CAARS
Centra Gas British Columbia Inc. Fort St. John District
1994 Revenue Requirement Decision March 11, 1994

1.0 BACKGROUND AND APPLICATION

1.1 Background

The City of Fort St. John, with a population of approximately 15,000 is located in northeastern British Columbia. Centra Gas British Columbia Inc. - Fort St. John District ("Centra-FSJ", "the Company", "the Applicant") provides natural gas service to the City of Fort St. John, the District of Taylor, the community of Charlie Lake and an extensive rural service area surrounding Fort St. John which is approximately 2,500 square miles.

Centra-FSJ appeared before the British Columbia Utilities Commission ("the Commission", "BCUC") at a public hearing held in Fort St. John in 1985 and made its subsequent and most recent general rate application in 1992. Initially, the 1992 application requested an increase in rates of 11.1 percent ($0.34/GJ) which the Company reduced to 9.7 percent. The Commission Decision on the 1992 Fort St. John application found the rates applied for to be excessive, rejected the Application, and ordered a refund with interest.

Prior to filing its 1994 Application, Centra-FSJ informed its customers by letter dated October 29, 1993 that the rates for residential and commercial customers could increase by 43 percent due to a cost of gas increase and a general rate increase. In response to the notice, a number of customers have written to the Commission expressing their concerns about the proposed rate increases.

On October 22, 1993, Centra-FSJ applied to the Commission pursuant to Section 67(4) of the Utilities Commission Act ("the Act") to pass-through a cost of gas increase to all customers that was expected from its suppliers effective November 1, 1993. By Commission Order No. G-106-93, a pass-through increase in the cost of gas was approved in the amount of $0.614/GJ to residential and general service customers and $0.745/GJ to industrial customers effective November 1, 1993. The Order also approved a deferral account to record the difference between the forecast price of baseload and peaking gas included in the pass-through application and the approved price of baseload and peaking gas negotiated with the suppliers. As discussed in Chapter 4.1 of this Decision, Order No. E-29-93 advised the Company that its 1993/94 gas supply arrangements would be reviewed at the Centra-FSJ 1994 Revenue Requirements Hearing.

1.2 The Application

Centra-FSJ applied on November 30, 1993, pursuant to Sections 64 and 104 of the Act, for an interim and permanent increase of 14.5 percent effective January 1, 1994 to recover a projected revenue deficiency of $1,214,095. The Company attributes the revenue shortfall to the following factors:

TABLE OF CONTENTS
(Cont'd)

Page No.

- an increased allocation of the costs of shared services;
- increased income tax expense;
- increased return requirements as a result of rate base growth;
- reduced volumes as a result of conservation and as a result of one large 1992 forecast customer that did not materialize;
- increased amortizations of deferred costs as a result of new deferral accounts; and
- increased municipal taxes that are a function of routine capital expenditures.

Centra-FSJ stated that the cost of gas increase approved by Commission Order No. G-106-93 effective November 1, 1993 averages 19.9 percent and that when combined with the applied for 14.5 percent general increase resulted in a total increase in average rates of 37.3 percent over the rates in effect on October 31, 1993.

The Commission reviewed the Application and determined that approval of an interim, refundable increase in revenue of 7.52 percent effective January 1, 1994 was appropriate. Commission Order No. G-122-93 approved the interim rate increase subject to refund with interest and set a public hearing in Fort St. John for February 8, 1994 with a Town Hall Meeting on the evening of February 7, 1994. The Company was to inform the customers of the interim increase by way of a Customer Notice and an Information Notice in the local newspapers of the service area.

The Commission informed Centra-FSJ that the hearing would also address the 1993 Shared Services Study and the Integrated Resource Plan ("IRP" and its planning process) of Centra Gas British Columbia Inc. ("Centra B", "the parent company") and the proposed transmission looping project. While the looping project had an estimated cost of approximately $3.5 million, the Company had proposed a December 31, 1994 in-service date for the project which would defer the rate impact from 1994 to 1995. As described in Chapter 2, the looping project would increase 1995 rates by approximately $0.254/GJ. The witnesses for Centra-FSJ were also the management of Centra B and could respond to questions about the parent company.

There are two small industrial service customers, Balfour Forest Products Inc. ("Balfour") and Canadian Forest Products Ltd. ("Canfor") that are in the seventh year of ten-year contracts with prices set at the cost of gas plus a fixed margin. The combined volume for these two customers is approximately 280,000 GJ or 12 percent of the total volume and $711,000 or 8.5 percent of the total revenue for 1994. While the rate increases mentioned above refer to the average increase for all customer classes, no general increase is allocated to Balfour or Canfor, therefore the rate increase for the other customer classes is greater than the average increases. The change in rates can be summarized for a typical Residential - Small General Service customer forecasted to consume 143.5 GJ's per year. If the looping project and the gas commodity and rate application were all approved as filed, the cumulative effect would be a 43.4 percent increase for a typical residential customer, as shown in the table below:

Effect of Rate Changes on Residential Customers

Date of Change	Fixed Monthly Charge	Commodity Charge per GJ	Annual Bill Based on 143.5 GJ	Increase over Previous Annual Bill	Increase over October 31/93 Annual Bill
October 31/93	$3.12	$3.283	$509		
November 1/93	3.12	3.897	597	17.3%	17.3%
January 1/94 Requested	4.32	4.470	693	16.1%	36.1%
January 1/95 Proposed Looping	4.32	4.724	730	5.3%	43.4%

The Commission conducted the Town Hall Meeting on the evening of February 7, 1994 which explained the hearing process, the function of the Commission and its complaint-handling procedures. Centra-FSJ made a presentation at the Meeting which summarized the Application and allowed the customers to ask questions of the Company. The Hearing took place from February 8 to 10, 1994 with final argument provided in writing during the week of February 15 to 18, 1994.

2.0 INTEGRATED RESOURCE PLANNING AND THE LOOPING APPLICATION

2.1 The Looping Application

2.1.1 CPCN Application and Project Description

Centra-FSJ filed an application, dated November 24, 1993, for a Certificate of Public Convenience and Necessity ("CPCN application") to loop the transmission pipeline from the interconnect with Westcoast Energy Inc. ("Westcoast", WEI") in Taylor to the location just beyond Fort St. John district regulating Station No. 2 where the pipeline diverges to Stoddart and North Pine. The 17.2 km. of 8-inch loop, and station upgrading primarily at the Taylor check meter, are forecast to have direct costs of $2,357,000 and $200,000 respectively. Including overhead and AFUDC[1], the total cost estimate is $3,536,960 (Exhibit 1, page 9.1.17).

The loop would go into service in November, 1994, but would not be added to rate base until December 31, 1994 to minimize the impact on 1994 rates (Exhibit 7, Tab 3). The loop would increase the 1995 revenue requirement by an estimated $522,773 which would add approximately $0.254/GJ to rates (Exhibit 4, Tab 1.2.4). Uncertainty about several aspects of this major system expansion at a time of modest load growth and large increases in rates for other reasons convinced the Commission that a public review of the CPCN application was required. On January 17, 1994 the Commission advised Centra-FSJ that the review would take place at the February 8, 1994 hearing.

2.1.2 Project Justification

The CPCN application states that looping is required to generally improve system reliability and specifically to provide capacity to reliably assure deliveries in the event the Westcoast delivery pressure falls to the contract minimum of 500 psig at the Centra-FSJ check meter station in Taylor. The Applicant has been concerned about reliability for some time but the matter came to the fore in late 1992 when Fort St. John recorded the coldest weather in 50 years, including -51ºC on December 28, 1992. This coincided with operating problems at the McMahon plant which reduced pressures in the Westcoast transmission line to as low as 630 psig and caused liquids to be present in the gas delivered to Centra-FSJ (Exhibit 24). There were references in testimony to the Westcoast supply pressure being 678 psig for a number of days coinciding with problems at the McMahon plant and cold temperatures in the Fort

[1] Allowance for Funds Used During Construction

St. John area. Acceptable distribution system pressures were maintained, but there was curtailment of one industrial customer and bypass of two regulating stations (T. 328).

Centra-FSJ used the 500 psig contract delivery pressure in the Westcoast tariff and a flow rate of 1162 thousand standard cubic feet per hour ("Mscf/h") to design the loop. As the meter in service at that time was unable to establish the instantaneous flow rate, a computerized hydraulics simulation based on results of a pressure survey on December 28, 1992 was used to calculate the rate (Undertaking T. 274).

Centra-FSJ evaluated and rejected two alternatives to looping. First, the Applicant assessed load curtailment opportunities, but found these to be inadequate to meet the design objective of peak deliveries to other customers at 500 psig receipt pressure. Second, the Applicant examined the option of additional compression, but found this to have similar revenue requirements to looping with a lower level of reliability and greater impact on the environment.

2.1.3 Issues Relating to Westcoast Deliveries

Under its tariff, Westcoast is required to deliver gas at the pressure in its transmission line, and this pressure is not to be less than 500 psig. The gas is not to contain water or hydrocarbons in liquid form (T. 245). The normal supply source is Tap No. 1 at the outlet of the McMahon and Natural Gas Liquids plants as shown on Exhibit 25 included as Appendix C to this Decision. When problems occur at McMahon, the supply source can be switched to Taps No. 2 and/or No. 3 to access dry Alberta Gas or to Tap No. 4 which was installed recently as a temporary measure (T. 254).

The normal minimum pressure in the Westcoast line is 800 psig and upgrading the intervening piping would result in at least 750 psig at the Centra-FSJ check meter station under ordinary operating conditions (Exhibit 9, Tabs 8, 9, 10 and 11). This pressure would enable the existing Centra-FSJ pipeline to deliver the design gas load (Exhibit 26).

However, upsets at McMahon plant such as occurred in December, 1992 can result in low delivery pressures and cause liquid hydrocarbons and water to be present in the gas. This requires Centra-FSJ to deal with condensate and freeze-offs at its regulating stations (Exhibit 24). The Applicant stated that problems with liquids or low pressures are expected to occur 20 to 60 times a year (T. 342). There is evidence that relocating the primary source of Centra-FSJ supply to the discharge of Compressor Station No. 1 would provide access to the dry Alberta gas compressed in that station (T. 254). Relocating and upgrading this piping would cost approximately $210,000, plus $90,000 to upgrade the Westcoast meter (Undertaking T. 614).

Although representatives of Westcoast stated the gas being delivered is within specifications (T. 330), Exhibit 24 and testimony of Centra-FSJ indicates that this may not be the case at all times (T. 331). To the extent Westcoast piping requires modifications to provide dry gas that meets specifications, the Commission believes Westcoast is responsible for these costs.

While reducing the problems with liquids, the piping relocation and upgrade discussed above would increase receipt pressures and transmission line capacity only to the extent that pressure drops through the piping are reduced. The McMahon plant outlet and the compressor discharge are a common pressure system and, with problems at the plant, pressures at the compressor discharge can be down in the 620 to 650 psig range (T. 264). Moreover, alarm malfunctions and other upsets typically take Compressor Station No. 1 off-line ten times a year for two to six hours (T. 262). A minimum pressure in the Westcoast line of 565 psig was referred to (T. 256). In response to undertakings at transcript pages 257 and 271, Centra-FSJ has filed historical pressure data to quantify how low pressures get and how frequently these low pressures occur.

2.1.4 Other Aspects of the CPCN Application

The Commission expects that a CPCN application will be based on a thorough analysis of need for the facilities and possible alternatives, a reliable cost estimate, an impact assessment and consultation with customers and others regarding the project and its impacts. Chapter 2.3 will discuss alternatives to looping and describe a process whereby the Applicant can work with customers to develop and evaluate cost-effective options.

