficient Boiler program. The TRC test results of 1.76 and 1.65 were estimated based on avoided cost estimates assuming a "customer" load profile and a "heating" load profile, respectively. Similarly, the RIM test results would fall between 1.09 and 0.90.

The Commission notes that this is an off-electric load building program which achieved marginal RIM test results, a low MATA ranking, and did not have the support of the entire stakeholder group. **Therefore, the request for deferral of expenditures for this program is denied.**

<u>Commercial Process Retrofit Program</u>

The Commercial Process Retrofit program is designed to add non-temperature sensitive or valley filling load by promoting conversion to natural gas for process loads. Conversions are encouraged with a rebate of $2 per GJ up to 50 percent of the conversion cost, to a maximum of $6000. The program TRC test result is 1.78, and the RIM test result is 1.62. The participant payback is six years. The consensus of the stakeholder group was to support this program although the MATA ranking was only 17. BC Gas has indicated that it has prior experience with this program and that it believes the program risks are low (Exhibit 28B, Tab F, p. 67).

The Commission notes that the TRC and RIM test results appear reasonably positive. Although the program involves some off electric fuel substitution, it also substitutes natural gas for oil and propane. **The Commission approves the deferral treatment of these program expenses, partly on the basis of the RIM score. The Commission will want to see evaluation results that indicate whether or not the assumptions leading to the positive RIM test result are valid, before it extends the program beyond 1995.**

<u>Construction Drying Program</u>

The Construction Drying program is an existing strategic load building program which promotes the use of natural gas as a cost-effective alternative to propane for construction drying. The program offers no financial incentives, but rather focuses on facilitating the market for natural gas heaters and raising industry awareness of the potential economic savings available. Therefore, program expenses are low. Participant payback for this program is immediate; the TRC test result is 5.09; and, the RIM test result is 1.82. Moreover, the program achieved the consensus support of the stakeholder group and had a MATA ranking of 14.

The Commission believes that since the program will build load by substituting natural gas for propane the environmental impact will be small. Given the low program expenses, the positive TRC and RIM test results and the support of the stakeholder group, the Commission approves the deferral of expenditures on this program.

Commercial Water Heater Program

The Commercial Water Heating program is designed to add flat load to the BC Gas system by providing commercial customers with financial assistance for converting existing water heating equipment to natural gas. The program is aimed at three distinct sub-markets: general commercial, multi-family apartment buildings, and food service operators. BC Gas calculated TRC and RIM test results for each sector individually and as a whole. In the aggregate the TRC test result was 1.44 and the RIM test result was 1.23. Participant paybacks were three years or less, and the program is considered by BC Gas to be a low risk program. However, the program achieved a low MATA ranking and did not have full support of the stakeholder group.

The Commission does not approve the deferral treatment of expenses for this program, which is an off-electric fuel substitution program. Therefore, the Commission sees the environmental benefits as uncertain as discussed in section 3.2. Furthermore, the TRC and RIM tests are marginal, and were coupled with a low MATA ranking and a lack of support by the full stakeholder group.

Areas for Further Investigation

BC Gas also applied for deferral treatment of expenses for various activities or studies listed as "Areas for Further Investigation" in each of the residential, commercial, industrial and Natural Gas Vehicle ("NGV") markets. In the commercial sector, several activities were identified as areas for further investigation:

- a study of building envelope measures in order to develop a marketable program;
- studies to identify the potential for broadened DSM activity in the commercial sector;
- encouraging "...the contracting and design communities to develop and implement programs that meet BC Gas' own load shape objectives";
- analyzing the commercial sector to further define sub-sectors and identify new opportunities for flat load addition measures;
- investigating new program delivery methods such as equipment rentals, financing, and energy service companies; and
- investigating gas cooling and gas heat pumps, district heating, and other new technology opportunities.

The total amounts for which deferral treatment was requested for commercial sector studies was $60,450 in 1994 and $135,732 in 1995. **The Commission believes that, although these may be beneficial**

activities to undertake, such activities are most appropriately funded as part of the normal operating and maintenance expenditures of the Utility. Therefore, specific deferral treatment of these expenditures is denied.

4.3 Proposed Industrial Programs

Industrial Cogeneration

BC Gas is proposing a significant amount of load building through its support of industrial cogeneration facilities that use natural gas to create heat and electricity. BC Gas recognizes significant uncertainties about the cost of back-up electricity, the sale of surplus electricity and the spread between the price of natural gas and electricity. By the year 2001, BC Gas anticipates that 2,054 annual TJ of gas could be utilized in B.C. cogeneration plants but that the cogeneration industry needs support from utilities and government (Exhibit 28B, Tab F, pp. 81-84). The cogeneration program was not subjected to the multi-attribute analysis conducted with the stakeholder group (T11: 1425). However, BC Gas will pursue only projects that have benefit to cost ratios of greater than 1 with the TRC and 1.1 with the RIM. BC Gas anticipates that, in the short-term "one or two high profile applications" will be implemented. To help achieve this the Utility is forecasting annual utility program costs of approximately $600,000 to $630,000 in 1994 and 1995. The bulk of the costs are represented by incentives to customers which amount to $500,000 in each year (Exhibit 33).

The Commission has significant reservations about this load building program. Any electricity generation benefits that displace load from the electric utility will receive appropriate incentives from the utility receiving the benefits. Consequently the gas utility should focus only on the benefit of increased gas sales for this purpose where the rates to other gas customers will be reduced. For example, an incentive might be considered if an existing, under-utilized gas main were used to deliver the natural gas and the net sales margin of the incremental sale was high.

Even with the foregoing conditions, the gas utility should only make a contribution when it is clear that a cogeneration project would not be viable otherwise. Also, the Commission is concerned that gas incentives not distort the competitive market for electricity generation from other fuels, notably wood waste.

