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

and

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

Rate Design Phase B

Volume 3

Written Evidence

June 1993

BC Gas

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

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

David M. Masuhara
Vice President
Legal and Regulatory Affairs

BC Gas

VIA COURIER

June 7, 1993

British Columbia Utilities Commission
6th Floor - 900 Howe Street
Vancouver, British Columbia
V6Z 2N3

Attention: R.J. Pellatt
Commission Secretary

Dear Sirs:

**Re: BC Gas Inc. Rate Design Phase B Application
Volume 3 - Written Evidence**

Pursuant to BCUC Order No. G-38-93, BC Gas files Written Evidence for witnesses in the above proceeding.

One copy of the above materials will be provided to registered intervenors and interested parties.

Yours truly,

per

David M. Masuhara

cc: Registered Intervenors
Interested Parties

bcuc13.93

BRITISH COLUMBIA UTILITIES COMMISSION

MAY 30 1991

→ PDL
SPC
ECE
JOW
CBJ
BAM

(F) Rule decision

Looks like Ocelot lost the war.
— [illegible]

May 24, 1991

Mr. R. B. Wallace
Bull Housser & Tupper
Barristers & Solicitor
3000 Royal Centre
P.O. Box 11130
1055 West Georgia Street
Vancouver, B.C.
V6E 3R3

Dear Mr. Wallace:

Re: Pacific Northern Gas Ltd. ("PNG")
Request for Reconsideration
Commission Decision Order No. G-23-91

Further to your April 10, 1991 request for Commission reconsideration of its February 27, 1991 Decision and Order No. G-23-91 we enclose Commission Order No. G-42-91.

Yours truly,

Robert J. Pellatt
Commission Secretary

RJP/lm
Encl.
cc: Mr. R.G. Dyce, Executive Vice President and General Manager
Pacific Northern Gas Ltd.
Registered Intervenors

PNG/Cor/Reconsider. Request-Wallace

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-42-91

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

and

IN THE MATTER OF an Application by
Ocelot Chemicals Inc. for Reconsideration of
Commission Decision and Order No. G-23-91 dated February 27, 1991

and

IN THE MATTER OF a Complaint by
Ocelot Chemicals Inc. against Pacific Northern Gas Ltd.
and

IN THE MATTER OF a Rate Design Application by
Pacific Northern Gas Ltd.

BEFORE:	J.D.V. Newlands, Deputy Chairman; N. Martin, Commissioner; and W.M. Swanson, Q.C., Commissioner	)	May 23, 1991

O R D E R

WHEREAS:

A. On April 10, 1991, pursuant to Section 114 of the Utilities Commission Act, Ocelot Chemicals Inc ("Ocelot") filed a request that the Commission review, reconsider and vary its February 27, 1991 Decision and Order No. G-23-91; and

B. By letter dated April 16, 1991 the Commission sought the submissions of all Registered Intervenors concerning the request for reconsideration with such submissions to be received by the Commission no later than April 26, 1991; and

C. Such submissions were received; and

D. By letter dated May 2, 1991, the Commission invited those intervenors to the proceeding to review the submissions and provide the Commission with any responses by May 10, 1991; and

E. Such responses were received; and

F. The Commission has considered the Ocelot Application for Reconsideration, has reconsidered its Decision and Order, has considered the evidence adduced at the public hearings together with other information forming the basis of the original decision, and has issued a Decision, with Reasons, concurrent with and attached as Appendix A to this Order.

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-42-91

NOW THEREFORE the Commission orders as follows:

1. Paragraph 5 of Commission Order No. G-23-91 is rescinded and replaced with the following:

   Large industrial customer service rates shall decline on a one time basis by approximately $0.03 per gigajoule for Eurocan Pulp & Paper Co., and by approximately $0.03 per gigajoule for Alcan Smelters and Chemicals Ltd.

2. In all other respects the Decision and Order No G-23-91 of the Commission is confirmed.

DATED at the city of Vancouver, in the Province of British Columbia, this 27th day of May, 1991.

BY ORDER

J.D.V. Newlands
Deputy Chairman and
Chairman of the Division

/lm

Attachment

BRITISH COLUMBIA UTILITIES COMMISSION

REASONS FOR DECISION

INTRODUCTION

On April 10, 1991 Ocelot Chemicals Inc. ("Ocelot") filed a request that the Commission review, reconsider and vary its February 27, 1991 Decision and Order No. G-23-91 in the matter of a Complaint by Ocelot Chemicals Inc. against Pacific Northern Gas Ltd. and in the matter of a Rate Design Application by Pacific Northern Gas Ltd. ("PNG"). By letter dated April 16, 1991 the Commission sought the submissions of all Registered Intervenors concerning the request for reconsideration. Submissions were received from PNG and Eurocan Pulp and Paper Co. Inc. ("Eurocan"). By letter dated May 2, 1991, the Commission invited the registered intervenors to review the submissions made and advise the Commission of any concerns by May 10, 1991. A response was received from Ocelot.

SUBMISSION BY OCELOT

In applying for a reconsideration of the Ocelot Complaint and PNG Rate Design Decision, Ocelot directed the Commission's attention to two particular matters. These were: (1) the proper treatment of the cost of gas when calculating revenue to cost ratios and (2) the timing of the implementation of value of service rates for industrial interruptible customers.

1. Cost of Gas and the Calculation of Revenue to Cost Ratios

With respect to the first issue, Ocelot noted that the revenue to cost ratio for Skeena Cellulose Ltd. ("Skeena"), a company which takes only transportation service from PNG and purchases its gas directly from the producer, was computed excluding the cost of gas while the cost of gas was included for all other classes of customers. This results in revenue to cost ratios amongst customer classes which are not directly comparable. Ocelot submits that the inclusion of the cost of gas in the revenue to cost ratios is inappropriate and results in ratios for industrial customers which are artificially low. Ocelot asks that the Commission recalculate the revenue to cost ratios for industrial customers excluding the cost of gas, and reflect the revised revenue to cost ratios in any rate reductions applied to industrial customers.

Because the revenue to cost ratios calculated for firm service included the cost of gas, Ocelot appears to imply that the rates for firm service to Ocelot, allowed by the Commission are not properly cost-based.

2. Value of Service

Ocelot argued in favour of value of service based interruptible rates during the hearing and the Commission adopted this approach in its Decision. However, Ocelot argues that it was implicit in its submission made during the public hearing that the Commission should not impose value of service based interruptible rates until such time as the revenue to cost ratios for firm service rates approach the mid-point of the Commission's zone of reasonableness. Because the revenue to cost ratios found by the Commission were not properly calculated in Ocelot's view, as indicated in Point 1 above, Ocelot submits that the revenue to cost ratios for industrial firm service rates fall outside this zone and that the Commission should not have set industrial interruptible rates on a value of service basis.

In particular, Ocelot argues that if firm service rates do not result in revenue to cost ratios approaching the mid-point of the zone, industrial interruptible rates should not be set such that revenues from industrial interruptible sales are maximized, i.e. should not be set on a value of service basis.

COMMISSION DECISION

1. Cost of Gas and the Calculation of Revenue to Cost Ratios

Based on the submissions made to it and the evidence adduced through the public hearing process, the Commission accepts the position put forth by Ocelot, with which PNG concurred, that the revenue to cost ratio set out for Skeena Cellulose Ltd. in Table 2 at page 38 of the Decision was calculated in a manner that is inconsistent with the revenue to cost ratios calculated for customers who take sales gas. Specifically, the ratio for Skeena, which takes only transportation service from PNG, does not include an imputed commodity cost of gas or the associated tolls on the Westcoast Energy Inc. ("Westcoast") system. Similarly, the ratio shown for Ocelot, which is a ratio based on the revenues and costs associated with both sales and transportation service, is inconsistent because an imputed cost of gas and Westcoast tolls were not included in the cost of transportation service Ocelot receives from PNG.

In order to achieve consistency, the Commission finds that the revenue to cost ratios calculated for customers who take transportation service, specifically Skeena and Ocelot, should include an imputed cost of gas and Westcoast tolls. In making this determination the Commission has considered that PNG's Application was based primarily on revenue to cost ratios which included the cost of gas and that the zone of reasonableness surrounding these ratios was established including the cost of gas. Accordingly, the revenue to cost ratios for Skeena and Ocelot are recalculated using an imputed cost of gas and Westcoast tolls and are shown in Table 1, attached to these Reasons.

As a result of the revised calculation, the revenue to cost ratio for firm transportation service to Skeena becomes 1.04 and for firm sales and transportation service to Ocelot becomes 1.08. Therefore, the Commission rescinds paragraph 5 of Commission Order No. G-23-91 and replaces it as follows:

> Large industrial customer service rates shall decline on a one time basis by approximately $.03 per gigajoule for Eurocan Pulp and Paper Co., and by approximately $.03 per gigajoule for Alcan Smelters and Chemicals Ltd.

2. <u>Value of Service</u>

In respect of Ocelot's second submission, as can be seen from the conclusion in Point 1 above, the Commission reaffirms its decision that revenue to cost ratios should include the cost of gas. The evidence before the Commission is that the 90% - 110% zone of reasonableness, traditionally employed in analyzing whether or not a particular customer or a particular class of customer is paying rates that are cost based, includes the cost of gas. As the revenue to cost ratio for Ocelot's firm rates, including an imputed cost of gas adjustment for transportation service as described in Point 1 above, is within the zone of reasonableness, the Commission finds that Ocelot's firm service rates are cost based and fair, just and reasonable. Therefore no adjustment should be made to the original Decision with respect to the Ocelot firm rates other than that resulting from the variance described in Point 1 above.

Because the Commission has set firm rates for Ocelot which result in a revenue to cost ratio which lies within the zone of reasonableness and interruptible rates have been properly set on a value of service basis, the Commission has implemented rates for both firm and interruptible service in the manner Ocelot requested.

The Commission has considered the request for an oral hearing. However, since the basic issue raised by Ocelot in this reconsideration application was canvassed through the evidence presented during the hearing, in argument at the hearing, and in thorough written submissions received as a result of the request for reconsideration, the Commission does not believe an oral argument would be of assistance.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of May, 1991.

J.D.V. Newlands, Deputy Chairman and
Chairman of the Division

N. Martin, Commissioner

W.M. Swanson, Commissioner

TABLE 1

COMMISSION COST OF SERVICE ESTIMATES

	Revenue	Gross Costs	Allocated Premium	Net Costs	Revenue Net Costs	Revenue Cost
Residential	6,086	10,386	(667)	9,719	(3,633)	0.63
Commercial	6,102	7,930	(678)	7,252	(1,150)	0.84
Small Industrial	4,327	4,208	(387)	3,821	506	1.13
NGV	186	140	0	140	46	1.33
Ocelot - Firm	41,988	38,805	(34)	38,771	3,217	1.08
Skeena - Firm	7,371	7,132	(66)	7,066	305	1.04
Eurocan - Firm	6,221	5,664	(81)	5,583	638	1.11
Alcan - Firm	677	611	(5)	606	71	1.12
Large Comm - Interruptible	330	226	104	330	0	1.00
Large Indust. - Interruptible	10,416	8,602	1,814	10,416	0	1.00
Total	83,704	83,704	0	83,704	0	1.00

NOTES:

1. The above Table is the same as Table 2 (page 38) of the BCUC Decision with the exception that the Revenue, Gross and Net Costs shown for Ocelot and Skeena have been adjusted to include the imputed purchase cost of gas for the firm transportation service volumes for each company.

2. The purchase cost of gas imputed for Ocelot's 140 10^3m^3 of firm transportation service was calculated as follows:

140 10^3m^3 x \$463.71/10^3m^3/month (i) x 12 months	=	\$779,033
1,904,000 GJ x \$0.561/10^3m^3(ii) / 38.5 GJ/10^3m^3	=	27,744
1,904,000 GJ x \$1.03/GJ (iii)	=	1,961,120
		\$2,767,897

3. The purchase cost of gas imputed for Skeena's 229.5 10^3m^3 of firm transportation service was calculated as follows:

229.5 10^3m^3 x \$463.71/10^3m^3/month (i) x 12 months	=	\$1,277,057
3,021,000 GJ x \$0.561/10^3m^3(ii) / 38.5 GJ/10^3m^3	=	44,020
3,021,000 GJ x \$1.03/GJ (iii)	=	3,111,630
		\$4,432,707

(i) Westcoast Demand Toll
(ii) Westcoast Commodity Toll
(iii) Gas Commodity Cost

EM

Mar -6 1991 FYI

+ Return

→ JOW / W.

SPC

ECE

return / Don

BRITISH COLUMBIA UTILITIES COMMISSION

March 1, 1991

Mr. R.G. Dyce
Executive Vice President and
General Manager
Pacific Northern Gas Ltd.
Suite 1400
1185 West Georgia Street
Vancouver, B.C.
V6E 4E6

Dear Mr. Dyce:

Re: Pacific Northern Gas Ltd. ("PNG")
Ocelot Complaint - Rate Design - Commission Decision

With reference to the January 17, 1990 Ocelot Chemicals Inc. complaint regarding rates charged by PNG and subsequent evidence on rate design filed by PNG, the Commission has made its determination into the matter. We enclose Commission Order No. G-23-91 and the Commission Decision issued concurrently with the Order.

Yours truly,

M. Donn

for Robert J. Pellatt
Commission Secretary

RJP/lm
Enclosures
cc: Ocelot Chemicals Inc.
Registered Intervenors
Interested Parties

PNG/Cor/Ocelot Compl. Decision

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

and

IN THE MATTER OF
a Complaint by Ocelot Chemicals Inc.
against Pacific Northern Gas Ltd.

and
IN THE MATTER OF
a Rate Design Application
by Pacific Northern Gas Ltd.

<u>DECISION</u>

February 27, 1991

BEFORE:

J.D.V. Newlands, Deputy Chairman;
N. Martin, Commissioner; and
W.M. Swanson, Q.C., Commissioner

TABLE OF CONTENTS

TABLE OF CONTENTS
(cont'd)

APPEARANCES

D.L. RICE	Commission Counsel
R. SIRETT C. DONAHUE	Counsel for Pacific Northern Gas Ltd.
R.B. WALLACE	Counsel for Ocelot Chemicals Inc.
P. De MEO	Counsel for CanWest Gas Supply Inc.
MAYOR P.J. LESTER T. LEWIS J. MUSSALEM	City of Prince Rupert
R. BRODY W. McLELLAN U. PRITCHARD	District of Kitimat
R.G. DYCE T.W. WEAVER	Pacific Northern Gas Ltd.
J.L. TYSON K.E. VIDALIN	Ocelot Chemicals Inc.

D.W. EMES S.S. WONG P.W. NAKONESHNY	Commission Staff
Allwest Reporting Ltd.	Court Reporters and Hearing Officer

LIST OF EXHIBITS

LIST OF EXHIBITS
(cont'd)

1.0 BACKGROUND

1.1 Chronology of Application

On January 17, 1990, Ocelot Chemicals Inc. ("Ocelot") filed a complaint with the British Columbia Utilities Commission ("the Commission") pursuant to Section 64 of the Utilities Commission Act ("the Act") requesting that the Commission commence an immediate inquiry into the reasonableness of the Pacific Northern Gas Ltd. ("PNG") rate structure. Section 64 states:

> **"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."

Sections 65 and 66 of the Act deal with the assertions of Ocelot and the remedies available. Sections 65 and 66 state as follows:

> **"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 the 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."

A rate is defined in the "Interpretation" section of the Act as follows:

> "'rate' includes a general, individual or joint rate, fare, toll, charge, rental or other compensation of a public utility, a rule, practice, measurement, classification or contract of a public utility or corporation relating to a rate and a schedule or tariff respecting a rate."

Ocelot asserted that PNG's rates were unjust, unreasonable and unduly discriminatory, and in particular that the rates resulted in a cross-subsidy of some $4 million from Ocelot to other customers, primarily residential.

After reviewing letter submissions and responses from Ocelot and PNG, and related information, the Commission issued Order No. G-20-90, dated March 14, 1990, requiring PNG to file a Rate Design Application by July 6, 1990. It also ordered a public hearing into the complaint to commence August 21, 1990 in Prince Rupert, B.C.

Pursuant to the Order, on July 6, 1990, PNG filed this Rate Design Application.

The Commission heard evidence on the complaint and the Application in Prince Rupert on August 21, 22, and 23, 1990 and in Kitimat on August 28, 1990. The interested parties requested (and the Commission granted) a delay in the hearing of argument to allow the participants to negotiate a settlement which could then be brought forward for Commission consideration. No settlement was reached and argument was heard in Terrace on November 6, 1990.

1.2 The Applicant

PNG transmits and distributes natural gas in the west central portion of British Columbia. The 350 mile system begins at Summit Lake, near Prince George, where it interconnects with the Westcoast Energy Inc. ("Westcoast") pipeline system, and terminates at the deep water ports of Kitimat and Prince Rupert. It is primarily an industrial gas transmission system. Currently, residential customers comprise three to four percent of PNG's load, while commercial, small industrial and natural gas vehicle customers comprise eight to nine percent. The balance, approximately 88 percent, is load from four major industrial customers, namely Ocelot, Eurocan Pulp & Paper Co. ("Eurocan"), Skeena Cellulose Ltd. ("Skeena"), and Alcan Smelters and Chemicals Ltd. ("Alcan"). Approximately three-quarters of the large industrial load is firm, with the balance made up of interruptible sales.

The single largest customer on the PNG system is Ocelot. Ocelot comprises about 66 percent of PNG's total load, including approximately 75 percent of PNG's interruptible volumes. PNG service to Ocelot began in 1982 and caused the PNG system to be expanded. The expansion of the transmission system, which consisted of looping and compression, was initially expected to cost approximately $30 million but ultimately cost $43 million. Debt of approximately $40 million was issued in two parts: $30 million for a term of five years and at a coupon rate of 17.75 percent and $10 million until 1997 at a coupon rate of 18 percent.

PNG holds long-term contracts with each of its major industrial customers which are not due to begin expiring until 1999.

PNG's gas requirements are met through a long-term contract (expiry: October 31, 2002) with CanWest Gas Supply Inc. ("CanWest"), the provincial aggregator and the successor to the British Columbia Petroleum Corporation ("BCPC"). Pricing provisions of the contract are negotiated annually or bi-annually. The current pricing provisions, which run through October 31, 1991, require PNG to take all its supply from CanWest. However, beginning November 1, 1991, PNG will be permitted to buy up to 25 percent of its core market requirements from sources other than CanWest. This percentage may increase over time.

1.3 The Complainant

Ocelot operates two petrochemical plants in Kitimat, B.C., which have the capability of producing more than 500,000 tonnes of methanol and 190,000 tonnes of ammonia annually. Gas supply to the plants consist of 44 MMcf/day of firm gas sales, 2 MMcf of firm gas transportation, and interruptible gas sales which average about 15.5 MMcf/day.

The arrangements for selling gas to Ocelot are complex and can best be understood by following the flow of gas from the wellhead. Producers sell their gas to CanWest which sells the gas to Westcoast, which in turn transmits the gas to the inlet of PNG's transmission system, at which point Westcoast sells the gas to PNG. PNG then sells the gas back to CanWest, which assigns the gas to BCPC (Kitimat) which, in turn, sells the gas to Ocelot.

This arrangement allows BCPC (Kitimat), a subsidiary of BCPC, a government agency, to guarantee minimum payments to PNG equivalent to an 80 percent minimum take provision on firm sales volumes.

Ocelot's total firm contract demand for sales gas is 44 MMcf/d of which the first 80 percent (35.2 MMcf/d) is sold at a rate of $2.4920* per gigajoule. PNG sells the next 12.2 percent of contract demand (5.4 MMcf/d) at $1.9950* per gigajoule, with the balance (3.4 MMcf/d) sold at an incentive rate of $1.2050* per gigajoule. PNG recovers all of Westcoast's demand charges in the rates paid for the first 80 percent of contract demand while the incentive rate of $1.2050* per gigajoule for gas taken above 92.2 percent of contract demand reflects the variable cost of providing this gas, i.e. the actual gas charge of $1.03 per gigajoule, the Westcoast commodity charge of $0.015, and a margin of $0.16 to PNG to cover compressor fuel, incremental taxes, etc., and a small contribution to fixed charges (Exhibit 6, IR 31). All interruptible gas is priced at this rate ($1.2050* per gigajoule).

As a result of these arrangements, PNG's financial exposure in serving Ocelot is limited to firm volumes between 80 percent and 92.2 percent of contract demand (5.4 MMcf/d).

---

* Pre 1991 Interim Rates.

In addition to the sales volumes discussed above, Ocelot takes 2 MMcf/d of gas through a transportation service contract with PNG. Ocelot pays PNG $0.9510 per gigajoule for the first 92.2 percent of transportation volumes which is equal to PNG's margin on firm gas sales between 80 percent and 92.2 percent of firm contract demand discussed above. For gas taken in excess of 92.2 percent Ocelot pays $0.16 per gigajoule. This rate is equal to PNG's margin on incentive and interruptible gas sales.

2.0 THE APPLICATION

2.1 PNG Proposal

PNG's Application proposes to restructure its rates to residential and large industrial customers but leaves unchanged its rates to commercial, natural gas vehicle and small industrial customers, as follows:

1. **Residential Rates**

Increase residential rates five percent per year for three years commencing January 1, 1991. This would result in a $0.2366 per gigajoule increase in each of 1991, 1992 and 1993. In argument the proposal was amended to commence January 1, 1992.

2. **Ocelot**

Eliminate the incentive rate on firm gas sales and service in excess of 92.2 percent. This would increase the rate charged on sales and service for the last 7.8 percent of contract demand by $.7348 per gigajoule, making it equal to the current rate charged on sales and service between 80 percent and 92.2 percent of contract demand.

Increase the current interruptible rate by $0.055 per gigajoule.

Decrease Ocelot firm service rates by $0.055 in 1991, using the revenues generated from the elimination of the incentive rate and from the increase in the interruptible rate. The proposed rates are $2.4368 per gigajoule for the first 80 percent of contract demand and $1.9398 per gigajoule for sales above 80 percent of contract demand.

3. **Skeena Cellulose, Eurocan and Alcan**

Decrease interruptible rates charged to the large industrial customers, other than Ocelot, by 10 percent or $0.19 per gigajoule in 1991.

4. **All Large Industrials**

Reduce firm service rates for all large industrial customers using the additional revenues generated by the increase in residential rates in 1992 and 1993.

These proposals would increase the contribution to PNG revenue made by residential customers, decrease the contribution made by Skeena, Eurocan, and Alcan, and shift the contribution made by Ocelot from firm service to interruptible service while leaving the absolute contribution essentially unchanged. Total revenues collected by PNG would remain unchanged.

2.2 Ocelot Proposal

Ocelot in the alternative maintained that the large industrial customers are paying rates for firm service in excess of the cost of providing it and further, that residential customers, in particular, and commercial customers are paying rates that do not fully recover the cost of serving them. Ocelot stated that this results in a cross-subsidy from the large industrial customers to residential and commercial customers and urges the Commission to:

> "(1) Quantify the cross-subsidy from the large industrials to other customer classes.
>
> (2) Do all the Commission can to rebalance the rates to eliminate the cross subsidy."
>
> (Exhibit 10, Tab 1, Page 3)

Ocelot states that it does not expect the Commission to rectify the problem in its entirety, in either the short or intermediate term but, rather to make a beginning. Such a beginning might consist of a five percent to seven percent increase in residential, commercial and small industrial rates, the increased revenues from which could be used to lower industrial rates. In addition, Ocelot proposed that industrial rates be restructured to contain a demand charge and a commodity charge.

3.0 GOALS OF RATE DESIGN

3.1 General Discussion

The legislative parameters with regard to the fixing of a rate are set forth in the Act and have been addressed in Section 1.1 of this Decision. However, depending on the perspective chosen, the parameters considered and weights given, different answers with respect to rates will result. The three primary perspectives are those of the utility, the customer and society. Society's perspective can be subdivided into further distinct categories, often with opposing objectives.

From the perspective of the utility, rates should ensure that revenue requirements, inclusive of return, are met; that the rate structure is strategically sound for load management, competition and long-term planning purposes; and that the negative cost impact, if any, of new customers and increased load is minimized or eliminated from both the customers' and shareholders' perspective.

From the perspective of the customer, the rates should be affordable, understandable, equitable and provide for an appropriate quality of service.

From the perspective of society, which may differ from that of the utility or the customer, rates should promote allocative efficiency, that is rates should encourage the appropriate levels of production and consumption while at the same time discourage the misallocation of society's resources. Society may also place a priority on the use of natural gas for one form of consumption over another and this may be reflected in pricing schemes.

PNG's expert witness, Dr. Robert H. Sarikas, testified that generally accepted objectives of rate design include the following:

- i) meeting the annual revenue requirement,
- ii) equity or fairness,
- iii) economic efficiency,
- iv) simplicity and understandability of the rate form,
- v) conservation of resources,
- vi) stability,

vii) social goals,
viii) administrative ease
ix) employment, and
x) protection of the environment.

He also testified that since these goals may sometimes be in conflict, informed judgment will be required to obtain a satisfactory compromise among the various goals listed above.

Four of the goals listed above received particular attention throughout this hearing, They were:

i) economic efficiency,
ii) equity or fairness
iii) gradualism, and
iv) employment and economic development.

3.2 Economic Efficiency versus Equity or Fairness

Throughout the hearing, the Commission heard evidence concerning economic efficiency, equity or fairness, possible conflicts between these two goals and the degree of weighting these goals should receive in establishing rates for service. Dr. Sarikas testified that it was his impression that the two goals of rate design considered most important by PNG were economic efficiency and fairness, with fairness being of slightly greater importance (T. 430). In contrast, Mr. Drazen, Ocelot's expert witness, placed greater emphasis on economic efficiency (Exhibit 10, Tab 2, Page 4).

No clear definition of either economic efficiency or fairness arose from the hearing. Dr. Sarikas testified that economic efficiency,

> "requires the proper identity of cost and price so that there will be an efficient allocation of resources as a result of the purchasing decisions made by utility customers."
>
> (Page 6, Tab 1, Exhibit 4)

while

> "In the minds of many, fairness is attained when a customer pays what a service costs."
>
> (Page 5, Tab 1, Exhibit 4)

It is not clear from these views, why economic efficiency and fairness should be seen as competing rather than complementary objectives.

Mr. Vidalin, Ocelot's policy witness, concurs with this view when he stated as follows:

> "Industry can pay fair rates and prosper."
>
> (Page 3, Tab 1, Exhibit 10)

3.3 Gradualism

Witnesses on behalf of both PNG and Ocelot testified that rate increases should be introduced gradually to allow customers time to adjust to rate changes and so that rate shock can be avoided (T. 440, T. 525). Dr. Sarikas testified that rate shock is usually defined as a rate increase in excess of 20 percent (T. 443). Concern with the avoidance of rate shock is the basis for PNG's recommendation that restructuring of the residential rates take place over three years as opposed to one year (T. 440) and lies behind Ocelot's statement that:

> "the rate rebalancing problems faced by Pacific Northern Gas cannot be solved by rate shifts alone."
>
> (Page 7, Tab 1, Exhibit 10)

In assessing the potential impact of a rate change, the Commission must be cognizant of all factors which will affect the price of the utility service. Through cross-examination it became clear that the increases in residential rates proposed by PNG as a result of the current rate design hearing are not the only increases faced by residential customers. Exhibit 24, prepared by PNG, outlines several sources of rate increases for residential customers over the 1991 to 1993 period. In addition to proposed increases due to this application, additional increases may arise from an imminent 1991 revenue requirement hearing, proposed changes to the handling of deferred taxes, an increase in Westcoast tolls, an increase in franchise fees and the impact of the seven percent Goods and Services tax. While not all of these changes lie within its jurisdiction the Commission believes it must consider the combined impact of all these factors in determining rates. If all the potential increases occurred as outlined in Exhibit 24, residential rates would increase 25.9 percent in 1991, followed by a further 5.2 percent increase in 1992 and a further 5.1 percent increase in 1993. Over the three year period the accumulated increases are projected to be 39.2 percent exclusive of any changes which may take place in the cost of gas. Over the same three year period, it is estimated that commercial rates would rise 14 percent , small industrial rates 14.8 percent and NGV rates 12.2 percent (Exhibit 24).

3.4 Employment and Economic Development

The impact of rates on economic development and employment was the subject of significant debate throughout the hearing. Dr. Sarikas testified that:

> "Rates for industry that both attract new business to British Columbia and retain existing employers can be viewed as enhancing this goal [of full employment]."
>
> (Page 9, Tab 1, Exhibit 4)

However he suggested that the goal of employment maximization should be pursued cautiously.

> "In my opinion, employment or labour should be effective in marginal terms. I view the purpose of an economic system as the production of goods and services, not the maximization of employment per se. The distortion of the economic system to provide partial solutions to the problem of income distribution can result in less goods overall."
>
> (Page 9, Tab 1, Exhibit 4)

Ocelot argued that rates must properly reflect the cost of serving industrial customers if negative impacts on employment and regional development are to be avoided.

> "If industry is asked to continue to subsidize other classes of customers, existing industries in the Pacific Northern service area will suffer and it will be difficult, if not impossible, to attract new petrochemical operations to Kitimat."
>
> (Page 2, Tab 1, Exhibit 10)

The Commission was pleased to receive the views of the City of Prince Rupert and the District of Kitimat on this issue. Mayor Lester, City of Prince Rupert, testified that employment considerations should not be the driving force in determining rates.

> "There shouldn't be any possibility of the Commission thinking that because an industry provides employment or because they can present more facts, that their submission should be agreed to." (T. 261)

And in response to a specific question from Mr. Wallace, Counsel for Ocelot, Mayor Lester stated that he believed industrial customers for natural gas should subsidize residential customers even if it inhibited economic development (T. 264/265). In addition, Mayor Lester suggested that PNG absorb a gas price reduction to industrial users instead of implementing an offsetting price increase to residential gas customers.

> "There doesn't seem to be any compelling reason why residential gas rates should be increased." (T. 261)

In contrast to Mayor Lester's position, the District of Kitimat stated

> "Appreciating the competitive nature of petrochemicals, we are concerned about natural gas prices that are above those justified by rational cost allocation. Such a practice could hinder further development in Kitimat. We do not propose subsidizing natural gas prices to industry, but we can not support a system that charges industry more than a fair share."
>
> (Page 3, Exhibit 32)

However, the District of Kitimat did support Mayor Lester's suggestion that the Commission investigate the possibility of PNG absorbing any rate decrease to industrial customers hence eliminating any impact on the residential consumers.

> "While respecting PNG must cover its costs and be allowed a reasonable return, adjustments to one class should not automatically be passed to another class."
>
> (Page 5, Exhibit 32)

4.0 COST OF SERVICE STUDIES

4.1 General Discussion

In fixing a rate under the Act the Commission shall have due regard, amongst other things, to fixing a rate that is not unjust and unreasonable within the meaning of Section 65. Section 65(4)(b) states that a rate is unjust or unreasonable if it is "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". Accordingly, a cost of service study is required to give proper consideration of this parameter.

The steps to be taken in preparing a cost of service study are four-fold:

1. the determination of the total cost to be allocated;
2. the division of these costs by function (eg. purchased gas, transmission, distribution, and so on);
3. the classification of the functionalized costs between capacity, commodity, customers, and so on; and
4. an allocation of these costs to the rate classes.

Various degrees of judgement are required in the compilation of a cost of service study. The two most significant areas of judgement occur in the determination of the type of study to be undertaken (historical cost or marginal cost) and the method chosen to allocate the capacity costs to the rate classes (eg. Average Demand, Coincident Peak Responsibility, Average and Excess, Modified Partial Plant and others). Depending on the method selected, a rate class can be assigned a significant portion of capacity costs or no capacity costs at all. Less judgement is required in the functionalization and classification of costs.

In this particular case both PNG and Ocelot chose to present cost of service studies based on historical costs using a Fully Allocated Cost of Service ("FACOS") methodology. The adoption of this method by both PNG and the Complainant appears to be predicated on the assumption that average historical costs are unlikely to be substantially different from incremental costs, particularly as they pertain to the transmission component of the cost of service which is by far the largest cost component in this case. This assumption should be reviewed if any disproportionate growth takes place on the system either through a significant increase in load by an existing customer or a major new user appearing on the system.

Using FACOS, the process of rate determination consists of three conceptually distinct steps. These are:

i) estimation of total cost;
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 established prior to this hearing by adopting an 1989 test year. Step (ii), which concerns the allocation of costs between classes, is the primary focus of this hearing. Step (iii), which is sometimes referred to as intra-class allocation, was not addressed by the Applicant since:

> "The Company believes the cost allocation principles and general rate design objectives should be established prior to the detailed assessment of changes in the various block rates."
>
> (IR 37, Exhibit 6)

In order to allocate the cost of service among customer classes, a three step procedure has been developed. The first step is to separate the rate base and annual revenue requirement into functional categories; i.e. allocate costs to various categories based on functions such as purchased gas cost, transmission cost, distribution cost, and so on.

The second step is to further separate each functional amount into classifications based on cause or type of cost, e.g. demand or capacity, commodity use and customer cost. This step requires judgement since many costs, e.g. purchased gas costs, have both a capacity and commodity component. Although a variety of methods have been devised to help apportion costs between capacity, commodity and customer components, some degree of imprecision in the apportionment is unavoidable.

The third step is to allocate the various functionalized and classified costs to the appropriate rate classes. Allocation of the costs can be assigned directly when the amount of class responsibility is clear, as with gas commodity charges. However, this task becomes significantly more difficult where there are joint costs; i.e. costs incurred to serve more than one customer or customer class, such as capacity costs.

This hearing addressed four major issues with respect to cost of service studies. These were (i) the role of cost of service studies, (ii) how should capacity be allocated amongst firm customer classes, (iii) to what extent should interruptible customers bear fixed costs, and (iv) how should interruptible revenues from large industrial customers be credited.

4.2 Role of Cost of Service Studies

PNG testified that the purpose of a fully allocated embedded cost of service study is to determine "the cost of serving the different rate classes and the ratio of revenue provided by each respective class to its allocated cost." (Page 3, Tab 2, Exhibit 4.) PNG stated that in carrying out its cost of service study, its choice of methodology was influenced by considerations other than cost and specifically by fairness. Ocelot's expert witness, Mr. Drazen, gave evidence that cost of service studies should reflect cost considerations only and that other goals of rate design, such as fairness, should be considered separately (T. 536).

Witnesses on behalf of PNG and Ocelot testified that cost of service studies require considerable amounts of judgment. In addition, there are limitations on what cost of service studies can measure. For example, there was considerable evidence to show that Ocelot receives a lower quality of interruptible service than do other interruptible customers. However, PNG testified that this was best captured outside of the cost of service study as an external adjustment to the rates indicated by the cost of service study (T. 275).

Similarly, PNG testified that it was subject to substantial business risk resulting from the composition of its load. PNG serves four large industrial customers which take approximately 88 percent of the company's gas sales with Ocelot taking 66 percent. The company testified that there is significant business risk associated with the loss of even one of these major customers (T. 257). This risk has been recognized previously by the Commission in the allowed rate of return on equity. However, in distributing the return on equity among customer classes for cost of service purposes, the company did not attempt to reflect this difference in risk, although the company believed that residential customers imposed less risk on the system (T. 267). PNG testified that this imposed a limitation on the usefulness of its cost of service study (T. 267).

As a result, both the Applicant and the Complainant suggested that these studies are seen more as a guide than a prescription in setting rates (T. 273/274 and T. 670/671).

4.3 Capacity Allocation - Firm Customers

As indicated in Section 4.1, there are three steps necessary to allocate the cost of service amongst customer classes. No particular issues or concerns were raised with respect to the functionalization or classification of embedded costs and Ocelot accepted PNG's cost of service study results for these two areas. However, they held markedly different views with respect to the appropriate allocation of capacity costs to customer classes.

4.3.1 Modified Partial Plant

The cost of service study presented by PNG used the Modified Partial Plant method, a variation on the Partial Plant method, to allocate capacity costs amongst the different rate classes, including the interruptible class, during the time period they use the system. This method implicitly assumes that the facility is constructed to meet the annual load and each increment of load over the base load requires the addition of a series of partial plants to serve the load. As such, PNG argued it enhances fairness.