The Applicant's reluctance to spend money on a project before it has been approved is understandable and the Commission supports the use of preliminary cost information for the initial screening of alternatives. However, the amount of design analysis and the confidence level of cost estimates should increase for the more favourable alternatives as they approach filing for approval. The Commission is concerned about the lack of detailed design work that was done prior to submitting the CPCN application. The Applicant makes the reasonable comment that impacts of the project are quite predictable because the loop would parallel its existing transmission line (T. 298) and states its contingency factor of 15 percent would be the maximum cost under a worst case scenario (T. 300). While this may indeed be a relatively straight forward project, either low or high estimates are undesirable. One will cause the impact on future rates to be understated, while the other would overstate rates for the 1994 test year. Generally, for a CPCN application, the Commission expects sufficient engineering design work has been completed so that the resulting cost estimate is within a confidence band of plus or minus 10 percent.

2.2 Integrated Resource Planning

IRP is an approach to planning and evaluating utility investments that requires utilities to consider all resource options for balancing supply and demand, including Demand-Side Management ("DSM") measures that influence the timing and/or magnitude of energy demand. Resource options are compared on the basis of cost and other attributes deemed important by the utility, its customers and the Commission. For this reason, significant public involvement is required throughout the IRP process. These other attributes might include, the financial integrity of the utility, environmental and social impacts, and risks.

In February of 1993 the Commission issued IRP Guidelines for the utilities it regulates. By letter dated March 4, 1993, the Commission required all utilities to file work plans for the completion of a draft IRP by December 31, 1993. The Commission emphasized that significant future utility investments must be justified within the context of IRP.
On December 23, 1993, Centra B filed a draft IRP with Commission staff for their review and comment. The utility witnesses at the hearing characterized the draft as "a current working copy of the stage that our IRP process is at" (T. 302) which focused primarily on the objectives in the plan, demand forecasting and some initial analysis of supply- and demand-side resources (T. 303). The witness indicated that there were no areas of the IRP which could be considered completed (T. 303). In particular, the witness indicated that Centra B had undertaken no public involvement (T. 305) and did not have a plan to involve the public (T. 310), had not determined the attributes it should use to measure its objectives (T. 306), had not undertaken a thorough review of potential demand-side resources available to the company (T. 307), and had not undertaken a Long-Run Avoided Cost study (T. 308). In some of these areas, the witness indicated that Centra B would attempt to incorporate into its IRP work completed by other utilities (T. 309) and expected to have an IRP completed by year-end 1994 (T. 303).
The Commission's IRP Guidelines encourages smaller utilities to adopt components of the IRPs of larger utilities where appropriate; however, this should not be interpreted as suggesting that smaller utilities can postpone all work on their IRP until those of the larger utilities are complete. Indeed, the Commission is concerned by the apparent lack of priority placed on the Commission's request to file a draft IRP by year-end 1993. While the Commission did not expect that the draft IRP would be complete in every aspect, the list of inadequacies identified by Centra-FSJ's witness renders the current document unhelpful for utility planning purposes and makes evaluation and decision on the looping project substantially more difficult.

Therefore, the Commission directs Centra B to provide the Commission with a completed IRP for its Fort St. John Division by

June 30, 1994. The Commission recognizes that the size and detail of the plan should be consistent with the size of the utility or utility division.

Because an IRP was not prepared by Centra B in time to allow evaluation of the loop proposal relative to other options, the Commission was obligated to rely on the rate application hearing in Fort St. John for a preliminary exploration of alternatives to the loop. Although full public involvement was not possible in this context, the hearing at least provided the opportunity for some valuable input from local citizens and political representatives. In the hearing, Commission staff, Intervenors and the Commission panel also questioned Centra-FSJ witnesses on the loop proposal and likely alternatives.

2.3 A Preliminary IRP Perspective on Centra-FSJ

Cross-examination of Centra-FSJ witnesses revealed several inadequacies with the analysis and justification of the loop proposal, inadequacies that would have been minimized if the loop had been presented within the context of an IRP.

2.3.1 The Demand Forecast

The weather normalized volume of gas sales for Centra-FSJ has been relatively stable for the last five years. Extension of service to new customers has been offset by declining average consumption per customer, so that forecast normal sales for 1994 are 0.2 percent higher than actual normalized sales in 1992, if one excludes the effect of one large customer that stopped taking gas in 1992 (Exhibit 4, Tab 2.1). The loop proposal was based on a forecasted growth rate of 1 percent per year over the next five years, whereby the additions of new customers more than offset the declining average consumption per customer (T. 496, 581).

There was no exploration of the factors that might cause a significant change in the growth rate and forecast loads envisioned by Centra-FSJ. A utility demand forecasting analysis within the context of IRP would have involved, at a minimum, examination of the following factors:

1. The prospects for population growth and increased commercial and industrial activity should be examined. In Fort St. John, there are certainly opportunities for population growth, given the low unemployment rate and the continued successes in gas exploration. Witnesses for Centra-FSJ appear to have taken this into account in their forecast, but there was no assessment of the range of possible population outcomes that might occur, as one might normally test via alternative scenarios of regional economic growth.

2. The consumers' response to price change should be assessed. Witnesses for Centra-FSJ admitted that price elasticity was ignored in their demand forecast (T. 704). This omission is particularly troubling when all components of the application, if allowed, would result in a 43 percent increase in price over two years. While it is true that natural gas is still a relatively cheap option for residential customers, the price change could nonetheless have an affect on the rate of growth in demand. An additional issue is the short-run elasticity. Short-run elasticity values are usually smaller than long-run elasticities. However, a survey by Centra-FSJ during the hearing indicated that 38 percent of residential customers in outlying areas have a functioning alternative heating option (32 percent if only wood burning appliances are counted) (Exhibit 23). This short-term dual-fuel option represents an additional uncertainty for forecasting demand, but could be turned into a potential resource for the development of least-cost, demand-side options. This has not yet been explored by the Company. Nor has any significant effort been made to establish a curtailment program with industrial and perhaps some commercial customers, other than the Applicant's Supply Disruption Response Plan (Exhibit 5, Tabs 3.2, 4.1 and 4.2).

3. An analysis of energy end-uses should be conducted. As with the above discussion of price elasticity, it is important to know how customers use natural gas, and what energy using technologies they have, in order to assess DSM resource options. Such an analysis would have revealed the substantial dual-fuel capability for residential space heating.

4. Other policies and regulations that might affect the rate of demand growth must also be evaluated. Chapter 2.4.2 discusses some of these, such as mains extension test and seasonal rates.

In addition to an examination of factors that affect the rate of demand growth, the demand rates presently being experienced need to be carefully evaluated, especially the peak load during high demand periods. The documented peak day flow of 443 10^3m^3/d (Exhibit 9, Tab 1) is equivalent to an average daily rate of 652 Mscf/h. In response to an undertaking at transcript page 274, Centra-FSJ stated that the average peak hourly flow in the winter is 780 Mscf/h and the maximum peak hourly send-out is 940 Mscf/h. These rates are 67 percent and 81 percent respectively of the design hourly flow rate of 1162 Mscf/h. Exhibit 26 illustrates that a lower design rate would significantly reduce the amount of looping that is needed. Although the Applicant did not feel that a blockage in the line affected readings during the period in December, 1992 on which the 1162 Mscf/h rate was based (T. 276), Exhibit 24 states that condensate was a problem at the time. Moreover, a statement at transcript page 239 indicates that often the quality of gas problem will lead to a drop in pressure. The Commission believes that additional data are needed to validate the simulation model and confirm the design flow rate under circumstances when liquids are not a problem. Meters on major deliveries off the transmission line at a limited number of locations, such as the Fort St. John town border station and district regulating Station No. 2, would be useful.

2.3.2 Assessment of Risk

Risk assessment is a key component of IRP. Alternative options can involve different levels of risk. Ideally, one would like to have some indication of the customers' willingness to pay for reduced risk when choosing among such alternatives. This kind of information is rarely available, although much innovative research is currently being undertaken. However, in the absence of monetary values, it is still possible to attain a general sense of the extent to which alternative proposals increase or decrease various types of risks, combined with broad impressions of customer values with respect to ability of the pipeline system to reliably deliver peak gas requirements.

With respect to the looping proposal, the Application states:

"The Company submits that in order to service continued customer growth and the concomitant increase in demand for natural gas, the above expenditure is essential to maintain safe and reliable service." (Exhibit 1, page 9.1.1)

Thus, the justification of the loop proposal depends upon a careful analysis of both load growth and the risk of reduction in gas quality and pressure at times of peak demand. Chapter 2.3.1 addressed the issue of load growth.

Before making a decision on investments to reduce the risk of a critical situation, the Commission and customers need to know as accurately as possible the real risks that are being mitigated by the investment. That was not clear from Centra-FSJ's CPCN application or its witnesses in the hearing. Adequate risk assessment would involve estimation of the probability of low Westcoast pressure coinciding with peak loads on the Centra-FSJ system. If that probability were extremely low, and if the cost of reducing the risk were extremely high, support for the investment might be different than if the probability were high and the cost low. Historical data should not be that difficult to collect for the frequency of temperature extremes in the Fort St. John area and the Applicant has filed data about the frequency of lower than normal pressures. From this it should also be possible to estimate the probability of coincidence of these events.

In an IRP, this kind of information is crucial for decision making. Such a risk analysis should also include dynamic factors that may affect future conditions. For example, smaller investments, such as moving the Westcoast tap closer to Compressor Station No. 1 discharge, may change the risks from what would have been estimated from historical data.

2.3.3 Assessment of Supply-Side Alternatives

Centra-FSJ did not present a full analysis of alternatives to the loop proposal but its witnesses were willing in cross-examination to explore these alternatives. Centra-FSJ did consider additional compression and rejected that option on grounds that appear sound, based on the information in the CPCN application. In the Applicant's view, compression could provide the capacity needed at design conditions, but availability of the facility would be a concern. The Commission notes that there are other investments which could increase capacity and improve reliability of deliveries.

Upgrading the facilities connecting the Westcoast and Centra-FSJ systems would have benefits whether or not the loop is built. This is discussed in Chapter 2.1.3 above. Also, more and better instrumentation would help operating staff cope with upsets and would permit the collection of data about actual pressures, loads and load patterns that is needed to assess demand and supply side alternatives. The discussion at transcript page 276 indicates some of this upgrading may already be in place.

Exhibit 26 shows the effects on cost and capacity of looping with 6 inch rather than 8 inch pipe and of building only a portion of the proposed loop. As anticipated, both capacity and cost go down with less looping. Centra-FSJ confirmed that some portions of the proposed installation have more benefits than others in terms of pressure gradient, or pressure gain per kilometre of loop (T. 287).

The Application includes approximately $34,500 for upgrading on the Baldonnel system which, with the upgrading at that purchase tap location in 1993, would enable 1 to 1.5 percent of design peak volumes to be off-loaded from the Fort St. John system (Exhibit 9, Tab 4). This may be a cost-effective alternative for handling modest amounts of load growth.

2.3.4 Assessment of Demand-Side Alternatives

DSM is utility programs to convince customers to change their investment or energy use behaviour in ways that provide the optimal satisfaction of all customers energy service needs. Initially, "optimal" is defined as least-cost (or cost-effective), from a life cycle cost perspective, but the definition broadens when other attributes beside financial cost are accounted for.

DSM programs are least-cost if they are cheaper than the alternative supply-side investment that is avoided if the DSM actions are taken instead. In this sense, the loop proposal provides an important component to the calculation of avoided cost. If the life cycle costs of the loop were added to the forecast commodity cost of gas, and the life cycle costs of the distribution expansion necessary to service new customers, a full estimate of avoided cost would be possible. This estimate would serve as the basis against which to measure DSM alternatives. Centra-FSJ is now in a position to use the loop cost estimate to immediately begin to evaluate DSM actions.

