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

and

IN THE MATTER OF
Columbia Natural Gas Limited
Rate Design and
Fording Coal Ltd. Complaint

<u>DECISION</u>

May 17, 1988

Before:

J.G. McIntyre, Chairman
N. Martin, Commissioner
H.J. Page, Commissioner

TABLE OF CONTENTS

TABLE OF CONTENTS
(cont'd)

LIST OF TABLES

APPEARANCES

D.M. MASUHARA C.B. JOHNSON	Columbia Natural Gas Limited
S. MULHALL MS. E SANDS	Fording Coal Ltd.
K. GUSTAFSON	Crestbrook Forest Industries Ltd. Cominco Ltd. Crowsnest Resources Ltd.
R.B. WALLACE	Westar Mining Ltd.
C. SANDERSON	Commission Counsel

Hearing Officer	R.D. GODFREY
Commission Staff	J. GRUNAU R. BROWNELL
Court Reporter	ALLWEST REPORTING LTD.

LIST OF EXHIBITS

LIST OF EXHIBITS
(cont'd)

LIST OF EXHIBITS
(cont'd)

LIST OF EXHIBITS
(cont'd)

BRITISH COLUMBIA UTILITIES COMMISSION

June 15, 1988

RECIPIENTS OF COMMISSION DECISIONS

Re: Columbia Natural Gas Limited
Commission Order G-51-88 - May 17, 1988
Commission Decision - Rate Design - Fording Coal Complaint

Please be advised that the following information corrects errors in the Commission Decision issued May 17, 1988 concerning Columbia Natural Gas Limited:

ERRATA

1. Page 59 - 7.2.3 Rate III - $1.657/GJ should read $2.657/GJ.

2. Page 59 - 7.2.4 Rate IV - $1.498/GJ should read $2.498/GJ.

3. Page 71 - 10.2 Segmented Gas Field Prices - special contract $1.03/GJ should read special contract $1.05/GJ.

Yours truly,

R.J. Pellatt
Commission Secretary

461A/1
RJP:jh

FOURTH FLOOR, 800 SMITHE STREET, VANCOUVER, B.C. V6Z 2E1, CANADA, TELEPHONE (604) 660-4700, FACSIMILE [RAPICOM 120] (604) 660-1102

1.0 BACKGROUND

The background to the Columbia Natural Gas Limited ("Columbia", "Applicant", "CNG") Application spans over two years since the first government announcement that a competitive market for natural gas sales would develop in British Columbia. Prior to the summer of 1985, all natural gas producers in British Columbia sold their gas to the British Columbia Petroleum Corporation ("BCPC"). The Corporation in turn resold gas to Westcoast Transmission Company Limited ("Westcoast") for delivery to all distribution utilities in British Columbia except Columbia and for export to the United States. Since 1979, but prior to 1986, Columbia Natural Gas bought about three-quarters of its gas supply from Alberta sources, the bulk from Alberta and Southern Gas and a small amount from Westcoast Transmission via a tap to a major transmission pipeline of Alberta Natural Gas ("ANG"). Columbia purchased the remainder from B.C. sources and its parent company, Inland.

On March 28, 1985, the Governments of Canada, British Columbia, Alberta and Saskatchewan entered into an Agreement known as the Western Accord which initiated a process of replacing government-set prices of oil and natural gas with prices set by the market. Sweeping changes to the marketing system for natural gas within British Columbia followed, along with a new royalty system and authorization for producers to sell their natural gas to customers other than BCPC.

On October 31, 1985, an agreement was struck between the Governments of Canada, British Columbia, Alberta and Saskatchewan on Natural Gas Markets and Prices. This Agreement reinforced the earlier provincial initiatives by signalling the governments' intent that immediate steps be taken to enable consumers to enter into supply arrangements with producers at negotiated prices. The agreement fosters a competitive market for natural gas in Canada.

Until 1985, gas supplied to the Columbia system from Alberta was subject to the Alberta Border Price. The Federal/Provincial Agreement alluded to above, also provided for the elimination of the Alberta Border Price which had been Columbia's biggest impediment to obtaining lower priced gas.

Columbia could not offer transportation service as contained in the Federal/Provincial Agreement since all firm capacity in the ANG system was fully contracted. However, "buy/sell" agreements which are tantamount to direct purchases were offered through the cooperation of Columbia, ANG and Alberta and Southern.

In June 1986, Columbia was successful in obtaining supplies of natural gas from the Deep Basin area of B.C. This gas was priced lower than that for the supplies of Alberta gas previously taken. Columbia flowed through this reduction in gas prices to the special contract customers immediately but deferred the flow-through to the core customer group in anticipation of a rate design hearing. In October 1986, Columbia decided that the reduction in the commodity gas price should be flowed through to all customers with refunds included in the December 1986 billings.

Since the September 1985 filing of Columbia's original application, several changes have occurred in the operations of its special contract customers which have had significant impacts on Columbia's sales to these customers.

First, both Fording and Westar Balmer ("Sparwood") have made capital investments in coal-fired drying equipment which has significantly reduced their annual consumption, but has not correspondingly lessened their peak requirements. Second, Crestbrook has made capital investments in an energy optimization program which has reduced its annual consumption. Third, Cominco has made its fertilizer operations more efficient, reducing gas consumption in Kimberley.*

---

* The only other large industrial customer is Westar Greenhills. These five customers are referred to as large industrial or Special Contract customers.

Columbia submitted that in spite of a significant reduction in the commodity price and resultant burner-tip prices for all customers since its original application, there was still urgent need for a revision to its rates to bring industrial rates more into line with their costs of service.

1.1 Chronology of Application

On September 24, 1985, Columbia first filed an application with the Commission for rate design (Volumes 1 and 2). This application included a review of rates prepared by Mr. Allan J. Schultz, and Columbia's proposed revisions.

The material prepared by Mr. Schultz was first filed with the Commission on January 25, 1985 (Exhibit 30) in response to a Commission request resulting from a complaint by Fording. Mr. Schultz's study demonstrated that except for residential customers, all rate categories and all individual special contract customers were paying more than their cost of service.

Columbia filed Volume 3 (Exhibit 3) on July 30, 1986 to update its application. On May 26, 1987, Columbia filed an amendment to its 1987 Cost of Service Study to reflect a change in the commodity cost of gas. In Volume 4 (Exhibit 4) its latest revision dated September 30, 1987, Columbia amended its material to reflect changes such as gas costs etc., which occurred in the last year.

On February 2, 1988, Columbia filed an addition to its application asking for a third year rate shift of $100,000 and $240,000 from small and large industrial customers respectively to residential customers.

On February 23, 1988, Columbia filed another exhibit (Exhibit 25) which proposed to establish the terms and conditions for nominations and set out how the nominations would determine the intra-class rate shifts for year three.

The hearing was completed in eight days: February 23 to 26, 1988 in Cranbrook; March 2 to 4, 1988 in Vancouver. Argument was also held in Vancouver, on March 10, 1988.

1.2 The Applicant

Columbia Natural Gas Limited ("Columbia") was incorporated on November 6, 1961 under the British Columbia Companies Act. It became a public company in 1962 and reverted to a private company in 1973. During the intervening period Columbia was acquired by Norcen Pipelines Ltd. On July 9, 1979, Columbia became a wholly-owned subsidiary of Inland Natural Gas Co. Ltd.

In 1962 Columbia was granted a Certificate of Public Convenience and Necessity by the Public Utilities Commission of British Columbia and commenced distribution of natural gas within the communities of Cranbrook, Kimberley, Creston and Fernie. Service has since been extended to the communities of Elkford, Sparwood and Yahk. In 1982 Columbia commenced gas service to the communities of Jaffray and Galloway, made possible by the Government of Canada Distribution System Expansion Program ("DSEP"). As of June 1986, Columbia served approximately 13,600 residential customers and 500 commercial customers. In addition, Columbia currently serves five large industrial customers located within its general service area.

The head office of Columbia is located in Vancouver. Its operations are managed from its Regional Office located in Cranbrook and from District Offices in Kimberley, Creston, Fernie and Sparwood. Columbia's direct payroll includes 33 permanent employees providing operational, maintenance and clerical services. Support services in the areas of customer billing, accounting, finance, marketing, legal, employee relations, gas supply, gas measurement and corporate matters, are provided by employees and officers of Inland.

Natural gas supplies are obtained from seven taps located on the transmission pipeline of Alberta Natural Gas Company Limited ("ANG"). These taps are located at Sparwood, Fernie, Elko, Jaffray, Cranbrook, Yahk and Creston. Gas supply is contracted from the Alberta and Southern Gas Co. Ltd. ("A & S") and Westcoast Transmission Company Limited ("Westcoast") on a "cost-of-gas" plus "cost-of-service" basis, at the taps or delivery points on the ANG pipeline. In 1976, natural gas became available from Inland on an exchange basis with A & S. This gas is provided through the East Kootenay Link on an "as available" interruptible contract basis.

2.0 THE APPLICATION

Table No. 1 is a summary of Columbia's Applications in an item by item listing of the more significant changes. Exhibit 4 of the hearing with amendments presented in Mr. Powell's testimony (Exhibit 25) is Columbia's application which superceded previous filings.

/

Table 1

APPLICATION SUMMARY

Rate Sched	Exhibit 1, Volume 1 (September 24, 1985)	Exhibit 3, Volume 3 (July 30, 1986)	Exhibit 4, Volume 4 (September 30, 1987)	Additional Information Presented At The Hearing February 23, 1988
I	Schedule is to be available to residential customers only. Commercial customers presently under this rate are to be transferred to Rate Schedule II It was proposed to apply all increases to the initial block (i.e. increase the minimum bill). Trailing block rates are proposed to decrease with any offsetting increase to the initial rate block.	Schedule is to be available to residential customers only. Commercial customers transferred to Schedule II. Decrease in trailing block level as a result of removing 1.0/GJ from the initial block at the same charge.	Monthly customer charge excluding gas. Established at $3.90/mo. Flat rate of $3.25/GJ charged. Rate shift to increase revenues from this class by $300,000 in year one and $340,000 in tear two. (An increase of 5.85% and 6.27%).	(Powell's testimony TR 22 - 24) Over a three year period move residential, small industrial and commercial contract customers closer to their allocated cost of service. Accomplish this by a series of revenue shifts over three years from both the small industrial and special contract customers. Result is two increases to residential class of 6% and one of 3% over three years. Residential and commercial rates to include a monthly customer charge.
II	Schedule is to apply to commercial customers. It was proposed to apply the same increase as Schedule I. The initial rate block to be increased by $2.95 less revenue requirements (Decision Jan. 11, 1985). The resulting excess revenue to be credited on a volumetric basis to the remaining rate blocks.	Schedule enlarged to incorporate small commercial customers. Decrease in schedule revenue. Increase in the first block charge with the removal of 1.0/GJ in the block. Trailing block rate is reduced and only one block retained.	Schedule to be available to commercial, institutional and small industrial customers. Rate is to be divided into two classifications, Rate IIA and and Rate IIB. Rate IIA is to include small commercial customers formally under Rate I. Revenues to increase $65,000 or 6.11% from this this group. Rate IIB is to include customers previously under Rate II.	
III	Decrease rates in an amount comparable to the revenue requirements (Decision Jan. 11, 1985). No change in rate form.	Rate changed to a monthly basis. Minimum monthly bill based on 500/GJ. Rate level reduced.	Rate is changed from annual to monthly. Monthly customer charge of $500/mo. with a three step block rate. In second year of the proposed rate shift reduce revenue by $210,000 and increase Rate I by the same amount.	
IV	No change in the rate form or rate level.	Decrease in rate level but retention of single block.	Seasonal rate extended to include the period Dec. 1 to Apr. 30 on an interruptible basis. Monthly customer charge payable during seven months, May through November, on the contract year.	
Special Contract Customers:				
VII	The difference between the revenue authorized by the decision and the revenue resulting from the changes to Rates I and III to be to be allocated to Special Contract Customers. Rate to remain in two parts (Cost of gas and cost of service). Individual customer's cost of service to be determined by deducting the cost of service determined by the decision from the revised cost of service. The revised cost of service determined by a factor based on the results of the 1984 FACOS study, gas usage , cost of service determined by the decision (Jan. 11, 1985) Cranbrook Looping, etc. The cost of service to be a fixed monthly minimum bill.	Two components cost of service dependent on Columbia's internal costs and cost of gas. The cost of service component to be $.23/GJ. Minimum bill provisions to produce additional revenue. Decrease revenues to bring revenues closer to costs.	Common large industrial tariff. Customers are to pay their costs of service in a monthly customer demand charge. The commodity cost of gas to be an additional charge. Customers will provide Columbia with a forecast of their monthly volumes for the following year on November 1st. Reduce revenues under rate shift by $365,000 in year one and $130,000 in year two.	Demand allocation for the purpose of determining allocated cost of service will be based upon nominations. Changes in nominations will depend upon actual demands with limitations on reductions from one year to the next. Volumes taken in excess of nominated amounts will be charged an A.O.R. One operational peak day demand to be waived each year for inclusion in the subsequent year's nomination calculations.

PGAC — PURCHASED GAS ADJUSTMENT CLAUSE proposed for all classes except special contract customers.

NOTE: Revenue Requirements Increases will be prorated to the respective customer classes based on class revenues net of the cost of gas.

3.0 THE ACT AND OTHER LEGAL MATTERS

3.1 Background

Sections 64 to 66 of the Utilities Commission Act, S.B.C. 1980 c. 60 (the "Act") are the key provisions defining the Commission's duties with respect to determination of rates for utility service. During the hearing, a number of issues arose regarding CNG's application and an interpretation of these sections of the Act. These sections read as follows:

Commission may order amendment of schedules

64. (1) The commission, on its own motion, or on complaint by a public utility or other interested person that the existing rates in effect and collected or any rates charged or attempted to be charged for service by a public utility are unjust, unreasonable, insufficient, unduly discriminatory or in contravention of this Act, regulations or any law, may, after a hearing, determine the just, reasonable and sufficient rates to be observed and in force, and shall, by order, fix the rates.