> "Only those rate classes which utilize capacity in a time period are asked to pay for it."
>
> (Exhibit 4, Tab 1, Page 13)

4.3.1.1 The First Step

The method consists of three steps. The first step assigns capacity cost responsibility to each time period. It begins with the assumption that system capacity can be viewed as a series of partial plants. Each increment of system load calls forth an additional partial plant which exists during the time the load is on the system. Once a load appears on the system, it exists from that point in time on the load duration curve through all remaining periods including the peak.

Capacity responsibility for each partial plant is allocated on an equal basis to each time period in which the capacity is in use. For example, base capacity is allocated equally to each of 365 days while capacity responsibility for the peak period increment is allocated solely to the peak period. For each time period, capacity responsibility is the sum of the portion of all partial plants used in the time period. The sum of all time period capacity responsibilities equals peak capacity. By developing ratios of each accumulated increment to the total, a weighting factor for each period of the year is calculated.

4.3.1.2 The Second Step

The second step allocates the capacity cost responsibility across rate classes. Time period weights are calculated based on time period capacities determined in the first step. The relevant weights are then applied to class demand in each time period. Summing the weighted class demands across time periods gives the total capacity responsibility for each rate class. Determining the percentage distribution results in the initial cost allocation factors.

However, at this point a problem arises in that the sum of class capacities calculated in the second step does not equal peak capacity. Although the time period weights calculated in the first step are based on peak capacity, the calculated class capacity responsibilities are based on demand in each period, which except for the peak period, is less than peak demand. Thus, total peak capacity is not allocated and any percentage distribution of capacity cost based on this initial allocation will be skewed with more capacity cost being allocated to a 100 percent load factor customer than that customer's maximum demand.

4.3.1.3 The Third Step

The third step is to take the capacity left unallocated under step two, and allocate it based on the aggregate of excess of period use over average use. As Dr. Sarikas testified, (Page 15, Tab 1, Volume 1), this should result in the 100 percent load factor customer being allocated the same capacity responsibility as he would have been allocated under the coincident peak day method.

The Commission heard several criticism of the Modified Partial Plant method First, Ocelot argued that this method was inappropriate in principle since it was incorrect to allocate capacity costs based on usage in all time periods instead of solely at peak. Ocelot maintained that gas utilities design their system to meet the maximum expected firm load (Page 10, Tab 2, Exhibit 10) and it is on this basis that capacity costs should be allocated. Mr. Drazen, appearing on behalf of Ocelot, stated:

> " I submit that ... the way you measure cost is, the way the utilities design their system, it's by how much do you have to serve at the time of the maximum demand, and how much gas is used on July 3rd or August 12th really doesn't have much impact, if any impact, on the cost of the system.
>
> So if you're trying to measure cost the way you do it here ... is by the contribution to peak." (T. 521)

Second, Ocelot asserted that the method had operational difficulties due to its complexity and was therefore rarely used (T. 130/131).

Finally, Ocelot argued that the method gave results which were inconsistent with the evidence given by PNG (T. 837), in that high load factor customers were allocated capacity cost responsibility in excess of that which they would have been allocated under the coincident peak day method. This resulted in faulty price signals being given to high load factor customers. Specifically, Ocelot demonstrated that high load factor customers could reduce their total cost responsibility under this method (and presumably rates) by increasing gas usage to 100 percent load factor levels even if this resulted in an uneconomic and wasteful use of gas (T. 340/355)

4.3.2 Coincident Peak Method

Ocelot presented its own cost of service study using the coincident peak day method to allocate capacity cost responsibility and restricting capacity cost responsibility to firm service customers only. This method calculates capacity cost responsibility by measuring the load of each customer class relative to the total system load on the peak day. If a customer class accounts for 40 percent of the load on the peak day, the class will be allocated 40 percent of capacity costs.

Ocelot argued that the coincident peak day method is a standard methodology (Page 9, Tab 2, Exhibit 10) and that other regulatory commissions have found it to be a more appropriate method of determining cost causation than the Modified Partial Plant method (Page 9, Tab 2, Exhibit 10). In particular, Ocelot argued that since gas utilities design their system to meet the maximum expected firm load (Page 10, Tab 2, Exhibit 10) it is on this basis that capacity costs should be allocated. No direct assignment of fixed costs should be made to other than those customers who used the system on the coincident peak.

However, over the course of the hearing, evidence was adduced to show that any method which does not consider mileage would be inappropriate for allocating capacity related costs on PNG's transmission system since customer classes are not evenly spread throughout PNG's distribution area. In particular, small industrial customers are located closer to the beginning of PNG's transmission system while large industrial customers are located towards the terminus of the system. This implies that if mileage is not considered, costs will be over-allocated to customers near the commencement of the system and under-allocated to customers located at the terminus of the system.

As a result, evidence was presented by both PNG and Ocelot with respect to the distance-weighted coincident peak day methodology.

4.3.3 Distance-Weighted Coincident Peak

The Distance-Weighted Coincident Peak Day method allocates capacity responsibility based on usage at peak, weighted by the distance gas is transported. Both Ocelot and PNG testified that the Distance-Weighted Coincident Peak Day Method was a reasonable method of capacity cost responsibility allocation. Ocelot testified that it was a refinement to the Coincident Peak Day method while PNG testified that it had been their second choice for the cost of service study.

Both PNG and Ocelot presented preliminary evidence indicating the impact which a change to the distance-weighted coincident peak-day method would have on their respective cost studies. Exhibit 20 presented by PNG, shows the results of a distance-weighted coincident peak day methodology assuming that interruptible customers are allocated capacity. The study indicated that a movement to this method from the Modified Partial Plant method would decrease PNG's estimate of Ocelot's capacity cost responsibility by approximately $975,000 resulting in an estimated over-contribution of approximately $3.6 million. Exhibit 33 shows the results of Ocelot's cost of service study using this method and assuming that no capacity cost allocation is made to interruptible customers, and indicates that Ocelot's capacity cost responsibility would increase by approximately $600,000 resulting in an estimated over-contribution of approximately $3.7 million.

4.4 Capacity Allocation - Interruptible Customers

4.4.1 PNG "Avoided Cost" Approach

The cost of service studies presented by PNG and Ocelot differed in their treatment of interruptible customers. PNG's study assumed that all customers, whether firm or interruptible, should bear capacity cost responsibility. PNG supported this method on the grounds that it is more equitable.

> "**Mr. Rice**: Q: Now, its your view that customers ought to be allocated a portion of the total system capacity because that customer is enjoying the benefits of the system to a greater or lesser degree.

> **Dr. Sarikas:** A: Yes, I generally favour someone paying for the use of a system even though they may not have caused an expenditure to be made in order to supply them, but that they should not enjoy the free use of the system that was provided by others." (T. 453)

In order to allocate capacity costs to interruptible customers, PNG employed an "avoided cost" approach. This approach requires that interruptible customers be treated as if they received firm service. Therefore, the costs of serving interruptible customers on a firm basis must be calculated. These costs include investment in plant needed to provide service and increased Westcoast demand charges. Second, it is assumed that these costs are incurred to serve all classes of customers and so are allocated across all customer classes based on the Modified Partial Plant allocation factors. Third, since these costs are not actually incurred, but represent the savings obtained by serving interruptible customers as firm, they must be subtracted from the "beefed-up" cost of service. Dr. Sarikas assumes that the savings are divided equally between interruptible and firm classes of customers. The rationale for the equal division is that equality would be the outcome of a hypothetical "hard bargaining" between interruptible and firm customers. Fourth, the 50 percent of savings allocated to interruptible customers are allocated on the basis of average load, while the 50 percent allocated to firm customers are allocated between firm classes on the basis of "valley gas", i.e. the difference between class peak load and firm requirements on any given day, and on previously determined capacity responsibility.

Dr. Sarikas testified that the avoided cost approach was chosen since it provides

> "an equitable way of arriving at what the savings were first of all, because by knowing avoided cost you know what the savings are from interruptible service." (T. 368)

or put another way,

> "it provides for a credit that is equal to the total savings derived from the provision of interruptible service."
>
> (Exhibit 6, IR 8)

Specifically, he argued that the avoided cost method requires less judgment than the approach used by Ocelot, since the actual benefits of interruptibility are calculated. Mr. Drazen disagreed with this approach, arguing that it is inappropriate to assign capacity responsibility to interruptible customers (Page 14, Tab 2, Exhibit 10). Support for this view was given by Mr. Dyce, who stated that PNG did not design its system to serve interruptible customers (T. 186).

However, a number of other problems with PNG's approach were also identified. First, two areas were identified which require the exercise of significant judgment. These are the estimate of the cost of making interruptible sales firm and the allocation of the savings from the provision of interruptible rather than firm service between interruptible and firm service customers.

PNG's cost of service study assumed that the savings are initially split equally between interruptible and firm service customers, arguing that this is the result which would likely be achieved through "hard negotiation" (Exhibit 6, IR 16). Dr. Sarikas stated that the equal allocation was entirely hypothetical (T. 366).

In addition, Counsel for Ocelot argued that the distribution of the estimated savings amongst firm and interruptible customers results in counter-intuitive results. In cross-examination, Dr. Sarikas and Mr. Bellin stated that this method resulted in an increased capacity cost allocation to high load factor firm industrial customers and that such a result was unlikely in a freely negotiated contract.

> "**Mr. Wallace: Q:** But they're [industrial customers] going to say, aren't they, say to you, well, forget it. Just treat us as firm, as you did on page 21. This share the benefits has cost us two million dollars and it was a nice idea, but we're out of here, aren't they? Isn't that what a reasonable party is going to say?
>
> **Mr. Bellin: A:** They probably would, yes."
>
> (T. 374/375)

4.4.2 Ocelot Value of Service Approach

As indicated earlier, Ocelot's witness argued that interruptible customers impose no capacity costs on PNG's system and therefore should not be allocated any capacity responsibility for interruptible service. Mr. Drazen stated:

> "Gas utilities do not build facilities to serve interruptible load. As a result, there is very little cost incurred in respect of such loads. There is no capacity-related cost; only commodity-related cost---that is, purchased gas, compressor fuel and pipeline commodity tolls. Therefore a standard method of calculating capacity cost is to allocate capacity costs only to the firm customers and to exclude the interruptible loads from that allocation."
>
> (Exhibit 10, Tab 2, Page 12)

And later

> "The allocation of costs to interruptible loads should be based only on those costs actually incurred, namely commodity costs but no capacity costs.
>
> (Exhibit 10, Tab 2, Page 14)

And also

> "That does not mean that the interruptible rates need to be set at the calculated cost. But the extent to which interruptible rates exceed the actual cost of service should be recognized for what it is, a pricing decision."
>
> (Exhibit 10, Tab 2, Page 14)

To the extent that the market will bear interruptible rates in excess of variable costs, Ocelot acknowledged that a premium can be generated which may be used as a credit against the fixed costs assigned to firm customers and thus reduce firm rates. (Exhibit 10, Tab 2, Page 14). Specifically, Ocelot argued that interruptible rates should be set on a value of service basis. And, though PNG did not espouse this methodology, Dr. Sarikas gave evidence that:

> "Allocated cost of any kind can't be applied in the face of market forces."
> (T. 369)

thus, suggesting that value of service considerations must be taken into account regardless of the method of capacity allocation.

Witnesses for both PNG and Ocelot testified that incremental or variable costs are the floor for interruptible rates; however, they appear to hold differing views as to the value of the floor. Given Ocelot's proposed demand commodity rate structure for industrial customers, it would appear that Ocelot views the floor as being $0.08. This number may be partially supported by Commission staff Information Request 31, Exhibit 6, which shows the makeup of the current $0.16 incentive and interruptible rate to Ocelot to be as follows:

Fuel Consumption	$0.0665
1 percent in lieu of Property Tax	$0.0121
Misc. O&M and A&G Expense	$0.0121
Contribution to Fixed Cost	$0.0693
Total Cost	$16.0000 cents

However, in cross-examination, Mr. Dyce testified that during some periods the variable cost of moving gas exceeded $0.16 (T. 41/42).

Witnesses for both parties testified that for the PNG system the ceiling price for interruptible gas is the firm service rate. Ocelot witnesses testified that if rates for interruptible service equalled the firm rate, Ocelot would take firm service in preference to interruptible service.

Ocelot did not present evidence to indicate the market value of interruptible sales or the amount of premium that might be generated by interruptible sales. However, it is clear that one factor which will influence the value of interruptible gas sales to Ocelot is the value of methanol. Methanol is a primary petrochemical produced mainly from natural gas. The two largest markets for methanol are for formaldehyde which is used in the production of resin for wood panel board and building materials and for methyl tertiary butyl ether ("MTBE") which is used as an octane enhancer. This second use for methanol is expected to grow rapidly as MTBE has proven effective in reducing motor vehicle carbon monoxide and nitrous oxide emissions.

Ocelot testified that methanol is sold in a world market rather than in regional markets. Traditionally, the demand for methanol has been inelastic, i.e. changes in the price of methanol have had little impact on the demand for it, and cyclical. Therefore when excess world supply exists the price will fall significantly and vice versa.

For the purposes of the cost of service study, Ocelot assumed that interruptible customers contribute $2 million above incremental costs, allocated as in the PNG study. The $2 million reflects the approximate difference between current revenue from interruptible sales and the cost of providing interruptible sales exclusive of any capacity allocation. Based on total (Ocelot plus others) interruptible sales of 7800 TJ, this would give rise to an interruptible rate of $0.253 per gigajoule. The PNG proposed rates for interruptible customers, which include a transportation rate for interruptible service to Ocelot of $0.215 per gigajoule also gives rise to the $2 million credit (Exhibit 11, Response to Staff IR 5).

Ocelot's witness stated that setting interruptible rates equal to firm rates at a 200 percent load factor would result in interruptible rates ranging from $0.2659 to $0.3070 per Mcf. Ocelot's rate would be $0.2842 per Mcf. These rates would also generate a $2 million credit. In testimony, Ocelot's witness testified that a 200 percent load factor rate appeared reasonable for interruptible service.

4.5 Results of Cost of Service Studies

4.5.1 <u>PNG Cost of Service Study Results</u>

The major conclusions of the PNG study are as follows:

1. The revenues resulting from rates charged to residential gas users appear to be less than the allocated cost of providing such service, by approximately $1.8 million.

2. The revenues resulting from rates charged to commercial gas users appear to be more than the allocated costs of providing such service by approximately $900,000.

3. The revenues resulting from rates charged to the large industrial firm gas users for firm gas deliveries are greater than the allocated cost of delivering such gas. In total, firm sales and service revenues for large industrial customers exceed cost of service by about $3.8 million. Ocelot's portion of this amount is estimated by PNG at $2.6 million.

4. The revenues resulting from rates charged to Skeena Cellulose Inc., Eurocan Pulp and Paper Co. Ltd. and Alcan Smelters and Chemicals Ltd. for interruptible gas deliveries are greater than the allocated cost of delivering such gas by an estimated $300,000.

5. The revenues resulting from rates charged Ocelot for interruptible service are less than allocated costs by an estimated $3.0 million.

4.5.2 Ocelot's Cost of Service Study Results

The major conclusions of the Ocelot cost of service study are as follows:

1. The revenues resulting from rates charged to residential gas users appears to be less than the allocated cost of providing such service by approximately $4.0 million.

2. The revenues resulting from rates charged to commercial gas users appears to be less than the allocated cost of service by approximately $1.6 million.

3. The revenues resulting from rates charged to large industrial firm gas users for firm gas deliveries are greater than the allocated cost of delivering such gas by approximately $5.9 million, of which Ocelot's share is $4.3 million.

In addition, a comparison of the revenues received from large industrial customers to the costs assigned to them in the Ocelot cost of service study shows that the revenues resulting from rates being charged large industrial customers for interruptible gas delivery are greater than the allocated cost of delivery of such gas by approximately $1.8 million.

The following table summarizes and compares the differences between the revenues collected under current rates and the allocated costs developed by the Applicant and Complainant using their respective cost of service methodologies.

Comparison of Cost of Service Results
Revenue Less Allocated Revenue Requirement
(Thousands of Dollars)

	PNG $000 Under Contribution	PNG $000 Over Contribution	Ocelot $000 Under Contribution	Ocelot $000 Over Contribution
Residential	(1,828)		(4,046)	
Commercial		912	(1,563)	
Small Industrial	(195)		(321)	
NGV		16		37
Ocelot		2,639		4,290
Skeena		607		778
Eurocan		444		735
Alcan		80		81
Interruptible				
- Large Commercial	(19)		-	
Interruptible				
- Ocelot	(2,976)			-
- Skeena		214		-
- Eurocan		78	-	
- Alcan		28		-

Source: PNG and Ocelot Cost of Service Studies.

4.6 Commission Summary and Conclusions

4.6.1 Role of Cost of Service Studies

A cost of service study is a guide to determine whether the revenues generated by the rates charged to a particular class of customer are sufficient to cover the cost of serving that class of customer. As such, cost of service studies should reflect costs only. Other considerations, while important in determining fair, just and reasonable rates, should be included following a review of the cost of service study results.

Given the above, the results of cost of service studies should be seen as a tool to be used in the setting of fair, just and reasonable rates. They are not, in and of themselves, fair, just and reasonable rates.

The Commission is also cognizant of the considerable reliance upon judgement involved in the undertaking of a cost of service study. Although judgement is required in lesser amounts to determine the specific component of the total cost of service and functionalization of costs, significant judgement is required to classify costs between capacity, commodity and customer components. Even greater judgement is required in determining the appropriate method to allocate these costs amongst rate classes. For example, compressor costs have been allocated 100 percent to capacity even though annual usage contributes to a decreased service life. Similarly, different classes of customers impose different levels of risk on the utility, but quantifying the appropriate cost differential is not attempted in these studies. Finally, there are benefits attributable to serving certain classes of customers but these, too, have not been included as an offset against costs within the study as they are not easily quantified.

Therefore, even as a tool for indicating the level of costs attributable to serving a particular class of customer, cost of service studies must be viewed as an indicator only, of the sufficiency or insufficiency of rates to cover a particular set of costs. Given the imprecision inherent in cost of service studies in general, and in particular the studies in issue, the Commission believes that as long as revenues from a particular class of service and costs allocated to that class of service do not differ by more than 10 percent, there is no compelling evidence to determine that the cost of service results indicate rate restructuring is required.

4.6.2 Capacity Allocation - Firm Customers

The primary issue before the Commission is whether capacity costs should be allocated amongst customer classes solely on the basis of usage at peak or on a basis that in addition reflects usage in all time periods. Secondary issues include the reasonableness of the results generated by each study and the ease of understanding each method.

Capacity was defined in this proceeding as the maximum amount of service a utility will be required to provide at any one point in time. Evidence was clear that it is on this basis that PNG's facilities were designed and constructed.

PNG testified that the Modified Partial Plant method is based on the assumption that capacity responsibility is a function of capacity use in all time periods and not solely the peak-day period. In assessing this assumption, the Commission had regard to its stated belief that cost of service studies should reflect costs only. If capacity costs are a function of capacity use in all time periods, then a reduction in usage off peak should result in a reduction in capacity costs. PNG presented no evidence at the hearing to lead to the conclusion that decreased usage off peak would result in such a reduction.

Additionally, if there were some portion of costs currently classified as capacity found to vary with a change in throughput, it would be more appropriate to separate out the commodity component during the classification stage of the cost of service study rather than to allocate capacity based on commodity usage.

Cost allocation methodologies, like rates, should be easily understandable, within the constraints of theoretical correctness, and additional complexities should have clear and identifiable benefits. Even if off-peak usage influenced capacity costs it would be difficult to endorse the Modified Partial Plant due to its complexity.

In assessing the reasonableness of the results generated by the Modified Partial Plant methodology, the Commission was influenced by the apparent inducement to wastefulness afforded high load factor customers. An appropriate method of cost allocation should not provide an incentive to the uneconomic use of energy or a commitment to higher firm nomination, which in turn could cause unnecessary capital expansions to the pipeline system.

Therefore the Modified Partial Plant method of capacity allocation proposed by PNG is found to be deficient as it is applied to the current circumstances of the PNG system.

The Coincident Peak Day method proposed by Ocelot allocates capacity costs based on rate class demand at system peak. Assuming full utilization of the system, if the demand for service at peak by one rate class increases then costs are imposed on the system. These costs occur since either facilities will need to be built to provide the increased service or another customer's demand at system peak will not be met. Therefore, in general terms, the Coincident Peak Day method results in a proper allocation of capacity costs between rate classes in these circumstances.

However, evidence adduced at the hearing did identify a deficiency with respect to the allocation of costs. PNG's customers are not distributed evenly throughout the service area. Small industrial customers are located near the beginning of the system while large industrial customers are located near the terminus. Therefore, if capacity is allocated solely with respect to use at peak, small industrial customers will be allocated capacity costs for facilities which they do not use. This problem can be overcome by weighting the Coincident Peak Day allocation factors by the average distance each customer class is located from the origin of PNG's system.

Therefore, given these particular circumstances, PNG's capacity costs to firm customers should be allocated using a Distance-Weighted Coincident Peak Day methodology.

4.6.3 Capacity Allocation - Interruptible Customers

The issues to be considered are two-fold: (i) are interruptible customers properly allocated capacity costs and if so how should these costs be determined and (ii) if interruptible customers are not allocated capacity costs how should rates be set.

PNG's argument with respect to interruptible customers follows from its endorsement of the Modified Partial Plant Method of cost allocation. Specifically, PNG argued that interruptible customers should be allocated capacity costs since they use the system and that the amount should reflect a portion of the "avoided cost " of capacity resulting from interruptible rather than firm service.

As stated in previous sections of this decision, cost of service studies should reflect costs. If interruptible customers impose capacity costs on the system, then a decline in interruptible service should lead to a reduction in capacity costs. There is no evidence to indicate that this would occur. Therefore, interruptible customers should not be allocated capacity supply costs.

If interruptible customers were to be allocated capacity costs there would still be problems with the avoided cost approach. Although this approach purports to be equitable, the equity is based on the assumption that the avoided costs can be known with a reasonable degree of certainty. However, in actual practice the approach requires significant reliance on judgement, not only with respect to the estimate of the cost of making interruptible service firm, but also with respect to the allocation of savings from interruptible service between firm and interruptible customers, and between firm service classes. Thus, the results of this methodology are likely to owe more to the assumptions which underlie the study than they do to an objective determination of costs.

However, the fact that interruptible customers are not properly allocated capacity costs does not mean that rates for interruptible service should be set without regard to capacity usage considerations. Although interruptible customers do not impose capacity costs, it is clear that they benefit from using the capacity installed and paid for by firm service customers. To the extent that this usage is valued by interruptible customers, it is fair that interruptible customer rates should be set so that this value is captured. Further, in order to preserve the integrity of the revenue requirement, the positive difference between the value and cost of interruptible service, ("the Premium") should be credited against firm service costs so that the rates for firm service customers may be reduced. The premium resulting from interruptible service should be credited to firm service customers in the same manner as that which made the interruptible gas available in the first instance, by capacity installed to meet the needs of the coincident peak day customers. Accordingly the adjustment is made pro-rata on the basis of one minus the load factor for each customer class.

The evidence led by both PNG and Ocelot suggested that an upper limit on interruptible rates is set by firm service rates. Similarly, the evidence suggested that the floor on interruptible rates is set by the variable cost associated with providing the service.

Given that revenues from interruptible service, over and above the cost of providing that service, are used to offset firm service capacity costs, the rates for interruptible service should be set so as to maximize this differential. The size of this differential will reflect the value of the final product using the interruptible gas and the amount of interruptible gas which the utility can provide. The Commission recognizes that the value of interruptible sales will reflect its demand at various prices and the avoidance of fixed costs of increased firm nominations. While the price must exceed the minimum variable costs of making interruptible gas available, the optimum price will depend on the amount of gas available, the production profiles of the industrial customers, the firm demand charges on the PNG and Westcoast systems, the inherent advantages of this form of service and the price of alternative fuels. This price could exceed the 100 percent firm load factor price.

The Commission's findings with respect to interruptible rates are set forth in Section 5.3.

5.0 RATE PROPOSALS

5.1 PNG Rate Proposal

Based on the results of PNG's study, the Company has recommended the following changes to its rates.

"1. Effective January 1, 1991:

a) residential rates be increased by 5.0 percent ($0.237 per gigajoule) to generate additional revenue of approximately $318,000 per year;

b) interruptible rates to large industrial firm gas users, other than Ocelot, be reduced by approximately 10.0 percent ($0.188 per gigajoule) resulting in a reduction in revenue of $318,000 per year; and

c) Ocelot's rates for firm incentive gas and interruptible gas be amended to eliminate the incentive gas rate, and that Ocelot's interruptible rate be increased by $0.55 per gigajoule. The additional revenues generated by these changes would be credited to Ocelot's firm gas rates which would result in no change to Ocelot's overall cost of gas based on its 1989 normalized gas requirements.

2. Effective January 1, 1992 and 1993

a) residential rates be increased by 5.0 percent on January 1, 1992 and by a further 5.0 percent on January 1, 1993. Each 5.0 percent increase would generate additional revenue of approximately $$318,000 per year and by the end of 1993 would result in the elimination of approximately 50 percent of the current difference between residential rates and allocated cost; and

b) the additional revenues collected from the residential sector be credited to large industrial firm gas rates with a view to making the revenue to cost ratios of all large industrial firm gas users equal as of December 31, 1993."

(Executive Summary Pages 3/4)

The proposal leaves commercial, small industrial and natural gas vehicle rates unchanged. Also unchanged are intra-class rate structures for all classes of service.

PNG put forward this proposal as reflecting the findings of their cost of service study. In addition, PNG argued that further changes are unnecessary since Ocelot's initial rates for service can be assumed to have been fair and that there have been no changes in circumstances since then to render them unfair today.

5.2 Ocelot Rate Proposal

Based on the results of Ocelot's cost of service study, Ocelot has recommended the following changes to PNG's rates.

1. Firm rates for all classes of service should move towards costs as rapidly as possible even if this results in concurrent increases in interruptible rates. Ocelot argued that this would allow it to make proper operating decisions based on whether incremental purchases were advantageous.

2. Interruptible rates should reflect market conditions.

3. There should be a five percent increase annually for the next three years for all classes currently under contributing to the cost of service. This would particularly affect residential, commercial and small industrial rates.

4. The increased revenues obtained from the under contributing classes should be used to reduce large industrial rates on a pro rata basis based upon their over contribution.

5. Rates to large industrial customers be restructured to reflect demand and commodity charges instead of the current commodity only rates which require industrial customers to take a certain minimum quantity. The demand charge would cover most or all of the capacity related costs while the commodity charge would recover only commodity related costs (T. 859 - 861).

Ocelot suggested the appropriate rates would be around \$16-\$19 per Mcf of Demand while the commodity charge would be about \$0.08 per Mcf. The \$0.08 commodity charge is proposed by Ocelot on the grounds that it covers a penny and a half of Westcoast commodity tolls, \$0.03 to \$0.04 of compressor gas and supply-related overheads (T. 675).

Ocelot supports this structure on the grounds that it is easier and makes it unnecessary for industrial customers to specify load factor. Ocelot further testified that it reduced the risk to the utility if the demand charge covered the fixed cost.

Although PNG did not propose the implementation of a demand commodity charge for industrial customers, the company testified that it would find such a rate structure acceptable in theory (T. 271). However, PNG argued that the Commission should not order such a rate change as part of this hearing but instead PNG and Ocelot should hold further discussions on the matter so that the full consequences of such a change could be adduced (T. 820).

Several potential consequences of this rate structure were discussed during the course of the hearing. Although it would eliminate the potential for extra profits on incentive rate gas sales, PNG testified that this rate structure would reduce the overall business risk from serving industrial customers.

> "Mr. Dyce: It certainly would go a long way to reducing the risk, if we had 100 percent of fixed costs for the industrial customers in the form of a demand charge and strictly the variable cost as a commodity, it certainly would go a long way to reduce the risk on the PNG system." (T.269)

As a result, the company testified that it was likely that such a structure could result in the company being awarded a lower rate of return on equity than it would otherwise receive.

> "Mr. Dyce: I agree, Mr. Rice, when you reduce the risk by having a demand charge that covers 100 percent of the fixed costs, it does reduce the risk and I would expect we would end up with a reduced return." (T. 280)

Although PNG did not testify as to the likely level of the demand charge and commodity charge, evidence presented at the hearing indicated that PNG would likely see the appropriate commodity charge as being in excess of $0.08 per Mcf and most likely around 16 cents per Mcf. In response to a staff information request, PNG testified that $0.16 is required to recover the variable cost of providing industrial gas plus a small contribution to fixed costs (IR 31, Exhibit 6) and in cross-examination, indicated that for certain sales, $0.16 may be insufficient to cover the variable cost of service (T. 42).

Finally, Ocelot asked the Commission to make a "strong endorsement of the principle that rates should be cost-based" (T. 860) in order to send a signal to Ocelot and other potential investors that the Commission is concerned with economic development in the Kitimat area.

5.3 Commission Summary and Conclusions

On the basis of the evidence in this proceeding, and for the purposes of a cost of service study, the Commission accepts the functionalization and classification of costs as prepared and presented by PNG in their cost of service study and accepted by Ocelot. Further, for the purposes of a preliminary cost of service study, the Commission accepts the total gross cost allocation presented in Exhibit 33, a cost of service study prepared by Mr. Drazen using the Distance-Weighted Coincident Peak Day Allocation, and allocating no capacity costs to interruptible customers.

This preliminary allocation of gross costs requires modification. Gross costs for firm service customers shall be reduced by the estimated amount of the Premium to be obtained from interruptible customers with the Premium distributed on the basis of one minus the class load factor at system peak. Where the class load factor at system peak is in excess of 100 percent, it shall be assumed, for these purposes, that the class load factor is 100 percent. For the purposes of the Commission's estimate of the results of the cost of service study, the premium shall be assumed to be \$1.9 million which is the amount by which interruptible customers revenues exceed their allocated costs.

Table 2 presents the Commission's estimates of the results that would be obtained from a cost of service study undertaken as directed by this decision.

Table 2

Commission Cost of Service Study Estimates

	Revenue (1)	Gross Costs (2)	Allocated Premium	Net Costs	Revenue-Net Cost	Revenue/Cost
Residential	6,086	10,386	(667)	9719	(3,633)	.63
Commercial	6,102	7,930	(678)	7252	(1,150)	.84
Small Ind	4,327	4,208	(387)	3821	506	1.13
NGV	186	140	0	140	46	1.33
Ocelot - firm	39,220	36,037	(34)	36,003	3,217	1.09
Skeena - firm	2,938	2,699	(66)	2,633	305	1.12
Euro- firm	6,221	5,664	(81)	5,583	638	1.11
Alcan - firm	677	611	(5)	606	71	1.12
Lge Comm - Interruptible	330	226	104	330	0	1.0
Lge Ind Interruptible	10416	8,602	1814	10,416	0	1.0
Total	76,503	76,503	0	76503	0	1.0

(1) Page 1, Tab 3, Exhibit 4
(2) Exhibit 33

Based on the above, the Commission finds the following:

1. The Commission accepts that firm rates should move as rapidly as possible towards costs, modified by the zone of reasonableness whereby, in the absence of compelling evidence to the contrary, a revenue to cost ratio of 90 to 110 percent shall be seen as revenue cost equality. Accordingly, the Commission orders that residential rates increase by five percent and commercial rates by three percent per annum for three years commencing in accord with the implementation date described in Section 6.2. The increases will be calculated exclusive of any changes in the cost of gas which may arise. The increased revenues received from residential and commercial customers will be used to lower firm rates to those customers whose rates are in excess of the zone of reasonableness established by this decision.

2. The cost of service study results indicate that current small industrial rates fall outside the zone of reasonableness. Therefore, the Commission directs that rates for service for small industrial customers decline on a one time basis by approximately $.09 per gigajoule. Such a decline will act to bring these rates within the required zone.

3. The cost of service study results indicate that Natural Gas Vehicle rates do not fall within the required zone. Therefore the Commission directs that rates for service for these customers decline on a one time basis by approximately $.52 per gigajoule.

4. The cost of service study results indicate that the firm service rates for Skeena, Eurocan and Alcan fall outside the zone of reasonableness. Therefore the Commission orders that their rates for service fall on a one time basis by approximately $.01 per gigajoule, $.03 per gigajoule and $.03 per gigajoule, respectively, in order to bring their rates into line with the required zone.

5. Further, the Commission directs that the balance of the increased revenues obtained from the increase in rates to residential and commercial customers ordered in (1) above shall be redistributed to firm service industrial and natural gas for vehicle customers on a pro rata basis, based on consumption volumes.

   The Commission rejects the suggestion advanced by Ocelot that the increased revenue resulting from the increase in residential and commercial rates be distributed to large industrial customers based on the absolute over-contribution of each customer since the Commission finds that this would result in an unfair distribution.

6. The Commission does not object in principle to the introduction of a demand/commodity charge for large industrial customers, but agrees to PNG's request to allow time for further negotiation on the subject to take place between PNG and all its large industrial customers prior to the implementation of such a rate structure.

7. The Commission accepts PNG's proposal to eliminate the incentive rate charged to Ocelot for the last 7.8 percent of contract demand and orders that the increased revenues resulting from the elimination of the incentive rate be used to reduce Ocelot's existing firm service rates.

8. The Commission accepts Ocelot's position that rates for large industrial interruptible service should be based on value of service. The absolute value of interruptible rates must be a matter for negotiation between the utility and its customers. However, until such time as negotiations can take place the Commission sets the rates for interruptible service at the existing levels.

   Negotiation must be completed by July 1, 1991 and presented to the Commission for consideration on or before this date. To ensure equitable treatment of firm customers, PNG will be required to provide evidence that it has achieved market value prior to approval of the interruptible rate of rates. Upon approval of the negotiated rates by the Commission, adjustments to the interruptible rates will be made. In the absence of negotiated rates by July 1, 1991, the Commission will fix the rates following a summary inquiry or hearing.

9. In setting these rates, the Commission recognizes that rate design is an evolving process with limits on precision. Therefore, the Commission directs PNG to file an updated cost of service study prior to November 1, 1993, inclusive of proposed rates. Among other matters, this study will further review the functionalization and classification of costs presented in this proceeding; the appropriateness of the determination of the peak day including whether or not more than a single day should be used; other costs, if any, emanating from the use of the system; and the impact of different levels of risk imposed upon one class of customers by another. The study must also address the appropriate intra-class rate structures, the impact of rate structures on Demand Side Management and the reasons, if any, for different rate structures within the large industrial class.

6.0 POSTPONEMENT OF IMPLEMENTATION

6.1 Issue

Three days prior to the commencement of final argument, PNG gave notice that it wished to amend its application to change the date the proposal would be effective to January 1, 1992 from January 1, 1991. PNG argues that the total potential rate, effective January 1, 1991, arising out of this proposal together with potential increases arising from an increase in PNG's revenue requirement, recovery of deferred income taxes, the implementation of the Goods and Services tax, an increase in Westcoast tolls and an increase in franchise fees would expose the residential consumer to rate shock as discussed in Section 3.3. PNG states that shifting the Application forward one year would eliminate this potential (T. 816).

In response Ocelot argues that "It would be very wrong for [the Commission] to defer implementing a proper decision, having heard this case, simply to make it easier for PNG to apply to you to increase rates for other reasons upon which you have no evidence at this time." (T. 827).

6.2 Commission Summary and Conclusions

The Commission accepts the argument put forward by Ocelot and directs PNG to file new rates at such time as the Commission has issued its Decision with regard to the Revenue Requirements hearing (commencing on March 18, 1991) and in any event, no later than July 1, 1991.

DATED at the City of Vancouver, in the Province of British Columbia, this 27th day of February, 1991.

J.D.V. Newlands, Deputy Chairman

N. Martin, Commissioner

W.M. Swanson, Commissioner

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-23-91

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

and

IN THE MATTER OF a Complaint by
Ocelot Chemicals Inc. against
Pacific Northern Gas Ltd.

and

IN THE MATTER OF a Rate Design Application
by Pacific Northern Gas Ltd.