Long-run avoided costs, like the loop, are generally used to estimate long-run DSM investments. However, there are also DSM actions which do not involve investments. A key DSM action to delay or avoid supply investments, is to distinguish potentially interruptible customers from non-interruptible customers. The IRP methodology encourages utilities to look more closely at this option, especially since it may be much less expensive and at times less risky than conventional supply-side investments. One suggestion in the hearing was for Centra-FSJ to establish a curtailable load program, or tariff. Curtailment of industrial customers could reduce peak hourly loads by 7.6 percent, although these customers have not been approached to establish their willingness to accept interruptible service or the rate incentives they would require to do so (Exhibit 5, Tabs 4.1 and 4.2; Exhibit 9, Tab 18).
Another suggestion in the hearing was for Centra-FSJ to develop a voluntary program in which it informed consumers of critical periods for the distribution system and asked its customers who could switch to their alternative fuel source for a few days. Even if the response to the voluntary appeal were only a small percentage of the total dual-fuel capability, this could be enough to deal with the critical period. This behavioural response could be reinforced by seasonal rates that better reflected the avoided costs during peak winter consumption and therefore rewarded more fairly those who reduced their consumption when it helped to prevent the system from having to undertake a costly supply investment just for security during critical periods. The savings of such a method over the supply alternative may be significant, but this cannot be determined until Centra-FSJ conducts the appropriate research for examination by the Commission and interested parties.

2.3.5 Accounting for Public Preferences

Finally, because IRP selection of resource options is based on more than just financial least-cost, involvement of the public from an early stage in the IRP process is important. While a hearing is not the best opportunity for informing the public about options and then involving the public in assessing trade-offs among options, at least some issues were explored.
Above all, it was notable that every public intervenor emphasized that the Commission should do everything possible to avoid further rate shock on top of the rate changes caused by the rising competitive market price of the natural gas commodity. This was in contrast to the Centra-FJS witnesses, who stated that they too felt deeply concerned about the timing of the rate increases, but were unable to consider alternatives to, for example, the looping investment because they had not found any that met their criteria (T. 508). Local intervenors were emphatic that all possible options be

considered. The Mayor of Fort St. John suggested that he felt the citizens of Fort St. John would respond well to a program that asked them to voluntarily switch during critical periods for the gas distribution system, especially if they were informed that this was the alternative to further rate increases that would otherwise result from the construction of the loop.

2.4 Commission Determination

2.4.1 CPCN Application for Looping

The Commission is not convinced that Centra-FSJ has adequately assessed the demand growth projections upon which the loop proposal is based, especially in the light of the potential effects of higher customer prices resulting from the large increase in the commodity cost of natural gas. Several factors may lead to lower than expected growth in demand, or at least to an ability to reduce the peak load, and each of these should be properly evaluated. These include:

1. cost-effective demand-side management programs established by the utility;
2. estimation of the demand response to higher natural gas prices;
3. a main extension test that disallows subsidies between customer groups;
4. rate design that shifts time-of-use prices to better reflect time-of-use costs; and
5. voluntary and incentive curtailment programs that allow a demand response to critical peak periods from all customers.

If the demand growth, or at least the critical peak load growth, is lessened by the reductions or shifts in demand, the only other principal justification for the loop is increased capacity to reliably handle current peak requirements. Until other less costly measures to mitigate this concern have been reviewed, the Commission is not convinced that improved reliability of deliveries and reduced threat of winter interruptions are sufficient, without the demand growth projections, to justify the magnitude of the expenditure entailed by the loop proposal. Capacity of the present transmission line is not a problem when supply conditions from Westcoast are normal or when demands are significantly below the peak. System capacity only becomes a concern when upsets at Westcoast cause lower than normal supply pressures and liquids in the gas that Centra-FSJ receives. Both of these problems may be addressed by relocating and increasing the size of the Westcoast supply tap and interconnecting piping. These modifications would be relatively inexpensive. **The Commission directs the Applicant to move expeditiously to make these changes.**

However, the Commission does not expect that these changes in themselves will provide sufficient security and Centra-FSJ will need to address alternative ways to deal with remaining concerns. Demand-side measures may be especially useful considering the problem is one of capacity and reliability of deliveries under unusual circumstances.

While the Commission does not assume that any of these alternatives are necessarily cost-effective, it does believe that Centra-FSJ should first determine, in a scenario of low or zero load growth, the potential of each option to make marginal, cost-effective improvements to system reliability during critical periods. One advantage of this approach is that improvements could be phased in over time, compared to a large looping expenditure.

Therefore, the Commission denies the CPCN application in its present form and directs Centra-FSJ, in the context of its IRP, to conduct a more complete assessment of options for addressing its concerns about system capacity over the range of Westcoast delivery pressures. The cost and timing of implementing the options are uncertain and the Commission has removed all costs associated with the transmission loop from the 1994 test year numbers.

The Commission will make every effort to review and evaluate future proposals without requiring a costly public hearing. The chance of achieving this is of course improved if Centra-FSJ has already made some effort to involve the public from the outset and to ensure an objective search and evaluation of resource options.

2.4.2 Other IRP Issues

The Company stated that its records indicated that the last rate design for Centra-FSJ took place sometime prior to 1984. In addition, the Applicant indicated that it believed its rates reflected the cost of serving customers with respect to the cost of gas (T. 501).

The Commission does not dispute the Company's assertion that it has appropriately passed on the cost of gas to its customers. However, comprehensive rate design is concerned not only with assuring that each customer class contributes the appropriate amount to the utility's revenue requirement in total, but that the actual rates faced by customers accurately reflect the cost of serving the individual customer, i.e. give a proper price signal. The Commission's 1993 Rate Design Decision with respect to BC Gas Utility Ltd. ("BCGUL") provides an indication of the relevant issues and rationale for seasonal rates.

The Commission directs Centra-FSJ to file a report with the Commission by June 30, 1994 addressing the appropriateness of seasonal rates for all classes of customers, especially in the context of the Company's IRP. The report should also propose means

TABLE OF CONTENTS
(Cont'd)

Page No.

for achieving rate design initiatives that would not require a full rate design hearing, with all of its associated costs for the customers.

Discussions at the hearing indicated that the current Centra-FSJ main extension test may not be consistent with recent determinations made by the Commission with respect to the main extension test to be used by BCGUL.

The Commission directs the Applicant to review the determinations made by the Commission in the BCGUL Phase B Rate Design Decision dated October 25, 1993 as well as further determinations which are expected to arise from the 1994 BCGUL Revenue Requirements hearing scheduled for April 25, 1994. Within two months of the issuance of a Decision on the latter proceeding, Centra-FSJ is directed to come forward with a main extension test consistent with the Commission's determinations in the two proceedings noted above and appropriately adjusted to suit the circumstances of Centra-FSJ.

In the BCGUL Phase B Rate Design Decision, the Commission directed BCGUL to come forward with a proposal for full revenue decoupling by the time of the next revenue requirement application. An application for partial decoupling has since been filed with the Commission and will be discussed at the upcoming hearing.

The Commission directs Centra-FSJ to review the BCGUL application, the discussion of this issue at the hearing, and subsequent Commission determinations. Further, the Commission directs Centra-FSJ to file, within two months of the issuance of the 1994 BCGUL Revenue Requirements Decision, its own revenue decoupling proposal, consistent with the Commission's determinations and adjusted appropriately for the utility's individual circumstances.

3.0 RATE BASE

3.1 Plant Additions

In addition to the major looping project discussed in Chapter 2, Centra-FSJ proposes to make significant capital expenditures for system betterment and to extend service to new customers. Before considering other plant additions, it is appropriate to address costs related to an expansion of the office building in Fort St. John.

3.1.1 Fort St. John Office

Centra-FSJ purchased two lots adjacent to its office building in 1992 and 1993 (T. 592) and intends to renovate the existing building to provide more office and meeting room space and to add a truck bay, shop and warehouse/storage area (Exhibit 3, Tab 2.7). Centra-FSJ spent $14,900 in 1993 to landscape and fence one lot and forecasts an expenditure of $25,000 for similar work on the second lot in 1994. The Applicant also plans to spend $30,000 for architectural design work in 1994 that would evaluate options presented by local operational staff (T. 644) and lead to construction in 1995. The total cost of improvements is estimated to be $391,000.

Mr. Yardley, counsel for the Peace River Regional District explored the need for expanded facilities in relation to local warehouse rental costs of $400 per month (T. 592). Centra-FSJ stated that it has outgrown its existing space and has had to convert one shop bay into office space. Additional rental space has not been considered as the Applicant feels it would not be efficient to have staff at two separate locations. Mr. Yardley also questioned the need to improve the second lot in 1994 if construction is planned the following year. The Commission shares these concerns.

Centra-FSJ witnesses suggested that the 1992 Decision had approved the expansion of the building (T. 596). The Commission has reviewed that Decision and finds that it referred to expenditures in 1992, including the land purchase, but not to subsequent improvements.

The Commission is not convinced that the need for investment in building expansion can be justified at a time of large rate increases for other reasons. Therefore, the Commission believes that Centra-FSJ should investigate the benefits and costs of other alternatives that could meet the business needs of the Division, such as renting office space. **Centra-FSJ is directed to evaluate these alternatives in relation to its needs and not make further investments, including architectural and other studies, regarding its Fort St. John office before it has received Commission approval for the expenditure.**

3.1.2 1994 Plant Additions

The 1992 Decision gives the following forecast plant additions for 1992 and Exhibit 3, Tab 2.8 provides a breakdown of plant additions for 1993 and 1994:

		1992 Decision	1993 Outlook	1994[2] Forecast
Total Plant	- Betterment		$302,300	$368,000
	- Other Direct		390,728	311,076
	- Overhead		242,106	253,598
TOTAL		$942,000	$935,134	$932,674

The costs and benefits of the larger capital projects for 1994 are shown under Tab 9 of the Application; several were the subject of information requests and discussion at the hearing. Centra-FSJ stated vehicles are replaced after 100,000 km or five years, depending on the conditions under which they have been used such as the amount of use on gravel roads. In fact, actual replacement often does not occur until 120,000 km or more has been accumulated on the vehicle (T. 666). The Commission believes that this replacement practice is satisfactory for the Fort St. John Division.

The Commission has identified the following concerns about specific plant additions projects:

Cecil Lake Station Upgrade and Loop (Approximately $84,500)

Centra-FSJ states that, as the result of steady load growth over the years, the present tap and piping are unable to maintain deliveries to customers at the extremities of the system during peak periods (T. 589). However, Exhibit 7, Tab 5 indicates that load growth on this separate system is expected to be minimal and the Commission feels that Centra-FSJ should limit upgrading to necessary additions which are cost-effective compared to other approaches that would reduce loads and improve reliability during high demand periods.

Centra-FSJ states that it cannot permit some customers at the extreme end of its system to use grain dryers at certain times of the year. Seasonal rates that reflect the actual costs of delivering gas at different times would permit customers to choose the service that best meets their requirements.

Natural Gas Odorizer Facilities ($80,000)

The Commission is not convinced that the bulk odorant storage facilities need be installed at all four remaining sites in 1994.

Moisture Analyzer - Taylor Check Meter Station ($20,000)

The Applicant intends to install an instrument to monitor both water and liquid hydrocarbons because of problems experienced with the quality of gas received from Westcoast (T. 689). If the tap supplying this gas is relocated as discussed in Chapter 2.3, Centra-FSJ is unlikely to require the instrument.