(2) The public utility affected by an order under this section shall amend its schedules in conformity with the order and file amended schedules with the commission.

Discrimination in rates

65. (1) A public utility shall not make, demand or receive an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service furnished by it in the Province, or a rate that otherwise contravenes this Act, regulations, orders of the commission or other law.

(2) A public utility shall not, as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description, and the commission may, by regulation, declare the circumstances and conditions that are substantially similar.

(3) It is a question of fact, of which the commission is the sole judge, whether a rate is unjust or unreasonable, or whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or whether a service is offered or furnished under substantially similar circumstances and conditions.

(4) In this section a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality furnished by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service rendered by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Rates

66. (1) In fixing a rate under this Act or regulations

(a) the commission shall consider all matters that it considers proper and relevant affecting the rate,

(b) the commission shall have due regard, among other things, to the fixing of a rate that is not unjust or unreasonable, within the meaning of section 65, and

(c) where the public utility furnishes more than one class of service, the commission shall segregate the various kinds of service into distinct classes of service; and in fixing a rate to be charged for the particular service rendered, each distinct class of service shall be considered as a self contained unit, and shall fix a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit.

(2) In fixing a rate under this Act or regulations, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of furnishing the service in that special area, but, where the commission takes a special area into account, it shall have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

> (3) For this section, the commission shall exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

3.2 The Issues

3.2.1 Revenue Requirement

The first issue is whether the Commission's determination of an equitable rate design can or should affect the revenue requirement of Columbia. Columbia took the position that the Commission could not, as a matter of law, deny it the opportunity to earn a fair rate of return. No party to the proceeding appeared to take issue with this proposition. Certainly, none suggested that the Commission should deny Columbia that opportunity. The Commission accordingly agrees that a motive for change in rate design should be revenue neutrality from Columbia's perspective.

3.2.2 Cost Based Rates

Position of the Parties

The next major issue requiring an interpretation of Sections 64 to 66 is to answer the question of the relationship between cost of service and rate design. A number of different positions were taken on this issue.

Westar submitted that "there is a legal imperative for cost based rates, or at least that this Commission not design rates with the express purpose of including a cross-subsidy to a particular customer or customer groups" (TR 1417 - 1418). This position was based on the reasoning of the British

Columbia Court of Appeal in Prince George Gas Company and the City of Prince George v. Inland Natural Gas, Number 2. (1958) 25 W.W.R. 337 (the Prince George gas case). Westar stated that that case establishes the rule,

> ". . . that you cannot have expressed subsidies for which there is no cost justification, or that the only justification is a desire to subsidize another class of customers." (TR 1423-24)

While Crestbrook seemed to agree with the approach advocated by Westar, it recognized that this position is,

> ". . . somewhat stronger than that which the Commission concluded was appropriate with respect to Inland, at least in our reading of the Commission's Decision of December 11, 1987." (TR 1353)

Nevertheless Crestbrook urged the Commission to go further than it had in the Inland Decision and make,

> ". . . a definitive statement to endorse cost of service methodology as an integral part of rate design." (TR 1353)

In essence, Crestbrook's position appeared to be that while in law the Commission is not under an obligation to rigidly follow cost of service formulas, as a matter of policy it should do so unless there is some clearly identified compelling factor leading it to deviate from cost of service. Crestbrook submitted that because there was a complete lack of evidence to justify such a deviation, it is beyond the Commission's authority to set rates at variance with cost of service. In this regard, Crestbrook relied on the decision of the Court of Appeal in Kootenay Okanagan Electric Consumers Association v. Utilicorp United Inc., unreported August 21, 1987, MacDonald, J.A., International Woodworkers and Sooke Forest Products, (1961) 1 D.L.R. 3rd 624 and Alkali Lake Indian Band v. Westcoast Transmission Company Ltd. et al, (1984) 53 B.C.L.R. 323. In essence, albeit using different reasoning, Crestbrook found itself supporting the conclusion of Westar to the effect that the Commission, in this case at least, lacks jurisdiction to significantly diverge from cost based rates.

Fording did not deal with this issue in argument. Columbia did not deal with cost based rates in its primary argument but did mention it in passing in reply. Columbia referred to the argument presented by its parent company, Inland, in its rate design hearing as summarized in the Commission's December 11, 1986, Decision at page 16. In that hearing Inland argued that the Commission had discretion to permit any rates which contributed to cost of service in the sense that they were in excess of the variable costs of serving a particular customer. Inland further argued that there was no obligation on the Commission to ensure that the fixed costs of the system were collected in any particular way from each class of customer.

The evidence in this proceeding clearly indicated that the rates which Columbia presently charges and wishes to charge in future to all rate classes exceed the variable costs of serving each class. Accordingly, Inland's argument, if adopted in this case, would suggest that the Commission has unfettered discretion to maintain rates between their current level and the level contained in its application.

Columbia, in reply, also referred to the Commission's conclusion in the Inland case at page 17 as follows:

> "The Commission disagrees however with the suggestion that the Act requires there be cost based rates for each class of customer. If this was the case there would be no need for the just, reasonable and not unduly discriminatory standard which is expressly provided for by the Act. Further, the Commission would be unable to set rates which would allow Inland to compete with an alternative source of energy if these rates were below Inland's cost of serving these customers. Pursuant to Section 65 of the Act it is a question of fact, of which the Commission is the sole judge, whether a rate is unjust or unreasonable. This requires consideration of a variety of factors which the Commission considers relevant, not only cost of service."

3.2.3 Commission Summary and Conclusions

As in the Inland case, the Commission disagrees with the suggestion that the Act requires that rates be strictly cost based. If this were the case, there would be no need for the just, reasonable and not unduly discriminatory standard set down in Section 65 of the Act. Pursuant to Section 65 of the Act, it is a question of fact, of which the Commission is the sole judge, whether a rate is unjust or unreasonable. Further, to confine rates strictly to a particular cost standard would fetter the Commission's discretion in fulfilling its mandate regarding rate design under Section 66 of the Act. This section of the Act invites the Commission to consider all relevant matters, not only cost of service.

When fixing rates the Commission gives consideration not only to historic and marginal cost but also to the various rate design objectives set out in Section 6.1 following. The objectives include government energy pricing policies, distribution of social benefits and the balancing of all regulated pricing objectives including economic efficiency. The Commission is encouraged in its view by further reading of the judgment of Mr. Justices O'Halloran, Davey and Sheppard in the Prince George gas case.*

The Commission finds that a departure from cost based rates can be appropriate, based on the merits of valid considerations identified above.

3.2.4 Third Year Rate Shift

Position of the Parties

The next major issue relates to the proposed third year rate shift. The Applicant proposed that in order to bring rates closer to the allocated cost of service, without at the same time introducing such a significant change as to

---

* Prince George Gas Company and the City of Prince George v. Inland Natural Gas Co. Ltd. op. cit. p. 11.

induce rate shock on the residential class of customers, it was necessary to phase in rate changes over a three year period. For the first two years of the period, the Applicant proposed that a precise additional amount of revenue be collected from residential customers instead of industrial customers. In the third year, the Applicant was unable to precisely define what this rate shift should be, but instead proposed using a mechanistic formula designed to attain a revenue to cost ratio of 1.2 on a net basis (ie. excluding the cost of gas) for the Special Contract customers.

The Applicant appeared to suggest in its initial argument that a hearing was not required where rate design matters were in issue. It suggested that,

> ". . . it's only when one of the parties is before [the Commission] claiming that a particular rate is unjust or unreasonable as being outside that ceiling, or when they're talking about all of the rates being outside that band that a hearing is necessary." (TR 1295 - 1296.)

The Applicant went on to suggest that the Commission could approve changes in rates in year three without a hearing, pursuant to Section 67 of the Act. The Applicant indicated, however, that it should be required to file a report at the end of year two indicating that the third year rate shift proposed in this proceeding was still desirable and reasonable.

Commission counsel argued that, pursuant to Section 64 of the Act, the Commission could only determine the just, reasonable and sufficient rates of the Applicant after a hearing. The question therefore arose as to whether the Commission had jurisdiction to authorize a change in rates three years hence based on the application of a mechanistic formula and without a further hearing. It was suggested that before authorizing such a procedure,

> ". . . the Commission must be satisfied there exists a sufficient nexus between the hearing you're [the Commission is] holding now and circumstances as they will exist at the end of Year 2." (TR 1482 - 1483)

In response to Commission counsel's argument, Applicant's counsel appeared to concede that Section 64, which does require a hearing, applies equally to rate design matters and to revenue requirement matters. Having conceded that point however, he argued that the Commission should now accept the third year shift necessary to accomplish the objective of industrial rates equal to 120 percent of fully allocated cost of service. Then he suggested to put in place a mechanism designed to ensure that the Commission will be provided with evidence going into year three that the circumstances which lead it to approve of the third year shift still exist. The Applicant did not make it clear what precise mechanism it had in mind in this regard nor did it make it clear how such a mechanism could satisfy the Act's requirement that there be a hearing before the Commission to determine rates. Presumably, the Applicant believes that there exists sufficient nexus between this hearing and the rate shift it proposes for the third year. No other counsel dealt with this issue directly.

3.2.5 Commission Summary and Conclusions

In respect of the proposed third year rate shift, the questions, therefore, are:

(a) can the Commission, within the provisions of the Utilities Commission Act, approve a formula to be given effect three years hence which will amend Columbia's rates; and

(b) should the Commission do so, on the evidence before this hearing?

This section will address the first question. The second question will be addressed in Section 6.0 following.

The proposal is, of course, to increase rates in Rate Group I and distribute the resultant revenue to defray reductions in other rate groups. In the tariff, Schedule I is expressed in terms of dollars per gigajoule, and to give effect to the third year shift, it would be necessary to change the filed tariff.

Under Section 67 a schedule or tariff shall not be amended without the Commission's consent. The grounds upon which a utility may file a new schedule of rates on receiving the Commission's approval under this section are quite specific; namely, ". . . to be made necessary by a rise in the price, over which the utility has no effective control, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes . . ." In this section, the Commission can approve rate changes, primarily regarding cost items of which the utility has little or no control --- a pass-through rate adjustment. This can be agreed to now to be given effect three years hence.

Section 64 was also considered in the context of the third year shift. This section contemplates the Commission ordering an amendment of schedules, and the fixing of rates. A hearing is a prerequisite and the question here is whether the present proceeding could reasonably be taken to be that hearing. A major amount of discussion centered on the implications of the rate shift in the third year. The Commission believes that there was enough discussion to enable it to consider this hearing as the primary hearing for a decision on this third year shift. Therefore this Panel does believe that it has the authority to decide on the treatment of rates in the third year. Based on the evidence of the hearing, the Commission's decision on the third year shift will be addressed in Section 6.0 following.

3.2.6 The Fording Complaint

Position of the Parties

The fourth issue arose in connection with the complaint of Fording Coal Limited. Fording complained that because it paid more per gigajoule for its gas than other industrial customers, it was being discriminated against. The history of the Fording complaint is complex. It was initially filed on June 20, 1984 and alleged that the rates charged to Fording were unjust, unreasonable and unduly discriminatory. The Commission conducted a public hearing into this allegation commencing September 25, 1984 and issued Order No. G-36-84 on November 30, 1984 dismissing the complaint. In the same Order, the Commission ordered that Columbia prepare a detailed cost of service study so that full investigation could be conducted into the rate design of Columbia at a public hearing.

Columbia did conduct a cost of service study which was filed with the Commission in early 1985. Upon review of that cost of service study, the Commission issued Order No. G-28-85 on April 2, 1985 in which it confirmed the interim rates then in effect for Greenhills until a hearing could be conducted into Columbia's overall rate design, including the fairness question raised by the Fording complaint.

Fording argued that the April 2, 1985 Decision amounted to a reconsideration of the November 30, 1984 Decision pursuant to Section 114 of the Act. Accordingly, Fording submitted that it was open to the Commission to uphold the original Fording complaint and make an Order retroactive to June 20, 1984 issuing Fording a refund reflecting the subsidy which Fording alleged resulted from the fact that Greenhills' actual per gigajoule cost of gas was less than that of Fording. Fording argued that,

> "The correct measure of the overpayment by Fording is the difference between the per gigajoule rates between Fording and Greenhills, multiplied by the actual volume of gas consumed by Fording since Greenhills went into operation." (TR 1468)

Both the Applicant and other intervenors took issue with Fording's position. In particular, they said that the November 30, 1984 Decision put an end to Fording's complaint and that accordingly the Commission should not entertain a request to adjust rates retroactively. The Applicant developed this issue most fully in its reply. It pointed out that the November 30, 1984 Decision of the Commission was neither appealed nor was reconsideration sought. With respect to Order No. G-28-85 of April 2, 1985, the Applicant said:

> "I think the April '85 order is very simple to understand. I said, Mr. Gustafson said, there was one issue left from the 1984 decision. The issue was, is the Greenhills rate unduly preferential. That issue was clearly left, and when the Commission made its order on April 2nd, 1985, referring to the Fording complaint, they can only have been referring to the one issue outstanding from that complaint, that being was the Greenhills rate unduly preferential.
>
> And that can clearly be seen by the last paragraph that Mr. Mulhall read, where the Commission said,
>
>> 'The Commission hereby orders that the matter of the Fording complaint be considered and resolved in conjunction with the hearing in the Columbia rate design application.'
>
> And then goes on to say;
>
>> 'And that pending the outcome of that hearing the Greenhills rate remains interim.'
>
> The reason the Greenhills rate would remain interim is to look at the question of whether or not that rate was unduly preferential. That's all that's left, that's what's to be considered at this hearing, and that's proper for this hearing, nothing else, no refunds to Fording, no discrimination to Fording, those are gone." (TR 1499 - 1500)

Thus, the issue is whether the Commission would be willing to consider retroactive adjustments to Fording's rate or whether it should restrict its consideration of the past to determining whether the Greenhills' rate, which on its face is interim, has been just and reasonable. All parties appeared to accept that in looking ahead, the Commission is free to determine the appropriateness of all of the rates charged by the Applicant including those charged to Fording.