The Commission will require much more justification before it will approve tariff amendments to allow either reduced rates or financial incentives for cogeneration load building projects. Deferral of costs for this program is not approved.

Industrial Audits

The Industrial Audits program will involve walk-through audits of small interruptible sales and firm transportation customers resulting in a set of recommendations being presented to each audited firm. No incentives are currently planned. The results of the first 20 audits will be evaluated and further economic assessment of the program is planned for early 1995.

The Industrial Audits program has a marginal TRC result of 1.05 and a RIM test result of 0.51. BC Gas sees some additional benefits to the program in providing information for the Industrial Cogeneration and Interruptible Sales Promotion programs, and for designing more specific programs in the future. This program also had the full support of the stakeholder group and the highest MATA ranking of any program.

The Commission sees potential benefits to such a program, but in light of the marginal TRC and RIM test results, is not convinced that a free audit is the optimal program design. In spite of the strong support of the program by the stakeholder group, **the Commission believes that BC Gas should consider a redesign of this program for its next Integrated Resource Plan, and specifically consider whether or not some partially refundable cost-sharing mechanism could not improve the benefit/cost test results. At this time, therefore, the Commission denies approval of deferral accounting treatment of the costs of this program.**

Industrial Interruptible Sales Promotion

This valley filling program is forecast to increase BC Gas commodity sales by 2,280 TJ (11 percent) by the year 2001 (T11: 1365). The Commission notes that the analysis of the Industrial Interruptible Sales Promotion program makes no mention of how the program compares with the present BC Gas valley filling activities such as off-system sales and sales to Burrard Thermal. While the Commission is prepared to accept BC Gas assurances that only applications having TRC and RIM exceeding 1.0 would be eligible for incentives, the Commission is concerned that the economic tests may not account for the fact that this program could displace some volumes presently sold off-system or to Burrard Thermal which may have a greater net value. Recognizing that the Burrard Thermal sales contract expires in 1998, this Interruptible Sales Promotion program may be more appropriate after that time.

The Commission specifically directs BC Gas not to spend funds on promotion or to provide any financial incentives to customers to participate in the Industrial Interruptible Sales Promotion program until it has addressed the above concern to the Commission's satisfaction. Deferral of promotion and financial incentive costs for this program is not approved.

Areas for Further Investigation

BC Gas has proposed two areas for further investigation:

- new technology developments in gas fired equipment and burner design, and
- evaluation of industrial manufacturing processes and the extent to which process improvements could contribute to increased energy intensity.

No expenditures requiring deferral treatment were indicated in BC Gas IRP for 1994. For 1995, $25,000 was requested for industrial sector studies. **As noted in the sections on residential and commercial DSM, the Commission believes that, although these may be beneficial activities to undertake, such activities are most appropriately funded as part of the normal operating and maintenance expenditures of the Utility. Therefore, specific deferral treatment of these expenditures is denied.**

4.4 Natural Gas For Vehicles Programs

NGV Program

BC Gas considered three levels of effort for this program. The first can be characterized as the status quo, currently approved by the Commission, where the objective is to retain 4,000 NGVs in the year 2000 from the current fleet of 6,400. BC Gas believes that this objective can only be met if customer goodwill and the NGV infrastructure are retained. Although the majority of vehicles will be conversions from gasoline to dual fuel, the utility expects that a growing number of vehicles will be original equipment manufactured ("OEM") and will operate only on natural gas. The current annual funding for this level is approximately $450,000. A more aggressive alternative was considered that would target 15,000 NGVs by the year 2000, with an emphasis upon OEMs. This alternative would involve financial support for operators of new fueling stations and could involve operating subsidies for the retailers for up to five years. The IRP Stakeholders reached a consensus on a third alternative targeting 10,000 vehicles by the year 2000, 70 percent of which would be OEM. All three alternatives pass the TRC and the RIM tests and provide customers close to a nine and a half month payback on their share of the investment (T11: 1455, Exhibit 28B, Tab F, pp. 99-101). The 10,000 vehicle program alternative is forecast to cost between $1,370,000 and $2,580,000 per year from 1994 to 1997 (Exhibit 33).

BC Gas identified the composition of its proposed 10,000 vehicle target and the market segments that are expected to provide the greatest opportunity. They also explained that, in terms of its promotional efforts and the need for an effective program:

> "The necessary market research has not yet been done for our service area, and, if approved, will be undertaken very early in the program."
>
> "...Without an effective Utility NGV program, there is considerable risk that BC will lose its existing NGV infrastructure and that international NGV vehicle developments will pass by." (Exhibit 27, Tab E, Item 1, p. 2 and 4)

Commission Determinations

Although no intervenor directly addressed any NGV program, other than the BC Transit program, the Commission notes the statement, which appeared in the draft paper prepared by the B.C. Energy Council, "An Energy Strategy for British Columbia":

> "Natural gas has an important transitional role. The role involves forward-looking, high-efficiency applications that do not preclude conversion to sustainable fuels due to building, equipment or infrastructure design."

The problem for the Commission, posed by BC Gas' proposed NGV program, is to determine how much BC Gas effort is necessary to sustain the NGV infrastructure in B.C., until it can be determined whether or not the OEM market will develop elsewhere in North America. As there is a distinct possibility that this OEM development may not occur to any significant extent because of infrastructure limitations or because of the success of competing fuels, the Commission is concerned that an aggressive marketing target may be inappropriate at this time. Expressed in terms of numbers of vehicles, the Commission cannot be reasonably certain that 15,000 or 4,000 is the appropriate number. The question then is, what needs to be done to identify the market potential of and barriers to the adoption of NGV. The longevity of the technology should also be carefully researched because other alternatives are also making significant progress.