BEFORE:	J.D.V. Newlands, Deputy Chairman; N. Martin, Commissioner; and W.M. Swanson, Q.C., Commissioner	)	February 27, 1991

ORDER

WHEREAS:

A. On January 17, 1990 Ocelot Chemicals Inc. ("Ocelot") filed a complaint pursuant to Section 64 of the Utilities Commission Act ("the Act"), alleging that the rates of Pacific Northern Gas Ltd. ("PNG") are unjust, unreasonable and unduly discriminatory; and

B. By Order No. G-20-90, dated March 14, 1990, the Commission set the matter down for public hearing to commence August 21, 1990 in Prince Rupert, B.C. and required PNG to file a Rate Design Application and evidence based on its most recent financial information by July 6, 1990; and

C. On July 6, 1990 PNG filed its direct evidence on Rate Design; and

D. The public hearing into the Ocelot complaint and PNG Rate Design Application proceeded on August 21, 1991 in Prince Rupert, B.C. and continued on August 28, 1991 in Kitimat, B.C., and November 6, 1991 in Terrace, B.C.; and

E. The Commission has considered the Ocelot complaint, the PNG Rate Design evidence and other information all as set forth in a Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. The residential service rate shall increase by five percent per annum for three years commencing in accord with the implementation date set out in Section 6.2 of the Decision.

2. The commercial service rate shall increase by three percent per annum for three years commencing in accord with the implementation date set out in Section 6.2 of the Decision.

3. The small industrial service rate shall decline on a one time basis by approximately $.09 per gigajoule.

.../2

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-23-91

4. The Natural Gas Vehicle Service rate shall decline on a one time basis by approximately $.52 per gigajoule

5. Large Industrial customer service rates shall decline on a one time basis by approximately $.01 per gigajoule for Skeena Cellulose Ltd. by approximately $.03 per gigajoule for Eurocan Pulp and Paper Co., and by approximately $.03 per gigajoule for Alcan Smelters and Chemicals Ltd.

6. The balance of the increased revenues obtained from the increase in rates to residential and commercial customers ordered in 1 and 2 above shall be redistributed to firm service industrial and Natural Gas Vehicle customers on a pro rata basis based on consumption volumes.

7. The incentive rate charged to Ocelot by PNG for the last 7.8 percent of contract demand is eliminated. The increased revenues resulting from the elimination of the incentive rate shall be used to reduce Ocelot's existing firm service rates.

8. PNG is instructed to enter into price negotiations with its large industrial interruptible customers, such negotiations to be completed on or before July 1, 1991.

9. PNG is to file an updated cost of service study prior to November 1, 1993 inclusive of proposed rates.

DATED at the city of Vancouver, in the Province of British Columbia, this 28th day of February, 1991.

BY ORDER

W.M. Swanson, Q.C.
Commissioner and
on behalf of the Division

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 an Application by
BC GAS INC.
for Rate Design Changes
PHASE B

VANCOUVER, B.C.
JULY 13TH, 1993

PROCEEDINGS

BEFORE:

DR. M. K. JACCARD	Chairperson
MR. F. C. LEIGHTON	Commissioner
MS. E. C. SLEATH	Commissioner

VOLUME 9

Allwest Reporting Ltd.
404-814 Richards St.,
Vancouver, B.C.

municipalities that we've proposed to negotiate with.

THE CHAIRPERSON: All right. Thank you. Those are all of my questions, so I believe if there are no other matters we can dismiss this panel. Thank you very much.

(WITNESSES ASIDE)

(PROCEEDINGS ADJOURNED 12:05 P.M.)

(PROCEEDINGS RESUMED AT 12:30 P.M.)

THE CHAIRPERSON: Go ahead, Mr. Johnson.

MR. JOHNSON: Thank you, Mr. Chairperson. This is Panel 4, but before moving to Panel 4, I understand from the time estimates obtained by Mr. Fulton that we may finish Panel 5, the main extension panel, early tomorrow, and it would be my suggestion that if we do finish that early that we don't move to Panel 7 until first thing Thursday morning. There are some studies and analyses that have been requested that I don't believe are yet completed.

THE CHAIRPERSON: I think that certainly seems reasonable, so let's assume that we'll go with that approach now.

MR. JOHNSON: Thank you. Panel 4, the members of which have taken the stand, addresses the fully distributed cost studies of BC Gas. Those are frequently referred to as the FDC studies. The FDC studies examine the embedded costs of the utility, and these embedded costs are the costs upon which the revenue requirements of BC Gas and other utilities, for that matter, are normally based.

The FDC studies do not address the future costs, such as the LRIC study did.

The documents that have been distributed with regard to the fully distributed cost studies were initially a binder in March which contained major studies, including the FDC studies.

That binder has not been marked as an exhibit in that it was then supplemented and augmented by the April filing, and the April filing, the fully distributed cost study material is found in Volume 2.

Subsequently there have been some revisions and update the Volume 2 material that has been distributed earlier.

The panel also can address the material found under Tab B2 of Exhibit 4. The material in Volume 2 addresses the costs and the revenue to cost ratios of the existing customer classes at existing rates. The material in Exhibit 4, Tab B2, provides the costs and revenue to cost ratios for the proposed customer classes using the proposed rates that would arise from the rate design changes set out in the application.

There is one other document, one other package of documents which I have distributed. It's entitled "BC Gas Inc. Errata" of Exhibit 2, Tab 2, I don't believe that has to be marked as a separate exhibit. It is some further revisions of the FDC material.

The pages have a revision date of July 12, 1993 on them. And those revisions are marked, if people can turn to the first table. That's the second page in in the package I've distributed.

Proceeding Time 12:35 P.M. T40

If you look in the right hand column about three quarters of the way down the numbers, lines 24 and 25, you'll see two numbers there that have small c's beside them. And those c's indicate changes. There's one also in column I, the next column to the left, and you'll see looking through the other material that there are a few numbers here and there that have had changes in them.

Those changes, I understand, arise from the use of incorrect divisors in certain of the calculations. Some of the calculations should use total volumes being both sales and transportation volumes and in some cases the incorrect divisor was used.

Mr. Moore can explain those more fully if anybody wishes more information on it. So I'll just ask when the people have an opportunity they insert the revised pages in the Tab 2 material.

The witnesses on the stand, I suppose firstly, they should be sworm? Or have they been?

THE CHAIRPERSON: Yes, could we have the witnesses sworn?

FULLY DISTRIBUTED COST STUDIES PANEL
ED MOORE, affirmed
DANIEL REED, affirmed
PETER VAN GENDEREN, affirmed
JOACHIM WESSLER, affirmed

MR. JOHNSON: The witnesses from closest to you, to closest to me are, Mr. Wessler, Mr. Moore, Mr. Reed, and Mr. Van Genderen.

EXAMINATION IN CHIEF BY MR. JOHNSON:

MR. JOHNSON: Q: Dealing firstly with you, Mr. Reed, you're a consultant that's been retained by BC Gas, is that so?
MR. REED: A: Yes.
MR. JOHNSON: Q: And your evidence appears in Volume 3, at Tab 4. Is that so?
MR. REED: A: Yes.
MR. JOHNSON: Q: And do you have any questions or revisions to make to that evidence?
MR. REED: A: No.
MR. JOHNSON: Q: And your role with regard to the FDC study was to provide guidance and direction to the staff at BC Gas in performing the FDC studies?
MR. REED: A: Yes.
MR. JOHNSON: Q: Mr. Moore, you're the supervisor cost of service in the regulatory affairs group at BC Gas?
MR. MOORE: A: That is correct.
MR. JOHNSON: Q: And your evidence is found under Tab 6 of

Volume 3 -- Exhibit 3?
MR. MOORE: A: That is correct.
MR. JOHNSON: Q: Do you have any revisions or amendments to make to that evidence?
MR. MOORE: A: No.
MR. JOHNSON: Q: And you adopt that as your evidence in these proceedings?
MR. MOORE: A: Yes.
MR. JOHNSON: Q: And your primary role with regard to FDC was in gathering data and also you had primary reponsibility for overseeing the running of the program, the model?
MR. MOORE: A: That is correct.
MR. JOHNSON: Q: Mr. Wessler, you're the manager of regulatory accounting and administration at BC Gas?
MR. WESSLER: A: Yes.
MR. JOHNSON: Q: And your evidence is found under Tab 3, of Exhibit 3?
MR. WESSLER: A: That's correct.
MR. JOHNSON: Q: And are there any revisions or amendments to that evidence.
MR. WESSLER: A: No, ~~they're~~ there aren't.
MR. JOHNSON: Q: And do you adopt it as your evidence in these proceedings?
MR. WESSLER: A: Yes.
MR. JOHNSON: Q: And your role with regard to FDC is that

you provided some guidance to Mr. Moore and other employees of BC Gas and you also were involved in reviewing and verifying the FDC results?
MR. WESSLER: A: That's right.
MR. JOHNSON: Q: Mr. Van Genderen, you're a consultant which has been retained by -- or who has been retained by BC Gas?
MR. VAN GENDEREN: A: That's correct.
MR. JOHNSON: Q: And your evidence is found under Tab 5 of Exhibit 3?
MR. VAN GENDEREN: A: I believe that's correct.
MR. JOHNSON: Q: And do you have any changes or revisions to make to that evidence?
MR. VAN GENDEREN: A: No, I don't.
MR. JOHNSON: Q: And do you adopt it as your evidence in these proceedings?
MR. VAN GENDEREN: A: Yes, I do.
MR. JOHNSON: Q: And, Mr. Van Genderen, you've had involvement in various matters for BC Gas for quite some time, for BC Gas and it's predecessor, Inland?
MR. VAN GENDEREN: A: Yes, I have.
MR. JOHNSON: Q: And insofar as the FDC studies were concerned, you assisted in the review of the results, did you?
MR. VAN GENDEREN: A: Yes.
MR. JOHNSON: Q: And I think, Mr. Reed, I forgot to ask you

if you adopted your evidence. Do you?

MR. REED: A: Yes.

MR. JOHNSON: Q: Thank you. There is one other matter. Mr. Reed, on the previous panel, Commissioner Leighton raised a question with respect to Exhibit 1, Tab 6, page 47.

MR. REED: A: Yes.

MR. JOHNSON: Q: And that is a graph which compares rates to the costs of alternate energy sources?

MR. REED: A: Yes.

MR. JOHNSON: Q: And perhaps you could just explain what that table or graph displays.

MR. REED: A: Mr. Commissioner, the rectangle indicated in cross X form for wood, could really be expanded into a larger box and applicable probably from four or six gigajoules per month all the way up to 30. And it was only represented as a rectangle here primarily to indicate the top and bottom. The bottom of that rectangle is about $3.10 -- no, $3.79 to $7.76 is a range at customers in the Inland area who will have to pay for wood for space heating, and furnace oil could be made broad or horizontally. The bottom of the range, the most efficient furnace and the best price for oil would result in a cost to the customer of about $9.28 up to a total of $12.25 for space heating purposes.

Now, let's move to the left where you see a rectangle for BC Hydro. In that part of the service area where the competition is from BC Hydro electrical power for cooking, water heating, and so on, and space heating, the floor is about $9.90 up to inefficient conversion devices and the highest price that a customer would pay for their electrical power depends on where in the schedule they would be using it, it could go up to $15.23. Now the horizonal range is important to look at. At the bottom left of the graph it shows one gigajoule a month and it goes up to about 30 gigajoules per month. And that's the relevant range of sales to residential customers.

Proceeding Time 12:40 p.m. T41

MR. JOHNSON: Q: And could the electric boxes for B.C. Hydro and for West Kootenay Power, could they be expanded across the base as well?

MR. REED: A: Yes, they could be expanded to the right for space heating and so on. And perhaps to the left too if you were considering competition for ranges and dryers and so on. Does that respond to your question, sir?

COMMISSIONER LEIGHTON: It certainly responds to the first part. May I ask a second question now.

MR. REED: A: Certainly.

COMMISSIONER LEIGHTON: Which was really in view of that, what I suspected was intended, we have a situation where BC Gas were proposing to raise rates for natural gas well into the areas represented by those two bands of electrical energy consumption, particularly in the Inland case we're looking at now, and I'm wondering, would you not be concerned that in the low consumer category, that's flats or condominiums, that there would be a tendency to push people into electric energy use for space heating purposes because of the inherent capital cost advantages of installing electric?

MR. REED: A: No doubt.

COMMISSIONER LEIGHTON: Thank you.

THE CHAIRPERSON: If I could just add something there and see the panel's response. The capital cost is obviously a key factor here, and also wouldn't it be the bias for first cost over life cycle cost, the fact that the initial cost of these investments become very important in the consumer's mind as opposed to just what the fuel and operating costs would be.

MR. REED: A: That's true. Mr. Gillies' work though dealt with energy competition and did not involve first cost, or life cycle cost. So a thorough review of his work, we have done a thorough review, you would see it's an energy on energy competition, not converting from gas to electric or to some other devices.

THE CHAIRPERSON: Fine. Thank you.

MR. JOHNSON: I have nothing further for this panel. They're available for cross-examination.

MR. FULTON: Q: Mr. Chairperson, I have prepared an order of cross-examination, and given the references to ball parking this morning and the day, I can refer to this as a line-up, and I've got one scratch to it, and that's the first person, Mr. Weafer, will be replaced by Mr. Kacir.

THE CHAIRPERSON: All right. Go ahead, Mr. Kacir.

Proceeding Time 12:45 p.m. T42

CROSS-EXAMINATION BY MR. KACIR:

MR. KACIR: Q: Batting lead off.

Gentlemen, just a brief introduction. I represent three large industrial gas users in the Columbia Division out in the East Kootenays, and what I'd like to focus on this afternoon is the 1988 Columbia rate design hearing as well had a fully distributed cost of service study done during that hearing. And first of all, are any of you familiar with that study and the methodology used in relation to the 1988 Columbia rate design hearing?

MR. REED: A: Until we find our ways of responding, let me respond first. I'd say yes, we are familiar with it.

MR. KACIR: Q: Right. At that time it was felt that the Columbia industrials were paying far more than their cost of service, and if I can just boil down how the Columbia rate design related to them specifically, it was proposed by Columbia Natural Gas at that time to reduce the rates being paid by the Columbia industrials to result in approximately a ten per cent reduction in the cost of -- which would translate into a 10 per cent reduction in the cost of service being paid by the Columbia industrials phased in ten per cent every year, so a total of 30 per cent reduction in the cost of service over three years, so that at the end of the three years it was intended that the Columbia industrials would be paying approximately 120 per cent cost of service, or would be at a 120 per cent level.

MR. WESSLER: A: Are you asking this as a question?

MR. KACIR: Q: Yes. Is that anybody's recollection, or --

MR. WESSLER: A: That is correct. The company proposed a three year phase in of rate reductions. The Commission allowed only the first two years and did not permit the third year because I believe, if I remember the decision correctly, they felt this was too far out in the future for them to make that decision.

MR. KACIR: Q: Thank you. So basically the Columbia industrials were then left at approximately thumbnail sketch, paying rates which represented 130 per cent of their cost of service.

MR. WESSLER: A: Well, I can't speak to that percentage. You mean at the end of year two?

MR. KACIR: Q: Yes.

MR. WESSLER: A: Okay. I'd have to check that out. I can't say that's so or not. You may recall, however, that in all this period since the 1987 rate design hearing, Columbia, or for that matter Inland, or now BC Gas , never had a revenue requirement hearing either, so while the rates were boxed in or left at those levels, there were no general rate increases which came to that group of companies.

MR. KACIR: Q: How did the price of gas, the commodity cost of gas, track over that same period?

MR. WESSLER: A: Well, the Columbia large industrial customers are the so-called group of Schedule 7 customers, and they have always had a two part rate, namely they were paying for the actual monthly average cost of gas, plus the cost of service which was determined in that 1987 or 1988 rate design hearing. So, they would have paid every month the actual average cost of gas in that period.

Proceeding Time 12:50 p.m. T43

MR. KACIR: Q: Okay. What I am having some problems with, and I -- is that we went from a situation in '87 or '88 where the industrials were well over their cost of service to an FDC study today that shows there somewhere in the 94 to 100 per cent range depending on which method you use. And my questions are, exploring that movement and first of all, have any new costs been incorporated into the FDC study since the 1988 FDC

study?
MR. WESSLER: A: When you say new costs --?
MR. KACIR: Q: Anything above and beyond which was disclosed in the application.
MR. WESSLER: A: The fully distributed cost study as is evidenced in the filing were based initially on the test year ~~end at~~ ended December 31, 1992 and as it -- subsequently updated to the 1993 level. Costs, whatever they were in the 1992 revenue requirement application and subsequent amendments by the Commission in it's August 1992 Decision, were embodied in the FDC studies. So, talking about new costs, I'm not familiar with what one could be thinking of other than those costs allowed by the Commission.
MR. KACIR: Q: Okay. The current FDS study uses for revenues from the Columbia industrials what was paid in the last year. Is that correct?
MR. WESSLER: A: That's correct.
MR. KACIR: Q: So, it doesn't incorporate any projected revenues what would be paid by the Columbia industrials under any new tariff?
MR. WESSLER: A: Not in the FDC study, no.
MR. KACIR: Q: All right.
MR. WESSLER: A: And I believe for that matter, in the proposed rate design so far the revenues are subject to Mr. Dinter visiting the large industrials and looking

over this matter have been temporarily parked, if I may say so, or have been grandfathered to remain as is.

MR. KACIR: Q: Okay. Just to be clear on this, then. The FDC study doesn't take into account any revenues that BC Gas has received from unauthorized overrun charges?

MR. WESSLER: A: No, they do not. In our test year, we do not forecast such occurrences because these are in a way items which one would not want to forecast because they -- the customer should be themself aware of the operating conditions or constraints which are put on the system by causing such overrun charges.

MR. KACIR: Q: But your test year for this study was an actual gas operating year and those -- and you used actual revenues figures didn't you?

MR. WESSLER: A: No. The test year was a forward test year which was forecast 1993 in the final update.

MR. KACIR: Q: Okay. So then similarly revenue represented by demand surcharges collected or benefits realized through daily balancing were not included as well?

MR. WESSLER: A: No, sir.

MR. KACIR: Q: Thank you.

MR. WESSLER: A: But, on unauthorized overrun charges, may I just say something in which flows out of the 1987 rate design hearing. Once those are collected they are supposed to be set aside and later on at the disposal of the Commission would be then redistributed. So, if they were incurred even, they would not be part of the overall revenue requirement.

MR. VAN GENDEREN: A: Excuse me, I wondering have we now moved to a more general question on this? Because to the extend we're dealing with Columbia, there wouldn't be any demand surcharges and I don't believe there's been any unauthorized overrun gas run or anything of that nature on Columbia.

MR. KACIR: Q: That's right. And I was just also inquiring to the scope whether that's -- so that's taken out by assumption by an FDC study, in any event if I understand correctly and that's separate from the reality or the fact that the last gas , there weren't any in any event? Is that right? Mr. Wessler are you nodding?

MR. WESSLER: A: I'm pretty sure that's so, yes.

Proceeding Time 12:55 p.m. T44

MR. KACIR: Q: Next question. Have you changed any method for allocating costs between customer classes in the Columbia Division, and point of reference of course is the 1988 set of studies and the current set of studies.

MR. REED: A: Well, I think the answer is yes. The previous cost study the company filed they rolled in cost allocation. The Commission requested a demand distance factor be involved in the calculations or the distance that certain demands are carried over the various laterals, and in this study we have used and submitted a rolled in study, one with costs rolled in, and demand distance was not taken into consideration period.

MR. KACIR: Q: I beg your pardon, the last --

MR. REED: A: Period.

MR. KACIR: Q: Period. Okay. And that applied equally to all customer classes in the Columbia Division, residential, large industrial, small industrial.

MR. REED: A: Yes.

INFORMATION REQUEST

MR. KACIR: Q: Was there any change in the allocation of administrative charges between the classes?

MR. MOORE: A: I'll have to get back to you. I need to review what was filed in the '87 cost of service study on administration expenses, just to make sure.

MR. KACIR: Q: What I'm looking for there, just to perhaps give you some guidance, is as you may be aware, the Columbia industrials have gone to direct purchasing, first through a buy-sell arrangement, and now an interim letter of agreement which provides for more it more appropriately, and they have taken on negotiating directly with suppliers and a lot of administrative functions themselves, internalizing those administrative costs within each industrial. And my question is: Has that been considered or taken into account while developing these studies?

MR. MOORE: A: The cost in the FDC study in respect to the gas controls has been allocated based on the sales and T-service volumes.

MR. WESSLER: A: But if your question is the company has taken the Columbia Division administrative costs which were in the 1993 test year and reduced them for a prospective or possible reduction in the administrative costs coming up in 1994, the answer is no.

MR. KACIR: Q: And if I'm reading you correctly as well then, as well the Columbia industrials as a group may require less administration now than they did before, and that hasn't been accounted for or shifted over to any other class?

MR. VAN GENDEREN: A: Perhaps I could respond to that because of my involvement with the Industrial Marketing Group, and also with the rate design. Certainly to the extent that gas supply purchasing on behalf of those customers is not there in a general sense, other than for peaking supplies, et cetera, one could make that argument. But there has been a -- it seems to be an overall increase in activity relating to the Columbia industrials by virtue of putting together the transportation -- first of all the interim transportation arrangements that are now in place, and dealing with a number of concerns on that system. And there's also the regulatory concerns. So you might be able to make the point with respect to the long-term direct purchase of gas, but there are other elements of gas supply which are still provided by the company, and there are a lot of other elements of cost that are administrative in nature.

MR. KACIR: Q: I think everybody recognizes that, and my point is simply this, that there used to be more services provided by BC Gas and presumably that would have taken into account more administration.

Proceeding Time 1:00 p.m. T45

MR. VAN GENDEREN: A: I don't think you can make a direct correlation between the provision of gas being from or not from the Utility and a decrease in cost per se. In fact, as I suggest there may have been increase costs.

MR. KACIR: Q: Okay. Just moving on to the next question. Has any plant, fixed plant, been fully depreciated since 1988? Do you track, you know, sections of pipeline or plants that are now fully paid for?

MR. MOORE: A: Yes, that's from our accounting perspective, are booked into a pool of common assets like all the transmission mains would be together on a common account and they are depreciated on that basis of common pool of costs. So I don't think there's any specific tracking of specific line laterals or line segments except for maybe the one exception for the lateral that built to service the Byron Creek which is still in operation and

I think the agreements still have another 10 years to go.

MR. WESSLER: A: Furthermore, if I may add, transmission plant, distribution mains, and services, are depreciated at the straight line of 2 per cent which is a 50 year life. The system is not 50 years old. So even the oldest pipe couldn't have been depreciated fully. As to meters and regulators the estimated life is 33 years, so there's a 3 per cent depreciation rate. There could be some meters which are nearing -- they have not been replaced they could be that old by now and they could be fully depreciated. But as Mr. Moore is pointing out, there the depreciation is applied to the pool of assets accumulated under the chart of accounts which is set out the British Columbia Utilities Commission.

MR. KACIR: Q: Okay, thank you. My final set of questions I guess relates to the relevancy of FDC studies with respect to setting industrial rates in light of bypass options and the other requirements to take into account exterior variables. So my question simply is this, is it appropriate to peg industrial rates at 100 per cent cost of service or is the end verse is the cost of service merely an indication that the rates that are set are appropriate?

MR. REED: A: I don't think this is a panel that should respond to that. There's going to be rate design panels and then industrial rate design panel coming forth soon. so, I think that the appropriate witnesses haven't appeared as yet.

MR. KACIR: Q: Okay. That's all the questions I have, Mr. Chairperson. Thank you.

THE CHAIRPERSON: Thank you, Mr. Kacir. Next questioner would be Mr. Wallace.

Proceeding Time 1:05 p.m. T1A

CROSS-EXAMINATION BY MR. WALLACE:

MR. WALLACE: Q: Thank you, Mr. Chairperson.

Gentlemen, I just have a few questions. I think it's been indicated fairly clearly that you've used three types of fully distributed cost studies, peak responsibility, non-coincident peak, and average in excess, is that correct?

MR. REED: A: Yes.

MR. WALLACE: Q: And would it be fair to say that of the three types the peak responsibility study best matches the system design and methodology?

MR. REED: A: I'd like to refer you to Tab 3, and let me find the page, and -- I'm sorry, Tab 2.

MR. WALLACE: Q: Tab 3 of Exhibit 2 or Tab 2 of Exhibit 2.

MR. REED: A: Exhibit 2, Tab 2. Page nine. At the top of the page you'll see a declining order sort of duration of degree day deficiencies that tend to be imposed on the system, and this is specifically for the Lower

Mainland, but the degree day deficiencies are the same in the -- roughly the same in Columbia and Inland. So it follows this particular pattern.

If you look at send-out, and that's the chart that starts about row 19 on that page down through 28, you will see that the BC Gas system must be designed to meet peak loads, even though the maximum peak loads on it are five or six days a year. Now these don't appear on the system in a chronological fashion, these are just sorted in in the way that the peaks appear on the system.

So I would say from the point of view of the way the system is designed, a peak responsibility method tends to follow the cost incurrence a bit better than an NCD or AED.

MR. WALLACE: Q: Thank you. if you could turn to Tab 2B, which is again it's Exhibit 2, Tab 2B, page 1.1, which is the first page after the index. That, as I understand it, is the summary of the peak responsibility study for Inland.

MR. MOORE: A: That is correct.

MR. WALLACE: Q: And in that study you show, as was shown in the LRIC studies we've looked at previously under columns H, I and J, small T-service, large industrial captive and large industrial non-captive. Are those, in this case, results for that actual class or group of customers, rather than and individual hypothetical customer?

Well, I'll simplify the question. In each case do those reflect all of the customers that fall within the class?

MR. MOORE: A: They reflect for the customers in the class, yes.

MR. WALLACE: Q: And the distinction I was trying to make, and I have brought in the LRIC, was simply there's nothing hypothetical about these customers. These are totals of the group that you're representing.

MR. MOORE: A: Of the actual customers that we're forecasting in those particular classes, yes.

Proceeding Time 1:10 p.m. T2A

MR. WALLACE: Q: And you've used actual incurred costs, in some cases allocated in part to this class and part to other classes.

MR. MOORE: A: Well, the costs are from the 1992 test year.

MR. WALLACE: Q: Okay. And you're using the actual load characteristics as to both size and load factors of the customers within those classes.

MR. VAN GENDEREN: A: You're looking at page 1.1, which is the peak responsibility method.

MR. WALLACE: Q: That's correct.

MR. VAN GENDEREN: A: And the load factors within that group would include both some interruptible volumes and

some firm volumes.
MR. WALLACE: Q: So you've used the actual load characteristics of the groups?
MR. VAN GENDEREN: A: Well, that's right, but the contract demand is what's used to drive the load factor, as opposed to the peak, because it's the peak responsibility method.
MR. WALLACE: Q: Thank you. I understand that. Could you provide for me just a -- seeing as these are actuals, a summary for the class for the Schedule 22 captives and non-captives, the average distance to the Westcoast main line of those customers, and their average contract demand and the average annual consumption? Would that be possible?
MR. VAN GENDEREN: A: In fact I can give you some of those right now. I'm not sure if I can give you average consumption.
MR. WALLACE: Q: Okay. Either way. Whichever is easier for you.
MR. VAN GENDEREN: A: I'll give you what I can here. We're referring to the Schedule 22 captive and bypass groups.
MR. WALLACE: Q: That's correct.
MR. VAN GENDEREN: A: And if I can just refer back to the working papers.
THE CHAIRPERSON: Is this lengthy? Would it be better just to have it as a written --

MR. WALLACE: I'm quite happy. If he's going to look through a table it might be easier just to give it to me on a sheet of paper as a subsequent exhibit.
MR. VAN GENDEREN: A: I think I have at least some of the numbers here. The bypass under the peak responsibility method for Schedule 22, the average bypass distance is 12 kilometres, and the average captive distance for the Schedule 22 is 165.1 kilometres.
MR. WALLACE: Q: Okay. Thank you. And you said on loads you weren't sure.
MR. VAN GENDEREN: A: The average loads are not on these tables. I may have them in my working tables here, but it would take a few minutes perhaps.
MR. WALLACE: Q: Okay. Well, then let's leave that for another time. Thank you.

Now looking at Tab 2 -- or at the same page, page 1.1, it down at the bottom line shows the revenue as the per cent of cost of service, excluding gas costs, as 112 per cent for the captive customers, is that correct?
MR. MOORE: A: That is correct.
MR. WALLACE: Q: And 175 per cent for the bypass customers.
MR. MOORE: A: That is correct.
MR. WALLACE: Q: Now in doing these studies, the peak responsibility study, how did you handle the fact that BC Gas can interrupt Schedule 22, both bypass and

captive, to half volume on five days per year. Did you adjust the contract demand for that? How did you handle that?

MR. VAN GENDEREN: A: No. It was assumed that the contract demand level for the Schedule 22 customers was the correct demand level. In fact that occurs at least 360 days a year, and in some years it's 365 days, so we felt that was the appropriate demand level for the peak responsibility level.

MR. WALLACE: Q: So they were assigned costs as if their contract demand was firm 365 days a per year.

MR. VAN GENDEREN: A: Yes, essentially that's correct, but we didn't assign any costs for the interruptible portion of the load.

MR. WALLACE: Q: Okay. And that's normal in a peak responsibility study.

MR. VAN GENDEREN: A: That's correct.

Proceeding Time 1:15 p.m. T3A

MR. WALLACE: Q: Now, BC Gas does get a significant benefit from the fact that it can interrupt these customers on the five half days?

MR. VAN GENDEREN: A: Yes. And from time to time that's been brought forward.

MR. WALLACE: Q: Is it possible to -- and presumably BC Gas gets a benefit both on it's own system in terms of bringing up capacity and also in contracting for gas

supply in both the gas purchase on the Westcoast system?
MR. VAN GENDEREN: A: Yes. I would concur. It's not so much BC Gas it's the core market benefits. And I think in fact all customers benefit by virtue of keeping costs to a minimum where there's efficiencies to be had that are economic in nature of this sort. The efficiencies are flowed through of course to all customers but the most direct beneficiaries are typically the core market.

INFORMATION REQUEST

MR. WALLACE: Q: Okay. Can you quantify those benefits? An approximately, and again, I can leave that to you to provide subsequently.
MR. VAN GENDEREN: A: Well, some efforts can be put into that. I think it may have been responded to or asked in a different manner but I'm not sure. I haven't seen the response myself.
MR. WALLACE: Q: Thank you. Well, I would like to leave that with you and obtain a response to that.
MR. VAN GENDEREN: A: Certainly.
MR. WALLACE: Q: That completes my questions for this panel, Mr. Chairperson.
THE CHAIRPERSON: Thank you, Mr. Wallace. Next would be Ms. McCool.

CROSS-EXAMINATION BY MS. McCOOL:

MS. McCOOL: Q: Thank you, Mr. Chairperson, and Commissioner. Good afternoon, gentlemen. I don't believe I have met all of you so I'll just introduce myself. My name is Caroline McCool and I represent a number of consumer and community based organizations. Many of whose members are living at very low income levels.

I would like to start in a slightly more general way, than my learned friends who preceeded me and this may reflect something about my client base, I'm not sure. But I would like to talk at the outset or ask you a few questions at the outset about the thinking behind the three different methods of doing fully distributed cost studies, being the peak responsibility, the non-coincident demand and the average and excess demand methods that are described at Tab 2 of Volume 2 of the material. And having regard to that material, there are some nice little descriptions of what each of these methods represent. And I'll just refer you to them briefly and I'm going to ask you if you would like to elaborate on these brief statements in any way.

First of all at page 7, at Tab 2, lines 29 to 31, we see the description of the peak responsibility method as being,

> "A method used in these studies to allocate capacity costs according to the demand imposed on the system by the various classes of customers during the peak day."

Would you agree that that's a fairly straight forward simply statement of the nature of this method of assessing fully distributed costs?

MR. REED: A: Yes.

MS. McCOOL: Q: And again at page, we have a page 10 similar statement to that non-coincident demand from lines 3 to 6 being,

> "A method which utilizing the maximum rates of consumption of all customers being added together irrespective of the peak to find the non-coincident demand."

And similarly at the bottom of that page with respect to average and excess demand, from lines 32 and on, a brief description that,

> "These allocate part of the capacity cost to various customers according to their individual maximum rates of consumption whenever they occur and the rest of the capacity costs being allocated to customers according to their individual total annual energy consumption."

Have I correctly identified the portion of the material that gives a very brief description of those two methods?

MR. REED: A: Yes.

Proceeding Time 1:20 p.m. T4A

MS. McCOOL: Q: Now why would one use one of those three rather than the other two?

MR. REED: A: I think that the approach that I take is to spread a record the results of several different cost studies to see essentially the floor that is cost incurred by BC Gas in the service of various customer classes, and the ceiling. I can illustate that in Volume 1, that's Exhibit 1, and it would be Tab 6. Tab 6, page 42. Pardon me for standing, but my paper is getting too high for my glasses to cope with.

MS. McCOOL: Q: I have the same sort of problem, Mr. Reed. I never know whether to take them off or put them on. I'm sorry, what page are you on, sir?

MR. REED: A: Exhibit 1, Tab 6, page 42. And this shows the head of the graph is proposed schedule number 1, residential rate and cost margins, present rate and proposed postage stamp margin compared with FDC.

The only thing that we're dealing with here is that bottom solid line, the present rate margin. That's 2101 and 2102 when I say the Lower Mainland, and the two dashed lines high on the chart FDC PR and FDC NCD margin. Now you'll notice that the cost differentials of the two methods is that the PR method is slightly higher but the NCD is only slightly lower and it so happens in the factual situation of this case that the AED or the average in excess demand method, falls about on the same line as the NCD. So you'll notice that the difference -- certainly there's difference in the method, but for the factual circumstances of this case it really doesn't make too much difference.

MS. McCOOL: Q: I understand that, that the results of the three methods produce relatively similar bottom lines that are represented in some visual way that I don't begin to understand by this graph, but I trust that it's been done properly and in fact we do wind up with those three lines at the place that they are at line 30 of that graph, and that this is some happy convergence of results. But I think my question was -- and I'll come back to that -- but my question was a bit prior to that. That is, without looking at the bottom line of each of the three methods and whether or not they do converge, what's the logic behind the three methods themselves? What purpose do they serve? What do they illuminate, each of them, that is different?

And I'm not speaking specifically absout out how they're done, you know, whether they're with reference to peak or non-coincident peak or whatever. Why would we want to use one of these three methods? Not necessarily with respect to this particular rate design application rather than the other two, what do we achieve?

MR. REED: A: It's the first sentence in the testimony are the report in the section Tab 2, page one.

"The basic purpose of a fully distributed cost study is to compare the revenue generated by rates to the cost that a utility incurs in serving its customer classes."

That's the basic purpose of any of these methods.

Now I started in my own business in 1963. For 30 years people have been nattering at me about method A, B or C or a number of other methods, and I'm getting old and tired and I like to go home quickly, and so with computers I can quickly calculate the incurrence of cost and say, oh gee, the ceiling is PR for the residential class and the floor is AED in this case, or the NCD, and some people are going to harass me by saying well, what would you do with the NCD on the distribution system and a peak responsibility on transmission and I say well, it's in between. And it falls between these two lines.

So really the purpose is to spread a record the cost incurrence and it provides a directional arrow that oh gee, the existing rate is too low in the front end, it's a bit high in the back end, and the rate designer will make their conclusions from this work. So I'm not trying to be humourous here, I'm just trying to say that there's a lot of people that feel that one method is better than the other, but oftentimes they're looking in the back of the book for their own particular client and they will -- some groups will say oh, I like the peak responsibility better than the NCD or AED and I'm just trying to shorten the process.

THE CHAIRPERSON: Shorten the process by giving all the results.

MR. REED: A: Yes, sir.

Proceeding Time 1:25 p.m. T5A

MS. McCOOL: Q: So, Mr. Reed, I take it then that your evidence is, I shouldn't worry about it.

MR. REED: A: Well, my wife told me, don't worry your poor bald head about this.

MS. McCOOL: Q: But I should just accept that we've got a convergence here and that tells us all something and we should not look too closely behind that, that meeting of the three methods.