3.2.7 Commission Summary and Conclusions

The Commission believes that no evidence has been introduced to warrant any re-examination of its Order No. G-76-84 which dismissed Fording's complaint that its rates were unjust, unreasonable and unduly discriminatory. That decision, which was not appealed by any party, stands.

The Commission must deal with the question as to whether the interim rate to Greenhills is/was insufficient. This matter is decided in Sections 5 and 6 following.

4.0 GENERAL PRICING AND COSTING CONCEPTS

4.1 Background

A fundamental distinction in regulatory pricing concepts is competitive versus cost based pricing. These pricing concepts can also be differentiated in terms of objectives, such as efficiency and fairness. Fully allocated and marginal cost pricing and price discrimination are typically involved in discussions of efficiency and fairness.

Competitive pricing refers to price setting in a competitive market. In a regulated monopoly such as in natural gas distribution, conditions for competitive price setting may be absent. The pricing principle used in a regulatory framework is often referred to as cost based pricing. Contrary to the demand/supply dynamics of competitive pricing, cost based pricing attempts to set the price according to the cost of supplying the product as this is considered to be fair.

Complexities arise in the cost based approach because "cost" is itself an ambiguous concept (TR 383 - 84). Generally speaking, there are two basic approaches to quantifying cost. The first is the long-run incremental cost analysis. This is typically advanced as a proxy for marginal cost and is concerned with the added costs of serving expected additional demand over some planning cycle. Thus, it is concerned primarily with future costs. The second is sometimes referred to as fully distributed or fully allocated cost of service (FACOS). It is generally concerned with how to allocate costs to various customer classes or rate categories. Thus, it deals chiefly with historical or "original" cost in terms of assets acquired for the purpose of production. Allocating joint use facilities to classes of customers becomes contentious as there are many methods of determining class cost responsibility.*

---

* In this hearing, the major cost allocation methods are based on postage-stamp and demand-distance concepts.

From an economic perspective, marginal cost pricing (often proxied by long-run incremental cost analysis) is advocated on the ground that it allows more accurate reflections of market forces in both production and consumption of goods. In this sense, marginal cost pricing enhances resource allocation efficiency.

Objectively, however, marginal cost pricing may be perceived to be incompatible with "fairness" For example, groups of customers in the same sector (eg. residential customers) tend to incur different marginal costs. A case in point is rural versus urban customers where the marginal costs of serving the former are typically higher than those of the latter. Yet residential customers, under postage-stamp rates, are charged the same base rate regardless of geographic location. Another example stems from the fact that the revenue derived under marginal cost based prices is almost never equal to the revenue derived under rates based on embedded costs, except in the most unusual or fortuitous circumstances. Consequently, marginal cost based prices result in the utility earning either more or less than the allowed amount. In both cases fairness considerations outweigh efficiency considerations.

Finally, price discrimination is an important issue in utility rate setting. Differential pricing is commonplace in public utilities as customers are typically classified into residential, commercial, and industrial sectors, and are charged different rates. Although the marginal costs of serving these customers are different, the different rates more often reflect the fact that industrial customers usually more fully utilize the system and have more service options available (ie. exhibit higher own and cross-price elasticities of demand). What regulation is meant to prevent is not price discrimination per se, but <u>undue</u> discrimination. The latter refers to price discrimination practices that are not based on classification of customers in terms of differences in cost of service, demand characteristics, and elasticities of demand. A clear case of undue discrimination is when one customer group is forced to subsidize another customer group, without any concomitant increase in overall benefits to the customers themselves.

Welfare economics has provided valuable insights into the problem of defining unjust discrimination. It is clear that if you can help someone without hurting anyone else, welfare as a whole will be increased. This is sometimes referred to as the "no-loser" test. This welfare principle suggests that if the added cost is less than the rate charged, that added service can be set below the average cost of the previously established business and the excess of revenue over added cost can be used to reduce the prices charged to the old business, thereby improving their welfare. If, however, service is sold below added cost, the added costs of new business will not be recovered and the old customer, or investor, will be worse off. This is the principle of economic subsidization as opposed to the accounting notion of cross-subsidization based on cost of service analysis.

4.2 Position of the Parties

The Competitive Situation

The transcript (TR 917 - 936) summarizes Columbia's evidence regarding either bypass or alternative fuel competition for the Special Contract customers. Competition of any kind is not really a threat at this time under either the existing or proposed rates due to a number of factors such as:

- economic and technical barriers
- financial position of the Special Contract companies
- reliability of alternative technologies
- training requirements for alternative technologies
- available alternative investment opportunities to increase production, productivity, etc.

Table 2

AVERAGE REVENUE BY CUSTOMER CLASS

Year	Rate 1 1)	Rate 2 1)	Rate 3 1)	Rate 4 1)	Special Contract Customers 2) Cominco	Crestbrook	Fording	Westar Sparwood	Westar Greenhills
1981	$3.32	$3.13	$3.00	$2.79	N/A	N/A	N/A	N/A	N/A
1982	$4.16	$3.97	$3.83	$3.61	$2.652	$2.649	$2.781	$2.728	N/A
1983	$4.15	$3.96	$3.82	$3.61	$3.170	$3.132	$3.256	$3.228	N/A
1984	$4.25	$4.04	$3.84	$3.66	$3.186	$3.192	$3.278	$3.266	$3.200
1985	$4.23	$3.99	$3.79	$3.60	$3.227	$3.217	$3.313	$3.295	$3.241
1986	$4.31	$4.07	$3.86	$3.67	$3.123	$3.093	$3.258	$3.211	$3.103
1987	$3.44	$3.21	$2.80	$2.62	$1.802	$1.933	$1.992	$1.915	$1.947
1988	$3.65	$3.21	$2.80	$2.62	$1.740	$1.704	$1.855	$1.602	$1.525

1) average rate as of July 1
2) annual average $/GJ for the years ending June 30 for cost of gas & cost of service

Columbia further agreed that for all classes of consumers, their rates are competitive, especially since gas costs have decreased substantially to all customer classes (see Table 2). It is not, therefore asking for rate design to meet competitive alternatives (TR 159). Rather, Columbia's application was undertaken primarily to address equity considerations. Although it did not intend to exactly match revenues and costs for each rate class, Columbia agreed that divergences between revenues and costs for each class were based on equity considerations (TR 160).

Columbia did express concern, however, that if its "no rate increase" policy to Special Contract customers is set aside, Westar Balmer might bypass. Columbia also testified that it has a long-run concern that depending on improved circumstances, Greenhills might convert to coal from natural gas for coal drying. However, its proposal of reducing large industrial rates closer to costs, lessens the attractiveness of alternative fuels. In any case, Columbia will continue to monitor the competitive situation (TR 931-37).

Westar took the position that alternatives to natural gas purchases from Columbia are available. Greenhills has a competitive alternative in the form of coal-fired drying facilities and Balmer has the possibility of bypass. Neither of the options will be taken advantage of immediately by Westar, but signals as a result of this hearing will be important to future natural gas purchases. If Westar considers itself to be treated fairly it will perceive Columbia and this Commission more favourably than it would if rates were set to maximize revenues (TR 1400).

The President of Westar Mining Ltd., Mr. Dolezal stated that Westar was prepared to pay for its own total natural gas costs, however it was not willing to subsidize Columbia's other customers or classes of customers. If the Commission does find the subsidy to be reasonable it is the position of Westar that the subsidy must be minimized and all industrials should contribute to the cross subsidy in a way that is fair and proportionate to their involvement with the Columbia system (Exhibit 44).

Crestbrook originally planned to construct its own line and had formed a company called East Kootenay Gas Transmission Line. Gas supply contracts had been drawn up in Alberta with firm gas pricing to the year 1993. Studies had been completed and the project had been costed and mapped. Columbia then offered to construct and operate a line to the mill that was competitive and the project was suspended (TR 560).

Mr. Gormley, Vice President for Crestbrook pulp division, stated that in his opinion, with the knowledge of current and past costs, the company should have built the line. He testified further that the Commission should recognize Crestbrook's viable bypass alternative and that the company relied on Columbia's rates being cost based without subsidization of other customer classes (TR 560-561).

In Mr. Drazen's opinion (expert witness for Crestbrook, Cominco and Crows Nest Resources) it would be appropriate for Columbia to adjust the industrial rates closer to the cost of service to prevent any further erosion of the industrial load (Exhibit 38, page 9).

Fording was in favour of a greater degree of intra class equity with the application of average unit rates for Special Contract customers. Mr. Bleaney considered this approach to be easily administered and resulting in a lower cost to Fording (Exhibit 22, page 8).

4.3 Commission Summary and Conclusions

The Commission notes that all customer classes have benefited from large end-use price decreases primarily as a result of field price reductions. The table below shows both the relative and absolute price reductions between 1986 and 1987.

Price Reductions 1986/1987

	RS* 1	RS 2	RS 3	RS 4	Cominco	Crestbrook	Fording	Balmer	Greenhills
Percent	25.3	26.8	47.3	40.0	73.3	60.0	63.6	67.7	59.4
$/GJ	0.87	0.86	0.94	1.05	1.321	1.16	1.266	1.296	1.156

* Note: RS = Rate Schedule

The above table also shows that both the relative and absolute price decreases for the large industrial customer class are higher than for the other customer classes.

Based on the evidence the Commission concludes that there is little competitive threat to any customer class in the Columbia service area at this time. The Commission also believes, based on the evidence, that any future competitive pressures that emerge in the large industrial sector as a result of bypass, conservation or conversion to alternative fuel, will be mitigated by Columbia's rate shift proposal. It was also noted that large industrial consumption is virtually immune to price elasticity beyond the level of outright conversion to alternative fuels. Factors apart from gas costs are the main determinants of the usage of the Special Contract customers.

The Commission finds that this rate design proceeding amounts to determining a rate structure which results in fair, reasonable and not unduly discriminatory rates with few other complicating features.

5.0 FULLY ALLOCATED COST OF SERVICE (FACOS) STUDIES - DEMAND DISTANCE VS. POSTAGE STAMP ALLOCATION METHOD

5.1 Introduction

The regulatory process of rate determination results from three conceptually distinct steps:

(i) estimation of total cost, revenue requirements and deficiencies; and

(ii) allocation of (i) above to the various customer classes (cost allocation); and

(iii) allocation of revenue requirements within each customer class to the various customers with differing consumption patterns (rate structure).

Step (i) was already determined prior to this hearing. Step (ii), which is sometimes also referred to as the inter-class cost allocation problem, is the subject matter of this section. This does not entirely complete the second step as the revenue responsibility of each class must be derived. Section 6 discusses the transition from class cost of service for revenue requirements.

Step (iii), which is sometimes also referred to as the intra-class cost allocation problem is the topic of Section 7.

The two main costing methodologies that were examined during the hearing were based on demand-distance (dd) and postage-stamp (ps) concepts. As the terms suggest, the first method takes geographic location into account. The second method ignores geography and essentially derives average costs and attributes these costs by customer class. Postage-stamp customer class costs can be derived using allocators based on coincident peak, non-coincident peak, average and excess and partial plant methods to name but a few. Columbia based its evidence on a hybrid ps cost of service to all except Special Contract customers. Fording did not perform a complete FACOS study but, using the Columbia study, applied the ps methodology to a limited portion of Columbia's plant, namely, the Fording lateral beyond the Kaiser Junction.

5.2 Position of Parties

Columbia

5.2.1 Fiscal Year 1984 - January 25, 1988 - Exhibit 30

Mr. Schultz, expert witness for Columbia developed the assumptions and methodology that form the basis of variations in the Cost of Service Study as shown in Exhibit 30 under Cases 1, 2 and 3.

The study is based on Columbia's actual operating results for the fiscal year 1984 (twelve months ending June 30, 1984). The only adjustments are the imputation of a full return and associated income taxes for each customer class. In 1984, 70 percent of gas sales were to five large industrial customers served under special individual contracts. The total gas supply accounted for 84 percent of Columbia's total cost of service. Therefore the allocation of the non-gas costs had relatively little impact on total class costs.

The main area of concern involved the allocation of transmission level costs to the large industrials. The consultant proposed three cases:

Case No. 1 - Columbia system is considered a single unit with the special contracts group as a service classification in the utility. Functional costs are allocated on a postage stamp basis.

Case No. 2 - All transmission related costs have been assigned to the special contract industrial class.

Case No. 3 - (Greenhills) Individual analysis of cost for the special contract class.

Cases 1 and 2 made no distinction between special contract customers by virtue of their location and these customers were considered a single class (TR 386). Mr. Schultz stated that he thought Case 1 represented a good proxy for a postage stamp rate appropriate for special contract customers (TR 468).

The Greenhills case and Commission Order (of November 30, 1984) forced a departure from this unified approach and an individual analysis for the special contract class was developed resulting in Case 3 (TR 388).

This analysis had transmission costs for the two laterals, Cranbrook and Sparwood, allocated to each of the customer classes and to each of the special contract customers on the basis of their respective use of transmission facilities on the system peak day. This individual allocation method became the consultant's favoured alternative and served as a foundation for later variations of this study.

Mr. Schultz's arguments to support this approach were based on customer location and systems operation. In general the test is whether location is the factor which the customer has been responsible for, or has it simply been an accident of geography that this system is located in close proximity to the customer's facility (TR 328).

A second deciding element is system operation. Mr. Powell, Executive Vice-President of Columbia testified that Columbia is a unique distribution utility since most customers are served by two long laterals, Cranbrook and Sparwood (TR 135). Its service area resembles more a pipeline which provides single dimensional coverage than a distribution company with area coverage (TR 329). Fording for example, is at the end of the Sparwood lateral and there is no other way for gas to reach this customer (TR 132-135)

Transmission plant was allocated to the special contract customers on a demand distance method. Although the first FACOS study (Exhibit 30) used the peak day consumption to derive demand allocation factors, subsequent studies starting with Exhibit 3 used the average of the monthly average of the three highest peak demands for the four peak months of calendar 1985. The distance factor is based on diameter and length of the pipe to serve each individual customer.