The Commission directs BC Gas to continue with the status quo level of effort reflected in its case 1 NGV program, but to identify, in its next IRP, the market research and funding that is required for a more thorough understanding of the potential for NGV in B.C., specific market segment barriers to the adoption of NGV, and the development of competing alternative fuel solutions. Deferral of costs for NGV case 3 is not approved.

NGV Bus Incentive Grant

BC Gas applied in Exhibit 46 for approval of an agreement which provided BC Transit with an incentive grant of $50,000 per bus towards the purchase of 25 new natural gas fueled buses. An expedited approval was sought in order to accommodate a BC Transit timing deadline of July 1, 1994 for ordering the new buses. The Commission responded to this request by issuing Commission Order No. G-44-94 dated June 23, 1994 which approved the application.

By way of background it should be noted that the present application was made in response to a letter to BC Gas from the Commission dated April 26, 1994. That letter suggested that in view of the marginal benefits of this project as shown in an earlier BC Gas application dated April 12, 1994, it might be more appropriate to consider it as an extension of the previous BC Transit Demonstration Project which, as the name implies, was intended to demonstrate to BC Transit the advantages of natural gas as a bus fuel. (The Commission has, from time-to-time, seen fit to approve certain "demonstration projects" which are expected to have favourable long-term benefits, but have short-term costs which do not pass normal financial tests.) Both applications are otherwise the same.

The significance of considering the application in this way is that it would then be reasonable to include revenues from the BC Transit refueling station built for the original demonstration project as an ongoing benefit. If such revenues are considered, analysis by Commission staff (related to the April 12, 1994 application) showed that due to safeguards in the agreement, the grant proposal requires no subsidy from other customers, even in a worst case where BC Transit disposes of the 25 new buses after only two years operating experience. The financial analysis contained in Exhibit 46 is conservative in that it does not consider these revenues. The Commission also notes that the IRP cost/benefit test calculations are conservative in assuming the imposition of road taxes in 1997 and including long-term distribution system reinforcement costs which, while appropriate if NGV buses become the standard throughout the Transit system, are not required for this demonstration because the refueling location is served directly from the transmission system.

If not considered as a demonstration project, this activity would only be beneficial in the long term from a ratepayer impact perspective if the operating and maintenance costs proved satisfactory to BC Transit so that it purchased a significant number of additional buses. Based on its decision to purchase some 25 buses initially, BC Transit apparently expects this will be the case. The continuing use of buses equipped with factory designed NGV engines in other jurisdictions (T14: 1742) also provides reason to believe that BC Transit is correct in assuming that its previous unsatisfactory experience with converted engines will not be repeated.

Considering the environmental benefits in terms of reduced exhaust emissions which can be obtained by using natural gas instead of diesel fuel (Exhibit 46), the Commission agrees with BC Gas and CAC(BC) (T14: 1744) that this is a desirable project from society's perspective.

In its approval of this grant program in Commission Order No. G-44-94, the Commission has considered it as a demonstration project, and notes that regardless of the outcome, no subsidy is required from other customers. The Commission is hopeful that the project will lead to long term use of B.C. natural gas as a bus fuel, thereby contributing to improved air quality in the GVRD.

Other NGV Projects

BC Gas provided brief descriptions of two other NGV projects in its IRP, one involving B.C. Ferries and another involving Canada Safeway. No discussion of either of these projects took place during the hearing.

The Commission notes that while the B.C. Ferries project shows a TRC result of 2.95, the RIM result for this project is only 0.78, making it the only strategic load building project to have a RIM of less than 1.0. However, these results appear very preliminary since a choice between LNG and CNG has not yet been made. The Commission also notes that there may be an original equipment opportunity for natural gas fueling of the recently announced catamaran service to Vancouver Island.

The Commission is unsure about the need for further expenditures for the Canada Safeway project based on the apparent success of the Canada Safeway demonstration project.

Considering these circumstances, the Commission will expect BC Gas to file detailed justifications at some future time before it is prepared to consider approval of incentives beyond those forecast for 1994 for either of these projects. Deferral of costs beyond this level is not approved.

BC Gas also applied for deferral treatment of $35,000 in each of 1994 and 1995 for "Areas for Further Investigation". Two specific market research projects were identified; one would be a study of the relative fuel prices, including the taxation components of alternative vehicle fuels, the second would attempt to determine the attitudes of potential buyers toward OEM natural gas vehicles.

As the Commission has noted in its comments on other DSM for market segments, **the Commission believes that, although these may be beneficial activities to undertake, such activities are most appropriately funded as part of the normal operating and maintenance expenditures of the Utility. Therefore, specific deferral treatment of these expenditures is denied.**

4.5 Non-Market Specific DSM Activities

BC Gas also applied for deferral accounting treatment of $100,000 in each of 1994 and 1995 for non-market specific activities related to its DSM Action Plan (Exhibit 33). These activities included updating the benefit/cost model for improved flexibility and consultation assistance in strategy and program design (Exhibit 28, p. 99).

The Commission believes that these activities represent valid areas of activity, but that they are appropriately considered part of the Utility's normal O&M activities. Therefore the deferral account request is denied.

4.6 Summary of DSM Programs

The total DSM 1994 Action Plan budget was $3,780,567. The related deferral account request was $1,746,000 as a result of reductions for delayed implementation of industrial programs, DRIA, and funds already incorporated in capital or O&M budgets; these reductions were partly offset by some additions for incremental labour. For 1995, the DSM Action Plan budget was $11,814,522 and the related deferral account request was approximately $9,947,000. A breakdown of Action plan budgets, adjustments and deferral account requests by market segment is provided in Schedules B1 and B2 of Exhibit 33 which are attached to this Decision as Appendix A.