The Commission is concerned about the magnitude of the Applicant's ongoing system betterment expenditures and the resulting effect on rates. In future and in concert with review of its main extension policy, the Applicant will be expected to do a better job of identifying components of its capital program that are mainly to handle customer growth. The Commission feels that a re-evaluation of proposed additions for 1994 will establish that some projects are not urgently required and can at least be deferred to future years. On the other hand, from discussion about the looping project in Chapter 2, upgrading of the Taylor check meter station would be appropriate. On balance, after removal of architectural fees and the looping project, the Commission is prepared to approve the plant additions budget in the Application. It is the responsibility of utility management to establish priorities and spend available funds in the most prudent and cost-effective manner.

The Commission directs Centra-FSJ to carry out upgrading at the check meter station to handle present and foreseeable loads at the check meter station within its 1994 plant additions budget, and approves the forecast plant additions budget of $932,674 for 1994. Approval of the budget does not imply approval of individual projects. The Applicant is directed to critically review allocation of budget funds considering the Commission's earlier comments and to proceed with those items which provide essential capacity and reliability to serve existing customers and are cost-effective for providing service to new customers.

3.2 Natural Gas for Vehicles

In the Application, Centra-FSJ excluded the gas plant rent and compressor lease revenue from Other Revenue since the Company anticipated that the Natural Gas for Vehicles ("NGV") assets would be sold. During the hearing, the witnesses confirmed that no sales agreement had been reached but anticipated that it would be completed during 1994 (T. 617-619).

The Commission is not convinced that the asset sale will be completed in 1994 and accordingly has included the gas plant rent ($30,700) and compressor revenue ($34,300) in Other Revenue at the 1993 levels. Adjustments were also made to record the NGV gas plant and compressor as plant in-service and to make a provision for depreciation expense.

4.0 GAS SUPPLY AND PURCHASES

4.1 Gas Supply Strategy

Section 85.3 of the Act requires that all energy supply contracts be filed with the Commission and the Commission may, after a hearing, find a contract is not in the public interest and, *inter alia,* declare it unenforceable. The Rules pertaining to Energy Supply Contracts (the "Rules") have been developed to facilitate reviews by the Commission to determine whether a contract is in the public interest. Two significant requirements of the Rules are that utilities must have a diverse supply and their baseload supply contracts must have a four-year rolling term. The Commission normally reviews energy supply contracts without the need for a public hearing.

Gas supply arrangements for Fort St. John were discussed at the 1992 Hearing and Centra-FSJ indicated it was negotiating contract changes with its supplier that would result in supplies from several sources that complied with the term requirements in the Rules. In late 1993, the Commission observed that the Applicant's supply portfolio still did not appear to comply with the rolling four-year term and diversity of supply requirements and, by Order No. E-29-93, directed that Centra-FSJ's supply arrangements would be reviewed as part of this hearing. The review included the Applicant's gas supply strategy and the value received from its gas supply manager, Westcoast Gas Services Inc. ("WGSI"). These more general matters will be discussed before reviewing the individual supply arrangements.

Centra-FSJ intends to extend the term of its baseload November 1, 1986 Gas Supply Contract ("the Conoco Arrangement") with WGSI for deliveries from Conoco Canada Limited ("Conoco") while reducing the firm maximum daily volume ("MDV") and removing the right-of-first refusal. This would permit the Applicant to diversify its supply by contracting with other suppliers and sharing baseload requirements pro-rata (T. 147,165). This restructuring is under discussion, with an expectation of completion by November 1, 1994, although the changes may not go into effect until the existing contract expires on November 1, 1996 (T. 168). Centra-FSJ confirmed its willingness to file quarterly progress reports on the restructuring.

Although it has not done so to date, Centra-FSJ expressed a willingness to expand supply planning to include coordination of its supply portfolios for Fort St. John and for Vancouver Island (T. 169). The Applicant's IRP process is the appropriate medium for this coordination and for evaluation of supply and demand alternatives generally.

The Commission accepts the overall direction of the Applicant's gas supply strategy but is concerned that it needs to be implemented in a timely and cost-effective manner and with due consideration of all alternatives. **Centra-FSJ is directed to bring its baseload supply contract(s) into compliance with the Rules by December 31, 1994 at the latest and to file progress reports at the end of each calendar quarter on activities to restructure its supply portfolio. The Applicant is to provide justification, in the context of its IRP process, that all changes are in the public interest.**

The Applicant terminated its Westcoast Offline Sales Agreement ("Offline Agreement") on October 31, 1993 and in its place entered into a Peaking Gas Management Agreement. The Offline Agreement had provided firm supply up to Centra-FSJ's total requirement for an indefinite term and was used as recently as 1992/93 to supplement purchases under the baseload Conoco Arrangement (T. 164). WGSI maintained that conversion of the Offline Agreement to service was appropriate considering concerns raised by the supplier of gas under the Agreement, uncertainty about prices for 1993/94 and the benefits of having access to Westcoast gathering, processing and transmission service. Having service was stated to provide an opportunity to develop new business relationships with other suppliers, both for peaking supplies and for restructuring the baseload contract (T. 167).
However, it was not clear who is presently benefiting from the use of the offline service. The Commission notes that 14,361.4 $10^3m^3/d$ (approximately 600,000 GJ) was handled through the offline service in November and December, 1993 while peaking purchases were only 230 GJ (Exhibits 22 and 30). The Commission further observes that the BCGUL Rate Design Decision dated February 21, 1992, found that excess or "valley" gas used to serve interruptible customers is an asset of the utility's firm sales customers, who should benefit from the margin from such sales. The same reasoning would apply to the offline service that Centra-FSJ obtained.
In its first quarterly progress report, Centra-FSJ is directed to file a complete description of the offline service it has obtained, the use that is being made of this service and the tolls and fees for use of the service. Centra-FSJ is directed to establish a deferral account for the use of offline service other than for Fort St. John customers and to record, commencing November 1, 1993, the difference between the toll paid to Westcoast and the fair market value of the service.

With regard to gas management services, Centra-FSJ indicated it is obliged to continue to pay a $.05/GJ or $110,000 to $120,000 per year gas management fee to WGSI until the Conoco arrangement expires in 1996 (T. 130). WGSI also charges Centra B approximately $250,000 per year or $.038/GJ to manage supply for the Vancouver Island Division (T. 120). Considering both Divisions, Centra B receives varied and important services from WGSI but at a significant cost. Although Centra B avoids the need for a gas supply department, one staff member is required to provide contact between it and

WGSI (T. 137). **The Commission directs Centra B to undertake a review of gas supply management alternatives comparing the cost and benefits of using WGSI, other brokers or an internal gas supply group, and to obtain Commission approval, prior to extending its commitment to WGSI.**

4.2 Conoco Baseload Supply Arrangement

On November 3, 1993, Centra-FSJ requested approval of an amendment to the Conoco Arrangement under which it buys gas from WGSI. Purchases by WGSI from Conoco occur under a matching agreement with terms identical to those between WGSI and Centra-FSJ, except for a $.05/GJ difference in price that WGSI retains as a supply management fee. The Conoco Arrangement provides a firm MDV of 340 $10^3m^3/d$ (approximately 12,750 GJ/d) and gives the supplier the right of first refusal for requirements above the firm volume. These agreements expire October 31, 1996.

The amendment primarily increased prices effective November 1, 1993 to $2.38/GJ for residential/commercial customers and to $2.14/GJ for industrial customers. These prices are for gas delivered to Centra-FSJ and are the same as those forecasted by the Applicant in its October 22, 1993 gas cost pass-through application. Gas prices under the Conoco Arrangement are entirely commodity, with no fixed charge payments or purchase commitment. Index-based prices were considered but it was felt fixed prices were a more prudent choice for 1993/94 (T. 125). WGSI estimated the negotiated prices are equivalent to a 100 percent load factor price of $2.07/GJ at Centra-FSJ and provided evidence that this price was comparable to domestic utility prices and lower than prices in alternative U.S. markets (Exhibit 5, Tab 2.4).

Section 85.3 of the Act and the Rules permit filed information to be kept confidential when the Commission considers disclosure is not in the public interest. Centra-FSJ prepared comprehensive descriptions of its supply contracts for this proceeding but requested that it not be required to file the documents as exhibits. The Company argued that requiring the contracts to be filed would unduly influence future negotiations with these or other suppliers (Exhibit 5, Tab 3.1) and could lead to higher gas prices and greater difficulty in securing new supplies. No one opposed this position and the Commission did not require the documents to be filed in the hearing.

The reserves dedicated to the contract have not been re-evaluated, but Conoco's deliverability is sufficient to meet the contract MDV (T. 152). WGSI must do whatever is required, and would rely on its considerable supply resources, to obtain the gas (T. 145). If the MDV is not available, WGSI must indemnify Centra-FSJ for all reasonable costs of the replacement gas that it acquires. Centra-FSJ acknowledged the Conoco arrangement does not meet the rolling four-year term or diversity of supply requirements of the Rules (T. 146). WGSI pointed out the difficulty of achieving compliance during the last years of an existing contract that includes a right-of-first refusal for all requirements of the Company.

The Commission believes that the prices for 1993/94 are competitive and, as set out in Chapter 4.1, orders the Applicant to take actions that will bring its baseload supplies into conformance with the Rules by December 31, 1994. **The Commission approves the Letter Agreement dated October 15, 1993 amending the Conoco Arrangement.**

4.3 Peaking Agreement

On February 3, 1994 Centra-FSJ filed a Peaking Gas Management Contract ("Peaking Contract") with WGSI that will be in effect until October 31, 1996 and will supply Fort St. John's needs that are in excess of the gas available under the Conoco Arrangement. For 1993/94, the Peaking Contract relies on a 5,000 GJ/d firm purchase contract and 10,000 GJ/d (T. 157) of storage capacity and WGSI is obliged to indemnify Centra-FSJ for all reasonable costs of replacement gas if it fails to deliver. Centra-FSJ has the right to add other supply arrangements, such as Centra B storage for the Vancouver Island Division, to the contract (T. 156).

Purchases under the contract are entirely on a commodity basis and a WGSI supply management fee of $.05/GJ is included in the price. WGSI confirmed the actual price is very close the $2.796/GJ forecast in the gas cost pass-through application (T. 159) and differences from the forecast price are recorded in the deferral account approved by Order No. G-106-93.

This contract provides a secure source of peaking gas at prices that are competitive considering the nature of the supply. **The Commission approves the Peaking Contract with WGSI dated November 1, 1993, including the supply and pricing arrangements under the Contract for the 1993/94 gas year.**

4.4 Gas Purchases and Unaccounted for Gas

Centra-FSJ buys gas for Fort St. John entirely on a commodity basis and prices under the baseload Conoco Arrangement are streamed by customer class. Consequently, the forecast of gas purchases only affects rates to the extent of the amount of unaccounted for and company use gas, and the relative amount and price of peaking gas purchases. By definition, purchase and sales quantities differ by the amount of unaccounted for and company use gas (including changes in line pack). The Application at page 15.1.3 indicates the average unaccounted for percentage for 1988 through 1992 was 1.83 percent. Upgrading to electronic metering for industrial and commercial customers is estimated to result in more precise measurement and a 22,500 GJ increase in sales. This increase would occur without a corresponding increase in purchases and Exhibit 3, Tab 4.1 acknowledges the upgrade program would have the effect of reducing the cost of gas by approximately $51,000.

The Application also notes the company use for lineheaters and buildings as 0.23 percent. The Company witnesses stated that lineheater gas is reclassified from cost of gas for company use and recorded as an operating expense (T. 665). The Commission will allow the recording of lineheater fuel as a cost of gas item or as an operating expense providing that the practice is followed consistently.

The reduction in gas cost to reflect the $51,000 as a result of meter upgrading is shown in the schedules that are attached to this Decision.