Mr. Schultz chose the 1985 calendar year as a typical representation of gas consumption. The utility must meet the demands of its customers and the customers' capability to burn gas is the limiting factor. In the consultant's opinion the 1985 season represents an approximation of what has happened over the years and potentially may happen again. Fording's dramatic reduction in gas consumption in recent years does not necessarily represent a reduced obligation on the utility (TR 360).

5.2.2 Fiscal Year 1987 - Exhibit 3, Volume 3, Schedules A & B

In this study the methodology of Case No. 3 remained intact, and a demand distance methodology was used to allocate transmission costs. As mentioned above, the demand allocation factor was based on the average of the three peaks in the four peak months of calendar year 1985 (TR 355).

The rather significant changes in this study compared to the 1984 FACOS study are due primarily to:

(1) modifications to the operations of certain Special Contract customers, and;

(2) a reduction in the cost of gas.

Fording and Westar Balmer switched from gas to coal as the principal heat source for coal drying. Crestbrook Forest Industries became more energy efficient, thereby reducing its requirements for gas. As has been discussed, Columbia now obtains most of its gas from the Deep Basin in B.C. at much lower prices than it did in 1984.

5.2.3 Fiscal Year 1987 - Exhibit 4, Volume 4, Tab 5

The study is based on the budget figures for 1987 with the exception of gas costs, which are adjusted for April 1, 1987 information. Additional changes were made to Exhibit 3 to reflect the Commission's decision of January 21, 1987 reducing the rate of return by .35 percent to 12.8 percent.

Adjustments to Columbia's allowed operating expenses were not reflected in the study as it was judged these changes would make no material difference on the results. Transmission related costs were allocated on the same basis as Section 5.1.2. Table 3 shows net costs for all customer classes based on Columbia's filed FACOS studies for 1984 and 1987.

Intervenors

Fording was the only intervenor who submitted a variation of Columbia's FACOS study. Mr. Claude Bleaney, Manager of Accounting for Fording Coal Ltd., changed two assumptions of Exhibit 4 (Exhibit. 31 and TR 1063). He substituted the 1985 Calendar year peaks for both Fording and Greenhills with peaks for the last two months of 1986 and the first two months of 1987. It was Fording's position that the 1985 information is inappropriate and that current peaks are more realistic (TR 1070). Since 1985, Greenhills has expanded and its peaks have actually increased, while Fording was in the process of working out operational difficulties of its recently installed coal-fueled dryer facility (TR 1064).

Reviewing Exhibit 65 (see Table 4) shows Fording to have a descending peak from 1983 to 1988.* Since 1985, these reductions are due primarily to the improved operation of the coal drying facility (TR 1068). However, Mr. Bleaney did acknowledge that the amount of coal and gas used for drying coal depends very much on the moisture contents of the coal being dried (TR 1070).

---

* The issue of historic versus current peaks arose at the hearing in two different ways: with regard to the FACOS study, as identified above; and, in the context of the effect of constrained nominations on the Special Contract customers allocation of rate shift in years 1 and 2. With regard to year 3, the constrained nominations combined with a targetted Special Contract customer class revenue cost ratio may be limited by the base nomination level and so both the inter- and intra-class cost allocations are affected.

Table 3

COLUMBIA NATURAL GAS NET COST COMPARISONS

	Rate Schedule 1	Rate Schedule 2	Rate Schedule 3	Rate Schedule 4	Special Contract
1984 (Exhibit 30)					
Total Cost	8,844,078	2,705,392	1,738,344	170,247	21,431,618
Gas Cost	5,064,826	2,158,100	1,490,050	157,405	20,516,860
Net Cost	3,779,252	547,292	248,294	12,842	914,758
1987 (Exhibit 4)					
Total Cost	7,407,415	2,185,977	1,216,356	111,492	6,995,415
Gas Cost	3,617,800	1,552,600	1,006,700	104,700	6,039,000
Net Cost	3,789,615	633,377	209,656	6,792	956,415
Net Cost Percentage Increase/(Decrease)	.27	15.7	(15.6)	(47.1)	4.6

The second element Mr. Bleaney excluded from CNG's study was the concept of distance. He used postage stamp costings for Geenhills and Fording beyond the Kaiser Junction leaving all other Special Contract customers on a demand distance basis (TR 1058). Mr. Bleaney concluded (and this was confirmed by Mr. Schultz) that of the two changes made, location had an overriding impact on the study results (TR 361).

In Exhibit 35, Mr. Schultz corrected minor errors contained in Exhibit 31. A comparison of the results of Exhibit 35 with Exhibit 4 shows that Fording over-contributed by 6.67 percent as opposed to under-contributed by 4.2 percent respectively (TR 358).

Although Westar did not conduct a FACOS study, it submitted that Westar Balmer should be recognized as being in a unique situation due to its proximity to the Alberta Natural Gas line, and that its allocated cost of service, as shown in Exhibit 45, is lower than the cost of service for other industrials (TR 1420-30).

5.3 Commission Summary and Conclusions

Several factors bear consideration in deciding whether demand-distance or postage-stamp allocations are appropriate, particularly for the Special Contract customers in the Cost of Service Study. Rate averaging, or postage-stamp as it was referred to in this hearing, is directed towards treating customers uniformly, eliminating locational advantages and disadvantages, and avoiding the complications of large numbers of separate calculations to determine proper billings for customers.

In its deliberations on the proper costing methodology, the Commission has had to consider several factors.

1. Distance is the main factor in establishing cost differences amongst the Special Contract customers.

2. Rates based on demand-distance costing reduce the bypass option which in Columbia's case, applied mainly to Westar Balmer.

3. Historically, distance has been a factor in the contracts between Columbia and the Special Contract customers.

4. Columbia is indeed a local distribution company which in many ways resembles a pipeline company.

5. The limited number of Special Contract customers and their proportion of the total load.

All of the above factors were important in the Commission's deliberations but the unusual configuration of Columbia's plant, the potential for bypass, and the opportunity to provide common treatment in the class were paramount factors in the Commission's decision. The Commission concludes that the demand-distance costing methodology as employed by Columbia is appropriate at this time for the large industrial customers. For rate design purposes, it is thus convenient to consider each Special Contract customer individually.

Although the Commission has rejected the application of the postage-stamp demand allocation methodology for large industrial customers, it is instructive to look at the first year differences in allocated costs for the dd and ps cases. For the case where historic nominations are used, the net allocated cost for the two cases are shown in Table 4 below.

Table 4

Nomination Impacts for Demand-Distance vs. Postage Stamp

		net FACOS ($000)		
(1)	(2) Nominations GJ	(3) dd	(4) ps	(5) = (3) - (4) Excess (Deficiency)
Cominco	2992	155.2	132.5	22.7
Crestbrook	7094	351.8	271.0	80.8
Fording	4738	258.3	186.9	71.4
Balmer	5694	79.6	222.7	(143.1)
Greenhills	3641	170.4	179.5	(9.1)

The ps averaging methodology results in the customers close to the ANG system being allocated higher costs and those at the end of the distribution system being allocated lower costs. (For a given revenue, this clearly affects the revenue to cost ratios as will be shown in Section 6.0.) For this section it is sufficient to note that the two methodologies result in significantly different allocated costs.

Although distance is the main variable which accounts for the cost allocation differences with respect to dd and ps within each methodology, there are impacts on class cost allocations as a result of the choice of peaks. Table 5 below summarizes the estimated impacts for all classes using both dd and ps allocators for historic and current peaks.

Table 5

Impact on Allocated Costs due to Historic versus Current Peaks in Year 1

Net FACOS ($000)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Demand-Distance		Postage-Stamp		Excess (Deficiency)	
	(dd)		(ps)		(dd)	(ps)
	historic	current	historic	current	(2)-(3)	(4) - (5)
RS I	3944.5	3948.1	4019.3	3983.5	(3.6)	35.8
RS II	680.5	682.1	658.2	645.4	(1.6)	12.8
RS III	234.1	235.1	222.4	218.0	(1.0)	4.4
RS IV	8.7	8.7	8.7	8.7	0	0
Cominco	151.2	151.3	132.5	131.1	(0.1)	1.4
Crestbrook	368.2	368.6	271.0	276.8	(0.4)	(5.8)
Fording	243.6	216.4	186.9	157.8	27.2	35.1
Balmer	76.7	79.6	222.7	274.7	(2.9)	(52.0)
Greenhills	193.9	211.3	179.5	211.3	(17.4)	(31.8)

Note: The table is based on Exhibits 57, 60, 68, 69 and interpolations where necessary.

From Table 5, the Commission notes that the effect of peak (historic versus current) within each methodology is minimal. The Commission also notes the Applicant's position that historical peaks must be used rather than the more recent actual peaks because the utility remains vulnerable to customers demanding gas to the full extent of their burner capacities. However, proposed Rate Schedule VII standard terms and conditions contains safeguards against the utility being rendered unable to perform.

With regard to peak usage, the Commission concludes that it is much more realistic to use demand levels which customers are currently using. In this regard, the Commission adopts the peak levels of 1986/1987 as shown in Table 6.

Notwithstanding approval of the costing methodology, the Commission has similar concerns as were expressed in the Inland Rate Design Decision. In summary, the main difficulties have to do with presentation and cross-referencing. It should be possible to follow the FACOS study process from the uniform system of accounts to the functionalization, classification and allocation of these costs. Ideally, the FACOS model should be designed so that it is possible to run "variations" with relative ease. The Commission is satisfied that work is underway at Inland (to the benefit of Columbia) to improve the quality of the FACOS model as a result of recommendations on page 42 of the Inland Rate Design Decision.

Table 6

PEAKS - FISCAL YEAR - 4-DAY PEAK AVERAGES - 1983/84 to 1987/88

Data Derived from Exhibit 13

	Cominco	% of Total	Crestbrook	% of Total	Westar Balmer	% of Total	Westar Greenhills	% of Total	Fording	% of Total	TOTAL
1983/1984	3,514	11.1	9,315	29.4	7,903	24.9	3,841	12.1	7,150	22.5	31,723
1984/1985	3,466	11.1	8,641	27.6	8,221	26.2	4,255	13.6	6,747	21.5	31,330
1985/1986	3,904	12.4	8,501	27.0	8,701	27.7	4,944	15.7	5,397	17.2	31,447
1986/1987	3,230	10.9	8,026	27.1	9,288	31.4	5,247	17.7	3,833	12.9	29,624
1987/1988	2,889	11.4	7,838	31.0	5,893	23.3	5,115	20.2	3,552	14.1	25,287
80% of 1986/1987	2,584		6,421		7,430		4,198		3,066		23,699

6.0 CLASS REVENUE REQUIREMENTS

6.1 Introduction

Section 5 discussed the problem of joint cost allocation. Cost is one of the important considerations in determining the rate level for each class. Other rate objective considerations include:

- effectiveness in yielding sufficient revenue under the fair return regulatory standard.
- relative revenue stability from year to year.
- fairness of rates with respect to joint cost allocation among customer classes over time.
- avoidance of "undue discrimination".
- economic efficiency to ensure that customers pay what a resource is worth.
- flexibility to meet competitive market constraints.
- appropriate reaction to federal and provincial policies with respect to energy pricing and economic development.
- accommodation of social considerations such as ability to pay and distribution of social benefits.

In summary, the translation of cost to pricing requires consideration of all the factors referred to above. Mr. Schultz, expert consultant to Columbia, described it as follows:

> ". . . The utility rate making recognizes the public character of the business, the public interest character of the business that's conducted, and the importance of the utility function to society at large.
>
> And it has created a mechanism to allow what is in effect an operating monopoly in return for the review of the operations of that utility, . . . through the Public Service Commissions.

> The rate making mandate of the Public Service Commission goes far beyond simply an analysis of the internal costs of the utility . . . and I think that's borne out by a number of rather eminent authors, and by court decisions.
>
> So that while cost is certainly an important consideration and I use cost in the broadest terms, because there are several kinds of costs that are of consideration, not only the historic costs, but current value of prices, and marginal costs, and things of that kind.
>
> But also other factors, including matters of public policy, matters of social consideration and so that while cost may be an important element, and it may even be the most important element. It is certainly not the only element to be considered in rate making." (TR 382-83)

Clearly, determining class revenue requirements based on the above listed considerations is a complex task which requires experienced judgement.

After describing Columbia's proposal regarding class revenue requirements and rate objectives, this section will assess the rate impacts of the various submissions.

6.2 Positions of Parties

Columbia proposed that on the basis of fairness, rates for each class should gradually approach their costs as determined by Columbia's FACOS study (TR 168, 411). Until Exhibit 20, which was filed on February 2, 1988, Columbia had been proposing a two-year phasing-in of rate shifts (see Exhibit 4, Tab 4, Schedule A). In Exhibit 20, the rate shift for the first two years remained at the same level as in Exhibit 4. However, Columbia now proposed a third year shift (see Table 7). In addition, previous submissions did not contain any reference to revenue to cost ratio goals. Exhibit 20 indicated that Columbia now wanted to establish ". . . a margin revenue target (net revenue less cost of gas) of 120 percent of the allocated cost of service (revenue/cost ratio)". On a gross revenue to cost ratio basis, the evidence shows that this is equivalent to about 103 percent for the Special Contract customers as a class (see for example Exhibit 63).

As seen from Table 7, Columbia proposed to shift \$365,000, \$340,000 and \$340,000 to the residential class in years 1, 2 and 3, respectively.

In Exhibit 20, Columbia proposed to allocate the amount of revenue responsibility transferred from the industrials to the residential customers. The credit would be transferred proportionately to each Special Contract customer's revenue responsibility in relationship to total excess revenue for this class (see Table 8). This method was later amended in Exhibit 25 and was first clearly identified as to impact in Exhibit 46. The new intra-class method was the result of "last-minute" negotiations with the Special Contract customers. In the first two years, the allocation of the fixed revenue shift amongst the Special Contract customers is based on constrained nominations. As has been alluded to in the footnote to page 31, in the third year, the proposed nomination procedure would affect not only the intra- but also the inter-class allocation as a result of a targetted net revenue to cost ratio of 120 percent for the Special Contract customers.