Because BC Gas' adjustments for deriving the deferral account requests from the DSM Action Plan budget were done by groups of programs, and because the Commission has reviewed the DSM plans of the Utility on a program-by-program basis, the Commission cannot approve an exact deferral amount. BC Gas will be required to revise its adjustments based on the Commission's views on deferral treatment of expenses for each DSM program.

For convenience, Table 4-1, "DSM Program Summary" follows, and showing the key benefit/cost test results, the results of the stakeholders consultations for each program, the program budget from the IRP Action Plan and a summary of the Commission's views. Although the Commission has expressed reservations about certain DSM programs, it is pleased that BC Gas has considered a broad slate of programs showing the range of initiatives it has undertaken.

TABLE 4-1 DSM PROGRAM SUMMARY

				DSM DEFERRALS	BC Gas 1994	Budget 1995	BCUC Comments
RESIDENTIAL MARKET PROGRAMS							
9.4.a	*Efficient Furnace*			*(Conservation program)*			
		TRC	1.01	Incentives	$0	$360,000	The Commission notes the marginal TRC and RIM results,
		RIM	0.4	labour, promotion	$38,500	$253,971	but is aware that this continues a pre-existing program.
		MATA	8	evaluation	$10,760	$39,480	Thus, the Commission approves committed expenditures for
		CONSENSUS		**total**	**$49,260**	**$653,451**	1994, but not beyond without further justification.
9.4.b	*Program Thermostat*			*(peak shaving and strategic conservation)*			
		TRC	3.93	Incentives	$0	$325,000	The Commission approves money spent in 1994, but is
		RIM	0.76	labour, promotion	$14,708	$177,581	uncertain that the savings anticipated will materialize.
		MATA	4	evaluation	$0	$25,080	Therefore, the Utility should re-apply for expenditures
		CONSENSUS		**total**	**$14,708**	**$527,661**	beyond 1994, at a pilot program level.
9.4.c	*Home Visit*		*(peak shaving and strategic conservation)*				
		TRC	3.3	Incentives	$0	$210,000	The Commission approves expenditures in 1994, but
		RIM	0.64	labour, promotion	$19,708	$166,776	perceives potential overlap with the GVRD pilot. Therefore,
		MATA	3	evaluation	$0	$57,280	it wishes to see evaluation results from the GVRD project
		BC GAS		**total**	**$19,708**	**$434,056**	before further approvals.
9.4.d	*Home Improvement*			*(peak shaving and strategic conservation)*			
		TRC	1.27	Incentives	$0	$250,000	The Commission is not convinced of the benefits of this
		RIM	0.62	labour, promotion	$30,586	$179,333	program, particularly in view of the low TRC test result,
		MATA	7	evaluation	$15,760	$67,960	and the risk that loans in the upper range of allowable
		BC GAS		**total**	**$46,346**	**$497,293**	amount could drop the TRC below 1. Monies already spent
							up to a 1994 maximum of $46,346, but no further, are
							approved.

TABLE 4-1 DSM PROGRAM SUMMARY

RESIDENTIAL PROGRAMS (Contd.)					BC Gas Budget 1994	1995	BCUC Comments
9.4.e	*GVRD Pilot Project*			*(strategic conservation)*			
		TRC	4.09	Incentives	$42,825	$0	Deferral of expenditures for the GVRD pilot project is
		RIM	0.44	labour, promotion	$36,255	$0	approved, given its high TRC result and collaborative aspect.
		MATA	2	evaluation	$6,336	$0	Any reapplication for the Home Visit program should occur
		CONSENSUS		**total**	**$85,416**	**$0**	after evaluation of the GVRD pilot project.
9.4.f	*Water Heater Conversion Program*				*(strategic load building)*		
		TRC	1.66	Incentives	$431,350	$431,350	The Commission does not approve deferral of expenditures
		RIM	1.37	labour, promotion	$148,477	$148,477	on the Water Heater Conversion program. This is primarily
		MATA	24	evaluation	$0	$51,600	an off-electric fuel switching program and the Commission's
		BC GAS		**total**	**$579,827**	**$631,427**	comments elsewhere in this Decision apply here. An off-oil
							or propane program may be acceptable. Future BC Gas
							proposals will be considered by the BCUC.
9.4.g	*Areas for further study*						
				Furnace Tune up	$0	$28,898	These amounts are not approved for deferral. Although
				New Constr. Res.	$47,779	$0	they may be beneficial actions to undertake, the
				HERS Research	$20,000	$0	Commission believes they are appropriately undertaken
				Fireplace Research	$14,432	$24,432	in the course of the normal operating and maintenance
				R-2000 Home	$57,850	$57,850	expenditures of the utility.
				total	**$140,061**	**$111,180**	
Total Res. Program Action Plan Appl.					**$935,326**	**$2,855,068**	
Action Plan Budget for Residential Programs Approved for Deferral					**$215,438**	**Nil**	