Centra-FSJ projects it will purchase 66,000 GJ of peaking gas in 1994. Purchases over the previous three years have been 40,779 GJ, 16,973 GJ and 64,233 GJ respectively (Undertaking, T. 163). An estimated 49,410 GJ were purchased in 1993/94 to the end of January, 1994 (Exhibit 30). Peaking gas is more expensive than baseload supply and the forecast purchase quantity has an effect, although relatively small, on rates. **The Commission accepts the peaking gas forecast for 1994, but directs that a weather normalized forecast of peaking gas purchases be included in future rate applications.**

5.0 OPERATING, MAINTENANCE AND ADMINISTRATIVE AND GENERAL EXPENSES

The total Operating, Maintenance and Administrative and General Expenses ("O&M"), after overhead capitalization, are projected to rise from approximately $1 million in the 1992 Decision to $1.2 million for 1994 (Exhibit 1, page 16.1.12). In 1994, gross O&M costs were capitalized at the rate of 7.89 percent.

Operating expenses have remained fairly constant from 1992 through to the 1994 test year and the Commission considers that no adjustment is required to this category (Exhibit 3, SR1-5.2).

Maintenance expenses have increased from $98,100 in 1992 to $295,108 in 1994 with the majority of the increase in transmission pipelines and measuring and regulating, as well as distribution mains and meters and regulators. The actual gross 1993 expenses were filed as Exhibit 50 and show that $225,600 was spent on maintenance in that year. The Commission considers that the increase in maintenance expenses over the 1992 level represents a catch-up of maintenance projects from prior years. According to Exhibit 3, SR1, 5.2, the actual normalized maintenance expense for 1992 of $98,100 was lower than the 1992 Decision allowance of $117,900. The Commission considers that the 1994 maintenance provision should be set at the 1993 actual level of $225,600, less capitalization at 7.89 percent.

Administrative and General expenses were shown as approximately $272,000 in the 1992 Decision and $283,735 for the 1994 test year. The Commission considers that no adjustment is necessary for Administrative and General expenses. **After providing for the adjustments above, the Commission allowed a net O&M provision of $1,070,254.**

6.0 SHARED SERVICES STUDY - 1993

In the 1992 Centra-FSJ Decision, the Commission directed Centra B to undertake a comprehensive study within the Westcoast family both with regard to allocation methods and costs. On December 1, 1993, Centra B filed the Shared Services Study which was based on the 1993 budgeted costs and activities of Centra B The Shared Services Study was reviewed at the 1994 Centra-FSJ hearing and recorded as Exhibit 2.

The Shared Services Study identified the services that are provided to the four service areas of Centra B, namely Centra-FSJ, Whistler, Vancouver Island and the Sunshine Coast ("the RSA"), and Port Alice from the head office of Centra B and its affiliated companies of Westcoast, WGSI, Centra Gas Alberta Inc. and Centra Gas Manitoba Inc. These shared services include engineering, construction, gas supply, regional operations, marketing, regulatory affairs, business planning, controllers, computer services, human resources, safety and training and administration.

In determining the total costs of the shared services, Centra B accumulates, in a shared cost pool, its head office costs and the amounts charged by the affiliated companies. If a service can be directly traced to a single service area then that cost is removed from the pool and directly charged to that service area. From the remaining shared cost pool an amount is removed for capitalized overhead. The allocation of the shared service expense is therefore total shared costs net of direct charges and capitalized overhead.

In evaluating the various methods of allocating the net expenses, Centra B considered that the methods could be grouped into two categories. The first group is called the Formula Method which uses a company statistic, such as revenue, and allocates costs to individual service areas based on each area's percentage of the total revenue. Commonly used statistics are revenue, employees, customers, net or gross plant, capital additions, rate base or gas sales volumes. The second group is the Direct Charge Method which uses either a value for service basis or time measurements. Centra B describes the value for service as determining a single output that is most representative of the activity within the function, such as payroll cheques for a payroll department. Time measurements are used when employees prepare timesheets to record their work which usually occurs in an engineering department.

Centra B proposes that customer accounting costs be allocated based on the number of customers in a service area. The corporate benefits are allocated based on the program cost structure which will ensure that benefits for higher paid employees will be allocated consistent with their salary.

Centra B considers that human resources costs are more closely related to the number of employees. The following table summarizes the methods that Centra B has selected for allocating the net shared expenses:

TABLE OF CONTENTS
(Cont'd)

Page No.

Shared Service Department	Centra B Allocation Method
Operating Expenses	
Customer Accounting	Customers
Corporate Services - Benefits	Benefit program cost structure
Corporate Services - Human Resources	Employees
All other departments	Average Net Plant & Number of Employees (Equal Weighting)
Engineering	Timesheet
Capital Overheads	
Engineering	Timesheet
All other departments	Direct Capital Expenditures

On page 42 of the Shared Services Study, Centra B showed that applying the preceding allocation methods results in Centra-FSJ receiving a shared expense allocation of $597,464 for 1993 which is equivalent to approximately 13 percent of the net shared expenses of about $4.6 million.

In addition to determining a shared expense allocation, the Shared Services Study provided information on the capitalization of overhead and the allocation of shared general plant. Page 43 of the Shared Services Study identified that approximately $9 million of shared expense had been recorded as capitalized overhead and would result in Centra-FSJ being allocated about $374,000.

On page 44, the Shared Services Study calculated an allocation to the four service areas of the investment in Centra B head office assets, net of accumulated depreciation. In the 1992 Centra-FSJ Decision (Exhibit 15, page 30), the Commission accepted that if the Centra B head office provides a service to a district office then it is appropriate to allocate a portion of that office's general plant to that district. The allocation of the net plant investment to the four service areas was based on their relative shared expense allocation and the direct district charges. For 1993, Centra-FSJ is allocated 11.75 percent of the shared net plant of approximately $4.6 million or $542,400. The Centra-FSJ allocation of shared general plant is added to the rate base for the current year but the percentage is recalculated each year.

Centra B described its suggested approval process for the Shared Services Study on page 39 of Exhibit 2. It considered that two issues related to shared services were the approval of the total amount of shared service costs prior to allocation and the methodology used to allocate amounts to individual service areas. Centra B preferred that a review of the total shared costs should be performed as part of an RSA cost of service application that it expects to file with the Commission in mid-1994.

Centra B considered that the main purpose of submitting Exhibit 2 was to have the Commission review and approve an allocation methodology. Once approved, the methodology would be used to determine the shared service allocation amounts in individual service area revenue requirement applications.
Centra B anticipates that an RSA cost of service review will be performed on a historic basis while other service areas would file a revenue requirements application on a future test year basis. To address the timing impacts of historic cost reviews and future test years, Centra B proposes that an interest bearing deferral account be established to record the difference between the amount of shared services that is recovered in the rates of a service area and the final allocation to that service area which results from the cost review.

Centra B preferred that the allocation methodology would allocate costs to the three service areas of Fort St. John, Whistler and Port Alice with the balance of the costs remaining in the RSA.

6.1 Shared Expense Allocation for 1994

The 1992 Decision set the shared expense allocation at $240,275 which was unchanged for 1993 (Exhibit 1, page 17.1.2). The Applicant calculated an allocation to the four service areas for 1994 based on the Shared Services Study methodology which would result in a charge to Centra-FSJ of $650,764, an increase of 270 percent over the 1993 level (Exhibit 1, page 17.1.4). The Company witnesses stated that the Shared Services Study methodology results in an allocation that is fair and reasonable (T. 196).
To support the position that Centra-FSJ was receiving shared services at a lower cost, the Company witnesses filed Exhibit 21 which identified the cost of providing similar services on a stand-alone basis. That exhibit determined that ten additional employees would be required at Centra-FSJ as well as consultants at a cost of $851,139.
The fault that the Commission finds with Centra B's approach to shared expense allocation is that it proceeds from the basis of services available rather than from a demonstration that common services used by Centra-FSJ were essential to its efficient operation. It is difficult to accept for example that the small stand-alone gas utility with 7,300 customers would have to have available to it all of the functions described in 13 pages of the summary of the Shared Services Study (pages 5-17 inclusive). It is equally difficult to accept that essential common services furnished to Centra-FSJ should account for an 8.9 percent increase from 1993 to 1994 ($597,464 to $650,764), a period of stable operating conditions. Exhibit 21 represented the Company postulation of what a stand-alone organization might comprise. Absent were any actual statistics from other small enterprises. The validity of the Company's approach was further shaken by the revelation that shared expenses allocated to Centra-FSJ had increased due to changes in capitalization policy in other parts of Centra B's holdings (T. 555-557).

In setting a shared expense allocation for 1994, the Commission considered the table shown on page 45 of the Shared Services Study (Exhibit 2). For the years 1985 to 1991, Centra-FSJ was allocated $495,500 for the shared services. For 1992, the Company proposed that the allocation should be $384,600 but the 1992 Decision approved an allocation of $240,275. In the 1992 allocation, marketing costs were not included in the shared expense allocation but sales promotion of $55,000 was forecast in O&M costs (Exhibit 15, pages 22 and 35). In the 1994 Application, Centra-FSJ is allocated $78,858 for shared marketing costs and has apportioned $53,989 of the area manager's salary as sales promotions in O&M costs (Exhibit 1, pages 16.1.11 and 17.1.4). As shown in the 1992 Centra-FSJ Decision, page 31, services were provided in 1992 to an average of 7,012 customers while the average number of customers is expected to increase to 7,265 in 1994 (Exhibit 3, SR1-1.0, page 3).
With the yearly growth in customers of approximately 100 per year, the Commission is not convinced that additional services and corresponding costs were necessitated by growth in Centra-FSJ. **The Commission considers that to provide the necessary level of services to the Centra-FSJ customers that a fair and reasonable allocation to Centra-FSJ should be set at $475,000 for 1994. Since the cost allocation to Centra-FSJ is fixed for 1994, the use of a deferral account for this service area is not required.**

The Commission acknowledges that Centra B has undertaken two studies which attempt to address cost allocations to Centra-FSJ. As mentioned previously, the cost allocations should encompass the common services that are essential to Centra-FSJ's operation rather than the services available. The Commission considers that the Shared Services Study may be appropriate when growth in the four service areas of Centra B have stabilized. Until such time as growth stability has been attained, the Commission considers that any future allocations to Centra-FSJ should be on the basis of essential common services required in the service area. In any future applications for shared services, Centra-FSJ should provide meaningful statistical comparisons with other utilities such as the PUC of the City of Kingston, Ontario shown on Exhibit 21 and Centra B's related company Pacific Northern Gas Ltd. ("PNG").

6.2 Capitalized Overhead

The total shared capitalized overhead for Centra B has declined from approximately $9 million in 1993 (Exhibit 2, page 43) to about $8 million in 1994 (Exhibit 31, page 4). The allocation of shared capitalized overhead to Centra-FSJ has increased for 1994 to $996,000 from $374,000 in 1993 primarily due to the proposed transmission looping project. The Company witnesses stated that a normal overhead capitalization rate for utilities tends to be in the range of 30 to 35 percent of the direct capital costs.

When the allocated shared capitalized overhead is combined with the local capitalized expenses of Centra-FSJ, the overhead rate as a percentage of direct capital additions for 1993 and 1994 is within the range of 30 to 35 percent (Exhibit 1, page 9.1.15). **The Commission accepts the combined overhead capitalization rates for Centra-FSJ as shown on Exhibit 1, page 9.1.15.**

6.3 Shared General Plant

By applying the methodology of the Shared Services Study, the Applicant calculated that Centra-FSJ should be allocated 10.04 percent of the net costs of shared general plant and depreciation expense. According to Exhibit 1, page 17.1.5, the mid-year rate base of Centra-FSJ would include an allocation of $537,471 for the net shared general plant and $52,950 would be recorded in depreciation expense for 1994.