MR. REED: A: In a serious way, I think you have to take the results of the studies and look at how it comforts with existing rights. And we do have to be concerned about it. And in the final analysis it gives the rate maker a signal an increase or decrease in certain ranges of the relevant consumption. Does that respond to your question, Ms. McCool?

MS. McCOOL: Q: Well, it certainly does respond to my question. I'm not sure it's quite the answer that I was looking for. But I take it that that is your testimony and I would ask if anyone else on the panel wants to respond to my question.

THE CHAIRPERSON: Just before they do, Ms. McCool, also I guess at least just after one o'clock Mr. Reed was also responding to Mr. Wallace's question about the strong argument or the argument that he would put in terms of peak responsibility. So I'm incorporating that as part of the answer to the question that you posed.

MS. McCOOL: Q: And I noted Mr. Wallaces's question which was directly put and directly answered. It's a different question from the one that I'm asking, which is not which of the these methods do you most prefer or think is most appropriate for this Utility at this point in time. My question was a more general one and I don't think it's inappropriate for this panel to talk about the purpose to which the other two methodologies might be put as well. And that's really what I'm getting at. panel. I don't know how to say it any better than the way in which I have said it which is, what logic do the three methods serve which is different from each other apart from the question of whether or not they, in this particular case, produce more urgent results.

MR. REED: A: Then I have failed you. The peak responsibility was an narrow question of course. Now, it is the way the system is designed. Now, the NCD for example are non-coincident demand it takes into consideration say interruptible customers add a load to the system for say 360 days a year or 355 they tend to be interrupted only peak days and the peak responsibility method just doesn't adequately show the cost -- well, it doesn't adequately show a burden that should be assigned to interruptible customers, and that is basically the purpose of what NCD or a AED method showing how the system is used. The system by and large is not installed merely to serve the peak day, but to serve customers firm and interruptible over the entire year and we wouldn't want to come up with a method that attaches all cost or fixed costs say to the firm customers that are earned during a peak day. Now, in fairness it shouldn't be done. Does that more fully respond to what you would like to see the record reflect.

MS. McCOOL: Q: I think it does, Mr. Reed, thank you. Mr. Chairperson, I should say we're still on the first question of my cross-examination. I'm not going to conclude in any very few moments.

THE CHAIRPERSON: All right. Then this is, I think, a good time for us to break for the day, so we'll continue again with this panel at 8:30 tomorrow morning.

(PROCEEDINGS ADJOURNED 1:30)

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 an Application by
BC GAS INC.
for Rate Design Changes
PHASE B

VANCOUVER, B.C.
JULY 14TH, 1993

PROCEEDINGS

BEFORE:

DR. M. K. JACCARD	Chairperson
MR. F. C. LEIGHTON	Commissioner
MS. E. C. SLEATH	Commissioner

VOLUME 10

Allwest Reporting Ltd.
404-814 Richards St.,
Vancouver, B.C.

Exhibit 31 I believe.

(COLUMBIA DIVISION LOSS OF MARGIN FROM COAL COMPANIES MARKED EXHIBIT 31)

And it can be seen from this document Exhibit 31 that if the coal companies were to leave it would result in a revenue increase to other customers of 6.15 per cent and that includes cost of gas, or an increase in margin of 14 and a half per cent excluding cost of gas.

The next document I have is answers to a number of questions from Mr. Wallace, pages 425 through 427 of the transcript, I won't detail what the questions are but they're all set out on the next document. Exhibit 32.

(ANSWERS TO QUESTIONS FROM MR. WALLACE ON TRANSCRIPT PAGES 425 THROUGH 427 MARKED EXHIBIT 32)

And the final document I have Ms. McCool's consultant or advisor requested further information relating to the LRIC study and in effect requested that the demand costs, the commodity costs and the customer costs displayed in that -- in the study material be depicted on a dollar basis as opposed to a dollar per gigajoule basis and we have an answer to that.

(TABLE LM-1 DETAILED LRIC SUMMARY MARKED EXHIBT 33)

Proceeding Time 8:45 a.m. T3

Exhibit 33 is -- or are copies of the three summary tables for Lower Mainland and Inland and Columbia and there has been added at the bottom of the page or towards the bottom of the page further information on the first page, you'll see a demand cost expressed in dollars per customer per year under residential of $36.80 and a commodity cost of $5.22 and a customer cost of $226.47. And that's -- similar information has been added for each of the customer classes and for each of the three divisions.

And then finally Mr. Moore has an answer to the question from Mr. Kacir at page 1350 of the transcript where Mr. Kacir asked if there had been any change in the allocation of administrative charges between the classes, and this is relating to Columbia, and it was a question asking is there had been a change between the fully distributed cost study used in 1988 and the present one. Mr. Moore?

MR. MOORE: A: Yes. Mr. Chairperson, in the Alan Schultz study that he performed based on the test year 1987 for Columbia, he broke up the administrative and general expenses into three parts, the insurance, the employee benefits and all other to balance into the total of A and G. The insurance was allocated based on arithmetic average of the the system peak weighting factor and the commodity weighting factor.

The employee benefits was prorated based on the payroll related to the transmission function, distribution, marketing and customer accounting and then each of those was allocated based on the own and expenses related to those functions.

The all other was again an arithmetic average of allocated plant in service and own expenses excluded the A and G. In the present cost study, there are two Information Requests where we have described how the ministry and general expenses was allocated and they can be found in Volume 4, Part A, Tab 11 and Volume 5, Part B, Tab 21. Both questions related to the Lower Mainland Division but the same procedure was used in all three divisions. The 1987 test year allocation to the large industrials in the Columbia system was 23 per cent of the A and G where we exclude the employee benefits --

MR. JOHNSON: Q: You say A and G, that's Administrative and General.

MR. MOORE: A: Administrative and General, that's right. And the reason why I've excluded the employee benefits is because in the 1992 test year the employee benefits no longer appears as a separate account in the administrative and general because the employee benefits are already loaded based on labour to all the various accounts and cost centres where there's labour. So it's already in the transmission, it's already in the distribution expenes, et cetera.

And the total dollars for in the '87 test year was about $167,000 and, again, as I said it was 23 per cent of the total. In the current study, I'm using the methodology for Columbia. The A and G that's been allocated to the large industrial is $177,000 and it represents 21 per cent of the total. So on a per, I guess, a pro rata share not much change has actually taken place between what Alan Schultz had done and what I have done now.

MR. JOHNSON: Q: Thank you, Mr. Moore, and that completes my preliminary matters.

THE CHAIRPERSON: Thank you, Mr. Johnson. I believe we're ready to recommence the cross-examination of this panel, Ms. McCool.

Proceeding Time 8:50 a.m. T4

CROSS EXAMINATION BY MS. McCOOL CONTINUED:

MS. McCOOL: Q: I'll just go back very briefly to the point that we were discussing yesterday at the end of the day, which is the basis on which -- there are different methods of analyzing fully distributed costs, and I guess we'd reached a point, Mr. Reed, where we had agreed there were different reasons underlying the various methodologies that might lead one to choose one over the other. I don't know that I need to revisit your comments, but I'll just confirm that there are -- these are not just different ways of sort of quantifying numbers or generating statistics, but there are actual reasons which underlie different methodologies, and one might prefer one method over another for various reasons of principle.

MR. REED: A: Yes.

MS. McCOOL: Q: Okay. And those reasons would depend on one's view of how one ought to attribute responsibility for historic or embedded costs to all of the rate classes, is that right?

MR. REED: A: I don't know whether it's -- I'm not trying to impart my view, I'm trying to spread a record different studies that illustrate the points of view of various parties. I don't think that it should be said it's my view. Maybe you said one in general and then I'd say yes to your questions.

MS. McCOOL: Q: That's what I meant.

MR. REED: A: Okay.

MS. McCOOL: Q: I realize that you're here as a professional consultant and in a sense I wish to draw on your professional expertise, rather than tying you personally down to any one position. But I am though concerned about the position that has been taken, or rather not been taken, by the company itself. And it's apparent, and we've discussed this previously in this hearing, that BC Gas has not come down with a recommendation as to which of the three methods it ought to use, and I'll invite anyone from the panel to respond to this.

The explanation that's been offered so far in testimony has been that the three methods generate relatively similar outcomes, or indicate a directional tug. Is that the evidence of this panel as well? And I would take it, Mr. Reed, from your comments yesterday that it probably is.

MR. REED: A: I think so. The outcome is essentially the same. I don't think that we take a position. We try to explain the various theories behind various methodologies, and in the wisdom of the Commission I think if you feel that you must choose one over the other fine, but what I had in mind at the outset was to try to develop a system by which BC Gas could calculate fully distributed cost of service study on an ongoing an a go forward basis, so that the company could spread a record cost under various methods and you could use the studies from year to year or from rate case to rate case to judge the increased or decreased cost incurrence by class.

One of the most useful parts of a fully distributed cost study is to see how it changes over time, and we try to develop a system that will give you stable results, or relatively stable results from year to year, and if different outcomes incur in the ensuing years, then you can have a view of the -- or a judgment of the cost incurrence changes by class. That's what we were hoping to set out, both for this case and for the long-term.

MS. McCOOL: Q: So would it then be your expectation that the utility would be coming back say in the context of revenue requirements hearings with all of these studies generated once again on an annual or an every two year basis?

Proceeding Time 8:55 a.m. T5

MR. REED: A: Well, I don't know the timeframe, but certainly if they are called on to produce a cost of service study it's programmed, and once you have the chart of accounts input and you evaluate load factors and things of this nature, then you can see how it changes from one year to the other. It essentially is in financial accounting, you like to see changes from one year to the next, so that's what I hope to do. So I can't define what time periods the company might file cost studies in the future.

MR. WESSLER: A: If I may add something to that.

MS. McCOOL: Q: Of course.

MR. WESSLER: A: From a company's point of view, while I'm relying on Mr. Reed as being the expert and advising us how to go about matters, but from a company's point of view I can well foresee that we will keep these cost of service studies up, if not annually, at least every other year, so that we have a feel of where things are going over time, and that matters do not go out of hand, so that if corrective action needs to be taken in the future we don't come in ten years from now and say oh my goodness, what's happened here again. So we hope to update these periodically, if not annually.

But back to your first question. When Mr. Reed recommended that we do three studies, and that was fine with me, and because you want to see how different methodologies -- the results of different methodologies. Now we have come before this -- with this application here, and we're saying, I believe, I think I'm in line with Mr. Sarikas' testimony here, that in setting rates there are various objectives that one would like to achieve, and when we can come along with our fully distributed cost of service studies, which are embedded costs, they're historic costs, because that's the basis on which the utility is regulated, first of all. Then we say in all, if I may say so, humility, we say that while we have made an honest effort in making this study, and as best as we can tell we have done as good a job as we can, nevertheless judgment has gone into it and the cost of service studies are pointing directionally of what ought to be done in the rate design.

And I think that satisfies me that we have done three studies, we're not necessarily picking one strictly over the other and say we must use this and no other, but all three seem to be pointing within a range in the same direction. So the cost of service studies, without taking away from their integrity, are not the be all and the end all, and therefore, I think, from a company's point of view, I'm quite happy with what Mr. Reed has recommended.

MR. REED: A: I'd like to add one thing. The studies -- the study and the program is designed to use a forward looking test year. In fact 1992 is recorded in actual results, but we have updated for the estimated 1993 results, and in the future the company can introduce estimates of forward looking periods, financial and in accounting matters, and be able to eliminate the objection that a lot of people have to fully distributed cost based on embedded results or historical results. It will have a forward looking aspect to it when we're preparing the study when the programs are run on a forward looking year.

MS. McCOOL: Q: If we were to come back say next year or in two or three years and look at -- well, no, let me start it this way. If the result of this hearing were -- or part of the result of this hearing were that say the peak responsibility method was the best way to go for this utility and a direction was given by the Commission that rates were to be set strictly in line with that method as opposed to any other -- now I'm not suggesting that that will be the outcome of this hearing, but just supposing that as a possibility, and then the company were to advance into the future and we came back in a year or two or three and looked at the results of these three studies again, am I right in thinking that the results might diverge much more significantly than they do today. Is that correct?

MR. REED: A: By and large they don't. Once you have load data, good load data, and financial data, actually the results are fairly close together, as you can see by the graph I illustrated yesterday. They aren't wildly different, and I don't think that you could say that -- I have looked at cost studies done in different ways, different methodologies over quite a period of time, and the result indicators you get from them aren't that wildly different over time.

Proceeding Time 9:00 a.m. T6

MS. McCOOL: Q: Well, I guess what I was asking was this, the peak responsibility method, for instance, shows a bottom line for, say, the residential class which displays a significant deficiency. I don't remember what the figures are but, you know, 75 per cent or something like that, 78 per cent. If that were to be, if one could, and it were to be corrected in some absolute way so that the deficiency was entirely eliminated and we came back after a year or two or three and did the same studies, would there not then be a significant -- and I don't know the answer to this question. Would there not then be a significant divergence in the outcome of the peak responsibility as opposed to the NCD or average excess demand studies?

MR. REED: A: It's almost a compound question. It assumes that there will be a correction all the way to the cost of service in this proceeding. And the, especially the Lower Mainland residential rates are so out of whack that it's impossible to do that in one fell swoop. So, I have difficulty with questions assuming that you'll move to cost based rates based on one methodology right now. Assuming it's done, I don't see why the results of three methods would be that much different if we produced a cost study in three years from now. All you would be doing is introducing the then existing revenue and forecast costs to compare the revenue with costs. I don't think you should fear that there'll be a divergence in the future between methods.

MS. McCOOL: Q: Okay. Well, I hadn't expected that answer actually, but I accept it as your evidence. My next question was going to be if there were a divergence that one could anticipate then at that point in time, how would we determine which of the three of FDC methods we would follow or adopt. But I don't think I can get to that question in light of your answer to my previous questions.

MR. REED: A: Good. Let's move on.

MS. McCOOL: Q: Mr. Reed, I should say I very much appreciate the assistance you're providing to me, at least, in this hearing and I hope that today you're not feeling harrassed by me if you were yesterday.

MR. REED: A: And I wasn't yesterday.

MS. McCOOL: Q: Thank you. Now, my next question goes back to, is it Mr. Wessler's --?

MR. WESSLER: A: Right.

MS. McCOOL: Q: Comments. And I apologize for not keeping all of the names completely straight yet.

MR. WESSLER: A: That's okay.

MS. McCOOL: Q: You made a statement, and correct me if I've got it a bit wrong, but that the cost of service studies are not the be all and end all, and I certainly would agree with that. But I wanted to ask what that suggests in terms of the relationship between these studies and their results and the actual setting of rates. What use are they then and what relationship do they play in the thinking of the company between the full distribution of historic costs on the one hand and the actual setting of rates? Now this may be a question that you would like me to put to another panel.

Proceeding Time 9:05 a.m. T7

MR. WESSLER: A: Possibly. But as I mentioned, I'm not the rate design person. My background is accounting, and accounting background sometimes is offensive to lawyers and also to economists --

MS. McCOOL: Q: Not to this lawyer.

MR. WESSLER: A: But I emphasize that these studies directionally point -- or show a certain direction, and within a certain range I'm saying the company -- what the Rate Design Panel is proposing directionally works along with what the FDC studies, each and every one within a range of -- you saw the graphs yesterday -- within a certain range seem to accomplish, ought to accomplish as well.

MS. McCOOL: Q: It may be that my question is a more mechanical one, and I just don't understand how one gets from the results of a variety of studies sort of to the actual rates that the company would then propose.

MR. REED: A: I think the Rate Design Panels are the appropriate group to address the question to.

MS. McCOOL: Q: So this panel doesn't want to --

MR. REED: A: They're the one responding to the questions.

MS. McCOOL: Q: Fair enough.

MR. WESSLER: A: In spite of what Mr. Reed said, we emphasize that we're not recommending totally cost based rates, and in that regard the range which is depicted by these various studies in my mind is what we're looking for.

MS. McCOOL: Q: I believe it was you again, Mr. Wessler, that said a moment ago that a certain amount of judgment goes into these studies, and I don't mean to put words into your mouth, but I don't think that's a very controversial statement either. It seems to me that the whole process of functionalization and classification and allocation is one which is laden with human judgment at different points in time. And I wonder -- well, first of all, if any of you would like to comment on that.

MR. WESSLER: A: It is certainly judgment which goes into these studies. However, again being an accountant I'd like to point out that we are tying our total studies into some numbers which have been established previously, so within these pre-established numbers, namely the 1993 test year numbers, or 1992 test year numbers, that within that there's a certain judgment which goes into various allocations no doubt, even though the judgment is not pulled out of the air. We've relied on Mr. Reed's advice and his expertise where other people have applied similar judgment, and so we're not hanging in the air totally with our studies.

Back to Mr. Sarikas. When I talked to him the other day he said apparently there are 42 different ways of doing cost of service studies, and he at one time had accounted for all 42 of them. So there is a very wide range of how cost of service studies can be performed, but I believe Mr. Reed advised us to use the more common ones.

MS. McCOOL: Q: I think we're all grateful for that advice. I would like to try and track one item through the peak responsibility method, and partly it's because I had a question about the outcome of the particular item. However, it will also serve to clarify for me at least the methodology used. And the item that I had a question about, I'm looking now at Tab 2 of Volume 2, and I'm looking at Tab 2A, page 2.0 which is Lower Mainland cost of study and it says rate base - function?

Proceeding Time 9:10 a.m. T8

MR. REED: A: Can you tell me the page again please?

MS. McCOOL: Q: Well, yes, there are several references in the upper right hand corner.

MR. REED: A: Yes.

MS. McCOOL: Q: Tab 2A, Section 2.

MR. REED: A: Section 2.

MS. McCOOL: Q: Page 2.0.

MR. REED: A: Page 2.0.

MS. McCOOL: Q: And then if you turn it sideways on the upper left hand corner it says BC Gas Inc. Lower

Mainland Division Functionatization of Rate Base?
MR. REED: A: Yes.
MS. McCOOL: Q: Gas Plant and Service?
MR. REED: A: Yes.
MS. McCOOL: Q: And just to make sure, this doesn't appear to be a page which was revised. In the lower left hand corner mine says, date 15 March 93.
MR. MOORE: A: Yes.
MS. McCOOL: Q: And the the account, and I presume that's the right word to use, the BCUC account that's dealt with here is storage gas. And I would take it that the bottom line figure under total, and I assume that total means the total amount in the account, is gross plant of some $16,454 with certain depreciation to a net book value of $14,000 and a bit, and I assume those are in millions of dollars.
MR. MOORE: A: Thousands of dollars, yes.
MS. McCOOL: Q: I beg your pardon?
MR. MOORE: A: They're in thousands of dollars, so it's 14 million 39 dollars.
MS. McCOOL: Q: I'm sorry, that's what I meant. Now, we see that all of the figures here appear under the function of gas supply reading down column number three and none of them are just -- no portion of storage gas has been functionalized to any other function?
MR. MOORE: A: That's correct.

MS. McCOOL: Q: And I'm just looking under the -- at the heading of column three, LNG/EKL, that means liquid natural --
MR. MOORE: A: Gas.
MS. McCOOL: Q: Gas and East Kootenay --
MR. MOORE: A: Link. That's correct.
MS. McCOOL: Q: Link. Yes. Okay, so 100 per cent of that account has been functionalized to gas supply?
MR. MOORE: A: That is correct.
MS. McCOOL: Q: Now, if we go the next stage of the process which is classification. I --
MR. MOORE: A: Section 3?
MS. McCOOL: Q: That's right, Section 3. I and -- correct me if I'm wrong, but it seemed to me that at page 1.0 we see this item being --
MR. MOORE: A: I'm sorry, you're losing me. 1.0?
MS. McCOOL: Q: Oh, Section -- Tab 2A, Section 3, page 1.0. And this is, again, Classification of Rate Base. And I'm just trying to find the same item that we were talking about in terms of functionalization in the classification stage and take it -- would take it that at that page what was called storage gas on the previous page that we were talking about, appears here at line 1 as part of gas supply. Where we see LNG/East Kootenay Link?
MR. MOORE: A: That's correct.

MS. McCOOL: Q: Okay. Now this gas supply item on this classification page includes, I presume, more than the storage gas referred to on the functionalization page?

MR. MOORE: A: That is correct. In fact, the 34919 ties into -- just go back a few. If you were to look at Section 2, page 1.0, at line 24 --

MS. McCOOL: Q: Just let me find it. Section 2, page 1.0. Yes.

MR. MOORE: A: That's right. And you go to column three again, you see the same number in the $34.9 million dollars and so the other parts are all the gas plant in service that you have not referred to, such as the transmission for the East Kootenay Link, plus any pro-rated general plant costs as well. Then there's all these other items listed here on page one as well that go into the $34.9 million.

Proceeding Time 9:15 a.m. T9

MS. McCOOL: Q: Okay. Going back to Section 3, page one, the classification page. Are you able to say what portion of the gas storage that was functionalized on an earlier page has been classified into demand and commodity. And I guess my question is: Is any portion of that gas storage classified by commodity causation?

MR. MOORE: A: All right. I'll answer the question this way. If you're at Section 3, page one, just go to the next page.

MS. McCOOL: Q: Yes.
MR. MOORE: A: Which is page two of Section 3. And you see at the very top the words -- maybe I should wait until everybody is there. Okay. You see at the very top "Total Net Gas Plant in Service". And at line four you have the $27.3 million. All of that is in demand.
MS. McCOOL: Q: At line six?
MR. MOORE: A: Yes, line five and line six, yes.
MS. McCOOL: Q: Yes.
MR. MOORE: A: So you can --
MS. McCOOL: Q: That's all been classified as demand.
MR. MOORE: A: Yes, that's right. So the LNG plant that you were referring to from page two has been classified as demand.
MS. McCOOL: Q: Okay. All of the LNG East Kootenay Link portion of line one on page one has been classified as demand.
MR. MOORE: A: For the plant, yes.
MS. McCOOL: Q: Okay. Then moving to the third stage of the process, I have looked at the allocation factors at Section 8, page one.
MR. MOORE: A: Yes.
MS. McCOOL: Q: And you'll have to correct me if I'm at the wrong page, but it seemed to me that that was the next page that I would go to from the classification stage. And if it is true that 100 per cent of the gas storage

that we've been talking about was classified as demand, would I be right in saying that 100 per cent of that 100 per cent would be allocated to the core market under the peak responsibility method?
MR. MOORE: A: That is correct.
MS. McCOOL: Q: Because it's demand related, and it's 100 per cent demand related.
MR. MOORE: A: The interruptible customers are not on the system at the peak day.
MS. McCOOL: Q: Right.
MR. MOORE: A: So it would be charged against the residential general service and the medium industrial, your firm customers.
MS. McCOOL: Q: Okay. So I understand the process, at least for this one item. My question then is this: Is not that gas storage used for purposes other than peak demand? Isn't it used to balance, for instance, winter and summer load?
MR. VAN GENDEREN: A: I believe I could respond to that, and the answer is yes, storage and particularly LNG plant is occasionally used. I think Brian Hanlon can refer to that a bit more, but it's occasionally used to balance supply and demand, including maintaining sales to interruptible customers from time to time.
MS. McCOOL: Q: I have had a look at Exhibit 25 in this context and I don't know if you have a book of exhibits

there, but it's the "Design Weather Send Out" graph, and I can show you my copy.

I believe the original of this document is probably coloured in some way, but the photocopy is not too unserviceable in terms of distinguishing, and some of you may not have been here when this was entered as an exhibit, but you'll see a correlation between the categories of gas in the bar at the top with the graph itself. It's quite a stunning visual graph actually.

And I would take it that at the very left-hand side above the number one at the bottom we have a visual representation of the peak day.

MR. VAN GENDEREN: A: Yes. That looks like a design day, that's correct.

MS. McCOOL: Q: Design day meaning the day that the system is designed to meet when all of the requirements are in place at one time.

MR. VAN GENDEREN: A: That's right.

Proceeding Time 9:20 a.m. T10

MS. McCOOL: Q: Peak day or peak hour, or whatever it is?

MR. VAN GENDEREN: A: Yes. From the appearance of this, it would look like a gas supply design peak day.

MS. McCOOL: Q: And we see --

MR. JOHNSON: Just so you understand, Ms. McCool, Mr. Van Genderen is referring to gas supply design day and that maybe somewhat different than system design day, system referring to the pipe in the ground.

MS. McCOOL: Q: Yes. Yes. I appreciate that. I was going to use this simply to have as a reference point for the use of seasonal gas and the storage gas, well storage gas in particular. And would you agree with me that this exhibit suggests that storage gas is, in fact, used over more of the year than peak day or peak hour?

MR. VAN GENDEREN: A: Oh, that's for sure. That the storage gas is used for various purposes including balancing as we referred to a minute ago. It's also occassionally used for sales to interruptible customers. But this design weather send out, I'm certain that on the top 10 or 20 or 30 days and perhaps even this whole graph excludes interruptible deliveries because we don't -- or BC Gas would not design it's gas supply on a peak day to include the interruptible load. So, it's only on an "as available" basis that those storage supplies are used to supply interruptible markets.

MR. REED: A: Ms. McCool, I think that I can respond in a way that in -- the storage is used to serve the peak requirement. If you wanted to put a weight on it, it would be about 99.5 or 99.9 per cent of the investment is used to supply natural gas on peak days. Now this is one of the elements of judgment that goes into a cost study. We did allocate that 100 per cent to the firm customers. There is some incidential uses but the value

of it is very minor as compared to the supply of gas to the firm customers on the few peak days a year.
MS. McCOOL: Q: But gas storage is not used simply to service peak demand. Is that right?
MR. REED: A: In the strict and narrow definition of your question, that's right. But the primary purpose of it -- a high percentage is to supply the peak demand on the peak days. Supply part of the peak demand on peak days.
MS. McCOOL: Q: Well, if part of gas storage, and I'm not talking now about what percentage or absolute numbers would be appropriate, but if part of gas storage is used to, say, balance winter and summer load and serve all classes of customers or at least some other than core market customers at times other than peak, why is it that 100 per cent of those costs are allocated to the core market?
MR. REED: A: Well, I tried to respond a moment ago, saying that the objective of the allocation process is to spread the cost of facilities to the customers that use it and if you would see the operation of the storage on peak days, I think you would recognize very quickly that the investment is there, you know, supply the peak requirements.
MS. McCOOL: Q: Is there some particular reason why the allocation factors of BC Gas don't include any seasonal allocation? And you're probably aware that other gas

utilities do have such allocators.

Proceeding Time 9:25 a.m. T11

MR. REED: A: On occasion utilities allocate a portion of the cost to one season and the other, but here again, if you're talking about judgment, that's an enormous exercise of judgment.

MS. McCOOL: Q: Well, that may be true. I'm not sure of the enormity of it. I mean as a matter of fact isn't it true that there are gas utilities in other jurisdictions in Canada that have seasonal allocators? I believe Centra and Consumers.

MR. VAN GENDEREN: A: If I could perhaps respond to that, that's correct. I've seen some rates with seasonal gas commodity costs being flowed through to customers in the rates. But in many cases, and I'm not sure if it's in all cases, but in a lot of cases that is simply a flow-through of seasonal gas cost pricing obtained from producers.

In other words, because the producer or marketer is selling to the utility on a seasonal cost basis, it's flowed through to the consumer on that similar basis. But in the case of BC Gas at least the base load supply is purchased on an annual basis and the costs on a commodity and on a demand basis do not vary on those contracts over that year.

MS. McCOOL: Q: Are you talking about the cost of gas?

MR. VAN GENDEREN: A: Yes.
MS. McCOOL: Q: Okay.
MR. VAN GENDEREN: A: Isn't this what we were referring to?
MS. McCOOL: Q: I'm talking about the gas storage figures that I was just referring to.
MR. VAN GENDEREN: A: Yes. And the rates reflect typically the gas, as well as the cost of facilities, and the rates I believe you're probably picking up in most cases are reflecting differentials in gas purchase costs. There may well be other differentials.
MS. McCOOL: Q: Okay. I just have a couple of other questions, and this one you may want to suggest that I should raise it with the next panel. But since we're talking about the allocation of demand or capacity -- I'm sorry, Mr. Van Genderen, did you want to say something else?
MR. VAN GENDEREN: A: No.
MR. REED: A: We were just discussing a matter. Go ahead, please.
MS. McCOOL: Q: I'm happy to hear what you want to say.
MR. VAN GENDEREN: A: Well, Mr. Reed was trying to get us back to rate base items, which is the topic of your discussion, and I was veering on to the gas supply side of it because I think that may have influenced the rates you're seeing from other utilities, but I certainly cannot confirm that in all cases that's the cause of the

seasonal rates.
MS. McCOOL: Q: Thank you. Since we've been talking about allocation of demand and capacity costs, I just wanted to raise one other item, and as I say, if you want to put me over to the next panel I'll certainly accept that, but my understanding is that, for instance 100 per cent of the distribution system, or the costs of the distribution system, would be allocated to the core market, is that right?
MR. MOORE: A: No, not quite.
MS. McCOOL: Q: Oh, okay. Correct me then.
MR. MOORE: A: The services and meters, those type of accounts that are the closest to the customer have been treated as a customer classification.
MS. McCOOL: Q: Of course.
MR. MOORE: A: So it's the mains and -- distribution mains have been treated as demand.
MS. McCOOL: Q: So the distribution mains would be allocated 100 per cent to the core market for the costs of them?
MR. MOORE: A: No, that's not correct.
MS. McCOOL: Q: Please correct me again.
MR. MOORE: A: They have been charged to all the accounts except for PCEC and Burrard, which take their gas at transmission pressure. Those two accounts don't use the distribution system.

MS. McCOOL: Okay. All right, well, I'm just going to leave that. And I believe that those are all the questions that I had for you, and I'll thank you for your patience. Thank you, Mr. Chairperson.
THE CHAIRPERSON: Thank you, Mr. McCool. I believe the next person is Mr. Rawlyk.
MR. RAWYLK: I have no questions, thank you, Mr. Chairperson.
THE CHAIRPERSON: That leads us to Mr. Fulton.
MR. FULTON: Thank you, Mr. Chairperson.

Proceeding Time 9:30 a.m. T12

CROSS-EXAMINATION BY MR. FULTON:

MR. FULTON: Q: I would like to start off by returning to Exhibit 2, Tab 2, the first page. And, Mr. Wessler, earlier in your evidence this morning you referred to the fact that there are some 42 different cost allocation approaches?
MR. WESSLER: A: That's what Dr. Sarikas told me and he said with great pain he had one time found what they all were.
MR. FULTON: Q: Yes, I'm sure it was a painful process for him. The application at Tab 2 indicates that the National Association of Regulatory Utility Commissioners and the American Gas Association, neither of them specify one of those allocation methods over any other allocation method. And my first question was, why was

it that the three methods that are discussed in the application where the ones that were chosen from amongst those 42, shall we say?

MR. REED: A: I can respond to that. Methodologies that are widely used, are the peak responsibility, the non-coincident demand method and the average and excess demand method. There are a number of other methods in the electric industry such as base intermediate peak and so on. But in natural gas, these three methods that they use pretty widely. Enough so, that the American Gas Association in it's rate manual illustrates the three methods that we used in our testimony. Not only that but these are fairly widely used in other jurisdications in electric and in gas and are enumerated in the NARUC manual. So, I think that we find by these methods the floor, and pretty accurately, the floor and the ceiling of cost incurrence by class and the other methods that we didn't use here will by and large fall in between.

MR. FULTON: Q: All right. Picking up on the floor and ceiling comment, Mr. Reed. Is it the position of BC Gas that the three methods that were adopted represent the extreme so that it is unlikey, for example, that costs allocated to a particular class of customers would fall outside of the range established by the three methods that were used if another method was used, one of those

other 42 methods?
MR. REED: A: Well, more than likely they fall within the range using this methodology.
MR. FULTON: Q: Thank you. At page 4 of Tab 2 of Exhibit 2, there is the indication that the customer served under the existing rate schedules have been arranged into pro forma customer groups which reflect the new rate schedules and the revenue to cost ratios for those pro forma groups have been calculated. Why couldn't you simply assume that all the existing, or all the current customers of an existing rate schedule would be served on the same proposed schedule as opposed to taking the approach it was taken?
MR. REED: A: May I ask a clarifying question at this point? With regard to the Lower Mainland presently, the one rate schedule serves a residential, commercial and a small industrial like 2101, 2102, 2207, 8, 9. You're asking, why could this not have been a scheme of things applied to Inland and Columbia?
MR. FULTON: Q: Yes. Well, using the rate schedules that would be applied at the present time to the Columbia and to the Inland systems. You can break the question down into the different divisions if that makes the answer more easy for you, or easier.

Proceeding Time 9:35 a.m. T13

MR. REED: A: Well, if it's dealing with the Lower Mainland they operate under a tariff that is a declining block rate that by and large was designed for service to the specific customers, having in mind certain things. And facts have changed so drastically that now it seems this is not appropriate to go forward on the basis of having one common rate applicable to all service. Does that respond to your question, Mr. Fulton?

MR. FULTON: Q: That's fine. Yes. And would the answer then be the same in terms of Inland and Columbia?

MR. REED: A: Yes, yes, I think it would be the same.

MR. FULTON: Q: And in establishing the various pro forma groupings, was it necessary for you to take customers from some of the other classes and put them in the grouping in order to establish those pro forma groupings, some of the existing customers from various classes.

MR. REED: A: For clarification, the pro forma groupings of customers, the grouping of customers in any migration that would occur between schedules was prepared by a group other than these people here before you right now, and we used those studies, and I think it would be more appropriate to direct this question to the rate design panel, perhaps series of questions.

MR. FULTON: Q: All right. And they would be able to tell me the steps that they took in order to establish the pro forma groupings as well.

MR. REED: A: Yes.
MR. FULTON: Q: Page five, at lines 21 to 27, there is the statement that;

"The functionalization procedure begins with plant and operating expense accounts. The investment associated with each facility is assigned to a function, for example gas supply, gas supply administration, transmission and so forth, and that after assigning plant costs functionally a related expense usually follows the same functionalization logic."

Would you agree that the primary purpose of functionalization is to ensure that each customer class is allocated only those costs in supplying service to that class?
MR. REED: A: Well, let's just deal with the word function. The utility has certain functions such as transmission or distribution, and I can only answer your question within that limit, that the rate base chart of account, and then the operation, maintenance or revenue requirement requirement chart of account, merely get converted into what a function is, and at that moment one is not concerned with how it's being allocated, but if you're trying to get all of the dollars into the right bucket, so to speak, or function of the utility.

Proceeding Time 9:40 a.m. T14

MR. FULTON: Q: Well, I'm not sure that that does answer my question. Isn't what you want to do in terms of functionalization though to make sure that you separate, for example, distribution costs from the transmission costs so that the transmission customers don't pay for the distribution?

MR. REED: A: Yes.

MR. FULTON: Q: Mr. Wessler, can you say to what extend the accounting records of the Utility at the present time are already organized in terms of the broad functions that I referred to -- or that are referred to at lines 21 through 27? And to what extent judgment is necessary to separate those costs into the broad basic functions?

MR. WESSLER: A: The company follows the chart of accounts or the code of accounts as set out the British Columbia Utilities Commission. And that chart of accounts, a certain group of accounts are under the caption of Transmission Expense, others are under the -- another group of accounts are under Distribution, Administration et cetera. So, the broad guidelines are given in that chart of accounts. When you say, how we interpret this, generally there is not that much interpretation needed. If the meter and regulator for a residential customer automatically is in distribution accounting the only grey area as best as I know may come up in certain

sections where you have intermediate pressure in the pipeline and, I'm not an engineer here so I'm giving my laymen's interpretation. But, that sometimes could be classified as transmission, sometimes you could argue it's distribution. So, there is a bit of a grey area but beyond that, it's my understanding, that the chart of account lays it out quite clearly where the records must -- in what account the records must be kept.
MR. FULTON: Q: Okay. Let's turn to a specific example. Tab 2A, Section 2, page 2.2, which is the Lower Mainland division functionalization of rate base.
MR. REED: A: Can you restate your cite on page number --
MR. FULTON: Q: Tab 2A.
MR. REED: A: Yes.
MR. FULTON: Q: Section 2.
MR. REED: A: Yes.
MR. FULTON: Q: page 2.2.
MR. REED: A: Thank you.
MR. FULTON: Q: And if you drop down to line 28 through 30, that refers to mains. And the mains are allocated partly to gas supply and partly to transmission. Can you indicate, Mr. Wessler, how that allocation would have been done?
MR. WESSLER: A: I'll refer that to Mr. Moore.
MR. FULTON: Q: Okay, thank you.
MR. MOORE: A: The transmission under column three relates

to the East Kootenay link.