TABLE 4-1 DSM PROGRAM SUMMARY

COMMERCIAL MARKET PROGRAMS					BC Gas Budget 1994	1995	BCUC Comments
9.4.h	*Efficient Boiler*			*(Peak shaving and strategic conservation)*			
		TRC	2.91	Incentives	$0	$1,961,000	The Commission approves deferrals of expenditures for the
		RIM	0.74	labour, promotion	$1,000	$115,960	Efficient Boiler Program, with reservations about risk and
		MATA	6	evaluation	$10,760	$10,080	incentive levels. BC Gas should consider increasing its
		BC GAS		**total**	**$11,760**	**$2,087,040**	evaluation budget with an offsetting decrease in incentives.
9.4.i	*Apartment Hot Water Saver*				*(Strategic conservation)*		
		TRC	3.72	Incentives	$4,400	$232,600	The Commission approves deferrals for this program, but
		RIM	0.52	labour, promotion	$4,688	$67,652	has concerns that savings from this program are uncertain.
		MATA	5	evaluation	$9,320	$10,080	The Commission notes the participant payback is very short
		BC GAS		**total**	**$18,408**	**$310,332**	but that several uncertainties exist regarding program
							benefits. BC Gas should re-evaluate the program after the
							GVRD pilot project results. The Commission will require
							further justification, if the program is to extend past 1995.
9.4.j	*Firm to Interruptible*			*(peak shaving)*			
		TRC	8.1	Incentives	0	$382,859	This program shows very beneficial TRC and RIM test
		RIM	4.19	labour, promotion	$7,208	$9,300	results, and the approval of the stakeholder group. The
		MATA	29	evaluation	$0	$2,880	Commission approves deferral of appropriate program
		CONSENSUS		**total**	**$7,208**	**$395,039**	expenditures.
9.4.k	*Multi-Family New Construction*				*(Load building)*		
		TRC	~1.7	Incentives	$82,500	$330,000	This program, which is primarily an off-electric load
		RIM	~1	labour, promotion	$14,368	$46,879	building program, shows a very marginal RIM test result.
		MATA	26	evaluation	$0	$25,840	The Commission does not approve deferral of expenditures
		BC GAS		**total**	**$96,868**	**$402,719**	for this program.

TABLE 4-1 DSM PROGRAM SUMMARY

COMMERCIAL PROGRAMS (Contd.)				Budget	Budget	BCUC Comments
				1994	1995	
9.4.l	*Commercial Process Retrofit*			*(Load Building)*		
	TRC	1.78	Incentives	$30,163	$120,650	This program shows reasonable TRC and RIM test results.
	RIM	1.62	labour, promotion	$46,519	$166,706	Although it involves some off-electric fuel substitution, it
	MATA	17	evaluation	$0	$84,480	also involves substitution of natural gas for oil and propane
	CONSENSUS		**total**	**$76,682**	**$371,836**	These program expenses are approved partly on the basis of
						the RIM result. The Commission will want to see evaluation
						results that indicate whether the assumptions leading to the
						RIM result are reasonable.
9.4.m	*Construction Drying*		*(Load Building)*			
	TRC	5.09	Incentives	$0	$0	This program will build load by substituting natural gas for
	RIM	1.82	labour, promotion	$18,753	$47,388	propane. Therefore the net change in environmental impact
	MATA	14	evaluation	$7,880	$0	will be small. The TRC and RIM results are good. Deferral
	CONSENSUS		**total**	**$26,633**	**$47,388**	account treatment for this program is approved.
9.4.n	*Commercial Water Heater Program*			*(Load Building)*		
	TRC	1.44	Incentives	$36,850	$147,400	This program is an off-electric fuel substitution program.
	RIM	1.23	labour, promotion	$40,075	$144,141	The environmental costs or benefits are uncertain, the TRC
	MATA	25	evaluation	$0	$73,120	and RIM results are marginal, and the program did not have
	BC GAS		**total**	**$76,925**	**$364,661**	stakeholder support. This deferral is not approved.
9.4.o	*Areas for Further Study*					
			Building Envelope	$20,740	$21,316	As noted in the comments regarding residential 'areas for
			Characterize Com.	$19,320	$20,472	further study', these ideas have some merit, but it is the
			Efficiency proposal	$0	$39,669	Commission's view that they could and should be covered
			Del. Method study	$8,116	$0	under the existing O&M budget. Therefore deferral of
			Mkt Seg./Penetr'n	$0	$18,701	program expenditures is not approved.
			Comm Other Areas	$12,274	$35,574	
			total	**$60,450**	**$135,732**	
Total Com Programs Action Plan Appl.				**$374,934**	**$4,114,747**	
Action Plan Budget for Commercial						
Programs Approved for Deferral				**$140,691**	**$3,211,635**	

TABLE 4-1 DSM PROGRAM SUMMARY

SUMMARY OF RESIDENTIAL /COMMERCIAL PROGRAM EXPENDITURES	BC Gas Budget 1994	BC Gas Budget 1995	BCUC Comments
Total Res/Comm Prog. Action Plan Appl.	$1,310,260	$6,969,815	
Action Plan Budgets for Programs Approved for Deferral			
Residential	$215,438	Nil	
Commercial	$140,691	$3,211,635	
Residential/Commerical Subtotal	$356,129	$3,211,635	
Program Development Adjustment	$87,000	$133,205	Allowed pro rata adjustment to $320,000 labour cost for program development, from Schedules B1 and B2 of Ex.33
Total Residential/Commercial*	$443,129	$3,344,840	
		*	Note: Amounts to be deferred must be adjusted to account for other differences between the deferral account request and the Action Plan Budget due to DRIA, incremental labour, funds already included in capital or O&M budgets, and other adjustments as set out in Exhibit 33, Schedules B1 and B2.