The Commission has considered the Centra B proposal to allocate shared general plant based on the relative shared expense allocation and the direct district charges of the four service areas. The Commission believes that the shared general plant is used to provide those services but that the shared general plant is also used to provide capitalized overhead for the service areas. **The Commission has recalculated the shared plant allocation to include the capitalized overhead and has included the schedule as Appendix D.**

In performing the recalculation, the Commission utilized Exhibit 31 and Exhibit 48, to remove the double-counting of capitalized overhead. Since the shared expense allocation to Centra-FSJ is a fixed amount, the shared plant recalculation was constant at $475,000. **The revised shared general plant allocation to Centra-FSJ has been reduced to $254,142 and the allocated depreciation expense has been reduced to $31,938 to reflect a revised shared plant allocation of 4.75 percent.**

7.0 CAPITAL STRUCTURE AND RATE OF RETURN ON EQUITY

Centra-FSJ is a division of the legal entity Centra B and as such does not possess an actual capital structure. As a result, a capital structure for rate making purposes must be deemed. The proposed capital structure and related costs, as set out in the Application, are shown in the table below:

	Capital Component %	Cost Component %
Short-Term Debt	21.21	7.25
Long-Term Debt	7.77	13.81
Deemed Long-Term Debt	38.47	7.25
Preferred Shares	.55	6.48
Common Equity	32.00	12.75
	100.00	

Only the actual long-term debt and preferred shares, which were issued by a predecessor company to Centra B, can be clearly associated with the Centra-FSJ utility assets. The table reflects the actual historical cost of these two forms of capital. The remainder of the capital structure represents an allocation of capital amongst the divisions by the parent company and estimated costs of capital.

7.1 Short-Term Debt

As indicated above, the Centra-FSJ capital structure contains 21.21 percent short-term debt which the Company proposes to fund at a rate of 7.25 percent. The funds are provided to the Applicant from its parent company, Centra B, who borrows the money from the Canadian Imperial Bank of Commerce ("CIBC") at the lower of the CIBC prime rate or the 30-day Banker's Acceptance rate plus 75 basis points. The Application showed that it expects these costs to range between 5.0 percent and 6.0 percent in 1994 (Exhibit 7, PRRD1-25) although a witness for the Company indicated that the costs could be lower than shown (T. 360).

The Company stated that the 7.25 percent cost used to determine the revenue requirement was the rate previously approved by the Commission as a result of the 1992 Revenue Requirements Decision. That Decision ordered Centra-FSJ to accrue the difference between the actual short-term rate and the proposed cost of capital in a deferral account. The Applicant proposed to continue this practice and credit the funds so accrued against the cost of service when the proposed long-term debt issue was placed to soften the impact of the long-term debt placement on rates (T. 415-416). However, the Applicant agreed that an alternative proposal would be to apply the funds already accrued in the short-term deferral account against the 1994 revenue deficiency (T. 415).

By way of Order No G-122-93, the Commission set the cost of short-term debt at 5.5 percent, on a without prejudice basis, for the purposes of establishing interim rates. In making this determination, the Commission was aware that short-term rates, as measured by the bank prime rate, have fallen approximately 125 basis points since the time of the last Decision.

The Commission believes that it is inappropriate to set the cost of short-term debt well above the rate which the Company actually expects to incur. In this case, the Applicant expects to incur short-term debt costs which will range between 5.0 percent and 6.0 percent. Therefore, the Commission directs that the short-term debt be funded at the rate of 5.5 percent for the 1994 year. Further, the Commission orders that the funds accrued to the end of 1993 in the short-term deferral account, for short-term debt and deemed long-term debt, be credited against the 1994 cost of service. Future differences between the cost allowed in establishing the permanent rates and the actual cost of short-term debt will continue to be accrued in a deferral account. In future applications, Centre-FSJ is directed to incorporate the average short-term debt rate that it expects to pay during the test year.

7.2 Deemed Long-Term Debt

As shown in the previous table, the proposed Centra-FSJ capital structure contains 38.47 percent deemed long-term debt which the Company proposes to fund at the same rate as short-term debt, i.e. 7.25 percent. As with short-term debt, this capital is provided to the Applicant from borrowings made by its parent company at the lower of CIBC prime rate or 30-day Banker's Acceptance rate plus 75 basis points. As with the short-term debt, the difference between the actual cost of the debt and the proposed cost is accrued in a deferral account.
Centra B expects to file an application to issue long-term debt after the first quarter of 1994. Some of the monies so raised would be used to replace the deemed long-term debt in the Centra-FSJ capital structure. At that time, the Company will make application for the disposition of the balance in the deferral account.

By way of Order No. G-122-93, the Commission set the deemed long-term debt at 5.5 percent, on a without prejudice basis, for the purposes of establishing interim rates. The Commission confirms that this rate be used for the purposes of establishing

permanent rates. Any differences between this cost and the actual cost of the capital which makes up the deemed long-term debt should continue to be accrued in a deferral account. When the long-term debt is actually placed, the Commission will consider an adjustment to the Applicant's permanent rates to reflect the cost of the long-term debt or alternatively the establishment of a deferral account to reflect the difference between the cost used to establish the current rates and the actual cost at time of placement.

7.3 Common Equity

In the previous Decision, the Commission deemed that Centra-FSJ had a 30.0 percent common equity component on which they awarded a cost rate of 13.0 percent within a band of 12.5 percent to 13.25 percent. In this Application, the Company is asking the Commission to approve a 32.0 percent common equity component and award a cost rate which is equal to the arithmetic average of the rates awarded PNG and BCGUL.

In support of the proposed common equity component, the Applicant provided a schedule showing its view of the distribution of capital in the parent company amongst the operating divisions (Exhibit 1, page 19.1.6) and which indicated there was sufficient equity in the parent to support the 32 percent deemed component. In addition, the Company stated that 32 percent was the mid-point between the common equity components of PNG and BCGUL and that the relative risks of Centra-FSJ were in between the risks of BCGUL and PNG (T. 399). In response to questioning, the Company was unable to identify any factors which would have led to an increase in risk since the 1992 hearing, but indicated that the looping project, security and safety of supply and system betterment expenditures suggested that the risk had not lessened (T. 412).

The Company stated that its proposal that its rate of return on common equity ("ROE") equal the simple arithmetic average of the ROE allowed for PNG and BCGUL was made to avoid the cost of expert witness testimony and was necessary given the magnitude of the revenue deficiency. For the purposes of calculating the revenue requirement and revenue deficiency in the Application, the Company assumed a rate of 12.75 percent.

In determining the appropriate interim rates for Centra-FSJ, the Commission accepted the premise, on a without prejudice basis, that the ROE allowed Centra-FSJ would equal the simple arithmetic average of the rates allowed PNG and BCGUL in their interim rates. Thus, for the purpose of setting interim rates an ROE of 11.7 percent was used. **Given the desire of the Company to avoid the cost of an expert witness in this area and the likelihood that the appropriate ROE for Centra-FSJ falls within the range set by the ROEs of PNG and BCGUL, this methodology is** accepted for the permanent rates. Thus, the final ROE for Centra-FSJ will await the Commission Decision regarding the appropriate ROE for these two utilities. In the meantime, the Company is instructed to calculate its rates for service based on the 11.7 percent rate of return established by the interim order. Should the final ROE differ from this rate, the rates for service will be adjusted accordingly, effective January 1, 1994.

With respect to the common equity component of the capital structure, the Commission is not convinced that the risks of the Company have changed such that an increase in the equity component is warranted. Further, as the Applicant is an operating division of a larger company and thus does not possess an actual capital structure, the Commission would prefer to consider the issue of the appropriate amount of equity to allocate to Centra-FSJ within an assessment of all the operating divisions of Centra B Therefore, the Commission allows Centra-FSJ a deemed equity component of 30 percent.

8.0 DEFERRAL ACCOUNTS AND OTHER

8.1 1992 Hearing Costs

In the 1992 Hearing the Commission was critical of the quality of the Application. Several pages in the Decision are devoted to discussion of the weaknesses and shortcomings in the Company's presentation. While it was true that there had been a longer than usual interval since the Applicant had been before the Commission, it is also true that among the allocated shared expenses are items for such services as regulatory affairs. The customers have a right to expect that when they are being charged for such services, the expense will represent good value for the dollars spent. However, the Company went beyond the in-house expertise available and employed consultants and legal counsel at significant expense to assist in drafting the submission. Notwithstanding this, the Commission considered that the evidence provided at the hearing did not support the increase sought, and accordingly rejected the application in its entirety.

The Commission did, however, offer the Company a further opportunity to support the claim for hearing costs, and the Commission directed that the provision for hearing costs of $128,302 be removed from the rate base and cost of service for 1992 and be placed in a deferral account attracting a carrying cost equal to the weighted cost of capital until a final determination and disposition of the costs could be performed. Centra-FSJ submitted additional information to the Commission on August 27, 1992 which described the costs incurred and revised the provision to $117,294. By letter dated December 7, 1992, the Commission directed Centra-FSJ to continue recording the hearing costs in a deferral account for examination at the Company's next revenue requirements hearing.

In the 1994 Application, page 11.1.2, Centra-FSJ increased the total hearing costs by approximately $41,000 to include additional legal costs and to record the Commission's hearing costs. The Company proposed that the deferred costs inclusive of carrying costs totalling $182,006 be included in rate base and amortized over two years. Centra-FSJ submitted that the costs were prudently incurred and that they are appropriately recoverable from its customers.

Commission counsel read an excerpt from the 1992 Decision (Exhibit 15) which expressed the Commission's concern over the number of revisions (Appendix A of Exhibit 15) and the quality of the application in total, and requested Centra-FSJ to comment on the excerpt. The Company acknowledged that the 1992 hearing was made difficult due to seven years elapsing since the last hearing in 1985 but that it was worthwhile for Centra-FSJ to appear before the Commission.

The Commission considered the summary of Centra-FSJ's hearing costs (Exhibit 41 and Exhibit 15). In examining Exhibit 15 and specifically pages 8 and 18 to 20 inclusive, it is evident that the previous Commission panel was concerned with the quantum of hearing costs and believed that the actions of Centra-FSJ resulted in higher costs than were necessary. These higher costs were identified in Exhibit 15 as 10 percent higher Allocation Study costs (page 18), and the magnitude and justification of Centra-FSJ's legal fees (page 19). The previous Commission panel also considered that the prudency of the hearing costs was further complicated when consideration was given to the results sought as opposed to those achieved.

The Commission considers that while the 1992 hearing may have been valuable to Centra-FSJ management, it had much less value to the customers on the system. Accordingly, the Commission will allow 50 percent of Centra-FSJ's 1992 hearing costs to be accepted into rate base and amortized over a period of two years.

8.2 1994 Hearing Costs

The Company made a provision of $125,000 for hearing costs in the Application and based on the most recent estimates the costs are expected to total $166,500. **The Commission considers that Centra-FSJ has provided an improved Application compared to the 1992 submissions and accordingly the full hearing cost provision for 1994 will be included in the rates based on a two-year amortization.**

8.3 Unrefunded Monies

By Order No. G-112-91 dated November 15, 1991, the Commission directed Centra-FSJ to refund the over-collection of the Balfour Forest Products Inc. and Canadian Forest Products Ltd. rider. Centra-FSJ informed the Commission on January 13, 1994 that a refund had been made to all customers except for those who had closed their account and could not be located or whose refund was $5.00 or less. Centra-FSJ reported that the amount not refunded was $14,368 plus accrued interest and applied to the Commission for approval to record the amount as general revenue in 1993. The Company calculated that it would not earn its allowed return on equity for 1993 of 13 percent and the inclusion of the unrefunded amount plus accrued interest would result in Centra-FSJ earning approximately 7.6 percent return on equity.