MR. FULTON: Q: Yes.

MR. MOORE: A: And on the far column there's a direct assignment of about $1.4 million and that was in the '92 test year as being the sort of medium rate base for acquiring the PCEC spur line. So, it relates to PCEC as a direct assignment. And the balance goes into the transmission.

MR. FULTON: Q: Thank you. Turn next to page -- or Section 3 of Tab 2A, page 5.2 and I'm moving ahead now from the functionalization stage to the stage where you divide the functional cost into the cost causation categories in which you've got the three main categories of demand related cost, commodity related cost and customer related cost and the application indicates that the fixed costs are usually assigned to demand classification except at the distribution, customer accounting and marketing levels where certain facilities are designed and operated with the requirements of customers in mind.

Now, the table that I referred you to shows that the distribution costs are allocated, and you can take my arithmetic as being subject to check, but 57 per cent to demand related costs and 43 per cent to customer related costs. Would you agree that, Mr. Moore, subject to check?

Proceeding Time 9:45 a.m. T15

MR. MOORE: A: Subject to check, yes.
MR. FULTON: Q: And then if we turn back to page five of that same section, services, at line 37, and the meters, which is page 5.2 again, the services and meters are allocated to customer costs while the mains and regulating equipment are allocated to demand. And the allocation of the mains to demand is on page 5.1, and the regulating equipment as well is on page 5.1.
Can you tell me, Mr. Moore, what the basis was for those assignments?
MR. MOORE: A: The basis for the mains and for the measuring regulating equipment for being demand related is that they regard it to be a capacity related cost.
MR. FULTON: Q: Okay. And the services and meters?
MR. MOORE: A: Services and meters are the closest elements of the system to the customer. The specific meter must be attached to a specific customer, and the service line to a specific customer.
MR. FULTON: Q: Thank you. Now there are alternative ways of assigning these types of costs, are there not? And without being overly cryptic, for example, distribution services are sometimes separated between customer and demand-related components to reflect the fact that the size of the pipe that's being used depends on the maximum likely draw or peak demand through the pipe, the

diameter to length method, for example.

MR. REED: A: Did you misspeak? You used the word distribution services. Did you mean distribution mains?

MR. FULTON: Q: Yes. Thank you.

MR. REED: A: Yes, there are other ways to handle it. There are about three different ways or methods used to classify plant cost and revenue requirement of distribution mains to the customer classes. The first is a zero intercept method, and the second is a minimum system method, and lastly a flat zero amount, since these first two methods are rather controversial. And as a preliminary matter to discussing these three matters, let's deal with classification of cost.

Now fixed costs arise each year in a regulated utility because of depreciation expense, income taxes, earned return and O and M costs. These fixed costs are classified either as capacity-related or customer-related, and we get down to asking a question, who really cares how the distribution mains are classified.

MR. FULTON: Q: Well, you care if the result is different, don't you?

MR. REED: A: Right. And I think that we have to look at the allocators that apply here. If we're talking about capacity-related costs, say the residential or small commercial customers would be allocated about 55 per cent of those costs, yet if the distribution mains were classified as customer-related, they would pick up about 85 per cent of the cost, or 30 per cent more. So you see why there's a point of argument on this level.

Now moving on to the specific methods, the zero intercept method attempts to calculate the cost of a hypothetical distribution system with zero diameter mains. By and large this approach causes about a quarter of the distribution mains to be classified as customer-related.

Moving on, the minimum system method calculates a cost of a theoretical distribution system that permits natural gas to flow to the customer service lines, but the distribution mains are so small that they can't carry any substantial load. There is several variants of this and by and large you use a two inch -- people who use this method use about a two inch diameter pipe size. And by and large this approach can cause half or all of the distribution mains to be classified as customer-related cost, between a half and three-quarters. Now that's a large amount to be allocating 85 per cent say to the small commercial and residential customers.

Proceeding Time 9:50 a.m. T16

The zero method, if I can call it that, or not classifying any of the distribution mains to customer-related cost, the whole of it remains capacity-related, and under this approach it's argued that the distribution mains -- the distribution mains don't connect the customer to the natural gas system. The services or the laterals from the mains do. From a cost causation point of view customer-related costs are those that we look at as those that can be avoided if the customer permanently ceases to take gas from the system.

Let's assume that the land use changes on which a residential customer or small commercial customer is located, and the structure is demolished and a gas lateral or service is removed and a gas meter and regulator and so on is removed. The costs that are avoided are meter reading, customer billing, and the cost of operating and maintaining a service lateral and a meter and a regulator.

Now the fixed cost of the distribution main in a public thoroughfare is not avoided. So I come down on this latter method that has none of the cost of the distribution mains classified as customer-related, and if you look in the back of the book it's beneficial to the residential and small commercial customers, but I think the theory holds in this case, as I feel, that the cost avoided is only those costs that are already over in service laterals, meters and so on, that are classified in the cost study as customer-related costs

anyway.
MR. FULTON: Q: Thank you. In terms of these alternative methods, Mr. Reed, did the company perform any tests to provide them with a comparison of what the effect would have been if they had used these alternative methods as opposed to the method that was used?
MR. REED: A: I think that -- well, I looked at it early on and it bore out what I said by and large the zero intercept method will classify about 25 per cent of the mains as customer-related costs.
A minimum system method would classify maybe a half or two-thirds of the distribution mains as customer-related costs, and my preliminary studies follow in that range. And yet I don't think that's a theory that the company should use on a go-forward basis.
MR. FULTON: Q: 2A, Section 5, page 2.1, indicates that of the BC Gas operating and maintenance expense, approximately $4 million was for total marketing, and that's at line nine under column 2, Mr. Wessler.
MR. WESSLER: A: Yes.
MR. FULTON: Q: Of that approximately 1.8 million has been functionalized into a function called marketing in column seven.
MR. WESSLER: A: I see that.
MR. FULTON: Q: And all of that has been classified as a

customer cost, and that is reflected at Section 6, page 6.10.

Proceeding Time 9:55 a.m. T17

MR. FULTON: Q: Do you that, Mr. Wessler?
MR. WESSLER: A: No, I don't find that number on page --
MR. FULTON: Q: Section 6.
MR. WESSLER: A: Section 6, page 1 --
MR. FULTON: Q: No. 6.10. It's at line 3, column 2.
MR. WESSLER: A: Oh, yes.
MR. FULTON: Q: Can you indicate in rather more detail those marketing activies which have been classified as customer related and explain why they have been so classified as customer related?
MR. WESSLER: A: I'll refer that question to Mr. Moore again.
MR. FULTON: Q: Thank you.
MR. MOORE: A: These costs are from the marketing -- or have been budgeted through the marketing activities. They include the labor and promotional activities that company engages in. And the approach taken was to first try to identify by cost centre whether anything could be specifically identified belonging to residential programs or commercial programs or to either customer classes in the industrial groups. The residual was dropped into the bucket of marketing function and then just allocated based on the customer related factors.

MR. FULTON: Q: And there's a number for direct assignment in the column number 9, Section 5, page 2.1. Can you tell me what that is?
MR. MOORE: A: That would be the marketing expenses related to the cost centre for residential marketing, commercial marketing and industrial marketing.
MR. FULTON: Q: Was there any reason why some of these expenses wouldn't have been allocated to the commodity component in a sense that aren't they intended to encourage the customers to buy more gas?
MR. REED: A: I'll respond to that. I think in a cost study, you have to look at the -- unless it's a very specific situation, you look at the cost whether it arises as a fixed cost or a variable cost. And going through the classification portion of the study, these in essense are fixed costs. Now, what your question deals with is, would you want to consider some of these variable costs -- consider certain costs as variable and then put that over into commodity cost. Well, in effect, the cost allocation procedures has already done that. If a fixed cost is a fixed cost we put it as a capacity related cost unless it's customer related. And in here some of these costs were dropped right into the customer buckets, so to speak, for the various classes where they're assigned. Dealing with your specific question, though, and going into the allocation

procedures, the fixed cost gets allocated on a capacity basis, but the average and excess demand basis takes a portion of the fixed cost and converts that into commodity cost and then fixed costs are allocated on fixed cost allocators or capacity allocators and then the customer related cost -- sorry, I'm going to start this sentence and paragraph over.

The fixed costs that would be, say, in this case first classified as capacity related, gets manipulated in an average and excess demand study and actually a portion of it gets assigned over -- assigned is a good word for it, into commodity related costs. And it gets spread volumetrically. So if you look at an outcome of an AED study, you do have that effect.

MR. FULTON: Q: And so, is that what in fact what has happened with the numbers at page 2.1?

Proceeding Time 10:00 a.m. T18

MR. REED: A: No, that's not what happens at 2.1.

MR. FULTON: Q: I didn't think it did.

MR. REED: A: I say in effect what you're driving at happens under an AED study, or we perhaps are not communicating at all.

MR. FULTON: Q: In terms of the marketing strategy --

MR. REED: A: Can you hold just one moment, please. Thank you.

MR. FULTON: Q: Doesn't the marketing strategy of the company focus principally towards increasing the use of the existing customers, rather than adding new customers?

MR. REED: A: I don't think that I want to respond or this panel is the ones to respond to that. I think you're going to have marketing people here and they can respond to your question more fully I'm sure.

INFORMATION REQUEST

MR. FULTON: Q: Well, I was just speaking with Mr. Johnson because I hadn't understood that there was going to be a Marketing Panel, and there is not going to be a Marketing Panel at this stage, so perhaps someone on the panel can inform themselves and we can be advised through counsel, and if it can be expressed in a percentage term as to what portion of the marketing strategy is focused on increasing the use of new customers and what portion is focused on the use of adding customers.

MR. REED: A: This is in the form of a data request?

MR. FULTON: Q: Yes.

MR. WESSLER: A: I'll undertake to do that.

MR. FULTON: Q: Thank you, Mr. Wessler.

THE CHAIRPERSON: Would this be a good time to take our break, Mr. Fulton?

MR. FULTON: Certainly.

THE CHAIRPERSON: All right. We'll be back at 20 after 10 then. Thank you.

(PROCEEDINGS ADJOURNED AT 10:05 A.M.)

(PROCEEDINGS RESUMED AT 10:25 A.M.)

THE CHAIRPERSON: Thank you. Please continue, Mr. Fulton.

CROSS EXAMINATION BY MR. FULTON CONTINUED:

MR. FULTON: Q: Thank you, Mr. Chairperson. Panel, if you would turn to page 6, of Exhibit 2, Tab 2, lines 11 through 15.

MR. MOORE: A: I'm sorry, I missed your section.

MR. FULTON: Q: Tab 2, page 6.

MR. MOORE: A: Oh, you're not referring to this?

MR. FULTON: Q: No, I've finished with those tables. Lines 11 to 15. And as I understand those lines, the customer costs are made up of a portion of distribution, customer accounting and marketing costs. Correct?

MR. REED: A: Are you starting on line 11 where the first word is, fixed costs are usually assigned?

MR. FULTON: Q: Yes.

MR. REED: A: Yes.

MR. FULTON: Q: Now, could you then turn to page 11 and the flow chart.

MR. REED: A: Yes.

MR. FULTON: Q: And specifically I would like you to direct yourselves to those parts of the flowchart that are related to functionalization and classification. And in the classification lines the box for customer fixed

cost.
MR. REED: A: Yes.
MR. FULTON: Q: Now, if you look at that box and then go up and then follow the arrows that are directed to it from functionalization, what I understand is that customer costs, the customer fixed costs, also include gas supply, storage and transmission costs.
MR. REED: A: Well, you see --
MR. FULTON: Q: No, just let me. Because you'll agree with me that there are arrows going from those boxes on the functionalization line to the customer fixed costs box?
MR. REED: A: Yes. And I made this drawing and I think I made it primarily as a eye test if you can read it with one eye or the other. The sole main theory is that -- and this is just theoretical, there might have been some gas supply that could be customer fixed costs, but as a practical matter is not.
MR. FULTON: Q: Well, let me put it this way. You spoke about theory. Did the lines coming from gas supply, storage and transmission, represent reality in light of what is said at lines 11 through 15 on page 6?
MR. REED: A: Well, with regard to BC Gas, no. But it's a general chart.
MR. FULTON: Q: Well, sir, I do see the chart is headed, BC Gas Inc., and I took it from that heading on the chart that that chart was specifically related to BC Gas Inc.

and you say it's not.

MR. REED: A: On my freelance graphic, I put BC Gas at the top and perhaps I shouldn't, I should have put in there, General Chart.

MR. FULTON: Q: Thank you. Those are my questions, Mr. Chairperson.

THE CHAIRPERSON: Thank you, Mr. Fulton.

MR. JOHNSON: No re-exam.

THE CHAIRPERSON: Commissioner Leighton has one question.

EXAMINATION BY THE COMMISSION:

COMMISSIONER LEIGHTON: My question concerns the treatment of subsidies in the FDC method. My concern would be if one pushes the rates close to the FDC level that the residential customer who is a tax payer has probably funded the subsidies might be paying twice for the same service. If the subsidy amount is in the embedded cost, then that one priced right to the level of the FDC, one would then be including the subsidy sum in the embedded cost so he would be, in effect, paying twice for the same service, if that were the case.

MR. REED: A: May I clarify. Are you using the word, subsidy? Subsidy cost? I'm hard of hearing.

COMMISSIONER LEIGHTON: I'm referring to the costs of government subsidies provided to --

MR. REED: A: Oh.

COMMISSIONER LEIGHTON: --the system such as the systems in the rate expansion, the expansion program or even in the case of the Vancouver Island Gas Pipeline immense subsidies. But you're not, fortunately you're not dealing with those here. So, my question is really, if one goes right to the level of the FDC pricing is there a danger that the residential customer, who's basically the taxpayer, would be paying twice for the same service?

MR. REED: A: May I clarify something with the panel members. Are there --

MR. WESSLER: A: May I try to respond to that. Commissioner Leighton, I believe if the government desires to make a contribution in aid of construction as a policy or as a social goal to get more gas service to other customers, that is the government's policy, and so I can't speak to that whether the government or the present government or any government desires to have this policy in place at any particular point in time. However, if -- and obviously the reason for making this contribution in aid of construction is because the customer is too far afield so that the socalled mains extension test is not met and the customer cannot or will not put up this contribution to make up the defficiency or because it's too costly to reach him, so the government is putting these funds in. However, when the company or when the Utility receives those funds, they are put into the bank and the credit goes into an account called 211 which is contributions in aid of construction. This contributions in aid of construction then in the chart of accounts gets deducted from gas plant and service. Therefore, the costs which are distributed are only the net cost after this contribution so the customer then does not get that cost allocated again to him. It's the net costs which are in the gas plant in service.

Proceeding Time 10:30 a.m. T20

COMMISSIONER LEIGHTON: Thank you, Mr. Wesler, for that very lucid explanation. That's what I was looking for.

THE CHAIRPERSON: I have no questions, so I believe at this time we can allow this panel to stand down, and thank you very much for coming before us.

(WITNESSES ASIDE)

THE CHAIRPERSON: We're ready for the next panel of BC Gas.

MR. FULTON: While the next panel is getting ready to be sworn, Mr. Chairperson, I have prepared an order of cross-examination. There's a long list, but essentially only Ms. McCool and myself will be cross-examining.

MAIN EXTENSION POLICY PANEL
JOHN C. TOUHEY, Affirmed:
WALLACE POWELL, Resumed:

MR. JOHNSON: Mr. Chairperson, this panel, Panel 5, speaks to the proposed mains extension policy of BC Gas. Mr.

BC GAS INC.

VOLUME 3

WRITTEN EVIDENCE

BC GAS INC.

WRITTEN EVIDENCE OF

P.D. LLOYD/ W.R. POWELL/ D.M. MASUHARA

EVIDENCE TO BE FILED AT A LATER DATE

BC GAS INC.

WRITTEN EVIDENCE OF

<u>ROBERT H. SARIKAS</u>

Q. What is your name and business address?

A. My name is Robert H. Sarikas. My business address is Foster Associates, Inc., 1015 15th Street, N.W., Washington, D.C. 20005.

Q. What is your occupation?

A. I am a consultant in the field of regulatory economics. I am also a Registered Professional Engineer and a Certified Public Accountant, holding certificates in the State of Illinois.

Q. By whom are you employed and in what capacity?

A. I am a Senior Consultant and a Senior Vice President of Foster Associates, Inc.

Q. What business is Foster Associates, Inc. engaged in?

A. Foster Associates, Inc. is an independent organization offering economic research and consulting service to business and government in the United States, Canada, and overseas. Our activities are largely in the areas of regulatory activity concerning energy, public utilities, communications, and transportation.

Q. Will you please describe your formal education?

A. I attended Washington University and earned a Bachelor of Science degree in 1954. My major field of concentration was Electrical Engineering. I also studied at the University of Illinois where I earned a Master of Science Degree in Finance in 1970 and Doctor of Philosophy in Finance in 1981.

Q. Are you a member of any professional associations?

A. Yes. I am a member of the American Economic Association. I am also a member of the National and Illinois Societies of Professional Engineers, the American Society for Engineering Education, the Institute of Electrical and Electronics Engineers, the American Institute of Certified Public Accountants, the Illinois CPA Society, the Institute of Management Science, the Financial Management Association, the Eastern Finance Association, and the Midwest Finance Association.

Q. Will you please briefly describe your professional experience?

A. As a member of the firm of Foster Associates, Inc., I have had consulting assignments in the area of cost and price analysis and rate case issues for gas distribution companies, pipelines, and electric utilities. Some of these assignments involved the economic analysis of alternative plans, market research, and similar areas of study.

Prior to joining the firm of Foster Associates, Inc., I was employed by the Illinois Power Company in various assignments in the engineering and rate departments. As Manager of Rates and Rate Research, I was responsible for all rate activities and the conduct of cases before state and Federal regulatory bodies.

Earlier, I was in charge of the design of electrical transmission and distribution systems for Illinois Power. Other work assignments included eight years of work in long-range planning of transmission and distribution systems. I also designed additions to the gas distribution system of Illinois Power.

Q. Have you previously testified as an expert witness with respect to your discipline before any courts or regulatory bodies?

A. I have testified as an expert witness before the National Energy Board, the Ontario Energy Board, the Public Utilities Board of Manitoba, the Saskatchewan Public Utilities Review Commission, the Nova Scotia Board of Commissioners of Public Utilities, the Newfoundland Board of Commissioners of Public Utilities, and this Commission.

I have testified before State Regulatory Commissions in Arkansas, Idaho, Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, New Mexico, New York, Ohio, Pennsylvania, Texas, and Wisconsin. I have also testified before the Federal Energy Regulatory Commission and its predecessor the Federal Power Commission, the Nuclear Regulatory Commission, and the Postal Rate Commission.

Q. Are you the author of any articles, papers, or other publications dealing with the subject area of your testimony?

A. Yes. I am the author of over seventy articles and papers published in various journals and magazines such as <u>Public Utilities Fortnightly</u> and the publications of engineering societies and other organizations. These papers cover various topics in the field of economics, cost analysis, rate design, and engineering. A list of those papers is included in Appendix A to my testimony.

Q. What is the purpose of your testimony?

A. The purpose is to present evidence on behalf of BC Gas with respect to:

1. Overall rate design methodology used in the Application.
2. Use of Uniform Postage Stamp Delivery Charges.
3. Difference between FDC and LRIC levels.
4. Consolidation of Lower Mainland, Inland, and Columbia Divisions into a single entity.
5. Franchise fee collection.

METHODOLOGY USED IN THE APPLICATION

Q. Have you had an opportunity to participate in the preparation of the Company's applications in the case, and review the document as filed?

A. Yes, I have.

Q. Based on the experience you have in preparing similar applications in the past, what are your general comments?

A. I find that the application is responsive to the rate design objectives set out by BC Gas. The stated rate design objectives are:

- Fairness or equity
- Economic efficiency (Proper price signals)
- Stability

- Gradualism
- Conservation

Fully distributed cost (FDC) analyses are included in the application as a tool for use in attaining equity in terms of the assignment of revenue among the various rate classes and, to a lesser degree, rate design within a rate class. Most persons believe that a rate is fair if they are paying what a service costs. FDC studies are provided for each of the geographic divisions and on a combined basis so as to allow for testing of the reasonableness of a uniform postage stamp margin.

Long-run incremental cost (LRIC) analyses are also included in the application as a tool for allowing economic efficiency in rate design and as a measure of the appropriateness of a postage stamp margin. Economic efficiency requires a proper reflection of cost in price so that a utility customer 's purchasing decision result in an efficient allocation of resources. If price is set below marginal cost, users will be encouraged to use less than the optimal amount of the resource. If price is set less marginal cost, users will be encouraged to use more than the optimal amount of the resource. Thus, the LRIC is useful for rate design within a rate class even though class revenues are established on the basis of an FDC study.

For this reason, the Company is in the mainstream of utility regulatory practice in dealing with the issue of fairness and economic efficiency.

Rate Design also recognizes the impact of competitive alternative fuels in the establishment of rate level. Such factors determine value of service, or the most that can be charged for a given service. These elements are quantified in the Application.

The Company's effort to better recognize the fixed cost component shown in both the FDC and the LRIC studies is accomplished by increasing the basic charge for the residential and commercial customer classes. This rate modification will provide an improvement in revenue stability as well as recognition of the fixity of costs in a gas system. Since the life cycle of gas transmission and distribution plant is on a par with the remaining life expectancy of most consumers, it is reasonable to say that plant related costs are fixed costs. As a consequence, all costs of a gas utility are fixed with the exception of a portion of the cost of gas plus compressor fuel and a portion of compressor maintenance. Since the increase in the basic charge is only about three percent of total revenue, it does not constitute a major shift. Also, it will not have a serious impact on the commodity price of the tail block rates.

Rate design changes are also directed towards the elimination of declining block rates which will more closely align tail block rates with LRIC and thereby further the goals of economic efficiency and conservation. In addition, this will also enhance future DSM efforts.

Q. Does the Company's rate design represent a balancing of objectives?

A. The Company's rate design represents a careful balancing of a number of objectives. Firstly, the design of uniform postage stamp margins, which in itself serves as a constraint in attaining any other objective and represents a prime objective in this proceeding. The need to phase-in the Colombia rates is an example of the constraints faced in the design of a uniform margin. The implementation of a uniform postage stamp margin will insure that all consumers are treated alike irrespective of their geographic location, thus furthering the objective of fair and equitable treatment.

Better recognition of both FDC and LRIC is achieved by the use of an increased basic charge. Better recognition of LRIC is also achieved by the flattening of the residential and commercial rates in terms of the elimination of declining block rates, thus furthering the goal of economic efficiency. Such changes were part of an effort to LRIC over a range of usage, not merely at the point of average consumption per customer. The somewhat inferior approach of using only a single point is typical of most utility presentations in this regard.

In the design of the postage stamp margin, some effort has been made to increase the residential and commercial margins. This is not only an attempt to recognize cost of service, it also attempts to recognize one of the causes of cost, namely, the higher rate of growth of the residential and commercial sectors as compared to the industrial sector.

The setting of the level of the interruptible rate also requires a careful balancing of objectives since present disparities between interruptible sales and interruptible transportation margins must be taken into account along with the need to provide an adequate difference between firm and interruptible rate options. Here too, this must be accomplished in the context of developing a company wide tariff for such service.

USE OF A POSTAGE STAMP DELIVERY CHARGE

Q. What are the reasons favoring the use of a single postage stamp delivery charge for the various rate classes irrespective of the division in which a customer is located?

A. The use of a single company-wide rate structure in terms of standardized rate margins (exclusive of gas supply costs) is a logical outgrowth of unified ownership. Important criteria for a combined postage stamp delivery charge include:

1. A similar design standard for the gas distribution system.
2. Use of a uniform extension policy.
3. A uniform policy with respect to the ownership of service connections and meters.

I do not believe that differences in the extent to which plant is depreciated in one geographic area vs. another are a valid basis for a rate differential. I also do not believe that price level differences resulting from vintage differences are a valid basis for rate differentials as among geographic areas.

Differences in rate level resulting from merger and acquisition become more difficult to justify with the passage of time. In a Pacific Power & Light case some years ago before the Oregon Public Utility Commissioner, the company was not permitted to perpetuate disparate area rate schedules which had resulted from company development and merger. The company was required to redesign its rate structure to make its schedules available at a uniform level.[1]

Q. Would the use of postage stamp delivery charges be relevant if the revenues and costs of the various divisions were not consolidated?

A. No. The use of postage stamp delivery charges assumes that regional differences within a division as well as among divisions are not of sufficient importance to justify the use of regional margins.

In terms of the inverse, the use of postage stamp delivery charge without consolidation would imply that regional cost breakdowns were to be retained absent the sole purpose of such costing: i.e., a basis for regional rate differences.

Q. Do you favour a phase-in of rates designed to equalize margins?

A. Yes, I do. I believe that the phase-in should encompass changes in the basic charge and rate blocks. If possible, the phase-in should be limited at most to a five-year time period based upon pre-approved annual changes in rate structure. I believe in most cases BC Gas anticipates all the rate design adjustments in this application will be completed within two years.

Q. Do you concur with the maintenance of separate gas costs in the lower Mainland, Inland, and Columbia areas, to be used in conjunction with the postage stamp margin (excluding gas supply costs) for those areas?

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[1] *Oregon Public Utility Commissioner, Order No. 70-664, October 5, 1970 re: Pacific Power & Light Co., 86 PUR 3d 417.*

A. Yes, I do. Gas supply cost should only be applied on a postage stamp basis if the areas are integrated in terms of transmission and pipeline supply, and the weighted average cost of gas is reasonably the same for each of the areas.

FDC VS. LRIC ANALYSES

Q. Have you had an opportunity to review the relationship between the phase-in of the postage stamp delivery charge and the results of the Fully Distributed Cost (FDC) and Long-Run Investment Cost (LRIC) structure for each of the divisions and the combined cost of service?

A. Yes, I have. The results of that analysis for the various rate classes are shown in terms of hyperbolic plots of FDC, LRIC, and postage stamp rate proposal shown in the Application. For the Columbia Division, the amount of the rate increase might be considered prohibitive without a phase-in over a reasonable time period.

Q. Is it commonplace to have a disparity between the unit cost calculated using an FDC analysis as compared to using the results of an LRIC analysis?

A. Yes, it is. That disparity is caused by vintage and price level as well as conceptual differences in the preparation of such analyses.

Q. Will you pleases explain what you mean by vintage and price levels?

A. The vintage or age of existing plant included in the FDC analysis is spread over many years, frequently dating back to the inception of the firm. Since price level has generally trended upward, except for a few years in the distant past, the unit cost of older plant measured in terms of the price level at the time of purchase will be substantially less than the cost of either the same plant today, or the cost of plant capable of performing the same function but using recent technology. In contrast, the plant included in the LRIC study is either priced at today's price level: i.e., in real terms, or it may be priced in terms of the nominal price level of each year of the expansion plan used in the preparation of an LRIC study.

Vintage is determinative of the extent to which the existing plant included in the FDC analysis is depreciated. Thus, plant constructed fifteen years ago will not only be on the books at a lower price, corresponding to the price level at the time it was constructed, it will also be substantially depreciated. If the plant life of the item is 45 years it will be one-third depreciated on a straight line basis. Since FDC analyses utilize net plant, the effect of accrued depreciation is to reduce the level of FDC. In the case of plant included in the LRIC, it will not be depreciated; however, the use of a capital recovery factor does reduce the revenue requirement of plant in the LRIC study as compared to straight-line depreciation for calculating expense in the conventional FDC analysis.

Q. Will you please explain the importance of conceptual differences on the results of an FDC versus a LRIC analysis?

A. Yes. The rate class units costs developed by an FDC analysis may differ as among FDC analyses prepared using a different capacity cost allocation methodology; e.g., peak responsibility versus Average and Excess. An FDC study is an apportionment of historic accounting costs. An LRIC study is concerned with added costs that will be incurred to serve planned-for load in the future. Such costs are based upon engineering estimates. An LRIC study is not concerned with existing plant. Such plant is regarded as a sunk cost. An FDC study is an apportionment of those sunk costs.

What has been said of plant also applies to expenses. To the extent that operating and maintenance costs have a fixed component, added expense to serve added load may logically be less than average expense per unit of throughput.

Q. Do you concur with the recognition of additional customers as the principal driver in the LRIC study?

A. Yes, I do. There has been very little growth in the consumption per customer of residential and commercial customers because there have been virtually no new gas appliances developed in the past forty-years. In fact, the introduction of more efficient furnaces has led to a decline in the average consumption per customer.

An LRIC study is used to answer the question, what is the change in cost caused by a change in load? Since the change in load arises from the change in the number of customers, this must be recognized in the analysis. Most of the increase in distribution investment and expense is due to the increase in the number of customers. A portion of the added distribution investment is due to reinforcement to supply the increased peak day demand.

In the rate design process, it is possible to estimate the revenue that would be derived if the rates were equal to marginal cost.

It would be possible to develop a separate estimate of the LRIC of serving added usage per customer if that cost component is relevant in some future time period.

INDUSTRIAL INTERRUPTIBLE & FIRM RATES

Q. Have you reviewed the Company's proposal with respect to the logic of the proposed industrial firm and interruptible rates?

A. Yes I have.

Q. Do you have any comments with respect to the Company's Interruptible Rate Design?

A. Yes. I believe it is a carefully crafted attempt to eliminate margin differences between interruptible sales and interruptible T-service margins in order to attain revenue neutrality. The proposed Schedule 7 General Interruptible Service and Schedule 27 General Transportation, with two levels depending upon a customer's reliability preferences, provides a resolution of that problem. It is important that shifts from interruptible sales to interruptible transportation on the basis of inconsistent margins be avoided. It is also important that shifts from interruptible sales or service to firm service be avoided since this will result in substantial increases in the amount of capacity purchased from Westcoast which in turn could adversely affect all customer classes. Those customers seeking firm service or highly reliable interruptible service (if interruption were due only to physical constraints on the distribution system) should there for pay a premium over the rates for the standard level of interruptible service provided by BC Gas.

Q. What is the nature of the economic constraints faced in the design of interruptible rates.

A. The widespread use of interruptible service is favoured in terms of achieving the economically efficient use of B.C. Gas facilities as well as the economically efficient use of facilities of the pipeline supplier. In the design of interruptible rates, the lower limit can generally be established by deducting avoided cost from the comparable firm cost of service. The upper limit of an interruptible rate is the value of service for that customer. Value of service can relate to the lowest priced alternative available to the customer such as firm gas service, or the use of an alternative fuel or manufacturing technology with different inputs. If the customer is a new customer, differences in the annual cost of alternative fuel burning equipment must be included when making the computation.

Revenue under the interruptible gas rate cannot be compared directly with revenue under the firm gas rate when calculating value of service for interruptible customers. As an example, it is necessary to add to the revenue under an interruptible T-Service rate the cost of gas and pipeline transportation, the annual cost of equipment to utilize alternative fuels during the curtailment period (unless this is a "sunk" cost), the cost of alternative fuel burned and the annual inventory cost for such fuel, the cost of lost production, and the annual cost of equipment changes to accommodate interruptible service (unless this is a sunk cost).

The establishment of an interruptible rate between those two limits, firm service cost less avoided cost, and value of service, will determine the extent to which the savings resulting from interruptible supply are shared between interruptible customers and other firm customers.

Q. Is the proposal to "grandfather" the large firm industrial rates in the Inland and Columbia divisions reasonable?

A. Yes, it is. It should be recognized that customers may have based their investment in equipment and prices for their products on a particular rate for services. In that event, the withdrawal of a rate could be viewed as a form of entrapment. Use of a grandfather treatment avoids inequity and, at the same time, provides assurance of the eventual elimination of rate differentials.

REGULATORY CONSOLIDATION

Q. Do you concur with the reasons advanced by the Company for consolidation of the Lower Mainland, Inland and Columbia Divisions?

A. Yes, I do. The savings resulting from such consolidation should be significant since numerous elements of duplication will be eliminated. The results of regional FDC as well as marginal cost analyses also support that proposal. Such consolidation is the normal consequence of merger and acquisition, and has been generally recognized in other regulatory jurisdictions

FRANCHISE FEES

Q. What are the arguments for and against the collection of franchise fees from all customers rather than from only the customers in the geographic areas that assess such fees?

A. The primary argument for collection of franchise fees from all customers is that customers located in unincorporated areas that do not levy such fees benefit from the economies of scale resulting from the provision of service to the high load density incorporated areas. To the extent that franchise fees are a payment for the right to use the streets of the city, they are a form of payment comparable to the cost of purchasing private right-of-way in non-franchise areas. A further argument is that it is not common practice to separately bill each geographic area for the amount of property and ad valorem taxes levied by the respective areas. It is more commonplace to base rates upon the average amount of such taxes.

The primary argument for collection of franchise fees from the residents of the areas that assess such fees is the objective of matching costs and benefits.

This concern has been given predominant weight by regulators in arriving at the usual decision to require that the fees be collected only from the residents of areas that assess such fees.

Q. Does this conclude your testimony?

A. Yes, at this time.

APPENDIX A

LIST OF PAPERS AUTHORED OR COAUTHORED BY ROBERT H. SARIKAS

CHRONOLOGICAL INDEX

1. Discussion of "Economics of 240/480 V as a Residential Utilization Voltage," by D. K. Blake, and "Higher Secondary Voltage - A Solution to Future Distribution" by R. F. Lawrence. Presented at the American Power Conference, Chicago, Illinois, March 21-23, 1956. Published in Proceedings, Vol. XVIII, 1956.

2. "Transient and Static Characteristics of Loads and Their Use in Distribution Planning and Design." Presented at 1956 Distribution Engineering Conference, Westinghouse Electric Corporation, East Pittsburgh, Pennsylvania, September 17-21, 1956.

3. Discussion of "What Do Losses Cost in Hydro, Thermal, and Combined Systems?," by V. W. Ruskin. Presented at AIEE Winter General Meeting, New York, N.Y., January 30 - February 3, 1956. Published in AIEE Transactions, Vol. 75, Pt. III, June, 1956, pp. 335-7.

4. "Distribution System Load Characteristics and Their Use in Planning and Design," AIEE Technical Paper 57-168. Presented at AIEE Winter General Meeting, New York, N.Y., January 21-25, 1957. Published in AIEE Transactions, Vol. 76, Pt. III, August, 1957, pp. 764-74.

5. Discussion of "Single-Phase Versus 3-Phase Service for Residential Air Conditioning," by A. S. Anderson and C. Hutchinson. Presented at AIEE Winter General Meeting, New York, N.Y., January 21-25, 1957. Published in AIEE Transactions, Vol. 76, Pt. II, p. 65.

6. Discussion of "Some New Mathematical Aspects of Fixed Charges," by C. W. Bary and W. T. Brown. Presented at AIEE Winter General Meeting, New York, N.Y., January 21-25, 1957. Published in AIEE Transactions, Vol. 76, Pt. III, June, 1957, p. 242-3.

7. Discussion of "The Criterion of Economic Choice," by P. H. Jeynes and L. Van Nimwegen. Presented at AIEE Winter General Meeting, New York, N.Y., February 2-7, 1957. Published in AIEE Transactions, Vol. 77, Pt. III, August, 1958, p. 624-5.

8. "Planning Rural Systems for Continuing Growth," AIEE Technical Paper 60-727. Presented at AIEE Rural Electrification Conference, Omaha, Nebraska, May 10-12, 1960. Published in AIEE Transactions, Vol. 79, Pt. III.

9. Discussion of "Distribution System Planning Through Optimized Design," Parts I & II, by R. F. Lawrence, D. N. Reps, and A. D. Patton. Presented at AIEE Winter General Meeting, New York, N.Y., January 31 - February 5, 1960. Published in AIEE Transactions, Vol. 79, Pt. III, June, 1960, p. 219.