Columbia also proposed that the starting nominations be the 1985 peak day average as used in the 1987 FACOS study. Thereafter, peak day nominations can be reduced by a maximum of 20 percent annually over the next three years. Further conditions imposed on nominations in the event that actual peak day requirements vary sufficiently with respect to their nominations will be discussed in Section 8.0.

Columbia testified that its application was undertaken to address several rate objectives. The result of the first FACOS study showed that there were large disparities between rates and costs for several classes. Columbia felt that this was unfair and unduly discriminatory (TR 186, 411). The Columbia policy witness also stated that lower industrial rates indirectly benefit residential consumers because employment is thereby enhanced as is economic development (TR 162).

Table 7

COLUMBIA NATURAL GAS LIMITED
SUMMARY OF REVENUE SHIFTS OVER 3 YEARS

Rate Schedule	Allocated C.O.S. $	Net Revenue July 1 $	Excess Net Revenue Over C.O.S. $	Excess Net Revenue Over C.O.S. %	Shift/Year 1	Shift/Year 2	Shift/Year 3	Year 3 Revenue $	Excess Net Revenue Over C.O.S. $	Excess Net Revenue Over C.O.S. %
I	3,800,617	2,539,300	(1,261,317)	67	365,000	340,000	340,000	3,584,300	(216,317)	94
II	637,844	943,600	305,756	148	–	–	–	943,600	305,756	148
III	212,496	566,300	353,804	267	–	(210,000)	(100,000)	256,300	43,804	121
IV	6,792	47,100	40,308	693	–	–	–	47,100	40,308	693
Special Contract	938,415	1,805,100	866,685	192	(365,000)	(130,000)	(240,000)	1,070,100	131,685	114
	5,596,164 1)	5,901,400 1)	0 1)		0	0	0	5,901,400	0 1)	

1) Revenues are actual and are not pro-rated to the cost of service study.

Table 8

REVENUE SHIFT CALCULATIONS - NET OF STRIKE ADJUSTMENTS
SPECIAL CONTRACT CUSTOMERS (EXCLUDES COST OF GAS)

Customer	Allocated Cost of Service *	Revenue July 1 *	Excess of Revenue Over Cost of Service	Shift Year 1	Proposed Revenue Year 1	Excess of Revenue Over Cost of Service	Shift Year 2	Proposed Revenue Year 2	Excess of Revenue Over Cost of Service	Shift Year 3	Proposed Revenue Year 3
Cominco	$149,720	$240,200	$90,480	$(37,712)	$202,488	$52,768	$(13,432)	$189,056	$39,336	$(24,797)	$164,056
Crestbrook	328,416	625,600	297,184	(123,866)	501,734	173,318	(44,117)	457,617	129,201	(81,446)	376,171
Fording	247,134	238,100	(9,034)	-	238,100	(9,034)	-	238,100	(9,034)	-	238,100
Balmer	68,809	236,600	167,791	(69,935)	166,665	97,856	(24,908)	141,757	72,948	(45,985)	95,772
Greenhills	144,333	464,600	320,267	(133,487)	331,113	186,780	(47,543)	283,570	139,237	(87,772)	195,798
	$938,412	$1,805,100	$866,688	$(365,000)	$1,440,100	$501,688	$(130,000)	$1,310,100	$371,688	$240,000	$1,069,897

The amount of shift for a specific customer in each year is calculated by the folloiwng equation:

$$\frac{\text{Excess of Revenue Over Cost of Service for Customer}}{\text{Total Excess Being Paid by Customers}} \times \text{Total Shift in Year} = \text{Shift}$$

eg. Cominco Year 1:

$$\frac{\$90,480 \times \$365,000}{(\$866,688 + \$9,034} = \$37,712$$

* Excluding cost of gas

With regard to the implementation of cost based rates, Columbia testified that gradualism and the avoidance of rate shock were taken into consideration. Columbia testified that these objectives are satisfied by implementing the phasing-in of the proposed residential rate increases of about 6, 6 and 3 percent per year for years 1, 2 and 3, respectively (TR 411-13, 434, 1377).

In determining how close the residential customer classes should be to their revenue to cost ratios, Columbia agreed that ability to pay was a consideration as were class risk differentials (TR 162-63). The result was that the residential class is proposed to remain below a revenue to cost ratio of unity over the next three years. Columbia's expert witness, however, indicated that a residential revenue to cost ratio of 94-95 percent is getting close to where "some rationale (sic) might be appropriate" (TR 418). This level was not achieved by even the third year in any of the impact exhibits prepared by Columbia (see for example Exhibits 57, 60, 63, 66, 67, 68, 69). Mr. Schultz did, however, admit that the determination of an appropriate revenue to cost ratio is largely based on experience and subjective factors (TR 411).

Columbia's concern regarding the three-year phasing-in as introduced by Exhibit 20, was not directed towards the residential class revenue to cost ratio as much as it was towards the Special Contract customers' revenue to cost ratios and their trend over time. The goal for the third year was to achieve a net revenue to cost ratio for Special Contract customers of not more than 120 percent. Indeed, Columbia intended to impose another constraint on Special Contract customers' rates to the effect that there should not be any increase to these customers' rates, regardless of their individual revenue to cost ratios.

Mr. Schultz provided the rationale for focussing on the industrial customers. He stated that it is Columbia's proposal to:

> ". . . give some assurance to the industrial customers . . . that they will be relieved of some of the burdens of their rates at this particular time. And Columbia is offering to that class of customers specific reductions over the next three years. And it is asking the Commission to endorse those reductions and what follows, the shift to other classes of customers.
>
> And I think, under the circumstances of Columbia, that it would be a positive thing to give that assurance to the industrial customers." (TR 436)

Mr. Schultz further testified that Columbia is losing industrial load and that the industrials have to have a "strong idea of where things are going". While Mr. Schultz is unequivocal about the need for a three-year plan for the industrial class, he is less so about the other classes of customers. In reply to a comment from the Chairman, Mr. Schultz's position appeared to be that he had reservations about a three-year commitment regarding residential class revenue requirements although he had no reservations about such a commitment to the large industrial customers (TR 437). He stated that he is ". . . concerned about making a program of three or more years with some sort of a commitment at this time because I don't know what the circumstances are going to be three years from today." (TR 414)

Yet, at page 438 of the transcript, Mr. Schultz argued that in order to assure the industrial customers of rate certainty over a three-year period that,

> ". . . all uncertainties from factors which are not now foreseen, have to associate with the smaller classes of customers."
>
> "But if there is any uncertainly, (sic) and as we discussed earlier I have to allow for the uncertainty, then that's the area [ie. smaller classes of customers including Rates I, II and III] that I would have to target." (TR 438-39)

With regard to the impacts of its proposal, Columbia submitted various exhibits.* All of the exhibits vary one or a combination of the following Special Contract customer parameters:

---

* Some of the more relevant exhibits are: Exhibits 46, 46A, 57, 58, 60, 63, 64, 66-69.

(a) Nominations - historic** or current or hybrid***
(b) Future Nominations - constrained or unconstrained or hybrid
(c) Fixed Cost Allocators - demand-distance, postage-stamp or hybrid.

The combinations of (a), (b) and (c) above excluding the hybrid cases, result in eight cases. The more important cases that emerged during the hearing are shown in Tables 10 to 13. Table 9 summarizes the rate shift impacts on affected customer classes for Exhibits 63, 67, 68 and 69. Tables 10 to 13 summarize the Special Contract customers' intra-class revenue requirements impacts. The only difference between Exhibits 63 and 68 is the nomination. Although both are constrained nominations with respect to historic peaks, Exhibit 63 is Columbia's estimate of most likely nominations and Exhibit 68 is based on all nominations being 80 percent of their preceding levels. In Table 9, Worst Case 1 (Exhibit 68) and Worst Case 2 (Exhibit 69) are so-called because of the relatively large third year residential impacts of 5.6 and 6.3 percent respectively, for a compound three-year impact of 18.8 and 19.6 percent respectively, based only on rate design impacts. Any additional potential increases due to revenue requirements or gas costs would exacerbate the impact. For example, Exhibit 62 indicates that if Columbia's proposal to flow through increased revenue requirements in the second year on a net basis is accepted, the residential rate will be increased by 4.1 percent. Adding this to rate design impacts results in a compound rate of about 23.4 and 24.2 percent for Worst Cases 1 and 2 respectively over the three year period. Table 9 also shows the amount of second year rate shift relief of $210,000 to Rate Schedule III customers. This reduces their net revenue to cost ratio from about 241 percent to 151 percent. The corresponding gross revenue to cost ratios are about 127 percent and 110 percent.

** The historic and current refers to calendar year 1985 and heating year 1986/87, respectively.

*** The hybrid in each case attempts to assess an impact in cases where Fording is treated differently from other Special Contract customers.

Table 9

Rate Shifts - Exhibits 68, 69, 67 and 63

Worst Case 1

	Shifts Year 1	Year 2	Year 3	Total Shift
RS I	365.0	$340.0	$365.6	$1,070.6
				$0.0
RS II		($210.0)	($74.9)	($284.9)
				$0.0
RS III/VII	(365.0)	($130.0)	($290.7)	($785.7)
	$0.0	$0.0	$0.0	$0.0

IMPACT ON AVERAGE RESIDENTIAL RATES

	Current	Year 1	Year 2	Year 3
% Change		5.85	6.27	6.34
Cost/GJ		$0.202	$0.228	$0.246
Average Rate ($/GJ)	$3.444	$3.646	$3.874	$4.120

Exhibit 68

Worst Case 2

	Shifts Year 1	Year 2	Year 3	Total Shift
RS I	365.0	$340.0	$324.3	$1,029.3
				$0.0
RS II		($210.0)	($68.6)	($278.6)
				$0.0
RS III/VII	(365.0)	($130.0)	($255.7)	($750.7)
	$0.0	$0.0	$0.0	$0.0

IMPACT ON AVERAGE RESIDENTIAL RATES

	Current	Year 1	Year 2	Year 3
% Change		5.85	6.27	5.62
Cost/GJ		$0.202	$0.228	$0.218
Average Rate ($/GJ)	$3.444	$3.646	$3.874	$4.092

Exhibit 69

Anti-Columbia Case or Extreme Case

	Shifts Year 1	Year 2	Year 3	Total Shift
RS I	365.0	$340.0	$219.7	$924.7
				$0.0
RS II		($210.0)	($88.6)	($298.6)
				$0.0
RS III/VII	(365.0)	($130.0)	($131.1)	($626.1)
	$0.0	$0.0	$0.0	$0.0

IMPACT ON AVERAGE RESIDENTIAL RATES

	Current	Year 1	Year 2	Year 3
% Change		5.85	6.27	3.81
Cost/GJ		$0.202	$0.228	$0.148
Average Rate ($/GJ)	$3.444	$3.646	$3.874	$4.022

Exhibit 67

Columbia "Most Likely Case"

	Shifts Year 1	Year 2	Year 3	Total Shift
RS I	365.0	$340.0	$175.1	$880.1
				$0.0
RS II		($210.0)	($73.9)	($283.9)
				$0.0
RS III/VII	(365.0)	($130.0)	($101.2)	($595.2)
	$0.0	$0.0	$0.0	$0.0

IMPACT ON AVERAGE RESIDENTIAL RATES

	Current	Year 1	Year 2	Year 3
% Change		5.85	6.27	3.04
Cost/GJ		$0.202	$0.228	$0.118
Average Rate ($/GJ)	$3.444	$3.646	$3.874	$3.992

Exhibit 63

Table 10
Exhibit 68

Year 1 - Industrial Nominations			Year 1				Shifts ($,000)			
Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %	Year 1	Year 2	Year 3	Total Shift
Cominco	2,992	155.2	240.2	85.0	154.8	108.4	0.0	(26.1)	(55.6)	(81.6)
Crestbrook	7,094	351.8	562.3	210.4	159.8	108.1	(63.3)	(68.0)	(120.8)	(252.1)
Fording	4,738	258.3	238.1	(20.2)	92.2	97.8	0.0	0.0	0.0	0.0
Sparwood	6,594	79.6	127.2	47.6	159.8	106.1	(109.4)	(12.4)	(25.8)	(147.6)
Greenhills	3,641	170.4	272.3	101.9	159.8	105.8	(192.3)	(23.6)	(53.5)	(269.4)
	25,059	1,015.3	1,440.0	424.8	141.8	106.0	(365.0)	(130.0)	(255.7)	(750.7)

Year 2-Revised Industrial Nominations — **Year 2**
Year 1 (Restated)

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %
Cominco	2,394	143.5	214.1	70.6	149.2	109.7
Crestbrook	5,676	331.3	494.3	163.0	149.2	108.9
Fording	3,790	253.6	238.1	(15.5)	93.9	98.3
Sparwood	5,275	77.0	114.8	37.9	149.2	106.4
Greenhills	2,913	166.7	248.7	82.0	149.2	106.1
	20,048	972.1	1,310.0	337.9	134.8	106.7

Year 3-Revised Industrial Nominations — **Year 3**
Year 2 (Restated)

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %
Cominco	1,915	132.1	158.6	26.4	120.0	102.7
Crestbrook	4,540	311.3	373.5	62.3	120.0	102.4
Fording	3,032	248.4	238.1	(10.3)	95.9	98.9
Sparwood	4,220	74.2	89.0	14.8	120.0	101.9
Greenhills	2,330	162.6	195.2	32.5	120.0	101.9
	16,037	928.6	1,054.4	125.7	113.5	101.8

Table 11
Exhibit 69

Year 1–Industrial Nominations — **Year 1** — **Shifts ($,000)**

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %	Shifts Year 1	Shifts Year 2	Shifts Year 3	Total Shift
Cominco	2,992	132.5	219.4	86.9	165.6	108.8	(20.8)	(29.1)	(52.0)	(101.8)
Crestbrook	7,094	271.0	448.7	177.7	165.6	107.0	(176.9)	(63.3)	(108.4)	(348.5)
Fording	4,738	186.9	238.1	51.2	127.4	106.1	0.0	0.0	(46.4)	(46.4)
Sparwood	6,594	222.7	236.6	13.9	106.3	101.5	0.0	0.0	(14.6)	(14.6)
Greenhills	3,641	179.5	297.2	117.7	165.6	106.7	(167.4)	(37.7)	(69.4)	(274.4)
	25,059	992.7	1,440.1	447.4	145.1	106.4	(365.0)	(130.0)	(290.7)	(785.7)