TABLE 4-1 DSM PROGRAM SUMMARY

INDUSTRIAL MARKET PROGRAMS					BC Gas Budget		BCUC Comments
					1994	1995	
9.4.p	Energy Audit Program			*(Conservation)*			
		TRC	1.05	Incentives	$0	$0	The Commission is not convinced that a free audit is the
		RIM	0.51	Labour, Promotion	$115,000	$115,000	best program design. BC Gas should consider a redesign for
		MATA	1	Evaluation	$0	$29,280	its next IRP, perhaps using a cost sharing/partially
		CONSENSUS		**Total**	**$115,000**	**$144,280**	refundable cost sharing mechanism. Deferral account
							approval is denied.
9.4.q	Interruptible Sales Promotion				*(Valley Filling)*		
		TRC	1.37	Incentives	$0	$500,000	This program did not include the costs of foregone off-
		RIM	1.14	Labour, Promotion	$46,374	$46,374	system sales. Therefore the Commission does not approve
		MATA	30	Evaluation	$0	$0	the request for deferrals for this program.
		CONSENSUS		**Total**	**$46,374**	**$546,374**	
9.4.r	Cogeneration			*(Load Building)*			
		TRC	1	Incentives	$500,000	$500,000	The Commission believes it is premature to offer incentives
		RIM	1.1	Labour, Promotion	$104,333	$104,333	for Cogeneration. Therefore program expenditures are not
		MATA	-	Evaluation	$0	$23,820	approved.
		BC GAS		**Total**	**$604,333**	**$628,153**	
9.4.s	Areas for Further Study						
				New Technology	$0	$25,000	The Commission believes that monitoring new technology
				Energy Intensity	$0	$0	is useful but that such activities should be funded out of
				Total	**$0**	**$25,000**	normal O&M expenditures. Deferrals for new technology
							are not approved.
Total Industrial Programs Application					**$765,707**	**$1,343,807**	
Delayed implementation of programs					($695,000)	($75,000)	(Exhibit 33: Schedules B1 and B2)
Total Industrial Deferral Acct. Request					**$70,707**	**$1,268,807**	
BCUC Approved Ind. Deferral Amount					**$0**	**$0**	

TABLE 4-1 DSM PROGRAM SUMMARY

NATURAL GAS VEHICLE MARKET					BC Gas Budget 1994	1995	BCUC Comments
9.4.t	NGV Case 3						
		TRC	3.33	Incentives	$210,000	$250,000	The Commission does not support this level of expanded
		RIM	1.19	Labour, Promotion	$1,159,600	$1,265,900	program marketing, as explained in section 4.4. This
		MATA	-	Evaluation	$0	$0	program is not approved for deferral treatment of costs.
		CONSENSUS		**Total**	**$1,369,600**	**$1,515,900**	
9.4.u	BC Transit Bus Project						
		TRC	1.11	Incentives	$0	$1,250,000	This program was approved by an earlier Commission Order
		RIM	0.97	Labour, Promotion	$100,000	$100,000	as explained in Section 4.4.
		MATA	11	Evaluation	$0	$0	
		CONSENSUS		**Total**	**$100,000**	**$1,350,000**	
9.4.v	BC Ferries Project						
		TRC	2.95	Incentives	$0	$0	BC Gas is directed to file detailed justifications at some
		RIM	0.78	Labour, Promotion	$100,000	$500,000	future time before the Commission will consider approval of
		MATA	9	Evaluation	$0	$0	1995 expenditures. Approval of costs forecast for 1994
		CONSENSUS		**Total**	**$100,000**	**$500,000**	is approved, but not beyond that.
9.4.w	Canada Safeway Project						
		TRC	1.36	Incentives	$0	$0	BC Gas is directed to file detailed justifications at some
		RIM	1.14	Labour, Promotion	$0	$0	future time before the Commission will consider approval of
		MATA	13	Evaluation	$0	$0	expenditures on this program.
		CONSENSUS		**Total**	**$0**	**$0**	

TABLE 4-1 DSM PROGRAM SUMMARY

NATURAL GAS VEHICLE MARKET		BC Gas 1994	Budget 1995	BCUC Comments
9.4.x	Areas for Further Study			
	Tax/Fuel Price	$17,000	$18,000	Such studies may be justifiable, but would appropriately be conducted out of the Utilities normal O&M budget. Deferral account treatment is not approved.
	OEM/NGV Mkt Res	$18,000	$17,000	
	Total	**$35,000**	**$35,000**	
Total NGV Programs Action Plan Budget		**$1,604,600**	**$3,400,900**	
Action Plan Budget for NGV Programs Approved for Deferral **		**$200,000**	**$1,350,000**	
			**	**Note:** Amounts to be deferred must be adjusted to account for differences between the deferral account request and the Action Plan Budget due to DRIA, incremental labour, funds already included in capital or O&M budgets, and other adjustments as set out in Exhibit 33 , Schedules B1 and B2.

NON-MARKET SPECIFIC ACTIVITIES		Budget 1994	Budget 1995	BCUC Comments
9.4.y	Benefit/Cost Model Results	$0	$0	
	Strategic Program and Design consulting	$100,000	$100,000	Again, these studies represent valid areas of review, but are appropriately considered as part of the Utility's normal O&M activities. Therefore the deferral account request is denied.
	Total	**$100,000**	**$100,000**	
Action Plan Budget for Non-Market Specific Activities Approved for Deferral		$0	$0	

TABLE 4-1 DSM PROGRAM SUMMARY

	Budget 1994	Budget 1995	
TOTAL BC GAS DSM ACTION PLAN BUDGET	$3,780,567	$11,814,522	
Action Plan Budget by Sector for Programs approved for Deferral			
Residential/Commercial	$443,129	$3,344,840	As noted above and in the text of the Commission's Decision
Industrial	$0	$0	all amounts in this Table represent the IRP Action Plan
NGV	$200,000	$1,350,000	Budget associated with the DSM programs for which
Non-Market Specific	0	0	deferral treatment of appropriate expenses is allowed. The
			actual amounts which may be deferred must be recalculated
Total	$643,129	$4,694,840	by BC Gas to adjust for "DRIA and other" funds.

5.0 MAIN EXTENSION POLICY

5.1 Background

In the BC Gas Phase B Rate Design Decision, the Commission approved the DCF methodology proposed by BC Gas for evaluating potential main extensions, but ordered certain modifications to the methodology. Subsequently, the Commission approved the use of an interim DCF test while the Utility did further work on the changes ordered, and directed the Utility to file an application by April 15, 1994, for a test which included avoided costs and appropriate DSM tests to more closely align the test with the Utility's IRP (Exhibit 95).