The Commission considers that the unrefunded amount plus accrued interest should be credited to the 1994 revenue deficiency.

8.4 Westcoast Contributions

Tab 11 of the Application identified contributions in 1993 totaling $190,000 to upgrade the Westcoast delivery facilities at Taylor, Baldonnel and Cecil Lake. Centra-FSJ proposed to include these contributions in working capital and amortize them at 2 percent per year. The upgrades at Taylor and Baldonnel have not been carried out and there is a question about the completeness of the work at Cecil Lake (T. 708, 709). The upgrade at Taylor is now expected to cost approximately $210,000 plus $90,000 for a larger Westcoast meter and the Centra-FSJ stated it would make a further application when the contribution exceeds $150,000.

The Commission believes relocating and enlarging the Westcoast delivery facilities at Taylor is an essential first step to improving system reliability and considers the new equipment should be designed and sized to handle foreseeable growth in load. At the same time, it was unclear if Centra-FSJ as a customer of Westcoast should bear full responsibility for upgrading that is needed to handle increased deliveries off the Westcoast system or to correct a problem with consistently meeting gas quality specifications. The Peace River Regional District argued that Centra-FSJ should not include such costs unless the contributions accord with provisions in Westcoast's tariff.

Centra-FSJ is directed to remove the provision for Westcoast contributions from the rate base and, to the extent Westcoast facility improvements are in service and the costs are properly the responsibility of Centra-FSJ under the Westcoast tariff, to record Westcoast contributions in a deferral account that calculates interest at the Applicant's average cost of short-term debt. The amount recorded should not exceed $200,000 unless the Applicant has applied for and received further Commission approval.

8.5 Format of the Rate Application

The Application contained schedules that primarily showed 1993 outlook and 1994 test year numbers. The references made by the Applicant to the 1992 Decision amounts for Centra-FSJ were primarily contained in the explanation sections of the Application which made year-to-year comparisons somewhat difficult.

The Commission directs Centra-FSJ that all future applications must contain schedules which show comparisons for the most recent Decision, a normalized base year and a forward looking test year. All schedules must reference the account numbers and titles from the Uniform System of Accounts. If the Company reclassifies amounts between accounts in any of the above comparison years, it

is required to identify the amount of the reclassification and the reason for the change. The Applicant must keep in mind that the Uniform System of Accounts is specific in the classification of utility transactions and intended to provide cross-comparison with other utilities.

9.0 REVENUE REQUIREMENT AND RESULTING RATES

As a result of the Application, the Commission received submissions from a number of concerned citizens in the local area who opposed the cumulative rate increase of 43.4 percent. The projected rate increase was viewed by the customers as too large an increase at one time. Local representatives requested that Centra-FSJ attempt to control its costs and even consider if capital projects could be delayed or spread over a number of years.

The Commission understands the concerns expressed by the Company as to reliability of supply and the need to do rehabilitation work on a system that evidently shows some signs of past neglect and unsatisfactory practices. It appreciates the point of view of expert witnesses who feel strongly that certain approaches and rates of catch-up repairs are appropriate. However, the Commission has also given thoughtful consideration to all those interested parties who have pointed out the difficulties that large rate increases cause. It is only a limited consolation that natural gas rates remain a bargain compared to other forms of energy when family and business budgets are already locked in with no prospect of offsetting increases in income. On the heels of a significant increase in the free market cost of gas, the Commission must therefore insist that the Company, at this time, use its considerable talents to get along with the least general increase that can be awarded consistent with the public interest.

This hearing dealt with three applications: a gas cost increase, a utility revenue requirement increase, and a CPCN for a transmission looping project. As noted in the table in Chapter 1, granting of all three requests as applied for would result, for a typical residential customer, in January 1995 rates that would be 43.4 percent higher than the rates of October 1993.

This Decision has confirmed the gas cost increase, that was initially approved and included in rates on November 1, 1993, leading to a 17.3 percent increase for the typical residential customer. The gas purchasing process was found to be competitive, and the increase in the commodity cost is comparable to gas cost increases experienced throughout North America.
Most of the remaining increase that was applied for has been denied in this Decision. The looping proposal is not approved. The utility revenue requirement increase application of an average 14.5 percent over the rates in effect at the end of 1994 has been reduced, and an increase of 4.92 percent is allowed.
In the Application, page 20.1.0, the revenue deficiency was allocated based on the gross margin of the customer classes. Following that approach, the allowed revenue deficiency of $410,995 would result in allocation to the Residential - Small General Service class of approximately of $353,202 or about $0.217/GJ. Therefore, for the typical residential customer, this Decision reduces the cumulative rate

increase, relative to October 1993 rates, from the 26.1 percent (43.4-17.3 percent) implicit in the applications down to 6.1 percent (23.4-17.3 percent) as shown in the table below:

Effect of Rate Changes on Residential Customers

Effect of Rate Changes on Residential Customers

Date of Change	Fixed Monthly Charge	Commodity Charge per GJ	Annual Bill Based on 143.5 GJ	Increase over Previous Annual Bill	Increase over October 31/93 Annual Bill
October 31/93	$3.12	$3.283	$509		
November 1/93	3.12	3.897	597	17.3%	17.3%
January 1/94 Allowed	3.12	4.114	628	5.2%	23.4%

The allowed revenue deficiency of $410,995 in this Decision is recovered from all customers, except Balfour and Canfor due to their fixed margin contracts. For comparative purposes and for simplicity, the estimated increase is allocated only to the commodity charge in the table since the annual bill is significant in calculating the percentage changes in rates.

A reconciliation of the refund should be provided to the Commission. Centra-FSJ is to file, by April 18, 1994, or such earlier date that is reasonable, new rate schedules that reflect the permanent rates.

DATED at the City of Vancouver, in the Province of British Columbia this
day of March, 1994.

____
Dr. M.K. Jaccard
Chairperson

____
Dr. Harold J. Page
Commissioner

TABLE OF CONTENTS
(Cont'd)

Page No.

APPENDIX A

APPEARANCES

P. MILLER	Commission counsel
G.K. MACINTOSH, Q	Counsel for Centra Gas British Columbia Inc.
J. YARDLEY	Counsel for Peace River Regional District
B. ROGERS	United Brotherhood of Carpenters and Joiners
S. THORLAKSON	Mayor of the City of Fort St. John
R. KELLY	District of Taylor
J. KRAUSS	Fort St. John and District Chamber of Commerce
R. NEUFELD	MLA for Peace River North District
PASTOR OLESEN	Administrator and Chaplain of the Peace Lutheran Care Centre in Fort St. John
D. JINKERSON	Customer of Centra Gas British Columbia Inc., Fort St. John District
B. GEORGE	Hotels' Association

TABLE OF CONTENTS
(Cont'd)

Page No.

APPENDIX A

LIST OF EXHIBITS

TABLE OF CONTENTS
(Cont'd)

Page No.

TABLE OF CONTENTS
(Cont'd)

Page No.

TABLE OF CONTENTS
(Cont'd)

Page No.

TABLE OF CONTENTS
(Cont'd)

Page No.

APPENDIX D

CENTRA GAS BRITISH COLUMBIA INC. - FORT ST. JOHN DISTRICT — Schedule

UTILITY INCOME AND EARNED RETURN
for the year ending December 31, 1994

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	1992 Decision	1994 Rate Application	1994 Amended	Commission Adjustments	Adj Bal
SALES VOLUME					
Natural gas - GJ		2,167,191	2,167,191		
Present avg rate per GJ		$3.776	$3.776		
Percent increase in rates		14.064%	14.064%		
Transportation Service (GJ)		170,963	170,963		
Present average rate per GJ		$0.960	$0.960		
Percent increase in rates		38.467%	38.467%		
Total Deliveries	2,450,654	2,338,154	2,338,154		2,33
Present average rate per GJ	$3.014	$3.570	$3.570		$
Unit price increase per GJ	($0.009)	$0.519	$0.519		$
Percent increase in rates	-0.29%	14.54%	14.54%		
UTILITY REVENUE					
Gas sales -present rates	$7,224,137	$8,183,793	$8,183,793		$8,18
-interim rates	704,889	1,150,936	1,150,936	[9]	1,15
Transp. revenue-pres. rates	162,497	164,190	164,190		16
-interim rates	11,681	63,159	63,159	[9]	6
				70,169 [7]	
Other Revenue	101,700	37,800	37,800	65,000 [4]	17
Revenue Adjustment	(738,000)		(803,100)	[9]	(80
REVENUE REQUIREMENT	7,466,904	9,599,878	9,599,878		8,93
EXPENSES					
Cost of Natural Gas	4,013,875	5,176,709	5,176,709	(51,000)[3]	5,12
Operating	604,800	578,719	578,719		57
Maintenance	117,900	295,108	295,108	(87,308)[2]	20
General	272,345	283,735	283,735		28
Allocated Costs- Regional	240,275	650,764	650,764	(175,764) [1]	47
Amortization (CIAC)	(92,642)	(92,543)	(92,543)		(9
Amortization (Deferrals)	106,027	249,570	249,570	(28,552) [6]	22
Amortization (Def Inc Tax)		(98,200)	(98,200)		(9
Depreciation	499,509	557,795	557,795	27,619 [5]	56
				(21,012) [8]	
Municipal & Other Taxes	281,292	405,354	405,354		40
	6,043,381	8,007,011	8,007,011		7,67
Utility Income before Taxes	1,423,523	1,592,867	1,592,867		1,26
Income Tax	293,004	416,164	416,164		29
EARNED RETURN	$1,130,519	$1,176,703	$1,176,703		$96
UTILITY RATE BASE	$10,975,553	$12,365,716	$12,365,716		$12,00
RETURN ON RATE BASE %	10.30%	9.52%	9.52%		

TABLE OF CONTENTS
(Cont'd)

Page No.

Schedule I
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[1] Reduce Allocated Costs - Regional to $475,000
[2] To reduce Maintenance expense to actual 1993 level less overhead capitalization
[3] To record decrease in unaccounted for gas due to meter upgrade program
[4] To record compressor lease revenue and gas plant rent at 1993 levels
[5] To increase depreciation due to NGV plant remaining in service
[6] To adjust amortization of deferred charges to Schedule II
[7] To record the Balfour/Canfor rider unrefunded amount of $14,368 plus short-term intere
and 1993 (5.56%) as Other Revenue
To record the short-term interest deferral account of $53,880 as Other Revenue.
[8] To adjust depreciation expense for reduced shared general plant allocation
[9] Net revenue deficiency= $410,995

TABLE OF CONTENTS
(Cont'd)

Page No.