Year 2–Revised Industrial Nominations — **Year 2**
Year 1 (Restated)

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %
Cominco	2,394	123.9	190.4	66.4	153.6	109.7
Crestbrook	5,676	250.9	385.4	134.5	153.6	107.9
Fording	3,790	173.3	238.1	64.8	137.4	107.8
Sparwood	5,275	203.8	236.6	32.8	116.1	103.6
Greenhills	2,913	169.0	259.6	90.6	153.6	107.4
	20,048	920.9	1,310.1	389.1	142.3	107.5

Year 3–Revised Industrial Nominations — **Year 3**
Year 2 (Restated)

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %
Cominco	1,915	115.3	138.4	23.1	120.0	102.4
Crestbrook	4,540	230.9	277.1	46.2	120.0	101.9
Fording	3,032	159.8	191.7	32.0	120.0	103.9
Sparwood	4,220	185.0	222.0	37.0	120.0	104.2
Greenhills	2,330	158.5	190.2	31.7	120.0	101.8
	16,037	849.5	1,019.4	169.9	120.0	102.5

Table 12
Exhibit 67

Year 1-Industrial Nominations | **Year 1** | **Shifts ($,000)**

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %	Year 1	Year 2	Year 3	Total Shift
Cominco	2,990	133.6	204.7	71.1	153.2	107.2	(35.5)	(22.1)	(22.3)	(79.9)
Crestbrook	8,100	301.6	462.2	160.6	153.2	106.3	(163.4)	(49.9)	(50.3)	(263.7)
Fording	2,500	125.1	191.6	66.6	153.2	108.6	(46.5)	(20.7)	(20.9)	(88.0)
Sparwood	5,700	199.6	236.6	37.0	118.5	104.1	0.0	0.0	0.0	0.0
Greenhills	5,200	225.1	345.0	119.9	153.2	106.7	(119.6)	(37.3)	(37.6)	(194.4)
	24,490	985.0	1,440.1	455.1	146.2	106.5	(365.0)	(130.0)	(131.1)	(626.1)

Year 2-Revised Industrial Nominations | **Year 2**
Year 1 (Restated)

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %
Cominco	2,990	133.6	182.6	49.0	136.7	107.2
Crestbrook	8,100	301.6	412.2	110.7	136.7	106.3
Fording	2,500	125.1	170.9	45.9	136.7	108.6
Sparwood	5,700	199.6	236.6	37.0	118.5	104.1
Greenhills	5,200	225.1	307.7	82.6	136.7	106.7
	24,490	985.0	1,310.1	325.1	133.0	106.5

Year 3-Revised Industrial Nominations | **Year 3**
Year 2 (Restated)

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %
Cominco	2,990	133.6	160.3	26.7	120.0	102.7
Crestbrook	8,100	301.6	361.9	60.3	120.0	102.4
Fording	2,500	125.1	150.1	25.0	120.0	103.2
Sparwood	5,700	199.6	236.6	37.0	118.5	104.1
Greenhills	5,200	225.1	270.2	45.0	120.0	102.5
	24,490	985.0	1,179.0	194.0	119.7	102.8

Table 13
Exhibit 63

Year 1 - Industrial Nominations / **Year 1** / **Shifts ($,000)**

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %	Year 1	Year 2	Year 3	Total Shift
Cominco	2,990	151.2	230.0	78.9	152.2	107.8	(10.2)	(26.9)	(21.4)	(58.5)
Crestbrook	8,100	368.2	560.3	192.1	152.2	107.3	(65.3)	(65.4)	(52.2)	(182.9)
Fording	4,740	243.6	238.1	(5.5)	97.8	99.4	0.0	0.0	0.0	0.0
Sparwood	6,595	76.7	116.7	40.0	152.2	105.1	(119.9)	(17.0)	(9.0)	(146.0)
Greenhills	5,200	193.9	295.0	101.1	152.2	105.7	(169.6)	(20.7)	(18.6)	(208.8)
	27,625	1,033.5	1,440.1	406.6	139.3	105.7	(365.0)	(130.0)	(101.2)	(596.2)

Year 2-Revised Industrial Nominations / **Year 2**
Year 1 (Restated)

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %
Cominco	2,990	151.4	203.1	51.8	134.2	107.8
Crestbrook	8,100	368.7	494.9	126.2	134.2	107.3
Fording	3,790	230.0	238.1	8.1	103.5	100.9
Sparwood	5,700	74.2	99.6	25.4	134.2	105.4
Greenhills	5,200	204.4	274.4	70.0	134.2	105.1
	25,780	1,028.7	1,310.1	281.4	127.4	105.8

Year 3-Revised Industrial Nominations / **Year 3**
Year 2 (Restated)

Customer	Nomination	Allocated Net COS	Net Revenue	Excess $	Net %	Gross %
Cominco	2,990	151.4	181.7	30.3	120.0	103.0
Crestbrook	8,100	368.9	442.7	73.8	120.0	102.8
Fording	3,030	216.6	238.1	21.5	109.9	102.5
Sparwood	5,700	75.5	90.6	15.1	120.0	101.9
Greenhills	5,200	213.1	255.8	42.6	120.0	102.4
	25,020	1,025.6	1,208.9	183.3	117.9	102.6

Whereas Table 7 stresses the inter-class problem, Tables 8, 9, 10, and 11 show the impact within the Special Contract customer class for Exhibits 63, 67, 68 and 69. As can be seen, there is no rate shift relief for Fording for any demand-distance based FACOS studies as represented by Exhibits 63 and 68. In addition there is no revenue shifting for the most Extreme Case based on postage-stamp as shown in Exhibit 67. Only in the case where constrained nominations are based on historic peaks and the cost allocation is based on the postage stamp concept does Fording obtain any rate relief and then only in year 3 as shown in Table 9. Columbia's proposal and expected outcome is represented by Exhibit 63 (Table 11).

Mr. Drazen, expert witness appearing for Crestbrook, Cominco and Crows Nest argued that the rate shift should be higher. He testified that an additional revenue shift of $100,000 from Rate Schedules II and III to Rate Schedule I should be made in year 1 (see Exhibit 38, pp. 10-11). Mr. Drazen stated that the rationale for reducing Rate Schedule III excess revenues is the same as for the Special Contract customers, and that Rate Schedule II revenue reductions are based on fairness. The $100,000 revenue reduction would be split $45,000 and $55,000 for Rate Schedules II and III respectively.

Mr. Dolezal, President of Westar Mining Ltd., stated that Westar is prepared to pay its own way but is opposed to any cross-subsidies (TR 635-37). Fording argued at the hearing that it was opposed to the FACOS study methodology and to Columbia's proposal to use historical peak demands as the starting point for constrained nominations.

6.3 Commission Summary and Conclusions

The Commission concludes that the year 1 and year 2 rate shifts of $365,000 and $340,000 onto the residential class are acceptable. The Commission also finds that the Special Contract customer class reductions of $365,000 and $130,000 for years 1 and 2 respectively, and the Rate Schedule III revenue reduction of $210,000 in year 2 are acceptable. The residential rate design increase of approximately 6 percent in both years 1 and 2 do not impose rate shock to this class of customer. The Commission believes that it is unlikely that there will be other increases to the residential rates, due to such causes as increased gas costs and transmission rates which may impact to the extent to constitute rate shock.

The Commission also feels that the reduction to the Special Contract customer class of about 5 and 2 percent in years 1 and 2 respectively, is warranted at this time, as is the reduction of about 13 percent to Rate Schedule III in year 2. The Commission is aware that the Special Contract customers' reductions are allocated on the basis of constrained nominations (see Section 8.0). The Commission is satisfied that the rate shift result of using constrained nominations on the Special Contract customer classes is appropriate.

The Commission's decision regarding the two year shift is based primarily on the already mentioned gradual impact and on the current relationship of revenues to costs. Considering all Special Contract customers as a single class, the Commission feels comfortable with the inter-class rate movement closer to costs over the next two years based on the evidence adduced during the hearing. (The unresolved intra-class issue of the Special Contract customers will be discussed below.)

The Commission is not, however, convinced of the wisdom of embracing a targetted revenue to cost ratio for any class. This imputes an absolute standard of correctness regarding revenue to cost ratios which is misplaced for several reasons:

1. Cost, especially in regard to joint use facilities, is not a precise concept. Using either the dd or the ps allocation methodology leads, for example, to a Fording net revenue to cost ratio range of some 35 percent (92 percent to 127 percent). Thus the notion of "true cost" in this situation is somewhat misleading.

2. Even for a given allocation methodology (dd or ps), there can be considerable variation in determining costs due to judgment and the various other refinements that can be used. During the Inland rate design hearing, the evidence indicated that costs could be out by as much as 10 percent. (See Inland Rate Design Hearing transcripts pp. 794, 6584, 6593-9).

3. Depreciation can be vulnerable to considerations other than physical life of property.

4. Revenues can vary significantly from year to year, especially for industrial gas use which is dependent on volatile international or national economic conditions.

5. The revenue to cost ratio also varies depending on whether or not the FACOS is prorated to revenues or revenues are prorated to the FACOS.

6. Historically, the gross revenue to cost ratio was used for comparative purposes. With the advent of direct gas purchasing, bypass and the segmented gas pricing policy, gross revenue to cost ratios have largely lost their meaning. Yet, net revenue to cost ratios are unstable in the sense that the biggest share of total costs is due to gas costs. The difference is margin or non-gas costs which result in exaggerated divergence of the revenue to cost ratio from unity.

With regard to the third year shift the Commission must be satisfied that cogent reasons exist to justify accommodating this late addendum to Columbia's Application. The Commission's decision regarding a legal interpretation of its jurisdiction respecting the third year shift as proposed by Columbia, has already been given in Section 3.2.4. In this section, the Commission discusses substantive reasons regarding the proposed third year shift.

The basis for entertaining any reallocation of responsibility for revenue requirement among customer classes is the Cost of Service Study, which took a prominent position in the evidence submitted. It is clear that the variation in revenue deficiency percentages portrayed in the study became indelibly imprinted on the minds of the parties as unjust cross-subsidies between the rate groups, and whetted the appetites of the intervenors for a share of the anticipated redistribution. With difficult competitive world markets, the special contract industrial customers understandably have strong incentives to decrease every element of their costs, even though for most of the intervenors, as evidence disclosed, the cost of gas is a small percentage of their total expenses; and the Applicant, by proposing the third year shift, was attempting to attenuate the hostility caused by the indicated cross-subsidies.

The Commission notes that Mr. Schultz had reservations about a three-year commitment to the residential class. However, the Commission does not accept that a firm three-year commitment can be made to the Special Contract customer class without making an off-setting firm commitment to the other classes. Also, the Commission is concerned about the potential rate design impact in year 3 on the residential class which realistically could vary from three to five percentage points. Additional rate impacts could result from changes to revenue requirements, gas costs, transmission costs, or other reasons. The Commission also notes that all other classes are subject to the vagaries of these cost changes. In these circumstances it seems that rates resulting from the mechanism, as proposed for the third year for Columbia's customers, are not practically feasible.

Therefore, the Commission concludes that the evidence does not support sufficient nexus between this hearing and the circumstances as they may exist at the end of year two. For these reasons, the Commission chooses to reject the proposed third-year shift. It prefers instead to monitor developments in market definition, supply pricing, and the utility's performance, in anticipation of the Applicant's voluntary report on the third year.

Much was said in the hearing about the "signals" which would be sent to industry as a result of this Decision. The signal that should be received is that the Commission will act as expeditiously as it can to correct inequities that develop in rate structures; however, it will not be circumscribed by so narrow a context as to impair fair consideration given to all affected parties in a proceeding, whether or not they appear at hearings.

Table 14 shows revenue deficiencies for Columbia's filed FACOS studies as shown in Exhibits 30, 3 and 4. Based on the table, the Commission concludes that the Westar Greenhills rate is/was not insufficient within the meaning of the Act. In Exhibits 3 and 4, Greenhills over-contributes more than its costs by a larger margin than all customers except Westar Balmer. Accordingly, the Commission confirms the interim rate as permanent for the periods involved.

With regard to Fording's complaints about high unit costs of gas, the Commission concludes that reduced load factor as a result of Fording changing its coal drying technology, is the cause. Exhibit 45, Case C (see Table 15), shows that when the load factor adjustments are made to fully allocated costs the difference between the Fording and Greenhills unitized rate is just over \$0.02/GJ. Since the transmission capacity is still available to Fording and since Fording still has the capability of requiring historical peak demands, the Commission has concluded in Section 5.0 that the demand-distance allocation methodology is appropriate. The Commission, therefore, rejects the "Fording Complaint" for both legal and substantive reasons.