By way of a May 11, 1994 letter (Exhibit 31), BC Gas filed a preliminary report by RCG/Hagler Bailly on main extension tests (Exhibit 32). During the hearing the Utility also filed a discussion paper titled "Further BC Gas Submission on Main Extension Policy" (Exhibit 71).

5.2 Position of the Utility

During testimony, Mr. Touhey, for BC Gas, stated (T13. 1634-5) that the Utility was requesting approval to begin a stakeholder consultative process to further study possible changes to its main extension test and that in the meantime it wished to leave the interim DCF-based test unaltered. In addition, through Exhibit 33, the Utility requested approval for deferral account treatment of $15,000 in 1994 for a main extension study.

In support of its request for further study through a stakeholder collaborative, and in defense of its failure to submit a definitive main extension test proposal as requested by the Commission, the Utility argued that its examination of the issue demonstrated an unexpectedly large number of potential problems flowing from many of the test implementation options.

Prominent among the cited concerns was a fairness issue related to the possibility of causing new customers to pay twice for the same service; once at the time of connection through a customer contribution to meet a high hurdle rate and subsequently through system-average costs rolled through to all consumers, including newly-connected ones. Another area of concern was the risk of incompatibility between the economic terms of the test and promotion of energy efficiency, insofar as efficient new customers could be penalized through a lower revenue stream and higher hurdle rate. In addition, the Utility identified the need for fair and equal treatment of avoided costs among competing fuels and between competitive gas and electric utilities; the latter, it argued, required inter-utility consultation in fixing the terms of any main extension test.

Furthermore, BC Gas argued possible pending government policy changes suggested a cautious response. BC Gas filed (Exhibit 91) a letter from the Ministry of Energy, Mines and Petroleum Resources to the Commission, which suggested that a broadly-based collaborative process should be considered to examine main extension policies. In addition, a recent report of the B.C. Energy Council proposed elimination of main extension tests and their replacement by "other decision criteria".

5.3 Intervenor Views

Counsel for the Energy Coalition provided extensive cross-examination of BC Gas' Main Extension Panel but in final argument took no position on the issue.

Counsel for CAC(BC) did not cross-examine the BC Gas panel but in final argument took the view that BC Gas' failure to file a specific main extension policy should result in disallowance of BC Gas' hearing costs with respect to that portion of the proceedings and that BC Gas should be ordered to provide a specific proposal by a specified date (T16: 1944).

Mr. Rawlyk, for Energy Resources Management, felt it important that the main extension test eventually be aligned with the Utility's IRP but supported further examination, through a stakeholder process, as the next step.

5.4 Commission Determinations

The Commission continues to believe that logic requires the effect of any new main extension test to be in harmony with the objectives and measures incorporated in the Utility's IRP. At the very least, the two should not be incompatible.

The Commission is satisfied that, through the RCG/Hagler Bailly Report (Exhibit 32), BC Gas made a serious attempt to comply with the Commission's February 21, 1993 directive. It also recognizes that the report, in identifying implementation options, disclosed a sufficient number of troublesome inter-related effects to require a cautious approach.

The Commission recognizes the need for consistency and equity in the treatment of new customers of the Utility through its main extension test. The former test also provided stability in that it endured for several decades. There was evidence that the interim DCF test is functioning reasonably well, albeit with an increased requirement for customer contribution because of a higher hurdle rate. **The Commission, therefore, accepts the BC Gas proposal for maintenance of the interim test and further study of the implications of the changes required by the Commission. It also accepts the**

proposal for the involvement of an augmented IRP stakeholder collaborative. The latter shall not be a new initiative but shall be accomplished by expansion of the ongoing IRP stakeholder collaborative to incorporate regional representatives of appropriate organizations directly impacted by main extension policies. Inter-utility participation may also be appropriate.

BC Gas proposes a timetable leading to a November 1, 1994 submission to the BCUC. Exhibit 91, the Ministry letter, speaks of a December 1, 1994 date for receipt by the Ministry of the B.C. Energy Council's Plan which "is expected to offer a road map to providing electricity and gas service to customers currently not served."

The Commission notes that the majority of gas main extensions are installed during the spring-summer-autumn construction season. It therefore believes that a spring 1995 target date for an amended main extension test will be satisfactory. **To allow for due consideration and approval by the Commission, a January 31, 1995 deadline is required for receipt, by the Commission, of a definitive BC Gas main extension proposal, compatible with the Company's current IRP. In making its submission, BC Gas shall indicate the extent to which the requirements of the test are supported by the stakeholder collaborative. It shall also compare how the proposed amended test, had it been in place, would have affected those main extensions installed in 1993 and 1992 under the interim rules and under the former rules.**

5.5 Main Extension Study Deferral Account

It is assumed that this request for deferral of a $15,000 account in 1994 relates to the RCG/Hagler Bailly consultant study. The Commission acknowledges that the report did provide a useful starting point for exploration of main extension issues during the hearing. Nevertheless, the Utility did not use the report to develop a definitive main extension test. In fact, it filed an additional discussion paper and concluded by requesting referral to a stakeholder collaborative for further study.

The Commission, therefore, denies approval of deferral treatment of costs for the main extension study at this time. It is prepared to reconsider the request after a definitive test proposal is presented at which time it will be able to judge the extent to which the findings of the RCG/Hagler Bailly study have been usefully incorporated into the test. If the deferral account request is intended to relate to a new study of main extension test issues, the request for such an account is denied.

DATED at the City of Vancouver, in the Province of British Columbia this 12th day of August, 1994.