10. Discussion of "Economic Analysis of Distribution Systems," by H. E. Campbell, M. W. Gangel, R. C. Ender and V. C. Talley. Presented at the AIEE Winter General Meeting, New York, N.Y., January 31 - February 5, 1960. Published in AIEE Transactions, Vol. 79, Pt. III, August, 1960, p. 442.

11. "Economic Justice and the Cost of Utility Relocation," Public Utilities Fortnightly, November 10, 1960, p. 699-707.

12. "Use of 34.5 KV Supply to Reduce 4.16 and 12.47 KV Distribution System Investment," AIEE Technical Paper 61-228. Presented at AIEE Winter General Meeting, New York, N.Y., January 29 - February 3, 1961. Published in AIEE Transactions, Vol. 80, Pt. III, P. 505-15.

13. Discussion of "Present-Worth Approach for Optimizing Distribution Transformer and Secondary Designs to Serve Growing Loads," by R. P. Burandt, A. D. Patton, J. A. Hughes, and D. N. Reps. Presented at AIEE Winter General Meeting, New York, N.Y., January 29 - February 3, 1961. Published in AIEE Transactions, Vol. 80, Pt. III, August, 1961, p. 353.

14. Discussion of "Optimizing the Applications of Shunt Capacitors for Reactive-Volt-Ampere Control and Loss Reduction," by R. F. Cook. Presented at AIEE Winter General Meeting, New York, N.Y., Vol. 80, Pt. III, August, 1961, p. 442.

15. "Motor Starting Problems Part I," AIEE Technical Paper CPA 61-5041. Presented at AIEE Conference on Rural Electrification, Louisville, Kentucky, May 1-3, 1961.

16. "Use of 34.5 KV to Reduce 4.16 and 12.47 KV Distribution System Investment," The Line, July - August, 1961.

17. Joint discussion of "Determination of Economical Distribution Substation Size" and "Economics of Primary Distribution Voltages of 4.16 through 34.5 KV" both by J. A. Smith. Presented at AIEE Summer General Meeting, Atlantic City, New Jersey, June 19-24, 1960. Published in AIEE Transactions, Vol. 80, Pt. III, October, 1961, p. 676-7.

18. Discussion of "A Further Look at Cost of Losses," by C. J. Baldwin, C. H. Hoffman, and P. H. Jeynes. Presented at AIEE Fall General Meeting, Detroit, Michigan, October 15-20, 1961. Published in AIEE Transactions, Vol. 80, Pt. III, February, 1962, p. 1005.

19. "Effect of Demand Interval Upon Indicated Peak Demand," AIEE Technical Paper CP 62-114. Presented at AIEE Winter General Meeting, New York, N.Y., January 28 - February 2, 1962.

20. "Sag and Tension Calculations by the Nomographic Method," AIEE Technical Paper CP 62-107. Presented at AIEE Winter General Meeting, New York, N.Y., January 28 - February 2, 1962.

21. Discussion of "Monte Carlo Simulation of Residential Transformer Loads," by D. N. Reps. Presented at AIEE Winter General Meeting in New York, N.Y., January 28 - February 2, 1962. Published in AIEE Transactions, Vol. 81, Pt. III, February, 1963, p. 862-3.

22. "Digital Computer Studies, Load Analysis and Economic Evaluation Techniques." Presented at Power Distribution Conference, The University of Texas, Austin, Texas, October 15-17, 1962.

23. "Load Characteristics of Standard and Quick Recovery Electric Water Heaters," IEEE Technical Paper CP 62-90. Presented at IEEE Winter General Meeting, New York, N.Y., January 27 - February 1, 1963.

24. "Motor Starting Problems Part II," IEEE Technical Paper CPA 63-5016. Presented at IEEE Rural Electrification Conference, Springfield, Illinois, April 22-24, 1963.

25. Discussion of "Transmission Conductor Ratings," by G. M. Beers, S. R. Gilligan, H. W. Lis, and J. M. Schamberger. Presented at IEEE Winter General Meeting, New York, N.Y., January 27 - February 1, 1963. Published in IEEE Transactions, Power Apparatus and Systems, October, 1963, p. 774.

26. Discussion of "Secondary System Distribution Planning for Load Growth," by R. M. Webler, M. W. Gangel, G. K. Carter, A. L. Zeman, and R. C. Ender. Presented at IEEE Winter General Meeting, New York, N.Y., January 27 - February 1, 1963. Published in IEEE Transactions, Power Apparatus and Systems, December, 1963, p. 923.

27. "Sidney-Cayuga 345 KV Wood H-Frame Line," IEEE Technical Paper 64-35. Presented at IEEE Winter Power Meeting, New York, N.Y., February 2-7, 1964. Published in IEEE Transactions on Power Apparatus and Systems, Vol. PAS-84 No. 2, February, 1965.

28. "Improving the Reliability and Performance of Rural Primary Feeders," IEEE Technical Paper CPA 64-243. Presented at IEEE Rural Electrification Conference, Denver, Colorado, April 13-15, 1964.

29. "345 KV Transmission Line on Wood H-Frames," Wood Preserving News, May, 1964.

30. Discussion of "Optimized Distribution and Subtransmission Planning by Digital Computer, III - Primary Main Circuit Design," by M. W. Gangel, J. P. Siken, J. A. Smith, and H. V. Taylor. Presented at IEEE Winter Power Meeting, New York, N.Y., January 31 - February 5, 1965. Published in IEEE Transactions, Vol. PAS-84, No. 12, p. 1163.

31. Discussion of "Optimized Distribution and Subtransmission Planning by Digital Computer, IV - Subtransmission System Design," by E. J. Hyland, M. K. Ramthun, J. A. Smith, and R. C. Ender. Presented at IEEE Winter Power Meeting, New York, N.Y., January 31 - February 5, 1965. Published in IEEE Transactions, Vol. PAS-84, No. 12, p. 1178-9.

32. "Three-Phase Electric Service for rural Customers." Presented at Missouri Valley Electric Association Residential and Farm Sales Conference, Kansas City, Missouri, October 18-20, 1967.

33. A Review of: "Profitability and Economic Choice," by Paul H. Jeynes, The Engineering Economist, Fall 1968, p. 57-60.

34. "Cost Analysis and Rate Design," Public Utilities Fortnightly, November 22, 1973, pp. 29-35.

35. "Rocky Mountain Coal for Electric Generation," AIME Paper No. 74-7. Presented at the 103rd AIME Annual Meeting, Dallas, Texas, February 24-28, 1974.

36. "Divergent Costing Techniques for Pricing and Other Managerial Purposes." Presented at Conference on Public Utility Valuation and the Ratemaking Process, May 21-23, 1974, Iowa State University, Ames, Iowa.

37. Portion of "Solar Heating and Cooling of Buildings," (Phase O), Vol. III, Appendices, TRW Systems Group, Prepared for National Science Foundation, Published by U.S. Department of Commerce, National Technical Information Service, PB-235424, May 31, 1974.

38. Portion of "Prospective Regional Markets for Coal Conversion Plant Products Projected to 1980 and 1985," Vol. 1, Market Analyses, Prepared for Office of Coal Research, U.S. Department of Interior," by Energy Division, Foster Associates, Inc., Washington, D.C., September 16, 1974, Published by U.S. GPO, Washington, D.C., Stock No. 2414-00091.

39. "What's New in Adjustment Clauses for Energy Utilities." Presented at the Utility Finance and Regulation Institute, Sponsored by Executive Enterprises, Inc., January 27-29, 1975, McCormick Inn, Chicago, Illinois.

40. "Incremental Cost Pricing: Answer to Profitability and Resource Allocation." Presented at the Symposium on Rate Design Problems of Regulated Industries, Sponsored by University of Missouri-Columbia Missouri Public Service Commission and Foster Associates, Inc., February 23-26, 1975, Kansas City, Missouri.

41. "Rate Level Forecasting: The Electric Utility Industry." Presented at the ORSA/TIMS Joint National Meeting, Chicago, Illinois, May 2, 1975.

42. Portion of "The Gas Desulfurization Process Cost Assessment," PEDCO-Environmental Specialists, Inc., Prepared for Office of Planning and Evaluation, U.S. ENVIRONMENTAL PROTECTION AGENCY, Washington, D.C., May 6, 1975.

43. "Electric Utility Rate-Making." Presented at the Colloquim in Electrical Engineering, Department of Electrical Engineering Ohio State University, May 15, 1975, Columbus, Ohio.

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45. "Incremental Cost Analysis and Rate Design." Presented at the Symposium on Rate Design Problems of Regulated Industries, Sponsored by University of Missouri-Columbia, Missouri Public Service Commission, and Foster Associates, Inc., February 22-25, 1976, Kansas City, Missouri.

46. "Electric Rate Concepts and Structures." Prepared for Bonneville Power Administration, Published by U.S. Department of Commerce, National Technical Information Service, PB-252 905, May, 1976.

47. "Rates in the Bonneville E.I.S." Presented at the 3rd Annual Retail Rates Symposium of the Northwest Public Power Association, July 7-9, 1976, Victoria, B.C., Canada.

48. Discussion of "Treatment of Inflation in Engineering Economic Analysis," by Frank Cassidy and Gerald W. Schirra. Presented at IEEE ASME/ASCE Joint Power Conference, Buffalo, N.Y., September 19-23, 1976. Published in IEEE Transactions, Vol. PAS-96, No. 3, p. 1033.

49. "Handling Rate Structure and Rate Proceeding Problems--Either on a Case-By-Case Basis or in a Generic Case." Presented at Eighty-Eighth Annual Convention and Regulatory Symposium of the National Association of Regulatory Utility Commissioners, November 15-18, 1976, Honolulu, Hawaii.

50. "Application of Long-Run Incremental Cost Analysis to Gas Distribution Utility Rate Design." Presented at the Symposium on Rate Design Problems of Regulated Industries, Sponsored by University of Missouri-Columbia, Missouri Public Service Commission, and Foster Associates, Inc., February 13-16, 1977, Kansas City, Missouri.

51. "The Impact of Current Gas Industry Problems on Cost Analysis and Rate Design." Presented at the Symposium on Problems of Regulated Industries, Sponsored by University of Missouri-Columbia, Missouri Public Service Commission, and Foster

Associates, Inc., February 5-8, 1978, Kansas City, Missouri.

52. "Use of Probability Methods in Electric Utility cost Analysis and Rate Design." Presented at the ORSA/TIMS Joint National Meeting, Los Angeles, California, November 13, 1978.

53. "Wheeling Service Alternative Rate Design." Presented at the Fifth Annual Symposium on Ratemaking Problems of Regulated Industries, Sponsored by the American University, University of Missouri-Columbia, Missouri Public Service Commission, and Foster Associates, Inc., February 11-14, 1979, Kansas City, Missouri.

54. "Gas Distribution Utility Long-Run Incremental Cost Analysis." Presented at the American Gas Association Rate Committee Meeting, September 24-26, 1979, San Antonio, Texas.

55. "Financial Aspects of Utility Construction Work in Progress," Public Utilities Fortnightly, June 19, 1980, pp. 111-112.

56. "Costing & Pricing of Interruptible Service." Presented at the 1981 Rate Symposium on Problems of Regulated Industries, Sponsored by the American University. Foster Associates, Inc., Missouri Public Service Commission, and the University of Missouri-Columbia Under the Auspices of the Institute for Study of Regulation, February 8-11, 1981, Kansas City, Missouri.

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58. "Rate and Regulatory Problems of Electric Utilities," Public Utilities Fortnightly, May 13, 1982, pp. 88-90.

59. "Conservation Program Economics." Presented at the 1983 Rate Symposium on Problems of Regulated Industries, Sponsored by The American University, Foster Associates, Inc., University of Missouri - Columbia, and the Missouri Public Service Commission, February 6-9, 1983, Kansas City, Missouri.

60. "Time Differentiated Electric Transmission System Cost." Presented at the ORSA/TIMS Joint National Meeting, Chicago, Illinois, April 27, 1983.

61. "The Effect of Regulatory Treatment of Construction Work in Progress Upon Stock Prices." Presented at the Iowa State Regulatory Conference, Iowa State University, Ames, Iowa, May 18-20, 1983.

62. "Electric Generating Plant Marginal Cost Under Non-Optimal Conditions." Presented at the ORSA/TIMS Joint National Meeting San Francisco, California, May 15, 1984.

63. "Impact of Competition on Pipeline and Distributor Rate Design." Presented at the Meeting of the Regulatory Committee of the Canadian Gas Association, Vancouver, B.C., January 11, 1985.

64. "Criteria for Determining Unjust Discrimination." Presented at the Thirteenth Annual Rate Symposium, Sponsored by The University of Missouri-Columbia, The University of Missouri-Columbia Extension and the Missouri Public Service Commission, February 8-11, 1987, St. Louis, Missouri.

65. Gas Rate Fundamentals, Chapter 8 "Fundamentals of Utility Pricing," American Gas Association Rate Committee, AGA, Arlington, Virginia, 4th Ed., 1987.

66. "Marginal Cost of Gas Supply for Gas Distribution Utilities," Presented at the American Gas Association Rate Committee Meeting," September 21-23, 1987, Seattle, Washington.

67. "Deregulation of Natural Gas Sales to Large Volume Industrial Users," Prepared by Foster Associates, Inc., Prepared for the American Gas Association, Printed by AGA, Arlington, Virginia, 1987, Catalog No. F00786.

68. "Technical and Engineering Considerations in Providing Access to Transmission Lines - Their Impact on Costing & Pricing," Presented at the Session on Electric Transmission Access, Pricing, Siting and Safety, Sponsored by American Bar Association Section of Natural Resources Law, San Francisco, California, January 26-27, 1989.

69. Discussion of "Cost of Electrical Power System Losses for Use in Economic Evaluations," by D.G. Boice, et al. Presented at the IEEE/PES 1988 Summer Meeting, Portland, Oregon, July 24-29, 1988.

Published in IEEE Transactions on Power Systems, Vol. 4, No. 2, May 1989, p. 593.

70. Discussion of "A Theory of Electricity Tariff Design for Optimal Operation and Investment," by R.J. Kay and H.R. Outhred. Presented at the IEEE/PES 1988 Summer Meeting, Portland, Oregon, July 24-29, 1988. Published in IEEE Transactions on Power Systems, Vol. 4, No. 2, May 1989, p. 613.

71. "Innovative Electric Utility Rate Design," presented at the 1989 APPA Accounting, Finance, Rates & Information Systems Workshop, Chicago, Illinois, September 19-21, 1989.

72. Discussion of "A Generalized Probabilistic Cost of Service Allocation Approach for Generation and Transmission Facilities," by K. Chu and R. Billinton. Presented at the IEEE/PES 1990 Winter Meeting, Atlanta, Georgia, February 4-8, 1990. Published in IEEE Transactions on Power Systems, Vol. 5, No. 3, August, 1990, p. 850.

73. "Competition in the Natural Gas Industry." Presented at the Natural Gas Conference, sponsored by the Center for Regulatory Studies, Chicago, Illinois, October 16-17, 1991.

74. "Economics for Transmission and Distribution Engineers." Presented at the T&D World Expo '92, Indianapolis, Indiana, November 10-12, 1992.

DR. ROBERT H. SARIKAS
UTILITY CONSULTING EXPERIENCE

Brief Description of Project

Niagara Mohawk Power Corporation.
A Long-Run Incremental Cost of Service Study, for both the electric and gas utilities along with a related time of day rate design study was prepared and sponsored before the New York Public Utilities Commission. Testimony has also been presented in connection with hearings dealing with Cogeneration, Generic Fuel Adjustment Clause, and Conservation Programs.

Assistance to Houston Lighting and Power Company. General consulting in terms of rate case preparation. Responsible for the presentation of an embedded cost of service study and related testimony before the Texas PUC in those electric rate increase applications. Testimony also presented before large Municipalities on behalf of Houston Lighting and Power. Preparation of an incremental cost of service study, and a report on interruptible cost of service and rate design.

Peoples Gas Light and Coke Company. Preparation of cost of service studies by rate class, along with related testimony before Illinois Commerce Commission in three rate cases.

Sherrard Power System. Preparation of rate base, rate of return, incremental cost of service, and rate design testimony in four rate cases. Also assignments with respect to fuel cost adjustment electric transmission planning, and negotiation of new wholesale power contracts.

British Columbia Utility Commission. Assistance to Commission Panel including preparation of a long-run incremental cost of service study and expert testimony with respect to cost analysis and rate design in connection with the rate design hearing of West Kootney Power Light Co.

British Columbia Utility Commission. Assistance to Commission Panel on technical rate design matters in connection with Power and Wheeling rates for West Kootney Power and Light Co. to be levied by B.C. Hydro and Power Authority.

Hennepin County, Minnesota. Assistance in the negotiation of a contract with Northern States Power Company for the sale of energy from a resource recovery plant.

Union Gas Company, Ltd. Testimony before the Ontario Energy Board in connection with the optimal use of gas underground storage capacity.

Consolidated Edison Company of New York. Preparation of a long-run incremental cost of service study including testimony before the New York Public Service Commission.

Report on Rate Concepts and Structures - BPA. Foster Associates was responsible for the preparation of a report for the Bonneville Power Administration on electric rate concepts and structures as they relate to pricing. Authors of the report are Dr. Robert H. Sarikas and Dr. Henry Herz. The report describes the principal rate design features which are proposed or presently in use, at the wholesale and at the retail rate level, including a detailed discussion of the advantages and disadvantages of each concept. The rate concepts explored include average cost pricing, marginal and long-run incremental cost pricing, capacity only pricing, commodity only pricing, time-of-day pricing, two tier rates, inverted rate structures, and life-line rates. An explanation was provided of the underlying theory including the social, economic, and political justification, along with the extent of use and the manner in which each theory is implemented in a rate structure. Other sections of the report discuss the effect on patterns of use and how utility customers might be expected to react given the use of these concepts. Research to date with respect to price elasticity of demand was also summarized in the report, and estimates developed for use by BPA.

North Shore Gas Company. Preparation of cost of service studies by rate class, along with related testimony before Illinois Commerce Commission in three rate cases.

Canadian Western Natural Gas Co. and Northwest Utilities Co. Testimony on cost analysis and rate design before the Public Utilities Board of Alberta.

Consumers' Gas Company. Preparation of Gas LRIC Study and testimony before the Ontario Energy Board.

Testimony on Behalf of Minnesota Public Service Commission. Presented testimony before the Minnesota Public Service Commission on their behalf in a Northern States Power Company rate case. The testimony was on cost analysis and rate design and addressed topics such as the objectives of rate design, the kinds of cost and their relative importance, revenue allocation among the various rate classes, and the relationship between value of service, cost of service, and welfare defined in terms of economic efficiency.

Assistance to Wisconsin Power and Light Company. Responsible for preparation of an embedded cost of service study with respect to wholesale rate classes, including related expert testimony before FERC.

Testimony on Behalf of Houston Lighting & Power Company in Generic Rate Cases. This testimony before the Texas PUC, dealt with rate costing and design methodology, including embedded cost and LRIC analysis, time-of-day pricing and related topics.

Assistance to Pennsylvania Public Utilities Commission Staff and Commission in Generic Rate Case. Foster Associates was a consultant to the Pennsylvania PUC Generic Electric Rate Case. Assistance was provided in terms of defining various issues, preparation of Staff cross examination of various utility and intervenor witnesses, presentation of expert testimony, and preparation of reports.

Sunshine Mining Company. Testimony in connection with objectives of rate design and importance of cost. Also, elements bearing upon the determination of class revenue and rate structure. Hearings before Idaho Public Service Commission in connection with adoption of Rate Making Standards.

Bonneville Power Administration Rate and Cost of Service Critical Review. Consultant to the Bonneville Power Administration in connection with the preparation of a critical review of the Staff's Rate Design Study, Fully Distributed Cost of Service Study, Long-Run Incremental Cost of Service Study, and Time-Differentiated Cost of Service Study. All of these analyses were prepared in conjunction with a proposed rate increase application filed with FERC.

City of Jamestown, New York. This assignment involved the preparation of a long-range plan for expansion of the power supply sources for the City of Jamestown, New York, which provided feasible solutions to the environmental problems faced by the Board of Public Utilities. Other assignments with Jamestown included the preparation of cost of service and rate design testimony for rate case presentation before the New York Public Service Commission, and assistance in negotiation of power purchase agreement with the New York Power Authority.

Illinois Power Company. Expert testimony before the Nuclear Regulatory Commission with respect to the economics of nuclear versus fossil generation and economics of site selection for the Clinton Nuclear Power Station. Also responsible for the presentation of electric load forecasts before the Nuclear Regulatory Commission in connection with that hearing as well as testimony in the area of energy conservation, electric ratemaking, and related topics. Other assignments for this client include cost of service and rate design studies and testimony.

Westcoast Transmission Company, Ltd. Expert testimony was presented on behalf of Westcoast regarding the pattern of regulation of natural gas prices in British Columbia and future considerations and alternatives.

Gas Company of New Mexico. Presentation of a forecasted rate base and expense and earnings statements before the New Mexico Public Utilities Commission.

Panhandle Gas Pipeline Co. Testimony before FERC with respect to the impact of competition upon the design of pipeline rates and tariff provisions.

United Gas Pipeline Co. Consulting assistance with respect to cost of service and rate design dealing with transportation and underground storage service.

U.S. Environmental Protection Agency. Prepared a report for the U.S. Environmental Protection Agency entitled the "Impact of Alternative Air Quality Requirements on Coal-Fired Power Plant Cost." This report analyzed the effect of proposed U.S. Senate and House legislation for preventing significant deterioration of air quality by reviewing the effect upon 53 existing and proposed electric generating plant sites taking into account meteorological criteria and terrain data. Alternatives such as site relocation were investigated. The report included the estimated cost of relocation for such items as additional electric transmission facilities, fuel transportation, and cooling water requirements.

Saskatchewan Power Corporation. Review of electric and gas cost analysis and assistance in rate hearings.

Midwest Natural Gas Company. Testimony on cost of capital before the Public Service Commission of Indiana.

Northern Illinois Gas Company. Provide a technical and an economic evaluation of the option of gas storage expansion coupled with a reduction of pipeline contract demand vs. maintaining current levels of contract demand, whether maintained as sales service or converted to transportation service.

Spartan Intrastate Pipeline System. Testimony before the Michigan Public Utilities Commission with respect to economic justification and costing and rate design for a new intrastate gas pipeline.

British Columbia Utilities Commission. Assistance to Commission's Panel including presentation of evidence on rate unbundling and related matters including a long-run incremental cost of service study in connection with Inland Natural Gas hearing.

Stora Forest Industries Ltd. Testimony and Exhibits before the Nova Scotia Board of Commissioners of Public Utilities in Nova Scotia Power Corporation Rate Case. Presentation dealt with design of rates for interruptible service.

American Gas Association. Co-Author of a report dealing with deregulation of natural gas sales to large industrial users.

U.S. Steel Corporation. Presented testimony and exhibits before the Illinois Commerce Commission dealing with electric interruptible service, in a Commonwealth Edison Co. general rate case.

U.S. Environmental Protection Agency. Prepared a research report for the Environmental Protection Agency on problems faced by electric utilities in scheduling generating units out of service. The report investigated the effect of various elements such as load factor, temperature-sensitive loads, load growth rate, reserve capacity requirements, forced and scheduled outages, load forecasting error, mix of generating capacity, capability of inter-connections, delays of scheduled operation, equipment derating, seasonal interchange, and numerous other factors.

Westcoast Gas Transmission Ltd. Presentation of testimony and exhibits with respect to unbundling of transmission tolls and other matters, before the National Energy Board (Canada).

Michigan Intrastate Pipeline System. Testimony before the Michigan Public Utilities Commission with respect to economic justification and costing and rate design for a new intrastate gas pipeline.

Douglas County Board of County Commissioners. Presentation of testimony and exhibits before PUC of Colorado in connection with need to uprate PS of Colorado 115 kV transmission line to 230 kV.

ICG Utilities (Manitoba) and ICG Utilities Greater Winnipeg Gas Company. Presentation of testimony and exhibits on cost analysis and rate design.

WPPSS. Selected as Witness for Washington Public Power Supply System, Defendent Northwest Utilities, and Others dealing with the "Ability to Pay" issue before the Federal Court in Tucson, Arizona. Extensive preparation and depositions before case was settled.

BC GAS INC.

WRITTEN EVIDENCE OF

J.O. WESSLER

Q. Mr. Wessler, please state your present position with BC Gas Inc.

A. I am Manager, Regulatory Accounting and Administration.

Q. Please describe your educational background and experience.

A. I am a member of the Certified General Accountants Association of British Columbia. I joined BC Gas' predecessor, Inland Natural Gas Co. Ltd., in 1969 as Chief Accountant, and became Assistant Controller in 1973 and Manager Forecasts and Regulation in 1978. In 1988, I was appointed to my present position.

Q. Have you previously testified before any regulatory bodies?

A. Yes, I have appeared before the British Columbia Utilities Commission and the Alberta Public Utilities Board.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with general information on the Company's three Fully Distributed Cost of Service Studies filed in Volume 2 under Tabs 2A, B and C.

Q. Have those studies been prepared under your direction?

A. Direction as to policy, methodology and structure of the studies was provided by Mr. D.J. Reed. The studies were carried out by Mr. E.A. Moore, Supervisor, Cost of Service and others reporting to him. My responsibility has been to give overall guidance and the verification of the end results. Mr. VanGenderen was also involved in reviews during development of the studies. Messrs. Reed and Moore will be available to answer any specific questions regarding policy, methodology and assumptions.

Q. Does that conclude your direct evidence?

A. Yes.

BC GAS INC.

WRITTEN EVIDENCE OF

<u>DANIEL J. REED</u>

Q. Please state your name, occupation, address, and qualifications to testify before the British Columbia Utilities Commission.

A. Daniel J. Reed, utility tariff consultant, 1065 East Prospect Street, Seattle, Washington 98102.

Q. Please describe your experience in regard to this proceeding.

A. I testified for BC Gas during Phase A of this proceeding regarding the allocation of natural gas costs.

I established my utility tariff consulting practice in 1963. My activities have been in electric power, natural gas, and water system tariff planning, rate and cost analysis, and energy resource evaluations. My clients have been utility regulatory commissions, public advocates, investor and publically owned utilities, and industrial intervenors. During the last 30 years, I have testified or assisted in rate case preparation in over 120 rate cases in the provinces of British Columbia, Newfoundland, and Ontario and in the states of Alaska, Arizona, California, Delaware, Florida, Georgia, Hawaii, Kansas, Louisiana, New Mexico, Nevada, Oklahoma, Oregon, and Washington. I have been an expert witness in electric power, water, and natural gas litigation in Alabama, California, and Washington.

I have conducted utility pricing seminars in United States, Canada, Europe, Africa, Asia, and Australia to over 1,300 participants since 1976. My Canadian seminars have been for British Columbia Hydro and Power Authority (1981), Gaz Metropolitain, Inc. (1984), and Alberta Public Utility Commission (1986). The seminar contents includes various utility analyses such as bill frequency analyses, forecasting sales and costs, modelling revenue requirements, fully distributed and marginal cost, rate design, demand elasticity measurements, and gas transportation. Examples of my publications on rate and cost analysis include Utility Rate Making; "Utility Rates under the National Energy Act, Quo Vadis?", a Public Utilities Fortnightly article; and "Training in use of Microcomputers and Regulatory Software", a NARUC/NRRI Regulatory Information Conference paper.

I have developed mainframe and microcomputer models for utility rate and cost analysis. I have developed computer models, trademarked RATEWARE, for natural gas, electric power, telephone, and water utilities. With regard to my Canadian utility modelling experience, I was engaged jointly by the Quebec Electricity and Gas Board and Gaz Metropolitain, Inc. to prepare a revenue requirement regulatory model to shorten the time frame required to evaluate rate cases. That activity was reported in "Use of Microcomputers in the Regulatory Process: The Experience of Regie de l'Electricite et du Gaz", a paper prepared jointly with Michel H. Cao of Quebec Electricity and Gas Board.

I received a BSEE from the University of Alabama in 1950. Since starting my practice in 1963, I have studied economics at UCLA in 1964-65 and accounting at the University of Washington from 1973-76.

Q. Please explain your participation in the preparation of the fully distributed cost of service studies.

A. I provided guidance and directions regarding functionalization, classification and allocation of costs as they related to the fully distributed cost of service for the Lower Mainland, Inland, Columbia, and Fort Nelson Divisions and consolidated BC Gas Inc. The Company's fully distributed cost work was performed under my general direction by Edward Moore, Suzanne Sue, and Tasso Tsalamandris, who are in the Regulatory Affairs group. Mr. Moore will address the details of the cost studies. I will address the general theory issues of the FDC's.

Q. Where can a description of the cost of service studies be found?

A. The studies are described in the national under Tab 2 of Volume 2. I am prepared to discuss the material under that tab.

Q. Does that conclude your direct evidence?

A. Yes.

BC GAS INC.

WRITTEN EVIDENCE OF

P. VAN GENDEREN

Q. Mr. Van Genderen, please state your name and business address.

A. My name is Peter C. Van Genderen. My business address is 5095 Pandora Street, Burnaby, B.C., V5B 1L5.

Q. Please describe your education.

A. I graduated from Queen's University in 1976 with a Bachelor of Applied Science - Mathematics and Engineering. Since graduation, I have taken courses in gas distribution, economics, finance, marketing, government and philosophy.

A. What is your occupation?

B. I am a consultant in energy planning, marketing and regulatory affairs. I am also a registered professional engineer in the provinces of British Columbia and Ontario. Since 1987, I have operated under the business name Van Genderen and Associates Engineering.

A. Will you please summarize your consulting experience?

B. My consulting practice has focused on serving energy clients in British Columbia. A majority of my consulting has been in connection with BC Gas Inc. and its predecessor Inland Natural Gas Co. Ltd., however, I have also been engaged by the Ministry of Energy, Mines and Petroleum Resources, BC Petroleum Corporation, Centra Gas, IPEC and indirectly by UBC.

Q. Please describe your consulting work with BC Gas?

A. I was first engaged for Inland's 1987 Rate Design Hearing on the gas deregulation issues prevalent at that time, and assisted in the development of the original Inland transportation services. I was engaged to support various Vancouver Island Pipeline applications and in the acquisition by Inland of the Lower Mainland gas distribution assets.

Since 1989, I have assisted BC Gas in numerous marketing and regulatory assignments, primarily in furthering deregulated rates, tariffs and contracts on their behalf. This has included the development of a number of industrial tariffs including those presented before the Commission in Phase A, negotiation of bypass rates for small and large industrial customers, and assistance in flowing through the utility's gas costs into rates. In this respect, I supported the development of the Phase A gas cost allocation methodology and the proposed Gas Cost Reconciliation Account mechanism in this application.

Q. Please describe your other experience?

A. Other consulting experience has related to independent power feasibility analysis, distribution system economic analysis, oil refinery analysis and gas exports.

Previous to my consulting practice, I was Manager, Planning (1985-1986) and Systems Planning Engineer (1980-1984) for Inland, was an Advisor to the Federal Ministry of Energy, Mines and Resources (1984-1985), and worked for Union Gas Limited)1976-1980) in southern Ontario.

Q. Will you please describe your role in this proceeding?

A. I have been involved in the development of the industrial rate schedules and have assisted in the analysis of rates, and in completion of the FDC and LRIC studies. I will be a member of a panel dealing with the FDC studies and a panel dealing with industrial rate schedules.

Q. Does this conclude your direct evidence?

A. Yes.

BC GAS INC.

WRITTEN EVIDENCE OF

EDWARD A. MOORE

Q. Please state your name, business address, and occupation.

A. Edward A. Moore, 1111 West Georgia, Vancouver, B.C., V6E 4M4. I am Supervisor, Cost of Service in the Regulatory Affairs group at BC Gas Inc. I report to Mr. J.O. Wessler.

Q. Please identify your experience in regard to this testimony.

A. I have been with BC Gas Inc. and its predecessor company, Inland Natural Gas Co. Ltd., for eleven years working in the Regulatory Affairs group. During this time, I have had experience in the preparation of revenue requirement applications, annual gas utilities reports for the British Columbia Utilities Commission and special projects analysis for other departments at BC Gas. I provided assistance in the preparation of the 1983 fully distributed cost of service study for Inland Natural Gas. I participated in the development and programming of the bypass models during the Inland rate design hearing in 1987.

I have a Bachelor of Commerce with a major in Transportation and Utilities from the University of British Columbia. I have completed my Master of Business Administration degree at Simon Fraser University with the exception of one course. I am a member in good standing of the Certified General Accountants Associations of British Columbia and Canada. I attended two rate design seminars, one by Barakat and Chamberlin, sponsored by the Commission, and by the Management Exchange, sponsored by

Public Utilities Reports, Inc.

Q. Please explain your participation in the preparation of the Test Year 1992 fully distributed cost of service studies.

A. I participated preparation of the Test Year 1992 Revenue Requirements in the Application and had primary responsibility for the development of the revenue requirements computer models. I reflected adjustments in the revenue requirements model after the Commission rendered its Decision, dated August 5, 1992.

I worked closely with Daniel Reed, a consultant to the Company, who is also presenting evidence in this proceeding. In order to gather data that are necessary to classify and allocate costs, Mr. Reed and I contacted a number of Company employees in gas supply, gas purchasing, gas dispatch, gas measurement, system design, financial accounting, measurement accounting, plant accounting, engineering, operations, facilities design, construction, marketing, taxation, and regulatory. We were assisted in our work by Suzanne Sue and Tasso Tsalamandris, who are in the Regulatory Affairs group.

We prepared fully distributed cost of service studies for each of the Divisions. Summaries of those models are contained in Volume 2, Tab 2. In general, I am available to answer questions relating to the process involved in preparing the fully distributed cost studies.

Q. What changes have been made to the FDC studies filed in April, 1993?

Q. The revised FDC material filed June 7, 1993 contains the following changes:

1. Substituted 1993 sales and transportation service forecast volumes, as revised.

2. Substituted 1993 forecast revenue, including PCEC and Burrard Margin in other revenue as revised.

3. Substituted 1993 Forecast Cost of Gas, as revised.

4. Increased General Property Tax and added annualized Corporate Capital Tax, as shown below:

	(000's)	
	Property Tax	Corporate Capital Tax
Lower Mainland	$306	$2,534
Inland	112	659
Columbia	12	69

5. Increased income tax rate to 44.84%, to reflect the permanent flowthrough in rates approved by the B.C.U.C. effective November 1, 1992.

6. Added sales to Columbia (under column heading "Other") in Inland Division.

7. Annualized Cranbrook Lateral in Columbia Division.

8. Revised customer class load factors (core market only) to correspond with 1993 cost of gas, which in turn modifies demand allocators.

9. Revised customer allocation factors after reflecting the number of customers in 1993 revised sales and transportation service forecast.

10. Pages 1.2, 2.2 and 3.2 have been added to the FDC study for each of the Divisions. On these pages the 1992 cost of service without cost of gas from pages 1.1, 2.1 and 3.1 (lines 11 and 13) have been grossed up by 1.0373 so that the costs (which are 1992 costs) equal the revenues less cost gas (which are 1993 revenues). The sum of the Division Adjusted cost of service without cost of gas (Pages 1.2, 2.2, 3.2 line 3) then equals the sum of the Divisional Gross Margins.

Q. Does this conclude your evidence?

A. Yes.

BC GAS INC.

WRITTEN EVIDENCE OF

E.C. EDDY

Q. Please state your name and present position with BC Gas Inc.

A. My name is Edward Constant (Ted) Eddy. I am currently the Manager, Gas Supply Regulation and Research ("GSR&R") of BC Gas.