Table 14

FULLY ALLOCATED COST OF SERVICE STUDIES COMPARED

Deficiency or Excess (-) In Revenues	Rate 1 %	Rate 2 %	Rate 3 %	Rate 4 %	Total Special Contracts %	Cominco %	Crestbrook %	Westar Balmer %	Westar Greenhills %	Fording %
Fiscal Year 1984	26.31	-6.55	-19.96	-10.98	-5.29	-3.18	-4.18	-8.72	-3.98	-4.35
Fiscal Year 1987 (included in July 30/86 filing)	18.56	-7.23	-12.38	-13.41	-6.19	-5.02	-5.33	-10.44	-8.93	0.48
Fiscal Year 1987 (adjusted for gas cost reduction)	22.36	-10.93	-21.35	-25.30	-9.30	-6.68	-8.81	-16.42	-14.01	-4.20

Table 15

INDUSTRIAL GAS USAGE AND ALLOCATED COSTS
BASED ON COMMON LOAD FACTOR ASSUMPTION

(Exhibit 45)

CUSTOMER	Allocated 1) Net C.O.S. ($,000)	Annual Use (GJ)	Peak Day (GJ)	Peak Day 10^3 m^3	Load Factor	Allocated Net C.O.S Commodity ($/GJ)	Allocated Net C.O.S Demand ($/10^3 m^3)
CASE A:							
Cominco	$166.9	632,000	3,740	98.9	46.3%	$0.264	$1,686.85
Crestbrook	$372.3	1,659,300	8,867	234.6	51.3%	$0.224	$1,587.11
Fording	$262.5	481,000	5,923	156.7	22.2%	$0.546	$1,675.25
Sparwood	$82.0	520,000	8,242	218.0	17.3%	$0.158	$376.07
Westar - Greenhills	$173.6	1,160,000	4,551	120.4	69.8%	$0.150	$1,441.90
		4,452,300	31,323	828.7	38.9%		
CASE B:							
Cominco	$166.9	531,609	3,740	98.9	38.9%	$0.314	$1,686.85
Crestbrook	$372.3	1,260,369	8,867	234.6	38.9%	$0.295	$1,587.11
Fording	$262.5	841,904	5,923	156.7	38.9%	$0.312	$1,675.25
Sparwood	$82.0	1,171,531	8,242	218.0	38.9%	$0.070	$376.07
Westar - Greenhills	$173.6	646,886	4,551	120.4	38.9%	$0.268	$1,441.90
	$1,057.3	4,452,300	31,323	828.7	38.9%		
CASE C:							
Fording	$262.5	1,509,708	5,923	156.7	69.8%	$0.174	$1,675.25
Westar - Greenhills	$173.6	1,160,000	4,551	120.4	69.8%	$0.150	$1,441.90
	$436.1	2,669,708	10,474	277.1	69.8%		

1) Based on historic peaks and prorated to revenues

7.0 RATE STRUCTURE - THE INTRA-CLASS PROBLEMS

7.1 Background

Section 5.0 discussed costs and Section 6.0 discussed the transition from costs to revenues. In this section, the intra-class allocation of costs or rate design is discussed.

7.2 Basic Customer Charge

7.2.1 Rate I

Columbia proposed that the small commercial customers currently receiving service under Rate Schedule I be moved to a commercial rate. Residential customers remaining on Rate Schedule I would have a monthly customer charge of $3.90/month and a single block rate of $3.25/GJ. A first year rate shift for existing customers of $300,000 is built into this rate structure (Exhibit 4, Tab 4, Schedule B).

The proposed total increase in residential rates would be phased-in over three years, resulting in two increases of about 6 percent each in years 1 and 2 and an increase of about 3 percent in year 3 (TR 23). The proposed average residential rate for Columbia after the first year shift will be $3.65/GJ, whereas Inland's is $3.89/GJ (TR 697).

7.2.2 Rate II

Columbia proposed that the existing Rate Schedule II would become the general service schedule that would be available to commercial, institutional, and small industrial customers. It would be divided into Rate Schedules IIA and IIB. Rate Schedule IIA would include the small commercial customers previously served under Rate Schedule I and Rate Schedule IIB would include customers previously served under Rate Schedule II. Initially the rates for Rate Schedule IIA and Rate Schedule IIB are identical, but the splitting provides flexibility to amend rate levels to the two different groups should future circumstances warrant it. Rates charged to Rate Schedule IIA customers would mean an increase of 6.11 percent, or $65,000, from their previous rates. Columbia proposed a Customer Charge of $8.75/month for both Rate Schedules IIA and IIB (Exhibit 4, pp. 2-3), plus three declining blocks at $3.25, $3.15 and $3.071 per gigajoule.

7.2.3 Rate III

Columbia proposed to move Rate III closer to its cost of service. To accomplish this, its rate would be changed from an annual to a monthly rate, with a monthly Customer Charge of $500/month (TR 14, Exhibit 4, p. 3) plus three rate blocks from $3.10/GJ to $1.657/GJ. Specifically, to avoid rate shock, Columbia proposed to keep Kootenay Wood Preservers and Hushcroft Sawmill on the existing tariff for one year, and receive service under the new rates thereafter (TR 644-5).

7.2.4 Rate IV

Kootenay Dehydrators is the only customer served under a seasonal rate. Columbia proposed that an interruptible availability be offered from December 1 to April 30. A charge of $1,000/month would be established for each month from May to November (Exhibit 4, p. 4). The commodity rate for all gas taken would be $1.498/GJ.

7.2.5 Rate VII

Columbia proposed a revised Schedule VII which purports to offer a number of advantages over the existing Special Contracts. These include: (i) closer cost-price relationship, (ii) clearer common commitment by the utility and its customers, (iii) more consistent terms and conditions for all customers, (iv) a structure that is more conducive to efficient use of gas, and (v) easier billing and administrative rate structure (Exhibit 4, Tab 3, pp. 3-4, TR 94).

Large industrial customers, under the new rate structure, will pay their share of cost of service in a monthly customer charge (TR 94), which is equivalent to paying a rental fee for facilities committed. The commodity cost of gas will continue to be charged on the same basis as in the recent past which is on a flow-through basis (TR 649). The current Greenhills schedule is proposed to be made permanent (TR 94).

7.3 Commission Summary and Conclusions

There was very little disagreement at the hearing regarding rate structure issues with respect to Rate Schedules I, II, III and IV. Only Fording had concerns with a fixed demand charge. Fording favoured a commodity charge for all Special Contract customers based on costs allocated by the postage-stamp methodology. Rate averaging would, of course, be of specific advantage to Fording because of its location, but the Commission notes that the industrial customers generally were in favour of Columbia's pricing proposal and to accede to Fording's position would be a major departure from rate setting under conditions of increased competition. Accordingly the Commission rejects the averaged commodity charge concept.

The Commission directs that the Applicant file first and second year rate schedules effective June 1, 1988.

8.0 TERMS AND CONDITIONS

Apart from Section 8.1 this section deals with the proposed Rate Schedule VII conditions.

8.1 Application Fee for All Tariff Schedules

Columbia applied to revise the General Terms and Conditions for all tariff schedules to include an application fee of $10.00 for new service connections or reconnections, turn-on of an existing service connection or transfer of an account to a new service (Exhibit. 10, TR 7-8).

8.2 Changes in Terms and Conditions - Rate Schedule VII Customers

8.2.1 Availability

Columbia submitted that, with respect to items l(a) and (b) of the proposed contract, it cannot sell gas it does not have, or gas that cannot be moved due to a lack of capacity. In such a situation, Columbia would not be obliged to serve a customer simply because the customer has asked for service. Columbia argued that a customer should not be allowed to demand service beyond the utility's capacity to deliver (TR 716-9).

Special contract customers who have nominated and paid for service, on the other hand, should have priority to capacity in the following years over customers not served in the preceding year. This priority, Columbia submitted, should be extended up to the customer's peak day nomination in the previous year (Exhibit 52).

Crestbrook argued that Columbia's proposal would allow the utility complete control over whom it wanted to serve and not serve. Columbia, it said, could effectively sign up new customers that would take up all the capacity (TR 710-17).

8.2.2 Nominations

Although nominations have been referred to previously this section is included for completeness.

Columbia proposed that for purposes of determining the allocated cost of service, the special contract customer's demand allocation be based on nominations. Allowable changes in nominations will be based on current peak demands with a maximum reduction of 20 percent from one year to the next. One operational peak day demand can be waived each year for inclusion in the subsequent year's nomination calculation (TR 23-4).

In practice, special contract customers are required to provide their estimated peak day nominations and monthly usage six months in advance. Nomination for any year cannot be less than 80 percent of the nomination from the previous year. If a buyer exceeded his peak day nomination more than once during the period November 1st to April 1st, the peak day nomination in the following year must be increased. The new nomination is to be not less than the preceding year plus 50 percent of the excess of the average of three of the four highest peaks, unless 50 percent of the average of the average of the three highest months is less than 105 percent of the preceding year's nomination. At that point, the new nomination reverts back to the previous nomination (Exhibit 51A). In either case, Columbia proposed that a customer who nominates artificially low, then takes gas in excess of the nomination, will be subjected to "authorized overrun" charges for the extra gas. In addition to maintaining a semblance of historical cost causation, the proposed nomination procedure is designed to ensure that nomination reductions are gradual (TR 1333).

The proposed starting point in the nomination procedure is the 1985 demands used in the 1987 study by Mr. Schultz. The use of historical demands recognizes the obligation imposed on the system by Special Contract customers (TR 1332).

While expressing no specific problem with Columbia's proposal, Westar submitted that customers must have the ability to adjust their demands over time. Westar argued that there are three factors that must be taken into account in demand allocation. They are: (i) there should be rate stability, (ii) the nomination must reflect the firm demand requirements of the customer, and (iii) customers must be able to reduce their nominated demands with reasonable haste as usage declines (TR 1431-2).

Fording agreed that there has to be some procedure to ensure that the nomination method is not abused. Fording stated that the proposed mechanism in the calculation of minimum nomination is close to the mark (TR 1238).

8.2.3 Peaking Gas

Regarding item 5 of the proposed contract, Columbia submitted that a customer can take as much gas as required in excess of the maximum daily delivery obligation (MDDO), as long as Columbia has no problem in supplying it. Should there be problems, the customer is curtailed to the MDDO. If he takes gas above the MDDO in contravention of a curtailment order, he will be penalized by a charge of three times Columbia's weighted average cost of gas for that month on all volumes taken in excess of MDDO. This will constitute the only time when a customer is charged differently from other customers (TR 721-2).

This arrangement is needed because Columbia's own situation, with respect to peaking gas purchase, is that it has a primary supply contract of up to 35 MMcf, with another 15 MMcf per day available at higher prices. The resulting monthly bills to the large industrials have to reflect the weighted average price of gas purchased by Columbia (TR 722-3). In addition, a portion of the amount of peaking gas forecast for the year by Columbia is allocated within the overall cost of gas to the various customer classes (TR 724).

Crestbrook argued that a customer could take gas over its MDDO without knowing it and thus be responsible for increased gas cost if Columbia did not inform them of their overruns (TR 722-3). Crestbrook also pointed out that in Columbia's proposed contract a customer may have a perfectly flat steady load without imposing on the system peak, yet will have to share in peaking gas cost that Columbia may incur if Columbia exceeds the prescribed limit in its contract with suppliers (TR 725).

8.2.4 Force Majeure

Columbia proposed, regarding item 11 of the contract, that a limitation of 90 days is set on Force Majeure as it applies to strikes or lockouts. This is consistent with Inland's method of calculating strike adjustments (TR 1054).

8.3 Authorized Overrun

Columbia proposed that volumes taken in excess of nominated amounts by special contract customers will be charged an authorized overrun rate (AOR). AOR would be specific to those volumes in excess of the nomination and will vary between the industrial customers. It will be based on 150 percent of their firm demand charge (Exhibit 51A) that is currently being paid, but would be expressed on a commodity basis (TR 41). The 150 percent figure was selected on the assumption that it presented a rate high enough to discourage people from exceeding their nomination, but not so high as to encourage gas load reduction or construction of alternate supply facilities. (The cost of AOR to Fording will be about 75¢/GJ extra) (TR 147-8).

Furthermore, Columbia suggested that it is fair to have in place a crediting system for other customers when one customer exceeds its nomination (TR 155). A customer setting an unrealistically low nomination will force increased costs on the remaining customers. The AOR sets a penalty on volumes in excess of the nomination which off-sets those costs (TR 148). Columbia expects that the combined effects of the ratchet and AOR will dampen adverse rate impact on residential customers (TR 198).

8.4 Commission Summary and Conclusions

The Commission appreciates that Columbia has a physical limitation to the capacity of its system and it can only supply gas that it has available up to its existing capacity to deliver the gas. The formalized conditions of Rate Schedule VII that specify availability are an attempt to set in priority excess demands if and when they materialize. The Commission does not believe that there is an attempt to discriminate but rather to accommodate both new and existing customers and to provide reasonable lead time to meet new loads. The Commission accepts the proposal and will monitor with interest its operation in practice.

Regarding nominations, the Commission has already declared its acceptance of constrained nominations based on current peak day demand (ie. 1986/1987 peak day averages as defined above). It is not clear to the Commission, what the effect of peaking gas costs and AOR gas costs will have on each Special Contract customer's nomination strategy. It may be that the incentives will prove to be sufficient to ensure realistic nominations. Failing this, it may well be that the cost impacts are negligible. The Commission concludes that a potential problem is minimal and that nominations should be monitored not only to determine the current proposals' effectiveness of the current proposal but also in order to provide a better basis for any future proposals beyond year 2. Therefore, the Commission approves the proposed procedure of advanced peak day nominations by the Special Contract customers but requires Columbia to submit to the Commission a full report of the current nominations after they are settled in negotiations for review by the Commission.

In summary, the Commission accepts the Applicant's proposals on the application fee for all rate schedules, peaking gas and AOR sales. These accepted terms and condition proposals should be reflected in the appropriate tariffs as soon as possible.

9.0 AUTOMATIC FLOW-THROUGH MECHANISM

9.1 Evidence

Columbia proposed a purchased gas adjustment clause ("PGA") for all classes except the Special Contract customers (TR 24). The clause provided for implementation of forecasted changes in gas purchase costs and an adjustment to actual at the end of each year. The PGA was proposed as the best way to deal with Columbia's gas supply situation. Columbia pays slightly less for gas than Inland and has more than one choice of suppliers. The current arrangement is that about two-thirds of the residential and commercial gas is supplied at $1.70/GJ and the remainder on a spot market basis. PGA can pass the savings or increases to the residential customers if a negotiated price other than than $1.70/GJ is obtained (TR 232).

Columbia's expert witness, Mr. Schultz, stated that the PGA clause was quite common about 10 years ago when gas costs were changing quite rapidly. As the field price of gas was beyond the control of the utility, PGA could deal more effectively with rapidly changing prices than full scale rate hearings. As gas price stability returned, regulatory commissions backed away from PGA, and returned to the practice of forecast gas price on the basis of one year. At the present time, there is a strong tendency to go back to the earlier situation of using PGA to provide flexability for utilities, particularly as a result of increased competition (TR 425).