F.C. Leighton
Commissioner

SCHEDULE B1
REQUEST FOR DEFERRAL ACCOUNT
INTEGRATED RESOURCE PLANNING
for 1994

ACTION	ACTION PLAN BUDGET	COMMENTS	DEFERRAL AMOUNT
IRP Deferral Account # 179-064			
9.1 File IRP	$50,000		$50,000
9.2 Public Involvement	$173,000		$173,000
9.3 End Use Forecasting	$0	Costs for model included in 9.7. Costs for data included in 9.5.	$0
9.5 Monitoring and Evaluation	$585,000	add $10,000 for incremental labour to operate DAS model. * minus $500,000 for equipment costs included in capital budget.	$95,000
9.6 Supply Side Resources	$2,360,000	minus $2,320,000 for LNG study request, filed 28 April 1994.	$40,000
9.7 Resource Integration	$170,000	add $43,000 for incremental labour to operate end use/ROM model. * deferral amount assumes remaining funds approved in Order G-69-93 for end use/ROM model development is not available. (Sch A, last two pages)	$213,000
9.8 Technology Development	$0	add $175,000 (see Sch. D)	$175,000
9.9 Energy Aware Guide	$40,000		$40,000
9.10 Community Integrated Energy	$20,000		$20,000
9.11 IRP Issues	$55,000	add $25,000 for misc. consulting for IRP related activities.	$80,000
Def Account #179-064 - IRP TOTAL	**$3,453,000**		**$886,000**
DSM Deferral Account #179-063			
9.4 Demand Side Management			
Res/Comm Programs	$1,310,260	add $320,000 for labour costs for program development. (see Sch. C) minus $470,000 for program costs which include DRIA and other operating costs. deferral amount includes remaining funds from rebate incentive grants for water heaters and commercial & multi-family programs.	$1,160,260
Industrial Programs	$765,707	minus $695,000 in 1994 for delayed implementation of programs due to hearing rescheduling.	$70,707
NGV Programs	$1,604,600	deferral amount represents additional incremental labour needed for revised programs after public input. Remaining funds in O&M and Capital.	$415,000
Non-Mkt Specific Activities	$100,000		$100,000
Def Account #179-063 - DSM TOTAL	$3,780,567	Total has been rounded	$1,746,000
TOTAL IRP-DSM COSTS	**$7,233,567**		**$2,632,000**

* Labour to operate these models was originally budgeted in IRDP deferral account, #179-098; the settlement eliminated this account and provided that these incremental IRP related activities could be applied for and justified separately.

SCHEDULE B2
REQUEST FOR DEFERRAL ACCOUNT
INTEGRATED RESOURCE PLANNING
for 1995

ACTION	ACTION PLAN BUDGET	COMMENTS	DEFERRAL AMOUNT
IRP Deferral Account			
9.1 File IRP	$50,000		$50,000
9.2 Public Involvement	$210,000		$210,000
9.3 End Use Forecasting	$0	Costs for model included in 9.7. Costs for data included in 9.5.	$0
9.5 Monitoring and Evaluation	$660,000	add $20,000 for incremental labour to operate DAS model. * minus $500,000 for equipment costs included in capital budget.	$180,000
9.6 Supply Side Resources	$4,250,000	minus $4,250,000 for LNG study request, filed 28 April 1994.	$0
9.7 Resource Integration	$20,000	add $85,000 for incremental labour to operate end use/ROM model. *	$105,000
9.8 Technology Development	to follow at later date		
9.9 Energy Aware Guide	$30,000		$30,000
9.10 Community Integrated Energy	$20,000		$20,000
9.11 IRP Issues	$20,000	add $25,000 for misc. consulting for IRP related activities.	$45,000
Def Account #179-064 - IRP TOTAL	$5,260,000		$640,000
DSM Deferral Account			
9.4 Demand Side Management			
Res/Comm Programs	$6,969,815	add $320,000 for labour costs for program development. (see Sch. C) minus $755,000 for program costs which include DRIA and other operating costs. deferral amount includes remaining funds from rebate incentive grants for water heaters.	$6,534,815
Industrial Programs	$1,343,807	minus $75,000 in 1995 for delayed implementation of programs (see comments for 1994).	$1,268,807
NGV Programs	$3,400,900	deferral amount represents additional incremental labour and incentives required for revised programs after public input. Remaining funds in O&M and capital budgets.	$2,043,784
Non-Mkt Specific Activities	$100,000		$100,000
Def Account #179-063 - DSM TOTAL	$11,814,522	Total has been rounded	$9,945,000
TOTAL IRP-DSM COSTS	$17,074,522		$10,585,000

* Labour to operate these models was originally budgeted in IRDP deferral account, #179-098; the settlement eliminated this account and provided that these incremental IRP related activities could be applied for and justified separately.

APPEARANCES

G.A. FULTON	Commission Counsel
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R.B. WALLACE	Weyerhaeuser Canada Ltd.; Cominco Ltd.; and Celgar Pulp Company
MS. C. McCOOL	Consumers' Association of Canada (B.C. Branch); The British Columbia Old Age Pensioners' Organization; Council of Senior Citizens' Organization of B.C.; Federated Anti-Poverty Groups of B.C.; Senior Citizens' Association of B.C.; and West End Seniors' Network
D. RAWLYK	Energy Resources Management
R.T. O'CALLAGHAN	R.T. O'Callaghan & Associates, Inc.
P. KACIR	Crestbrook Forest Industries Ltd.; Consumers' Packaging; Elkview Coal Corporation; Hiram Walker & Sons Ltd.; and Fording Coal Ltd.
J.G. SMITH	The Agriculture Committee of the Chilliwack Chamber of Commerce
H. LEDERHOF	Ecology Circle
MS. P.E. SCHMID	William Storage Company
MS. C. REARDON	Westcoast Environmental Law Society

W.J. GRANT P.H. GRONERT D.W. EMES J.W. FRASER J.J. HAGUE	Commission Staff
ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

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