Q. How long have you held that position?

A. Since December 1988.

Q. What are your responsibilities?

A. Reporting to the Vice President, Legal and Regulatory Affairs, GSR&R is responsible for all national and international regulatory matters including filings with the National Energy Board of Canada ("NEB"), U.S. Federal Energy Regulatory Commission ("FERC") and the U.S. Department of Energy ("DOE"). With respect to matters under provincial jurisdiction, the Department oversees Company efforts with respect to Gas Supply, such as filing of Gas Supply Contracts as per the B.C. Government "Domestic Natural Gas Supply Policy" under the Utilities Commission Act, Section 85.3; overseeing applications for Energy Removal Certificates ("ERC"), Energy Project Certificates ("EPC") and Certificates of Public Convenience and Necessity ("CPCN"). I was also Project Manager for the BC Gas Least Cost Integrated Resource Planning ("LCIRP") process and the SIPI-HIPCO International Pipeline System ("SHIPS"). I represent the Company on the Westcoast Toll and Tariff Task Force, the Pacific Cost Gas Association Rates and Regulatory Affairs

Section and sit on the Advisory Committee of the Canadian Energy Research Institute IRP/DSM Study.

Q. What were your previous positions?

A. I was employed by Hudson's Bay Oil and Gas Co. Ltd. from 1969 to 1973 in the Supply and Transportation Department and on leaving that company, I was senior Supply and Transportation Analyst. In 1973, I joined the staff of the Economics Department of the Alberta Energy Resources Conservation Board ("ERCB") and concentrated on forecasting crude oil and natural gas prices, as well as, oil, coal, petrochemical and fertilizer product and feedstock requirements. I was the ERCB representative to the industry's Statistical Supply Committee and the Economist-in-Charge of the Alberta Crude Oil Prorationing System.

Subsequent to leaving the ERCB in 1976, I joined Alberta Gas Trunk Line, now NOVA, Corporation of Alberta, where I attained the position of Manager, System Development Services. In this position I was responsible for, amongst other things, managing NOVA's Regulatory Affairs, Energy Demand Economics and Gas Supply modelling. I was NOVA's representative on both the CPA and IPAC Natural Gas Committees, the Pacific Coast Gas Association Gas Committee and the IPAC Economics Committee.

I joined B.C. Hydro and Power Authority in September 1981 as Supervisor of Gas Hearings and Regulations and held that position until October 1984, when I assumed the position of Supervisor, Gas Supply Contracts and Hearings. In addition, between March 1982 and June 1983, I was Project Hearing Manager of B.C. Hydro's Application for an Energy Project Certificate for the Vancouver

Island Gas Pipeline which was heard before the British Columbia Utilities Commission in 1983/84.

Q. Please outline your educational background.

A. I received a BA in Economics from the University of Calgary in 1972. I have augmented that degree with several post-graduate courses in finance, accounting, management and marketing in pursuit of B.Comm and M.B.A. degrees at that institution.

In addition, during my career, I have attended several employer sponsored courses including, but not restricted to, the following:

1. STONE AND WEBSTER
   Utility Management Course
   (May - June 1980);

2. UNIVERSITY OF TORONTO
   Regulated Company Management Course
   (June 1981);

3. SPROULE & ASSOCIATES
   Oil and Gas Economics Course
   (April 1975);

4. PROJECT MANAGEMENT
   B.C. Hydro & Power Authority
   (June 1982).

Q. Have you testified before Regulatory Boards and Commissions on previous occasions?

A. Yes, I appeared as a witness on behalf of Alberta Gas

Trunk Line before the ERCB, in July 1976, in conjunction with an Industrial Development Permit Application for a Benzene Refinery. I also appeared as a witness for B.C. Hydro, in British Columbia, at the 1982 Govier Commissioner Inquiry on British Columbia's Requirements, Supply and Surplus of Natural Gas and Natural Gas Liquids. In 1989, I appeared in front of the BCUC as a witness in an inquiry called under BCUC Order No. GH-4-89 on BC Gas Lower Mainland Rate Design. In April 1992, I appeared in front of the FERC as a witness on behalf of Sumas International Pipeline Inc. ("SIPI") at a Technical Conference in conjunction with FERC Docket Nos. CP92-259, CP92-247, CP92-336 and CP92-383.

I have also appeared as a witness at the National Energy Board in the following proceedings called under NEB Orders as noted:

GHR-1-78	Natural Gas Supply and Requirements
GHR-2-85	Phase I - Gas Export Omnibus Hearing
RH-6-85	Westcoast 1986 Tolls Application
RH-1-87	Westcoast Application of 12 February 1987
GHR-1-87	Natural Gas Surplus Determination Procedures
RH-2-87	Westcoast Toll Application of 19 December 1986
RH-1-89	Westcoast Toll Application of April 1989
GH-4-89	BC Gas Applic. - Gas Export & Import Licence
RH-1-90	Westcoast Toll Application of June 1990
RH-3-92	Westcoast Toll Application of July 1992

Q. What is the purpose of your testimony?

A. As LCIRP Project Manager up to 31 May 1993, I had overall responsibility for coordinating the development of the BC Gas Integrated Resource Planning process and the publication of the "Draft" LCIRP and Executive Summary circulated to potential stakeholders, including the BCUC, in July 1992. The purpose of my testimony here is to support the approval of the BCUC of the deferral account treatment applied for in our Application of 30 April 1993.

Q. Could you briefly describe the development of the BC Gas LCIRP?

A. In the Fall of 1990, BC Gas identified the need to integrate its long-term planning functions under the umbrella of a more formal framework in response to further deregulation, its new responsibility to develop a portfolio of gas supplies for the "Core Market" and it's commitment to encourage wise and efficient use of natural gas. Research commenced in the identification of those aspects of the LCIRP which would have some use for gas utilities in general and BC Gas in particular. BC Gas developed a Mission Statement, Objectives and LCIRP Goals in the Spring of 1991 and an LCIRP Team was assembled from all corners of the BC Gas Organization. Development of the LCIRP was suspended to concentrate on the new BC Gas gas supply portfolio and requisite flow through and Revenue Requirement filings with the BCUC following development of the initial range of provincial long-term energy and service area natural gas forecasts in August 1991. Subsequent to receipt of BCUC comments on the Draft LCIRP in December 1992 and finalization of the BCUC Integrated Resource Planning ("IRP") guidelines in February 1993, BC Gas made a filing in April 1993 updating the IRP and answering some requests and implementing suggestions by the BCUC. In preparation for filing a new IRP in December 1993, BC Gas has created a new department to elevate IRP from "project" status and to give IRP a new full-time focus.

Q. What is the purpose of your 30 April 1993 Application?

A. The purpose of our 30 April 1993 Application is to gain BCUC approval for the deferral accounts listed under Tab 3 in the Application for Development Costs so that the new IRP Department can forge ahead in enhancing the IRP process within BC Gas and meet major expectations of the BCUC for more rigorous application and integration of IRP in BC Gas' planning.

Q. Are there any amendments to the 30 April 1993 filing?

A. Yes, at Tab 2, Page 3 under the second "bullet", the in-service date should be 1994 not 1993 as shown. In addition, the dates to allow for procurement and construction activities are to meet the demand of all customers so we would strike the words "Core Market" and amend the dates to 1994-95.

Q. Are there any additions to the 30 April 1993, Tab 3 Applications for Deferral Accounts?

A. Yes. As detailed in response to BCUC Staff Information Request No. 1, Part B, Item 9, BC Gas has identified the need for an additional $160,000 which represents the costs for Residential and Commercial surveys. In addition, in order to accelerate the development of the Monitoring Study Strategy Document, an additional $35,000 for outside consultants during 1993 should also be added to the Deferral Account Application. This would bring the total applied for deferral account amount to $2,000,500.

Q. Does that conclude your direct evidence?

A. Yes.

BC GAS INC.

WRITTEN EVIDENCE OF

<u>IAN PHILIP WIGINGTON</u>

Q. Please state your name and present position with BC Gas Inc.

A. My name is Ian Philip Wigington. I am currently a Senior Analyst in the Gas Supply Regulation and Research ("GSR&R") Department of BC Gas.

Q. How long have you held that position?

A. Since November 1990.

Q. Please outline your employment history.

A. From October 1986 until October 1990 I was employed by the B.C. Ministry of Energy, Mines and Petroleum Resources, initially as a Research Officer responsible for the provincial gas royalty revenue forecast, the provincial gas price forecast, and the provincial gas export forecast, and then as a Policy Analyst reviewing the implications of regulatory and market factors on the B.C. gas industry.

Q. Please review your academic qualifications.

A. I hold a Bachelor of Arts degree (1978) from the University of Calgary and a Master of Science degree (1987) in Agricultural Economics from the University of British Columbia.

Q. What are your current responsibilities at BC Gas?

A. Reporting to the Manager, Gas Supply Regulation and

Research, I am responsible for co-ordinating the development of the Company's Demand-Side Management ("DSM") programs. I am also responsible for the BC Gas Long Run Incremental Cost study.

Q. Have you previously testified before any regulatory bodies?

A. No.

Q. What is the purpose of your testimony?

A. As Coordinator of Demand-Side Management development, my testimony concerns the development of the DSM pilot programs and associated budgets for which BC Gas is requesting deferral account treatment. I will also discuss the long run incremental cost study.

Q. Would you review the process of developing the BC Gas DSM pilot programs?

A. In late 1990, shortly after joining BC Gas, I was directed to begin investigating demand-side management as it pertained to gas utilities and to BC Gas. Subsequently, we recommended to management that BC Gas actively pursue DSM. In early 1991, the Company began investigating DSM efforts in other jurisdictions in order to identify possible programs that BC Gas might run as DSM pilots. Also begun at this time was a preliminary investigation into DSM evaluation methods. In the spring of 1991 we brought in Dr. Dan Violette of RCG/Hagler, Bailly, Inc. ("RCG/HBI") to give a seminar on DSM program development and evaluation. This led to a contract with RCG/HBI to work with BC Gas staff in developing a method for determining the value of gas saved through conservation and efficiency programs and development of a series of benefit-cost tests for screening pilot programs. These methodologies provided BC Gas with the tools necessary to analyze benefits and costs associated with DSM programs.

With these tools in place, we were able to begin collecting the program-specific data needed for screening prospective pilot programs.

Q. Would you outline the approach taken by BC Gas in determining the value of gas saved through DSM programs?

A. A major reason for contracting with RCG/HBI was their experience with the Targeted Marginal Cost ("TMC") approach to gas valuation. RCG/HBI pioneered this approach, which assigns the costs associated with specific gas supply sources to specific end uses. Working with our Gas Supply Planning staff, RCG/HBI was able to incorporate the TMC approach into the existing Gas Supply Optimization Model ("GSOM"), thereby obtaining more accurate gas marginal cost estimates than would otherwise have been possible (Appendix D(2), draft LCIRP). Because the GSOM is used for selecting optimal future supply resources, this "modified TMC" gas valuation approach provides the mechanism for integrating supply-side and demand-side resources.

Q. How are supply-side and demand-side resources integrated?

A. Using the BC Gas service area demand forecast as one of the key input parameters, the GSOM is used to determine the most cost effective gas supply resource mix. The marginal gas supply costs derived from the GSOM constitute one of the input parameters into the benefit-cost tests used for selecting DSM pilot programs. Gas savings resulting from the DSM programs are factored into a "DSM-adjusted" demand forecast which is then fed back into the GSOM. If changes to the demand forecast are significant, the GSOM would select a different supply-side resource portfolio resulting in new marginal gas supply costs. These new marginal supply costs would then feed back into the benefit-cost analysis used for selecting DSM programs, and the process would repeat. This iterative process would continue until a stable and optimal solution was achieved, consisting of a set of demand-side and supply-side resources. The process is shown in Chart 9-1 on page 9-3 of the draft LCIRP.

As it turned out, because the proposed DSM pilot programs are small in scale, the projected effect of DSM on gas consumption was within the margin of error of the demand forecast and only one iteration was needed.

Q. As part of this deferral account application, BC Gas is applying for funding to develop a resource optimization model ("ROM"). Could you explain why this model is needed?

A. As discussed above, the process of optimally selecting demand-side and supply-side resources is accomplished using an iterative mechanism involving the Gas Supply Optimization Model and a series of benefit-cost tests. This integration process has been adequate to screen the DSM pilot programs since only one iteration was required. BC Gas anticipates that expansion of successful DSM pilots to full scale programs may result in gas savings which significantly impact future gas demand. When this occurs, it is likely that more than one iteration of the integration process will be required, adding considerably to the complexity of the analysis. If BC Gas is to be able to optimally select demand-side and supply-side resources, a less cumbersome integration mechanism is required. The ROM model, as outlined in the LCIRP Action Plan (LCIRP Objective 2), would provide BC Gas with this integration capability.

Q. How does BC Gas account for environmental factors in analyzing DSM programs?

A. The benefit-cost analysis used for screening the pilot programs consists of five separate tests, one of which, the Societal Test, requires the explicit incorporation of externalities. To address this requirement, the firm of G.E. Bridges and Associates Inc. was contracted to quantitatively determine the externalities associated with natural gas use in the BC Gas service territory. The study is attached as Appendix E in the "Draft" LCIRP.

Q. Could you describe the DSM pilot programs BC Gas ~~in~~ is proposing?

A. The selected pilot programs have been confined to the residential sector. Three pilot programs are being proposed: the Hot Water Saver Program; the R2000 Energy Efficient New Home Program; and the Customer Energy Education and Information Program. These programs are described in Tab 7 of the April 1993 Deferral Account Application.

Q. Are there DSM opportunities in the industrial market?

A. A preliminary survey of the industrial market indicated that while viable DSM opportunities may exist, more detailed customer-specific analysis is required. BC Gas is proposing to survey industrial customers (Appendix 3, Tab 7, April 1993 Deferral Account Application) and depending on survey results, run an energy audit program. Also proposed is an Energy Audit Course for industrial customers. These programs are described in Tab 7 of the April 1993 Deferral Account Application.

Q. Please describe your role in the preparation of the Long Run Incremental Cost (LRIC) Study.

A. I had primary responsibility in developing the LRIC Study. I was assisted in the task by Dr. G.C. Watkins, a consultant to BC Gas who is also presenting evidence in this proceeding.

Data, information, and assistance used to derive LRIC estimates were obtained from BC Gas staff in system planning, operations engineering, and regulatory groups. A description of the methodology used in the LRIC Study together with LRIC estimates are given in Volume 2 Tab 3.

Q. Does this conclude your evidence?

A. Yes.

BC GAS INC.

WRITTEN EVIDENCE OF

IAN PHILIP WIGINGTON

EVIDENCE TO BE FILED AT A LATER DATE

BC GAS INC.

WRITTEN EVIDENCE OF

DR. G.C. WATKINS

Q. Dr. Watkins, please state your present position and company name.

A. I am President of DataMetrics Limited, Calgary, Alberta.

Q. Please describe your educational background and experience in the natural gas industry.

A. I have a PH.D. in Economics from the University of Aberdeen, an M. Phil. from the University of Leeds and an Honours B.A. (Economics and Statistics), also from the University of Leeds. I am a Fellow of the Royal Statistical Society.

From 1965 to 1969 I was Chief Economist and Manager of the Economics Department at the Alberta Energy Resources Conservation Board.

I joined the Royal Bank of Canada in 1970 as an Associate Economist and worked there until 1971.

In 1971 I joined Gas Arctic Systems as Director of Economic Studies and worked there until 1972.

In 1973 I became President of the economic consulting firm of DataMetrics Limited.

Much of my work with the Alberta Energy Resources Conservation Board, Gas Arctic Systems (as the name implies) and with DataMetrics Limited has concerned various aspects of the natural gas industry.

Q. Please describe your other business and related activities.

A. I have had an appointment as adjunct Professor of Economics at the University of Calgary since 1973. I have served as: President of the International Association For Energy Economics in 1991; Petroleum Advisor to the Minister for the Ministry of Minerals and Energy, United Republic of Tanzania, 1987; Consultant for the Ministry of Finance, Government of Indonesia, 1987; and as President of the Economics Society of Alberta 1966-67. I serve on journal editorial boards, act as an article referee and have published many articles dealing with natural gas. I am also a member of the Energy Data Committee of the American Statistical Association.

Q. Have you previously testified before the British Columbia Utilities Commission?

A. Yes.

Q. Did you have input into the contents of Tab 3, "Long Run Incremental Cost Studies" and Tab 4, the "Competitive Energy and Price Elasticities of Demand Studies" contained in the Application to the British Columbia Utilities Commission by BC Gas Inc. to Amend its Schedule of Rates, Volume 2, Rate Design Phase B, dated April, 1993?

A. Yes I did.

Q. What was your contribution to the "Long Run Incremental Cost Studies"?

A. I provided some general assistance during the preparation of this study concerning the calculation of capacity costs for lumpy investments, levelized transmission costs, allocation of annualized costs to demand sectors, allocation of operating & maintenance costs to facilities for peaking, distribution and transmission, and statistical cost analysis. And I reviewed text drafted by BC Gas. I also provided specific assistance in the definition and calculation of capital carrying charges. Moreover, Appendix B in the study, "Salient Aspects of Other LRIC Studies" was prepared under my supervision.

Q. What was your contribution to the "Competitive Energy and Price Elasticities of Demand Studies"?

A. My role was one of general assistance in Section 2.0, "Estimates of Natural Gas Price Elasticities of Demand", and Section 3.0, "Measuring the Impact of a Change in the Price of Natural Gas on Demand Using Econometric Model Simulations".

The econometric models used to generate price elasticities in Sections 2.0 and 3.0 partly relied on the framework adopted by DataMetrics Limited for B.C. Hydro in 1982.[1] These models were used as the starting point for the elasticity analysis since tests by BC Gas indicated they had provided quite adequate projections of energy and individual fuels demand for B.C.

More specifically, our work included: a review of the new equations generated by BC Gas; provision of data from 1961 to 1979 on the prices of petroleum products, coal

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[1] DataMetrics Limited, "Projections of British Columbia Energy Demand: Residential, Commercial and Industrial Sectors, 1982-2001", September 1982.

and natural gas liquids; provision of data and the methodology to calculate the new housing stock variable; advice on statistical tests and corrections; advice on price indexes; advice on the treatment of share equations; and reviewing text drafted by BC Gas.

Q. Does this complete your direct evidence?

A. Yes, it does.

BC GAS INC.

WRITTEN EVIDENCE OF

JOHN GILLIES

Q. Please state your name and position with BC Gas Inc.

A. My name is John Gillies. I am a Senior Analyst in the Gas Supply Regulation and Research Department of BC Gas Inc.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Arts degree with a major in economics from Simon Fraser University in 1977. I entered the Graduate program in economics at Simon Fraser University in 1978 and eventually earned a Masters Degree in Economics from Carleton University in 1986.

From November 1979 to May 1982 I was a Research Analyst in the B.C. Ministry of Finance. I was also employed by the National Energy Board as Energy Supply Economist from June 1983 to September 1988. I have held my current position with BC Gas Inc. since September 1990.

Q. What are your responsibilities in your current position?

A. My major responsibility is to produce long term natural gas demand and customer forecasts for the BC Gas service area. I also provide economic analysis and data for a variety of projects undertaken by the company.

Q. Have you testified before a regulatory board or commission on previous occasions?

A. This is the first time I have testified before a regulatory commission or board.

Q. What is the purpose of your testimony?

A. I had the primary responsibility within the Company for preparing the competitive energy and national gas price elasticity studies which are found at Tab 4 of Volume 2. I will answer questions relating to the contents of those studies.

Q. Does that conclude your direct evidence?

A. Yes.

BC GAS INC.

WRITTEN EVIDENCE OF

<u>JOHN C. ("JACK") TOUHEY</u>

Q. Please identify yourself and your title at BC Gas.

A. My name is John C. ("Jack") Touhey and I am the Manager, Special Projects. I have held this position since December 1992 and I am currently assigned to work on the Company's Rate Design application.

Q. Please state your academic and business experience.

A. I am a graduate of Simon Fraser University with a Bachelor of Arts degree, Commerce and Economics. I joined Inland Natural Gas in 1980 and worked as a Branch Manager in Prince George and Kamloops until 1986. I then became a Marketing Supervisor for Inland's Natural Gas for Vehicles program until 1987 when I left to join International Forest Products Ltd.(Interfor) in Vancouver. At Interfor I held a number of production and sales positions at various sawmills in the Lower Mainland. I joined BC Gas in 1990 as Manager, Natural Gas for Vehicles and held that position until assuming my current position.

Q. Please describe your professional affilations.

A. From 1990 to 1992 I was a member of the Canadian Gas Association Natural Gas for Vehicles Development Committee. I am currently a member of the Rotary Club of Vancouver.

Q. Have you appeared as a witness before any regulatory authorities?

A. No.

Q. What is the purpose of your testimony?

A. I will speak the proposed rate structures and levels for residential, small and large commercial, and general service customers as part of the Company's panel on Non-Industrial Rates and Tariffs, including the proposed changes to the Application for Service Fees. As well, I worked on the Company's proposed revision to the main extension policy and test. I will speak to issues related to the Company's main extension policy and test with the support of Mr. Powell. In addition, I will speak to matters related to the Companys' proposed changes to the Natural Gas for Vehicles (NGV) rates.

Q. What was your involvement in the designing of the proposed residential, commercial, and general service rates?

A. I was involved in the development of the rate design proposals for these customer classes. During the process of developing the submission, significant attention was paid to designing rates that would meet a number of rate design principles such as fairness, cost recovery, and energy efficiency while always being aware of the impact such rates would have on our customers.

Q. What was your involvement in the proposed revision to the Company's main extension policy and test?

A. With the assistance of members of our Engineering and Regulatory Affairs departments, I analyzed the existing main extension tests for the Lower Mainland, Inland, and Columbia divisions. The analysis has shown that differences exist between divisions and a uniform policy and test should be implemented. Furthermore, the accuracy of the test could be improved by moving to a more sophisticated economic test. A key consideration in the proposed revision of the main extension policy is the desire of the Company to provide gas service on a broad basis and to serve those parts of our service area that currently do not enjoy the benefits of natural gas.

Q. What role did you have in developing the proposed changes to NGV rates?

A. As Manager, NGV for the period 1990-1992 I developed and implemented many of the NGV programs currently in place at BC Gas. As well, I have considerable experience in dealing with NGV customers, particularly those who retail NGV at service stations. I advised the current NGV Manager who prepared the material under Volume 1, Tab 10 of the application.

BC GAS INC.

WRITTEN EVIDENCE OF

DAVID A. PERTTULA

Q. Please identify yourself and your title at BC Gas.

A. My name is David Perttula. I have worked for BC Gas since August 1990 in the Regulatory Affairs Department. I was assigned my current position, in June 1991, as Supervisor, Regulatory Reporting and Tariffs.

Q. Please state your academic, professional and business experience.

A. I have a Bachelor of Science - Chemistry major from the University of Western Ontario, a Masters of Business Administration from McMaster University and a degree in Theology from Regent College (U.B.C.). I have about 8 years of experience in natural gas distribution, oil and gas and petrochemicals.

My work with BC Gas has involved the preparation of numerous reports and applications for filing with the B.C.U.C. Included are the 1993 Revenue Requirements Application (withdrawn as per B.C.U.C. Order G-33-93), various gas cost flow-through applications, other flow-through applications, responses to information requests and annual utility reports. I developed the gas cost flow-through model for the Lower Mainland and Inland Divisions approved in the Rate Design Phase A Decision dated February 21, 1992 and appeared as a witness in the Phase A hearing. More recently, I have supervised the development of the model for reporting on the Gas Cost Reconciliation Account.

Prior to joining BC Gas I worked for more than three years as an economist in the oil and gas industry. In this position I performed economic analyses for a broad range of capital investments, including exploration and development drilling prospects, enhanced recovery projects, gas plant construction and acquisition/ disposition opportunities. I also prepared studies used in submissions to governments on matters relating to royalties, taxation and incentive regimes. I also worked as a market supply analyst in the petrochemical industry for one and one-half years.

Q. What is the purpose of your testimony?

A. I will explain the operation of the Gas Cost Reconciliation Account. This pertains especially to the materials in Tab 14 of the revised application filed June 7, 1993.

BC GAS INC.

WRITTEN EVIDENCE OF

D.H. SMITH

Q. What is your name and present position?

A. My name is Don H. Smith. I am a senior Planning and Forecast Coordinator, with the Planning & Forecasts Department, BC Gas Inc. I have held this position since 1989.

Q. Please state your educational background and business experience.

A. I am a graduate of the British Columbia Institute of Technology (BCIT), in the Civil and Structural Engineering discipline. I am a member of the Applied Science Technologists and Technicians of British Columbia (ASTBC) registered as an Applied Science Technologist. I joined B.C. Hydro in 1981, and have held numerous positions within the Company. Between 1981 and 1983 I was a member of the Electrical Transmission Planning group. In 1983, I joined the Gas Supply Planning department in B.C. Hydro's Gas Operations Division. In 1989, I transferred to the Planning and Forecasts department of the newly formed company BC Gas Inc.

Q. Please indicate the regulatory Boards or Commissions that you have appeared before as a witness.

A. I have previously testified before the British Columbia Utilities Commission on behalf of BC Gas Inc. in the 1992 Revenue Requirement Hearing as a member of the Marketing, Sales & Revenue Panel.

Q. What are your principal responsibilities as Senior Planning and Forecast Coordinator?

A. Reporting to the Manager of Planning and Forecasts, my principal responsibilities are the weather normalization of historic use per customer statistics, the coordination and modelling of the short term sales forecast, and the generation of revenue projections for the company.

Q. Please outline the problems that were experienced with the Company's proposed Weather Stabilization Account Mechanism (WSAM) that was filed with the Company's 1993 Revenue Requirement Application.

A. During the month of January, and into February 1993, the temperatures in the BC Gas service area were unusually colder than normal. A review of the actual consumption relating to temperature sensitive customer classes indicated that after applying the WSAM mechanism to actual volumes and revenues the Company was left with a significant negative variance to test year projections.

Q. Has the company attempted to determine the cause of the unusual results?

A. The company has and continues to attempt to determine the cause of the erroneous results, but unfortunately without success to date. We have gathered additional weather statistics and billing information to try and help us understand the unusual customer response to this winter's weather pattern. But at this time the cause is still speculative. We believe that a number of factors may have caused a reduction in the customer's response. However to prove so mathematically is not an easy exercise and may not even be possible. If we are not successful at finding the cause, or unable to correct the WSAM mechanism to mitigate the results, even though the weather pattern experienced was unusual, there is no guarantee it will not repeat itself in the future.

Q. Does this end your testimony?

A. Yes it does.

BC GAS INC.

WRITTEN EVIDENCE OF

D.H. SMITH

EVIDENCE TO BE FILED AT A LATER DATE

Inter Office Memorandum

(P) Rate Design

BC Gas

TO: DM Masuhara

FROM: TA Loski

SUBJECT: Rate Design Hearing Preparation
Your Memo Dated May 26th 1993
WSAM / Decoupling

PDL
CBJ
JON
comments?

DATE: May 27th, 1993

Item #5 of Mr. Johnson's memo dated May 21st 1993 indicates that evidence relating to a workable WSAM or decoupling should be filed by June 7th 1993. Please be advised that the only workable WSAM mechanism currently available, one which would meet senior management's expectations, is the mechanism that was proposed and accepted by the BCUC on an interim basis in April 1993. This mechanism is the same technique that was proposed last Fall that Mr Sherwin would not agree with. Specifically adjusting monthly residential and commercial gas sales revenues by the margin impact of the volume adjustment calculated by taking the difference between the actual and test use per customer multiplied by the actual number of accounts multiplied by the appropriate unit margin. The only consideration that should be addressed is the application of a deadband (1%, 2%, or greater) around the test use per customer and the months in which the adjustment mechanism is to be applied. Both of these considerations would interject risk to the Utility which should somewhat alleviate concerns centred around the allowable rate of return.

Planning retained the services of Mr. Bill Eyers to review BC Gas' filed WSAM proposal, to review similar adjustment mechanism used by other utilities and to compare them with BC Gas' filed WSAM. His report, while still in draft form, concludes that there is nothing theoretically wrong with BC Gas' filed proposal, and that other utilities have conceptually structured their mechanisms under the same approach. He feels that the application and problems experienced are of unfortunate timing and unforeseen and unforeseeable circumstances. His recommendation was that we seek relief from the operation of the original WSAM mechanism for this past winter (which we did).

In addition to his review, Mr. Eyers suggested a few courses of action to explore in working towards a modified WSAM application. However, not only will his suggestions require considerable time and resources, it could end up impacting on our overall approach to normalization. In addition there is no guarantee that a workable solution will be found.

Given the uncertainty surrounding the future application of the filed WSAM proposal, and the fact that a modified version is and will not be immediately available with no guarantee of success, Planning recommends that if senior management is not comfortable with a decoupling approach, the Utility adopt the "test year userate" solution as outlined above.

CC: D.G. Besel
A.F. Toselli

BC GAS INC.

WRITTEN EVIDENCE OF

STANLEY P. CROCKER

Q. Please identify yourself and your position at BC Gas Inc.

A. My name is Stanley Crocker. I joined BC Gas in August of 1989 and have held my current position of Manager, Rate Design since July 1990. I am responsible for rate design related matters of the Company.

Q. Please state your academic, professional and business experience.

A. I graduated from the University of British Columbia with a Bachelor of Applied Science degree in Mechanical Engineering and the University of Calgary with a Master of Business Administration degree. Prior to joining BC Gas, I worked for Alberta and Southern Gas Co. Ltd., Alberta Natural Gas Company Ltd., and Pan Canadian Petroleum Ltd. with assignments in the areas of regulatory affairs, project economics, pipeline operations engineering and pipeline system design. I am a registered professional engineer in British Columbia and Alberta. I represent the Company on the Rates Committee of the American Gas Association.

Q. Have you testified before regulatory boards and commissions on previous occasions?

A. No.

Q. What is the purpose of your testimony?

A. I will discuss how BC Gas has implemented its rate design objectives and discuss the processes involved in arriving at our non-industrial rate design proposals, including the new tariff General Terms and Conditions. I will also discuss discounts for handicapped, low income or senior customers.

Q. What objectives did BC Gas have in preparing its rate design proposals?

A. The major objectives were fairness, economic efficiency, stability, gradualism and conservation. The overall rate structure for non-industrial firm service is a two-part structure consisting of a postage stamp basic charge and a postage stamp delivery charge. We believe the proposed rate design meets our objectives as follows:

1. Fairness - Under the proposed rates similar customers pay the same margins for utility services. The Phase A gas cost allocation methodology recognizes the differing gas supply costs and transmission distances to Lower Mainland, Inland and Columbia customers.

2. Economic Efficiency - The rate design proposal, both through the higher basic charges and delivery charges, is more in line with fully distributed and long run incremental costs for each class. The proposal recognizes the rate classes which use the system more efficiently and considers the price of competing energy sources.

3. Stability - The BC Gas proposal achieves higher stability in annual bills and revenues through the higher basic charge.

4. Gradualism - Where the proposal has increased customer's bills, consideration has been given to a

phase-in of the increases.

5. Conservation - The Company's objective is to ensure its pricing signals are not inconsistent with conservation. An example is the removal of the declining block delivery charges for the residential, commercial and general classes.

RESIDENTIAL PROPOSAL

Q. Please summarize the process used to arrive at the proposed $7.00 basic charge.

A. We determined a $7.00 basic monthly charge best met the Company's rate design objectives. The higher basic charge has advantages in pricing for low volume customers, such as those with only a hot water tank or fire place set, since the utility's fixed meter, service and mains costs are very similar to the costs for larger volume space heating customers. Other Canadian gas utilities also have basic charges in the range of $7.00 per month or higher. We analyzed billing and cost data to help judge the appropriate level for the basic charge as follows:

1) Billing Data

The ogive curves for the Lower Mainland, Inland and Columbia areas at Tab 6, Pages 26, 27 and 28 show that 60 to 65% of the monthly residential bills each year are below 10 GJ per month. The postage stamp $7.00 basic charge seeks to somewhat stabilize revenue and move rates more in line with the FDC and LRIC, especially for those customers who consume less than 10 GJ per month.

2) Cost Data

The $7.00 basic charge will remain considerably below the

FDC customer related costs of $11.33, $12.11 and $13.62 per month in the Lower Mainland, Inland and Columbia service areas respectively.

Q. What are the considerations underlying the proposal for uniform delivery charges for residential customers?

A. A flat delivery charge is consistent with our objective of removing pricing signals that may conflict with conservation. BC Gas has not developed monitoring programs to measure rate impacts on conservation nor have we obtained conclusive evidence from the work in this area by other utilities. The demand elasticity study results in Volume 2, Tab 4, Page 28 show a relatively inelastic response to price changes in the residential class. In the absence of more conclusive data on which to base rates designed to achieve conservation we ensured our proposal was not inconsistent with conservation.

The following comparison from Tab 6, Pages 23 and 24 compares existing and proposed delivery charges:

Residential Delivery Charges ($/GJ)

	Lower Mainland		Inland		Columbia	
Existing						
	0-500 GJ	$1.503	0-10.5 GJ	$2.105	all GJ	$1.483
	501-8000 GJ	$1.013	>10.5 GJ	$1.595		
Proposed						
	all GJ	$1.540	all GJ	$1.540	all GJ	$1.540
Forecast 1993 Customers	414,450		145,180		14,910	
% of customers	72%		25%		3%	

The postage stamp delivery charge is higher than the existing delivery charges for Lower Mainland and Columbia (75% of residential customers), while the Inland service area (25% of residential customers) margins are reduced somewhat.

Q. Please summarize the process used to arrive at the proposed $1.54 per GJ postage stamp delivery charge.

A. The proposed general and large volume firm and interruptible rates resulted in a $10.8 million shift in revenue from those classes which must be recovered from the residential class. The existing commercial class revenue to cost ratios and bill impacts also indicated a shift in revenue of $2.9 million from this class.

The net effect of the revenue shifts was to increase the revenue level at which the residential postage stamp delivery charges were calculated. For the reasons noted above we decided the $7.00 basic charge was an appropriate level at which to calculate the delivery charge to match the required residential class revenue. The resulting $1.54 per GJ delivery charge was consistent with our conservation objective since, for three-quarters of our customers, we now have a uniform delivery charge slightly higher than the existing delivery charge.

Q. Did the gas cost recovery determined by the Phase A gas cost allocation methodology change for any of the residential customers?

A. During Phase A, the Lower Mainland gas costs for the residential, commercial and small firm industrial classes were determined on an average basis only. In Phase B we have now calculated separate gas costs for residential, commercial and general customers. These separate gas costs reflect the class load factors and efficiency with which each class uses the production and pipeline facilities. The Lower Mainland residential class gas cost recovery increases as a result by $0.04 per GJ. The existing and proposed gas cost recoveries for all classes are presented in Tab 11, Table 1.

Q. Did you consider customer bill impacts in arriving at the postage stamp proposals?

A. Yes, we considered the annual and monthly bill impacts for customers. We checked the impacts for high, medium and low consumption customers, both with and without the implementation adjustments as outlined in the Application. The implementation adjustments include a reduction due to revised application fees, allocation of forecast off-system sales revenues, disposal of deferral account balances and reductions in certain depreciation rates. In addition, we believed it would be reasonable to use the Columbia deferred income tax balance to assist phasing in Columbia rate changes over 2 years, which bring the Columbia changes more in line with those anticipated for the Lower Mainland.

Q. Has BC Gas considered discounts for handicapped, low income or senior customers in its rate design proposals?

A. We have reviewed the income versus consumption data obtained from the 1990 Residential Energy Use Survey which shows no discernable correlation between income and consumption. The survey showed a number of low income, high consumption customers which concerned us since their gas bills would be a greater overall portion of their disposable income. The proposed higher basic charge to some extent moderates the proposed delivery charge level and corresponding impact on customers with special needs to the extent their gas consumption may be high. BC Gas believes there are more effective means to assist low income, handicapped and senior citizens households, such as government assistance programs than through rate design.

COMMERCIAL PROPOSAL

Q. Please summarize your reasons for proposing two standard commercial classes, one for customers below 2000 GJ per year and the other for customers above 2000 GJ per year.

A. The proposed standard classes represent a compromise in achieving our rate design objectives of equity, efficiency, stability, gradualism and conservation.