When questioned, Mr. Schultz cited examples of jurisdictions where the utility's industrial customers have available to them differently priced supplies of gas. He suggested Elizabeth Town Gas in New Jersey, Union Gas in Philadelphia, and Equitable Gas in the Pittsburgh area (TR 426-7).

With respect to the special contract industrial customers, Columbia suggested that PGA is unnecessary because they have already the equivalent of a PGA in their contracts. The actual average price of gas for this class varies, based on the changing supply price, and is flowed through monthly (TR 24, 521, 1345).

The proposed year end adjustment in the PGA is based on the following reasons:

(i) A year end adjustment can ensure a degree of rate stability for residential rates as the latter may change as a result of rate design, implementation of revenue requirement decisions, or changes in the cost of gas (TR 1048-9).

(ii) A year end adjustment can allow more effective participation by Columbia in the developing spot market in Alberta and B.C. With the year end adjustment, savings can be deferred and then passed through to customers at a time that may offset an increase in the overall revenue requirement.

9.2 Commission Summary and Conclusion

The Commission acknowledges the merits, in principle, of PGA as presented by the Applicant. At this time, in light of the major rate shifts proposed, the Commission believes it would be inappropriate to institute this proposal.

10.0 OTHER ISSUES

10.1 Minimum Bill - Westar Balmer

Columbia stated that the minimum bill in the current contract with Balmer defines the amount of minimum revenue that Columbia collects from that customer (TR 810). The current contract specifies that Balmer must pay for a minimum volume of 3,116 $10^3 m^3$/month whether or not it uses that volume. If Balmer consumes more than that minimum volume in a month, then any deficiency payment paid within the previous 12 months can be applied toward paying consumption in excess of the minimum bill (TR 805-807). In any month when Balmer consumes less than 3,116 $10^3 m^3$ it pays \$17.24/$10^3 m^3$ for the deficiency (TR 808).

Columbia submitted that over the years virtually all the customers who were in a deficiency position recovered the money within the next 12 months (TR 312-3). In the case of Balmer, Columbia suggested that Balmer is currently still better off, in spite of the deficiency payment, than it would be if it received service under Rate Schedule III, the next best alternative. Balmer would have to pay more under that schedule than it now pays, including the deficiency payment (TR 807).

Columbia's proposed Rate Schedule VII has no minimum monthly bill apart from the fixed cost of service charge (TR 821). However, Columbia is prepared to retain or grandfather the accumulated deficiency payment provisions in the new Rate Schedule VII for Balmer (TR 820-1). Based on forecasted gas consumption for 1988, Balmer's total minimum bill payment would add up to about \$450,000 for the year (TR 822). Realistically, Balmer may not be able to recover this amount in the subsequent 12 month period if it continues the same consumption pattern (TR 822). The 1989 revenue from Balmer with the new proposal, effective June 1, would be about \$170,000 in deficiency payments from January to the end of May, in addition to its revenue contribution of about \$240,000 for the entire year for a total of about \$410,000 (TR 824-25).

Westar submitted that Columbia is currently receiving minimum bill payments in the range of $25,000 to $30,000 a month for the last six months (TR 808). Given that the new proposed contract does not contemplate minimum bill payments, Westar asked whether Columbia would be prepared, taking into account the over-contribution of Westar-Balmer as shown in the current cost of service studies, to drop the minimum monthly bill charge effective immediately (TR 816). Columbia indicated it cannot arbitrarily change a tariff (TR 817).

To put it in perspective, Westar pointed out that under the existing contract, Columbia's revenue to be received from Balmer in 1988 will be $250,000 in deficiency payments from 1987 (TR 808) and $240,000 in normal revenue. In 1989, the deficiency revenues will amount to about $450,000 associated with 1988 and roughly $240,000 in projected revenues without a new contract (TR 823).

The suspense account, so-called because it suspends disposition of minimum bill payments to Columbia's revenue for a year, has minimum bill payments of about $250,000 from 1987. Columbia does not take a minimum bill payment into revenue until the thirteenth month. Given a 12 month forecast of a deficiency payment starting in April 1987, Columbia expects that the $250,000 currently in the suspense account will be taken into revenue in the 1988 calendar year (TR 809-10).

Columbia stated that if it is ordered to keep the $250,000 in the suspense account instead of taking it into revenue, then Columbia will have to come before the Commission for an additional $250,000 in revenue, as this amount has already been included as revenue in its 1988 revenue forecast (TR 814-16).

Westar pointed out that Columbia has never before used these minimum bill amounts prospectively for revenue requirement calculation since the customer has always used gas subsequently in excess of the minimum and reclaimed it (TR 818-9). Table 16 summarizes the situation described above.

Table 16

IMPACT OF MINIMUM BILL PAYMENTS ON WESTAR BALMER

CASE A - Annual Total Payments Under Existing Contract for 1987 and 1988

Year	Minimum Bill Payments	Minimum Bill Payments Taken Into Revenue	Revenue	Revenue Plus Minimum Bill Payments
1987	$250,000			
1988	$450,000	$250,000	$240,000	$490,000
1989		$450,000	$240,000	$690,000

CASE B - June 1, 1988 Implementation of Columbia's Proposed Rate

Year	Minimum Bill Payments	Minimum Bill Payments Taken Into Revenue	Revenue	Revenue Plus Minimum Bill Payments
1988	$170,000			
1989		$170,000	$240,000	$410,000

Source: (TR 809, 823 - 824)

10.2 Segmented Gas Field Prices

Since mid-year 1986 Columbia has been purchasing gas coming from the Deep Basin area of B.C. through the Nova and Alberta Natural Gas systems. The gas is priced on a commodity basis as follows:

- residential/commercial $1.70/GJ,
- small industrial $1.50/GJ, and
- special contract $1.03/GJ.

Commissioner Page pointed out that the cost of gas differential has an impact on the revenue to cost ratio. This is one reason why the revenue generated from the residential class falls short of the cost of service component, and serves to exaggerate the difference between the residential and large industrial revenue to cost ratios (TR 671-672).

Crestbrook argued that a more appropriate way to calculate and compare revenue to cost ratios is to exclude the costs of gas altogether. It holds that a net revenue to cost ratio more accurately reflects subsidies between customers than a gross revenue to cost ratio (TR 696).

10.3 Cranbrook Looping

Columbia argued that the construction of the loop was a result of pressure problems on the Cranbrook lateral to meet peak day demands or the real obligations put on the system by customers (TR 1328) There was a period when Columbia was unable to supply all its customers and had to curtail large industrials to protect smaller customers. Crestbrook was one of these customers curtailed, and later sought compensation (TR 623).

Columbia pointed out that Crestbrook did not object to the construction of the proposed loop which began in October 1985 (Exhibit 42, TR 1340).

Mr. Schultz's Cost of Service Study (Exhibit 19, Item 4) identified $1.18 million as looping costs on the Cranbrook lateral out of a total $3.7 million capital costs (TR 254-6). The costs were allocated according to the demand levels assigned for each class of customer. Mr. Schultz's view is that if it were not for Crestbrook, the other customers would not have required the loop, and once the facility is installed, it is impossible to say one customer is more responsible for it than another (TR 515 - 1341).

Crestbrook argued that during the winter of 1983, Columbia curtailed Crestbrook as a result of extreme cold temperatures and a reduction in pressure on the Alberta Natural Gas transmission line. Columbia was unable to force Alberta Natural Gas to re-establish historic pressure levels (TR 586). Crestbrook threatened to sue for contract default, Columbia attempted to claim Force Majeure, but Crestbrook objected and negotiations followed. In 1984, Crestbrook and Cominco agreed to take some reduction in their contract demands so as to relieve Columbia from their maximum requirements (TR 727 - 728).

Crestbrook pointed out that it did not oppose the construction of the loop based on the limited information available, but was led to believe that regardless of its particular load requirement, at least some portion of the proposed loop would be required (TR 729-730). Crestbrook had real doubts regarding the necessity of looping. It's own load was decreasing as a result of a pulp mill optimization program, which reduced peak requirements. The belief held by the industrials was that the Alberta Natural Gas transmission line pressures would return to higher historic levels though there was no contractual obligation to do so.

Crestbrook management considered installing its own peak shaving facility, a propane air plant, at its site (TR 728-9). Prior to initially taking service from Columbia, Crestbrook considered constructing its own pipeline but the option was dropped when Columbia offered an attractive rate proposal. The Company claims that had it known that there would be a departure from cost based rates, a bypass pipeline would have been constructed. Crestbrook is now once again examining its bypass option (TR 1371-2).

Crestbrook testified that it is not attempting to re-open the looping application, but is asking the Commission to consider finding that Mr. Schultz's cost allocation with respect to the looping is unfair to Crestbrook and Cominco (TR 1371). The argument is that there are three pertinent factors to be considered:

(i) Columbia's own evidence states that looping was necessary because of anticipated increases in residential load;

(ii) Crestbrook's load was declining, and Crestbrook and Cominco had made every effort to defer the decision for looping construction;

(iii) pressures on the Alberta Natural Gas system have returned to historic levels, and Columbia's forecast of increased residential load did not materialize thus rendering the looping no longer necessary (TR 1370).

However, Crestbrook's consultant Mr. Drazen, testified that looping was a benefit to all customers and they should all share in the costs (TR 514).

10.4 Commission Summary and Conclusions

The Commission concludes that the argument put forth by Columbia that the Westar Balmer 1987 minimum bill payment of $250,000 is already disposed to revenue, is of no moment. However, there are other relevant factors which the Commission must consider.

The Commission notes that Westar agreed to the minimum bill provision in the contract. The minimum bill or take-or-pay default payments must have been factored into the cost analysis at the time Balmer made the decision to convert from gas to coal for coal products drying purposes. The Commission concludes, therefore, that there are no unforeseen or unexpected costs to Balmer.

The Commission also notes that there are no minimum bill provisions in Columbia's proposed Rate Schedule VII. Based on Table 16, the total estimated minimum bill exposure in 1988 is $450,000. If, however, the proposed tariff takes effect on June 1, 1988, this five month amount is about $170,000. The Commission views the difference as a benefit to Balmer. In addition, the proposed Balmer rate would significantly reduce Balmer's payments to Columbia. Based on these benefits and the gas cost savings since 1986, the Commission orders that there will be no retroactive adjustment to the previous minimum bill payments as shown in the suspense account. The Commission will accept, however, the grandfathering of the make-up provision for one year past June 1, 1988.

The segmented field price issue is important. It explains the emergence of exaggerated profit margin differentials appearing in the testimony of this hearing because of the change from traditional mark-up between a common purchase price and different selling prices of gas to the different rate groups. Therefore, the Commission must give careful consideration to interpretation of the testimony as to what constitutes a subsidy and what does not. As Mr. Justice O'Halloran observed in Prince George Gas Company and City of Prince George v. Inland Natural Gas Co. Ltd. Number 2* referred to earlier, the fixing of a fair price to consumers involves three separate steps, the first of which is determination of a fair price at the point of diversion from the supply pipeline. While there was little conclusive evidence in this hearing on this point, there were enough questions raised by the testimony to suggest the need for a more complete canvass of the subject in a future hearing.

---

* (1958) 25 Western Weekly Reports, p. 354.

The Commission reluctantly must once again address the Cranbrook looping issue. It has been a source of irritation to all parties for several years now and parties addressed it at this hearing with a certain amount of impatience. The Commission intends that this review will end the issue once and for all.

Based on the evidence of previous hearings, the Commission issued a Certificate of Public Convenience and Necessity (the "Certificate"). There was no stipulation as to who needed the Cranbrook looping except that all of Columbia's system users would benefit. There was no intention to confer proprietary rights on any consumers on the Cranbrook lateral. Firm gas deliverability cannot be left dependent upon the fortuitous circumstance that Columbia's supplier, for its own reasons, has chosen for many years to furnish gas at pressures significantly above the contract specifications. The Commission therefore agrees that all parties benefit from the additional looping and therefore should bear the costs.

DATED at the City of Vancouver, in the Province of British Columbia, this 17th day of May, 1988.

J.G. McINTYRE, Chairman

N. MARTIN, Commissioner

H.J. PAGE, Commissioner

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-51-88

PROVINCE OF BRITISH COLUMBIA

BRITISH COLUMBIA UTILITIES COMMISSION

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

and

IN THE MATTER OF Applications by Columbia Natural Gas Limited

BEFORE:	J.G. McIntyre, Chairman; N. Martin, Commissioner; and H.J. Page, Commissioner	) May 17, 1988

O R D E R

WHEREAS Columbia Natural Gas Limited ("Columbia") applied to amend its filed Gas Tariff Rate Schedules by filing Volumes 1 and 2 of its application (the "Application") on September 24, 1985, Volume 3 on July 31, 1986 and Volume 4 on September 30, 1987; and

WHEREAS the Commission directed on January 21, 1987 that any outstanding issues associated with the complaint by (the "Complaint") Fording Coal Limited ("Fording") in connection with the rates of Columbia be heard with the Application; and

WHEREAS the Complaint and the Application were heard at at public hearing on February 23, to 26, 1988 in Cranbrook and March 2 to 4 and 10, 1988 in Vancouver pursuant to Commission Order No. G-86-87; and

WHEREAS the Commission has considered the Application by Columbia and the evidence adduced thereon during the public hearing of the Application and the Complaint all as set forth in the decision (the "Decision") issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. Columbia is to file Rate Schedules to be effective June 1, 1988 and June 1, 1989 in conformity with the Decision .

2. The Interim rates of Columbia currently in effect are confirmed.

3. All aspects of the Fording Complaint are dismissed.

4. The Application of Columbia to include a purchase gas adjustment clause in its tariff schedule is dismissed.

5. Columbia is to file reports as specified.

.../2

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-51-88

DATED at the City of Vancouver, in the Province of British Columbia, this 17th day of May, 1988.

BY ORDER

John G. McIntyre
Chairman