Schedule II

CENTRA GAS BRITISH COLUMBIA INC. - FORT ST. JOHN DISTRICT
Utility Rate Base for the Year Ending December 31, 1994

	1992 Decision	1994 Rate Application	1994 Amended	Commission Adjustments	Adj Bal
Gross plant in service					
Beginning of Year	$18,081,356	$20,015,471	$20,015,471		$20,01
Accumulated Depreciation					
Beginning of Year	(4,100,266)	(5,183,144)	(5,183,144)		($5,18
Net Plant in Service					
Beginning of Year	13,981,090	14,832,327	14,832,327		14,83
Gross plant in Service				552,383 [3] (30,000)[5]	
End of Year	18,893,856	23,936,436	23,936,436	(3,536,960)[4]	$20,9
Accumulated Depreciation				(346,671)[3]	
End of Year	(4,522,985)	(5,315,032)	(5,315,032)	(27,619)[3]	(5,68
Net Plant in Service					
End of Year	14,370,871	18,621,404	18,621,404		15,23
Net Plant in Service					
Mid-Year	14,175,981	16,726,866	16,726,866		15,03
Adjustment to Daily		(1,860,607)	(1,860,607)	1,860,607 [1]	
Head Office Average					
Net Plant Allocation	187,506	537,471	537,471	(283,329)[6]	25
Less: Customer Contribution					
Mid-Year	(3,971,524)	(3,897,666)	(3,897,666)		(3,89
Total Net Plant in Service					
Mid-Year	10,391,963	11,506,064	11,506,064		11,38
Working Capital					
- Other	678,823	536,774	536,774		53
- Deferred Charges	101,167	470,178	470,178	(245,977)[2]	22
Deferred Income Taxes	(196,400)	(147,300)	(147,300)		(14
TOTAL RATE BASE	$10,975,553	$12,365,716	$12,365,716		$12,00

Schedule II

[1] Remove Adjustment to Daily
[2] Adjustment to Deferred Charges:

	Opening Balance	Additions	Amortization	Balance	Mid
- - - - - -					
Hearing Costs - 1992	$91,003	$0	$45,502	$45,502	$6
Hearing Costs - 1994	0	166,500	83,250	83,250	4
Scurry Rainbow - 1992	24,077	0	24,077	0	1
Property Tax - 1993	136,380	0	68,190	68,190	10
	$251,460	$166,500	$221,019	$196,942	$22

To remove 50% of the 1992 hearing costs of $182,006.
[3] To reverse disposal of NGV compressor and plant:
To add NGV cost of $552,383 to ending plant in service
To increase accumulated depreciation by ($346,671) for NGV plant
To record depreciation at 5% for NGV plant
[4] To remove transmission looping cost from ending plant in service
[5] To remove architectural fees on office expansion
[6] To adjust the shared general plant allocation in accordance with Appendix A.

TABLE OF CONTENTS
(Cont'd)

Page No.

Schedule III

CENTRA GAS BRITISH COLUMBIA INC. - FORT ST. JOHN DISTRICT

CALCULATION OF INCOME TAXES ON UTILITY INCOME
FOR THE YEAR ENDING DECEMBER 31, 1994

	1992 Decision	1994 Rate Application	1994 Amended	Commission Adjustments	Adj Bal
Earned Return	$1,130,520	$1,176,703	$1,176,703		$963
Deduct: interest on debt	(698,045)	(667,749)	(667,749)	(128,833)[1]	(538
Before Tax Accounting Income	432,475	508,954	508,954		425
Add:					
Depreciation	499,509	557,795	557,795	6,607 [2]	564
Amortization - CIAC	(92,642)	(92,543)	(92,543)		(92
Amort - Hearing Costs	0	153,503	153,503	(153,503) [3]	
Amort -Deferred Charges	106,027	96,067	96,067	124,952 [6]	221
Large Corporate Tax		37,233	37,233	(726) [4]	36
	512,894	752,055	752,055		729
Deduct:					
Capital Cost Allowance	504,561	568,414	568,414	(68,975) [7]	499
Hearing Costs, studies	0	153,503	153,503	(153,503) [3]	0
Overhead capitalized	32,700	66,048	66,048		66
Cumulative Eligible Capital	6,420	15,241	15,241		15
AFUDC	0	101	101	(101) [8]	0
Deferred Charges	163,900	68,190	68,190	257,503 [6]	325
	707,581	871,497	871,497		906
Taxable Income after Tax	$237,788	$389,512	$389,512		$248
Tax Gross Up (1-Tax Rate)	55.16%	54.66%	54.66%		5
Taxable Income Before Tax	431,088	712,609	712,609		453
Income Taxes - 44.84%	238,007				
45.34%		323,097	323,097		205
Large Corporation Tax	30,302	37,233	37,233	(726) [4]	36
BC Capital Tax	24,695	55,834	55,834	(1,089) [5]	54
INCOME TAXES PAYABLE	$293,004	$416,164	$416,164		$296

TABLE OF CONTENTS
(Cont'd)

Page No.

Schedule III
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[1] Interest on debt equals debt cost components multiplied by rate base.
[2] Adjust depreciation by $6,607 from Schedule I
[3] To remove hearing costs and include as deferred charges in [6]
[4] Adjust Large Corp Tax to include adjustments to capital structure on Sch. V 0.2% * (36
[5] Adjust BC Capital Tax to include adjustments to capital structure on Sch. V 0.3% * (36
[6] Expense deferred charge additions and remove deferred charge amortization
To deduct the 1992 hearing costs $91,003 and 1993 property tax $68,190.
[7] To adjust CCA for:
Transmission Looping project removed ($68,975)
[8] To remove AFUDC on transmission looping project

Schedule IV

CENTRA GAS BRITISH COLUMBIA INC. - FORT ST. JOHN DISTRICT

RETURN ON CAPITAL FOR THE YEAR ENDING DECEMBER 31, 1994

1992 Decision	Capitalization	Commission Adjustments	Capitalization Amount	Capitalization Percentage %	% Average Embedded Cost	Compo
Bank Advances	584,783	$605,535	1,190,318	10.85	7.25	0.7
Long-Term Debt	2,194,574		2,194,574	20.00	13.89	2.7
Deemed Long Term Debt	4,201,125	21,169	4,222,294	38.47	7.25	2.7
Preference Shares	75,700		75,700	0.69	6.48	0.0
Common Equity	3,919,370	(626,704)	3,292,666	30.00	13.00	3.9
	$10,975,552		$10,975,552	100.01		10.3

1994 Rate Application	Capitalization	Commission Adjustments	Capitalization Amount	Capitalization Percentage %	% Average Embedded Cost	Compo
Bank Advances	2,626,462		2,626,462	21.24	7.25	1.
Long Term Debt	961,359		961,359	7.77	13.81	1.
Deemed Long Term Debt	4,757,090		4,757,090	38.47	7.25	2.
Preference Shares	63,775		63,775	0.52	6.48	0.
Common Equity	3,957,029		3,957,029	32.00	12.77	4.
	$12,365,715		$12,365,715	100.00		9.

1994 Amended	Capitalization	Commission Adjustments	Capitalization Amount	Capitalization Percentage %	% Average Embedded Cost	Compo
Bank Advances	2,626,462		2,626,462	21.24	7.25	1.
Long Term Debt	961,359		961,359	7.77	13.81	1.
Deemed Long Term Debt	4,757,090		4,757,090	38.47	7.25	2.
Preference Shares	63,775		63,775	0.52	6.48	0.
Common Equity	3,957,029		3,957,029	32.00	12.77	4.
	$12,365,715		$12,365,715	100.00		9.

Adjusted Balances by BCUC	Capitalization	Commission Adjustments	Capitalization Amount	Capitalization Percentage %	% Average Embedded Cost	Compo
Bank Advances	2,626,462	132,818	2,759,280	22.99	5.50	1.
Long Term Debt	961,359		961,359	8.01	13.81	1.
Deemed Long Term Debt	4,757,090	(139,696)	4,617,394	38.47	5.50	2.
Preference Shares	63,775		63,775	0.53	6.48	0.
Common Equity	3,957,029	(356,254)	3,600,775	30.00	0.00	3.
	$12,365,715	(363,132)	$12,002,583	100.00	0.00	8.

[1] To set common equity at 30%
[2] Deemed long term debt percentage kept at 38.47% and embedded cost set at short-term de
[3] To balance capital structure with short-term debt

EXECUTIVE SUMMARY

This Decision of the British Columbia Utilities Commission deals with three applications from Centra Gas British Columbia Inc. - Fort St. John (Centra-FSJ), each of which would require an increase in rates:

- a cost of gas increase effective November 1, 1993;
- a revenue requirement increase to affect rates as of January 1, 1994; and
- a Certificate of Public Convenience and Necessity for a transmission looping project to affect rates as of December 31, 1994.

According to the information submitted by the Applicant, granting of all three requests would result, for a typical residential customer, in January 1995 rates about 43.4 percent higher than the rates of October 1993 as shown in the table below:

Effect of Rate Changes on Residential Customers

Date of Change	Fixed Monthly Charge	Commodity Charge per GJ	Annual Bill Based on 143.5 GJ	Increase over Previous Annual Bill	Increase over October 31/93 Annual Bill
October 31/93	$3.12	$3.283	$509		
November 1/93	3.12	3.897	597	17.3%	17.3%
January 1/94 Requested	4.32	4.470	693	16.1%	36.1%
January 1/95 Proposed Looping	4.32	4.724	730	5.3%	43.4%

The cost of gas increase was initially approved and included in rates effective November 1, 1993, resulting in a 17.3 percent increase for the typical residential customer. In this Decision the Commission confirms its earlier approval. The cost of gas is now set in competitive markets throughout most of North America. The Commission found the gas purchasing process of Centra-FSJ to be competitive and notes moreover that the increase in gas costs to its customers is comparable to the increases experienced by customers throughout North America. However, this Decision requires Centra-FSJ to make specific adjustments to its contracting and contract reporting practices to comply with Commission contracting rules, ensure efficient utility gas supply management and allow effective Commission oversight.

The Company's revenue requirement application was for an average increase of 14.5 percent, effectively increasing the typical residential customer's rates by 18.8 percent (36.1-17.3 percent) relative to the rates of October, 1993. Instead of the 14.5 percent requested, this Decision allows an average increase of 4.92 percent (Schedule I). Since Balfour and Canfor have a fixed margin contract, the rate increase is spread among the remaining customers and results in an increase to the typical residential customer of 6.1 percent (23.4-17.3 percent) relative to the rates of October, 1993 as shown in the table below:

Effect of Rate Changes on Residential Customers

Date of Change	Fixed Monthly Charge	Commodity Charge per GJ	Annual Bill Based on 143.5 GJ	Increase over Previous Annual Bill	Increase over October 31/93 Annual Bill
October 31/93	$3.12	$3.283	$509		
November 1/93	3.12	3.897	597	17.3%	17.3%
January 1/94 Allowed	3.12	4.114	628	5.2%	23.4%

To achieve this reduction, the Commission has denied or adjusted several expense items. These include operations and maintenance expenses, general capital expenditures, capitalized overhead, share of equity in the capital structure, returns to debt and equity capital, the building expansion in Fort St. John, the NGV gas plant, the share of Centra utility costs allocated to the Centra-FSJ Division, and recovery of hearing costs.

Because Centra-FSJ had not yet submitted its integrated resource plan, the Commission was asked to approve the transmission looping project without evidence of a thorough review of all supply and demand options. The hearing provided an opportunity to better explore some of these options, and revealed that further investigation is required. Preliminary evidence from the hearing suggested that a combination of lower cost supply and demand measures may meet the utility's desire to improve system security, especially in the light of the low rate of projected demand growth. In this Decision, the Commission requires the utility to undertake additional supply and demand analyses and to take those immediate actions which are necessary and cost-effective in the short-term to improve the quality and pressure of gas received from Westcoast Energy Inc. The utility should not proceed at this time with the looping project.

TABLE OF CONTENTS
(Cont'd)

Page No.

Denial of the Certificate of Public Convenience and Necessity reduces another 7.3 percent (43.4-36.1 percent) from the increase that the typical residential customer would have experienced relative to October 1993.

Thus, the total effect of the Decision on the Company's revenue requirement application and the transmission looping application is to allow a 6.1 percent increase relative to October 1993 rates (23.4-17.3 percent), instead of the applied for increase of 26.1 percent (43.4-17.3 percent).

Centra-FSJ is also directed to complete several undertakings related to efficient provision of service, including completion of its integrated resource plan, review of rate structure, review of main extensions, and exploration of revenue decoupling.

TABLE OF CONTENTS
(Cont'd)

Page No.

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS
(Cont'd)