The existing commercial customers are classified differently in each of the areas as follows:

Lower Mainland	Inland	Columbia
with and without space heating	above and below 6000 GJ per year	no current distinction

In considering efficient use of gas we reviewed the load factors of various groups of commercial customers and found that the load factor for customers with annual consumptions below 2000 GJ (90% of all commercial customers) was lower than the residential class. At about 2000 GJ annual consumption, load factors were fairly close to those for higher volume customers and load factors tended to level out as volumes increased significantly above the 2000 GJ level.

The load factor for commercial customers above 2000 GJ per year (top 10% of commercial customers) was significantly higher than for the residential or small commercial groups. In reviewing other jurisdictions, we found that other utilities (Centra Ontario and Centra B.C.) also divide their customers at the 2000 GJ per year level, although we are not certain this break point was determined for load factor reasons.

Q. Did the Phase A gas cost allocation methodology for Lower

Mainland and Inland have an impact on the selection of two commercial classes and the commercial burner tip rates.

A. Yes, the Phase A methodology allocates fixed gas supply costs on a peak demand responsibility basis. Variable costs are allocated on an annual throughput basis. The result is to recover fixed gas costs from the firm classes in relation to the peak system usage of each class. This provides a more favourable price to those classes that use the system more efficiently.

The proposed standard classes provide a basis for more equitably flowing through gas costs to the Lower Mainland service area where, until now, average gas costs have been used for the residential, commercial and small firm industrial customers. Gas cost allocation to the proposed individual classes completes the process begun in Phase A. The revised gas costs for the proposed standard commercial classes are listed in Volume 1, Tab 11, Table 1, Page 1. The existing Inland commercial class is currently divided between small and large at 6000 GJ per year. The customers between 2000 and 6000 GJ per year are reclassified into large commercial Rate 3. There are different Inland gas cost changes for each of the three groups (<2000, 2000 to 6000 and >6000 GJ per year). The resulting changes are as follows:

Commercial Class Gas Cost Changes

Commercial		Lower Mainland		Inland	
Small	Rate 2	(<2000 GJ)	$0.20/GJ	(<2000 GJ)	$0.11/GJ
Large	Rate 3	(>2000 GJ)	($0.18/GJ)	(2000-6000 GJ)	($0.22)/GJ
				(>6000 GJ)	$0.09/GJ

The resulting gas cost changes reflect the relative load factors and efficiency with which the rate classes use the system.

Q. Please summarize the process used to arrive at the proposed commercial $14.00 basic charge.

A. The process was similar to that for the residential class. We chose a $14.00 per month basic charge based on an indication from the FDC and LRIC studies that rates to low volume customers should be increased. A $14.00 per month basic charge represents a reasonable movement toward the existing FDC customer-related cost of $19.57, $19.40 and $20.46 for Lower Mainland, Inland and Columbia respectively. The proposed basic charge level is similar to the existing Inland basic charge of $12.91 per month.

Q. Please summarize the process used to arrive at the proposed $1.32 per GJ postage stamp delivery charge.

A. The Inland revenue to cost ratio was much higher than 1.00, while the Lower Mainland and Columbia ratios were lower than 1.00. It was considered appropriate to reduce the revenue from Inland and increase the revenue from Lower Mainland and Columbia in calculating the $1.32 per GJ delivery charge. The overall result of postage stamping considering the revenue to cost ratios and annual bill impacts was to decrease the commercial class revenue by $2.9 million. The combined impacts of the uniform postage stamp delivery charge and gas cost recovery charges on small commercials resulted in higher Lower Mainland and Columbia rates and lower Inland rates.

Q. Are the proposed commercial rates consistent with the Company's conservation objective?

A. Yes. We have eliminated the declining block delivery charges in this class for all service areas. As previously described, 0-2,000 gigajoule customers (with peakier loads) will see a price increase which is consistent with conservation initiatives. For larger volume commercial customers, we have maintained most of the Company's revenue in the delivery charges.

NGV PROPOSAL

Q. Please describe how the rate design objectives are reflected in the NGV postage stamp margin proposal.

A. Our NGV proposal reflects the major rate design objectives as follows:

1. Fairness - The postage stamp proposal eliminates the current rate inequities between service areas. These inequities are especially noticeable by NGV customers travelling between the Company's various service areas.

2. Economic Efficiency - We are pricing NGV more in line with the FDC. By establishing a basic charge and two-step delivery charge we are sending pricing signals that are more in line with actual costs and, at the same time, will encourage the increased substitution of other motor fuels with natural gas.

3. Stability - NGV is a high load factor class and is not temperature-sensitive. The basic charge and two-part delivery charge will result in stable revenues and customer bills.

4. Gradualism - We have carefully considered bill impacts in the proposal. The basic charge will remain much less than the FDC customer related cost, and the two-part delivery charge has been designed with existing customer contract and consumption levels in mind.

5. <u>Conservation</u> - The NGV class has a high load factor using the distribution system efficiently, but continues to suffer from the high cost of conversions and lack of original equipment manufactured (OEM) vehicles. These high costs will continue to provide an incentive to develop the most efficient vehicles, in order to bring down barriers to use of NGV.

Q. Are the Company's NGV rates the rates charged at the service station?

A. No. BC Gas' NGV rates are charged to the service station retailer and to fleet NGV users. The retailer, in turn, charges individual customers a market based rate which competes with other motor fuels.

Q. Please summarize the process used to arrive at the proposed $35.00 per month basic charge for NGV service.

A. A $35.00 per month basic charge was considered reasonable since the NGV class is a high load factor class allowing effective recovery of the customer related costs through the delivery charge. A basic charge closer to the FDC customer related cost (334.00 per month for the Lower Mainland area) generated unacceptable small consumption customer bill impacts.

Q. Please summarize the process used to arrive at the proposed delivery charge for NGV.

A. What is being proposed is a two-step delivery charge which was again a compromise between pricing low consumption customers appropriately, sending pricing signals to encourage substitution and achieving acceptable customer bill impacts.

Q. Were there any changes to the gas cost recovery determined by the Phase A methodology for NGV customers?

A. There were no changes in classification as was the case for the commercial and general customers. In Phase A the Lower Mainland and Inland NGV class gas cost recovery had already been calculated separately from the other classes, taking into account the efficiency with which the NGV class uses the distribution system. This flowthrough of gas costs resulted in a $0.44 per GJ decrease in the Lower Mainland area and $0.12 per GJ decrease in the Inland area based on the February 1992 Phase A decision.

GENERAL TERMS AND CONDITIONS

Q. What were your reasons for proposing a new set of tariff General Terms and Conditions?

A. BC Gas currently operates under separate tariffs in each of its service areas. The proposed standard tariff will be used in the Lower Mainland, Inland and Columbia areas to help achieve the increased efficiencies associated with consolidation. The proposed Terms and Conditions which reflect the current operations of BC Gas are more user-friendly, are expected to reduce administrative time, and provide a framework for the postage margin proposals. This matter was also raised by the Commission in its 1992 Revenue Requirement decision for BC Gas.

Q. Does that complete your evidence?

A. Yes it does.

BC GAS INC.

WRITTEN EVIDENCE OF

<u>Dietz D. Kellmann</u>

Q. Please identify yourself and your title at BC Gas.

A. My name is Dietz Kellmann. I am Rate Design Supervisor, and have held this position since my employment with BC Gas.

Q. Please state your academic and business experience.

A. I am a graduate of the University of Western Ontario with a Master's degree in Economics. I have been employed with BC Gas since July 1991. Prior to joining BC Gas, I was employed by the National Energy Board in Ottawa in its Economic Analysis Group from March 1989 to July 1991.

Q. Please describe your professional affiliations.

A. I am a member of the Association of Professional Economists of British Columbia and the Pacific Coast Gas Association.

Q. Have you appeared as a witness before any regulatory authorities?

A. No.

Q. What is the purpose of your testimony?

A. I am part of a panel that will provide testimony regarding specifics of the proposed consolidated General Terms and Conditions.

Q. What was your involvement in the development of the proposed consolidated General Terms and Conditions?

A. I led a company group that undertook the consolidated General Terms and Conditions and coordinated all revisions to the draft document.

Q. Please describe the composition of the focus group and the process used to draft the consolidated General Terms and Conditions

A. The focus group was comprised of BC Gas employees representing its legal, regulatory, marketing, operations and billing departments. Members were selected based on their experience working with customers, Company procedures and using the existing divisional General Terms and Conditions
The initial step in consolidating the General Terms and Conditions was to organize the existing divisional clauses in order to develop appropriate consolidated General Terms and Conditions.

Throughout the process, an attempt was made to eliminate jargon and legalize and to use gender neutral language. In addition, the order of many of the sections was revised in order to improve the readability of the consolidated General Terms and Conditions and to make them more user-friendly.

Q. Does that conclude your direct evidence?

A. Yes.

WRITTEN EVIDENCE OF

H. L. DINTER

Q. Please identify yourself and your title at BC Gas.

A. My name is Henry Dinter. I am Manager, Industrial Sales, and have held this position since first coming to BC Gas in October 1989.

Q. Please state your academic, professional and business experience.

A. I am a graduate of Simon Fraser University with a degree in Business Administration. I hold membership in various gas associations both in Canada and the United States. My employment prior to BC Gas consisted of procurement and contracting positions with Weldwood of Canada Ltd., the most recent from 1986 - 1989, as Administrator, Energy and Raw Materials. I was responsible for the negotiation and administration of the company's natural gas, petroleum and chemical requirements. In May 1986, I arranged for the first direct purchase and transportation service of natural gas in B.C. As member of the customer group representing Inland's non-captive industrials, I took part in the protracted negotiations that brought about the first "bypass" agreements effective November 1, 1988.

Q. Please indicate the regulatory Boards and Commissions you have appeared before as a witness.

A. I have previously testified before the Public Utilities Board of Alberta while employed by Weldwood of Canada Ltd., and subsequently before the British Columbia Utilities Commission on behalf of BC Gas.

Q. What are your principal responsibilities?

A. My principal responsibilities are to develop and administer the sales and technical advisory functions as they relate to the company's industrial customers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information on the Company's filing with regard to:

a) Industrial Rate Schedules and Charges to Industrials
b) Buy/Sell Arrangements for Interruptible Customers
c) Burrard Thermal Priority
d) Unbundling

Q. Mr. Dinter, were you involved in Phase A of the BC Gas rate design proceedings?

A. Yes, I appeared as a witness for BC Gas in Phase A.

Q. From the perspective of the Manager, Industrial Sales, what were the important decisions that came out of the Phase A rate design proceedings?

A. The Phase A Decision recognized that the fixed costs associated with gas supply should be allocated to the firm customers of BC Gas. The fixed costs include costs associated with gathering, processing and transporting gas by Westcoast, fixed charges associated with underground storage which is leased by the Company, and fixed charges in the baseload gas purchase contracts and the seasonal peaking contracts which the Company has arranged to provide gas supply to the firm customers. The Decision also recognized that during off-peak periods the Company will have gas supply available to it which is not needed to meet the requirements of the firm customers on the BC Gas system.

BC Gas proposed, and in its Decision of February 21, 1992 the Commission agreed, that gas sold by BC Gas to other than its firm customers should have market based pricing. The concept of market based pricing is an important one for it allows BC Gas to sell gas to interruptible customers within the BC Gas service area and to persons outside the service area of BC Gas at a price which is higher than the incremental cost of the gas being sold. The difference between the sale price and the incremental cost flows back to the firm customers of BC Gas, by way of deferral accounts or the Gas Cost Reconciliation Account, to reduce the overall gas supply costs of the firm customers.

Q. Has the concept of market based pricing been followed by BC Gas in the development of rate schedules and charges which are being presented in these Phase B proceedings?

A. The proposals that are being put forward in the industrial area are consistent with the Commissions' Decision in Phase A. BC Gas is proposing to sell gas, when it is not required for the firm customers of BC Gas, at market based pricing. In this manner the Company will be seeking to obtain the maximum benefit for the firm customers on the BC Gas system. This is appropriate since the firm customers have allocated to them the fixed costs associated with the gas supply arrangements that the Company has put in place to meet their requirements.

Q. Please outline the key functional responsibilities of the Industrial Sales department and how the department has adjusted to the new gas supply and marketing environment.

A. At present the department consists of seven staff members; one Manager, four Sales Engineers, one sales assistant, and one secretary (see attached organization chart - Appendix "A"). The major responsibilities of the group include:

1. <u>Contract Administration</u>
   - transportation agreements; small and large industrial "bypass" agreements
   - sales agreements; interruptible sales, peaking, backstopping and negotiated contracts that are competitive with alternative fuels.

2. <u>Technical Advisory Services & Engineering Support</u>
   - Demand Side Management (DSM) program development
   - environmental
   - technology applications

3. <u>Cogeneration</u>
   - engineering design assistance
   - technical seminars
   - industry and government liaison

4. <u>Off System Sales</u>
   - research and promotion
   - sales and administration
   - regulatory interface
   - market recognizance

5. Communication & Development
   - rates and tariff issues
   - gas supply and market trends
   - environmental and technological developments
   - government and regulatory initiatives

The department's primary function is to promote the responsible use of natural gas by means of efficient and environmentally sound gas technology.

By far the greatest proportion of the department's activity has centred around items 1, 4 and 5, with two sales engineers engaged in the handling of contracts (primarily transportation) and their day to day administration. Off System sales has also become an important function of the department. At present this activity is handled on a part-time basis by one individual who splits his time with domestic industrial account issues. However, with revenues and margins approaching those provided by the Company's domestic interruptible sales, the near term strategy will be to dedicate more permanent resources to this activity in order to ensure firm customers receive maximum benefit from excess "valley" gas supply and contract transportation.

Although still in the initial stages of development, the industrial DSM program, with the proposed Energy Audit Course and individual customer surveys, offers some exciting prospects for both the customer and BC Gas. The promotion of cogeneration has also identified a handful of promising opportunities which the utility will be pursuing.

Q. Please describe how the Company's gas supply arrangements interrelate with the industrial sales function.

A. Until recently, sales and supply functions were fairly independent activities. The primary object of the Company's gas supply group has been, and continues to be, contracting gas for core market (firm sales) customers on the basis of the lowest cost measured against a reasonable level of supply risk. This has led to a supply portfolio comprising of base load gas, storage and a host of different peaking contracts which enable the Company to meet its firm peak day demand.

However, with the advent of market based pricing for interruptible gas, off-system sales and a changing outlook for short term winter supply and transportation, the gas planning, purchasing and sales functions must now work together more closely in order to realize the lowest gas costs and maximum benefits for the Company's sales customers.

At present, approximately 20 to 25 petajoules of interruptible gas is sold annually to BC Gas system customers. Burrard Thermal is contracted to purchase an additional 20 petajoules per year, but has rights to exceed this amount. In 1992 approximately 10 to 12 petajoules were sold into markets outside the province bringing with them an estimated $6.0 million in additional contribution towards the cost of gas for firm sales customers. Burrard Thermal's priority to the Company's Lower Mainland "valley" gas has severely restricted the ability of BC Gas to engage in significant off-system sales activities thus far in 1993.

Q. What does BC Gas perceive to be the major issue(s) of transportation service for industrial customers.

A. As was apparent in the Company's Phase A hearing, and in subsequent meetings with customers and interested parties over the ensuing months, the single biggest concern has been and continues to be that of balancing. While other issues, such as the unauthorized overrun Demand Surcharge arose, none has been more prominent than the matter of day to day balancing of a customer's gas.

Balancing is the process by which the utility and customer reconcile the difference between the customer's actual gas consumption and the amount he has requested to be ordered from his producer and transported on the BC Gas system.

On some days the customer orders too much and "leaves gas on the system". In this case BC Gas must find some means of disposing of the excess. The excess gas may be absorbed into "line pack", resold (in the event line packs are already high), or be left on the Westcoast system if too much gas has been ordered for BC Gas to absorb. As part of the pipeline to pipeline balancing arrangement between BC Gas and Westcoast, BC Gas is forced to balance the overage by under ordering the next day so that Westcoast can redeliver the amount previously left on the system. Day to day imbalances may cause BC Gas to have to under order from its baseload suppliers (if the situation occurs in the summer), or from less expensive storage sources (if in the winter).

On the other hand, on a day when a customer takes extra gas, BC Gas has one of two options;

a) to curtail the customer to an authorized volume as delivered by his producer, or

b) to provide the shortfall from its own available resources such as storage and line pack.

Prior to Phase A, BC Gas provided what is called "monthly balancing". Simply put, monthly balancing was a day by day record of the pluses and minuses, with the end of the month serving as the point of reconciliation. Any positive inventory was carried forward into the following month. If the customer took more gas than what he had delivered to the utility, the customer purchased the shortfall at the going interruptible sales rate. This methodology offered no incentive to customers to nominate accurately (since large positive swings could later be offset with large negative swings by way of the daily gas ordering procedure), and failed to recover the reasonable costs of supplying extra gas to customers to make up daily shortfalls.

In the winter months, BC Gas has a wide variety of peaking and storage supply from which it draws gas to provide a customer's extra needs. However, these extra supplies come at a premium. Under the old monthly balancing system BC Gas provided gas from storage or peaking contracts without the chance for either cost or value recovery, because the month end balancing could cancel out major day to day swings that occurred over the month. This has not been a major problem during the summer, but it is another matter in the winter. Many customers are to some degree temperature sensitive. Hence, they tend to leave extra gas with BC Gas when it is warmer (the shoulder months) and want extra gas during periods when it is colder. Consequently, under the former monthly balancing procedure BC Gas was on many occasions providing higher priced gas in return for extra gas left on the system by customers during warmer or lower demand periods. In order to account for this, BC Gas in Phase A applied for and the Commission accepted a daily balanced procedure whereby customers paid for extra gas requirements on a day by day basis in accordance with their needs. This ensured, to some degree in any event, that supply and billing matched with the service provided.

This balancing procedure was instituted only for the winter gas supply billing - NOT on the Company's charge for transportation services which are still calculated based upon monthly transportation volumes. This means that customers are not charged for interruptible transportation until they have received value for the entire amount of firm transportation they have contracted and paid for.

Q. Please outline the Company's curtailment priority for its various sales and transportation services.

A. BC Gas service curtailment will occur in the following manner, in descending order starting with the lowest priority being listed first.

1. Off System Sales
2. Burrard Thermal Interruptible Agreement
3. Burrard Thermal - Swing Agreement
4. Schedule 10 - Priority 2 Interruptible Sales
5. Schedule 10 - Priority 1 Interruptible Sales *
6. Schedule 7 - Interruptible Sales
7. Schedule 22 - Level 2 Interruptible Transportation
8. Schedule 27 - Level 2 Interruptible Transportation
9. Schedule 22 - Level 1 Interruptible Transportation **

10. Schedule 27 - Level 1 Interruptible Transportation**
11. Schedule 22 - Firm Transportation (subject to 1/2 day curtailments)
12. Firm Service

* Priority may change subject to negotiation.

** Priority may change with Schedule 22 Firm Transportation depending on operating conditions.

Q. What has BC Gas done with regard to "unbundling" as directed by the Commission in its March 11, 1993 decision.

A. BC Gas has considered the matter of unbundling at some length, and has with this application filed new and revised service schedules which the Company feels are a significant stride in meeting the objectives of the Commission. For example, BC Gas has filed as part of this application a revised Schedule 13 and a new Schedule 14; both of which provide gas from peaking and storage sources and both of which are available to any customer in the BC Gas service area, whether or not the customer normally purchases gas from BC Gas. Due to the limited availability of storage (which BC Gas does not generally own, but rather contracts for) the Company is unable to offer a fully unbundled storage service. It is, however, offering to use its contracted storage in making available peaking and backstopping gas supply and balancing service.

Q. Please provide a list of the industrial rate schedules to be dealt with in this Rate Design Hearing.

A. Rate Schedule 4 - Seasonal Service
Rate Schedule 5 - General Firm Service
Rate Schedule 7 - General Interruptible Service
Rate Schedule 10 - Large Volume Interruptible Sales
Rate Schedule 13 - Interruptible Peaking Sales
Rate Schedule 14* - Interruptible Backstopping Sales
Rate Schedule 22 - Large Volume Transportation
Rate Schedule 22A - Large Volume Transportation (Existing Inland Shippers)
Rate Schedule 22B - Large Volume Transportation (Existing Columbia Shippers)
Rate Schedule 25 - General Firm Transportation
Rate Schedule 27* - General Interruptible Transportation
Rate Schedule 32* - Large Volume Gas Balancing

* Denotes new service options.

<u>Schedule 4</u>

Q. Please describe Rate Schedule 4 and who uses it.

A. Schedule 4 is a generally firm service offered to customers who use gas primarily during the company's off-peak periods. Customers include asphalt plants, community or individually owned pools and process related loads that have limited productions periods.

Q. Please explain the main features of proposed Rate Schedule 4 Seasonal Service.

A. Schedule 4 combines a number of the features from the current seasonal or "dual fuel" schedules available on a divisional basis.

a) We have used the "Peak Period" and "Off-Peak Period" terminology of the current Lower Mainland seasonal rate schedules (2601 and 2602), and retained a November 1 through March 31 peak period consistent with other rate schedules.

b) We have continued to allow for flexibility in the tariff on occasions when a customer may request an extension to the off-peak period.

c) We have allowed for limited interruption provisions in the event the utility is on occasion unable to provide totally firm service.

On the basis of the proposed schedule 4, it should be relatively easy to accommodate all customers currently served by seasonal tariffs, and we anticipate further interest will develop for schedule 4 in the future.

<u>Schedule 5</u>

Q. Please describe Rate Schedule 5 and 25 and the customers proposed to receive service under these schedules.

A. Schedule 5 is the Company's proposed General (Sales) Service that provides firm gas to a customer's meter. General Service is proposed to be limited to customers that have a connected load that is primarily non-space heating.

Schedule 25 is the proposed General Transportation equivalent to Schedule 5. Under Schedule 25 the customer purchases its own gas and delivers the gas to BC Gas so that BC Gas can transport the gas to the customer's meter. Rate Schedule 25 is described in more detail later in this evidence.

Q. Please explain why BC Gas proposes to restrict Schedule 5 to customers that use more than 50% of their approved connected gas load for applications other than space heating, but this restriction was not imposed on the parallel Schedule 25 transportation service.

A. There are two primary reasons, namely:

a) Although BC Gas is not currently able to institute demand metering rates for all of its general service customers, the Company wished to send out market signals that reflect the costs of gas supply. This restriction relates entirely to the gas supply component of Schedule 5. As BC Gas is not involved in the gas supply arrangements of Schedule 25 transportation customers (other than in ensuring customers have nominated adequately, which will depend on their load characteristics), it was not necessary to similarly restrict Schedule 25; and

b) The proposed gas cost allocations to the Company's gas sales customers are based upon the load factor of the service classification. Until demand metering can be put in place the Company wanted to ensure that customers that exhibit a significant non-space heating component received gas cost reductions in line with their better load factors.

Q. Rate Schedule 5 contains a restriction which limits its availability to customers who use more than 50% of their load for applications other than space heating. Has the Company filed a rate schedule that provides transportation service on a basis similar to Rate Schedule 3 (large commercial) for customers to whom Rate Schedule 5 is not available and who do not find Rate Schedule 25 financially attractive?

A. No.

Q. Why not?

A. The basic charge for General Service is designed to recover the costs of demand metering. This is not the case for commercial customers in general, however, commercial transportation service customers would need demand metering to permit BC Gas to maintain proper gas inventory and billing management. The costs of demand metering are not reflected in the commercial customer FDC or LRIC studies nor in the basic charge of $14.00 proposed for commercial customers.

In order to have complete rate parity (between commercial sales and transportation service customers), BC Gas would be required to determine an upfront cost to be paid by commercial transportation customers in order to compensate for the costs of these incremental facilities.

This alternative could be made available, although we believe customers will be equally well served by choosing the proposed Schedule 25, with these incremental costs already accounted for in the rates being paid.

Q. Please explain the impact of the Phase A gas cost allocation methodology for Lower Mainland and Inland customers in the new General Service class?

A. The gas costs for the General Service class in the Lower

Mainland will be reduced by approximately $0.60 per gigajoule as a result of the allocation methodology. This reduction will be effective with the implementation of new rate Schedule 5.

Gas cost changes to Inland and Columbia customers are minimal except to the extent a number of customers that were previously classified as commercial customers will be eligible for General Service. Gas costs to those customers will also be reduced.

Schedule 7

Q. Please describe Rate Schedules 7 and 27 and the customers proposed to receive service under these schedules.

A. Schedule 7 is the Company's proposed General Interruptible (Sales) Service that provides gas on an interruptible basis to a customer's meter. General Interruptible Service has no limitations as to size, although customers with very low consumption (less than approximately 1,500 gigajoules per month) may not find it economic to subscribe to it and customers with high consumptions (greater than 20,000 gigajoules per month) may find schedules 10 and 22 more financially attractive. Schedule 27 is the proposed General Interruptible Transportation equivalent to Schedule 7. Rate Schedule 27 is described in more detail later in this evidence.

Q. Are there significant changes to the proposed Schedule 7 compared to existing interruptible sales services.

A. The primary feature of Schedule 7 is that for the Lower Mainland it will combine three service levels - 2501, 2502A and 2502B - under one rate schedule, and it will for the first time make general interruptible service available to customers in the Columbia service area.

It is our view that by making large volume interruptible service generally more accessible (as I will discuss under Schedule 22), the Company will be able to offer a high level of sales service to the remaining general interruptible service customers. We are hopeful this will continue to make interruptible service appealing to smaller customers.

Q. Why has BC Gas not presented an alternative sales option for Schedule 7 customers similar to that available for the Company's large industrials (i.e. Schedule 10, which is sold at the interconnection with the transporter and transported by BC Gas under Schedule 22)?

A. BC Gas believes there is relatively little interest by small volume customers in purchasing gas in a manner that mirrors the Schedule 10 and 22 sales and transportation separation. More particularly,

1. Small volume customers, in general, value supply reliability and administrative simplicity as their prime considerations.

2. The smaller the volume the lower the potential for worthwhile savings from any separation of the sales and transportation functions.

3. If BC Gas were to broaden the applicability of Schedule 10 to include possible sales to customers below the proposed 240,000 gigajoule annual use threshold (who may therefore purchase their gas at lower prices while retaining access to monthly

balanced Schedule 27), this availability could undercut the utility's ability to sell gas at the higher prices normally paid by smaller volume customers in the direct market.

On October 19, 1992 BC Gas wrote to all Lower Mainland interruptible customers, advising them of the Commission's decision to reduce the minimum volume obligation in the tariffs that became effective November 1, 1992 from 30,000 gigajoules per day, as proposed by BC Gas in the Phase A hearing, to 1500 gigajoules per day. In its letter BC Gas specifically highlighted the potential for economic benefits to its interruptible customers. Of the 100 or so customers who became eligible as a result of the lower threshold, only three customers chose to take advantage of the rate differential between the Company's burnertip sales and the combination of Schedule 10 sales and Schedule 22 transportation service. In discussions with many of the customers who enquired about this alternative, it became evident that customers in general preferred services with minimal administrative requirements, particularly so for smaller customers.

It is the preference of BC Gas that administrative simplicity be retained to the extent possible as an abundance of new options that are not needed will substantially increase administrative costs of the utility.

<u>Schedule 10</u>

Q. What is Rate Schedule 10?

A. Schedule 10 relates to the sale of gas by BC Gas to large volume customers. It provides for interruptible sales to those customers.

Q. Will you please summarize the changes made to Rate Schedule 10?

A. Aside from the rewording of Schedule 10 to make it consistent with other filed rate schedules, the change of significance involves making the former highest priority interruptible sales, (now called Priority 1, so as not to be confused with Level 1 transportation service) subject to negotiation. It's proposed that customers seeking a quality of service better than that provided by the utility's Priority 2 sales (formerly level 2), may now negotiate a price commensurate with a specific level of service desired. This price would necessarily include any incremental costs BC Gas may have to incur to provide the level of service needed.

BC Gas is offering to negotiate the price and quality of Priority 1 sales in response to customer concerns that the current Schedule 10, Level 1 sales provide uncertain benefits. Customers have indicated a greater interest in services with specific delivery obligations rather than merely a commitment as to priority. Despite this general market signal, we are reluctant to specify (by means of the tariff) a predetermined fixed number of interruption days since this will lead to better service and higher costs for some customers than they in fact wish, while for others it may not be enough. We therefore take the position that Priority 1 sales arrangements should be negotiated, with each agreement subject to Commission approval, on the basis of each customer's unique requirements. This will afford the customer an opportunity to negotiate with the utility on the same basis as all other suppliers, for price and quality of service commensurate with the customer's needs.

BC Gas will not sell firm gas under this arrangement.

Priority 2 sales will continue to be at a posted price set annually based upon spot market conditions.

Schedule 13

Q. Please explain the purpose of Schedule 13 and how it differs from Schedule 10?

A. Schedule 13 has been retitled "Interruptible Peaking Sales" (IPS) and is now confined to the supply of either gas from storage or other sources (i.e. seasonal peaking supply) on short notice, or as a last resort during cold weather conditions. This IPS service will be made available to all customers of BC Gas having a transportation service in effect. All customers will have access on an equal priority basis, whether they purchase gas from BC Gas under Schedule 10 or directly from a producer or marketer.

Schedule 13 IPS service is intended to supplement a customer's baseload supplies, whether from the utility (i.e. Schedule 10) or other sources, during periods of curtailment by BC Gas, supply shortfall or unexpected additional requirements which are not forecast and come to light sufficiently late in the nomination process or gas day such that alternative arrangements are no longer possible. The IPS service is optional as customers may wish to make their own arrangements for a peaking supply, but commits the customer to a take or pay obligation when utilized.

This service has been priced on the basis of the residential burner-tip price less the Schedule 22 transportation margin. A provision has been incorporated to permit BC Gas to recover the greater of cost or posted tariff on any given day. This provision only takes effect when the cost of incremental gas supply to BC Gas is greater than the charge in the rate schedule.

Schedule 14

Q. Please explain the purpose of Schedule 14 Interruptible Backstopping Sales (IBS).

A. Schedule 14 is a new service option which separates (unbundles) from the former Schedule 13 the backstopping provision. Backstopping as provided by this new IBS service is defined as gas which supplements a customer's baseload supplies during periods of curtailment or shortages when those curtailments or shortages are sufficiently predictable to enable parties to arrange for an alternative supply. This will occur when BC Gas or another gas supplier (producer or marketer) has notified the customer of an impending shortage of their regular supply, and the customer accordingly wishes to arrange for a backstopping supply that will provide gas over this period. Schedule 14 IBS will be the BC Gas option for serving this need should the customer not wish to pursue other alternatives.

The rate for Schedule 14 will be the greater of cost or the market price on any day in which gas is supplied by BC Gas. The market price will be set in relation to the "Inside F.E.R.C. Index" established for the Canadian Border at the time of purchase or nearest previous publication date.

Supplies for such backstopping, if provided by BC Gas, may come from a host of different sources (i.e. baseload, storage or seasonal peaking contracts). As with Schedule 13, any request for such gas will entail a take-or-pay obligation.

Schedule 22

Q. What is Rate Schedule 22?

A. Schedule 22 provides transportation of gas over the facilities of BC Gas to large volume customers. Schedule 22 does not include the provision of any gas; it is transportation only.

Q. Why has BC Gas set the minimum monthly quantity of Schedule 22 at 20,000 GJ.

A. This value was established for large volume transportation as a compromise between the current 30,000 GJ/month minimum applicable to Inland Division large industrials (or 28 10^3M^3/day), the approximately 390,000 GJ/annum level set for Columbia large industrials and the 1500 GJ/month minimum effective for Lower Mainland. At present no distinctive large and small industrial categories exist for the Lower Mainland. With this application BC Gas proposes to introduce into the Lower Mainland the same large and small volume customer classifications prevailing in the Inland and Columbia service areas (albeit at slightly altered minimum quantity levels).

Q. How many customers and what percentage of the Lower Mainland interruptible volume will qualify for the "large" designation and how many customers and what percentage of volume will be defined as "small"?

A. The Company's forecast customer base and volume projections for 1993 are as follows:

	Customers	TJ/annum	% of volume
"Small" Volume	97	6,743	38%
"Large" Volume	17	10,936	62%
TOTAL	124	17,678	100%

Q. Why has BC Gas decided to phase out the "Firm Curtailment Buyout" option provided in Rate Schedule 22.

A. Prior to 1990, Schedule 20 (the forerunner of the "buyout option") was the transportation equivalent of Schedule 22, but without provision for the utility to use 50% of a customer's firm demand for 5 days of peak shaving. The cost for this included in Schedule 20 rates equated to the annual charge for Westcoast capacity;

i.e. (Firm nomination x .5) times
(Westcoast Demand Charge/month x 12)

In late 1989 BC Gas restructured Schedule 20 in order to recognize that BC Gas was then able to contract for short term winter supply which did not require 12 months of Westcoast capacity. Accordingly, BC Gas lowered its charge for giving up 1/2 firm curtailment access to the equivalent of 5 months of Westcoast demand charges, as a reasonable approximation of the costs associated with contracting alternate supply.

In the ensuing period, however, short term peaking supplies have become more scarce and costly, to the point that BC Gas is now finding it increasingly difficult to acquire sufficient peaking supplies for its own needs without taking into account the extra requirements associated with the buyout options.

In order to provide customers ample time to evaluate their options and to make alternative arrangements, BC Gas proposes to extend the buyout option for one more year through to November 1, 1994.

Q. As an alternative to the buyout option, BC Gas proposes to allow customers to arrange a substitute supply in lieu of curtailment. Why does BC Gas believe it needs "10 day deliverability" instead of the 5 day curtailment provision available to it at present.

A. Under the new "prior day" nomination procedure imposed by Westcoast, BC Gas and its transportation customers are compelled to nominate 24 hours in advance of the gas day in which the gas will be used. This means BC Gas must forecast its demand and supply situation a full day ahead and order gas accordingly. Since access to industrial firm gas is the very last gas supply resource the utility calls upon, the decision to impose such curtailments is left to the last possible moment (which may in fact be, if absolutely necessary, during the gas day). BC Gas takes seriously its responsibility to manage this resource as sparingly and in the least disruptive manner possible.

However, in the event alternative gas supply is offered as a substitute, BC Gas will be required to order such supply 24 hours in advance of each gas day. To ensure there are sufficient supplies for each day, BC Gas is forced to err on the side of conservatism. This will likely cause one, two or perhaps several days (such as this past winter) wherein gas will have been ordered in advance, but the actual events of the day 24 to 48 hours later no longer warrant this action. Forecast errors, could, if not provided for, eliminate one of the most critical peaking resources available to BC Gas. In effect, the 10 day alternative gas supply protects against such circumstances developing.

Q. Why has BC Gas introduced Level 1 and Level 2 transportation.

A. Historically, interruptible transportation service has contained provisions which entitled BC Gas (or its predecessors) to access customer owned gas; i.e. gas in transport, for peak shaving purposes. This has evolved, in effect, for system efficiency purposes and to ensure both sales and transportation customers receive similar levels of service and pay similar rates for those similar service levels. Nominations for firm and interruptible service remained largely independent of whether gas was being obtained directly from producers or in part from BC Gas.

Inland customers have from time to time requested the Company introduce an interruptible service level that would not permit a customer's gas to be used for peak shaving, but would nevertheless permit BC Gas to curtail for capacity reasons. This would be a higher quality of interruptible service. While such an arrangement limits the utility's access to low cost peak shaving, it nevertheless is still system efficient since it is curtailable on a peak day. Prior to Phase A, Lower Mainland interruptible customers also had available to them a "capacity only" interruptible service.

As a result, BC Gas has developed a two tiered (Level 1 -

Level 2) transportation toll which recognizes first, the value of interruptible service as a function of its reliability, and second the value of peak shaving supply. For greater clarity:

1. <u>Level 1</u> - under this arrangement the customer arranges upstream supply and pipeline transportation. BC Gas transports whatever gas arrives except when BC Gas has insufficient <u>capacity</u>. The rate for Level 1 is independent of whether a customer's supply arrangements are firm or interruptible.

2. <u>Level 2</u> - under this arrangement, the customer obtains a rate discount as compensation for the alternative fuel and operational inconvenience he would experience as a result of granting BC Gas access to its gas for peak shaving. This discount has been calculated as a function of the alternative fuel cost of a typical customer and the additional days of expected curtailment in any year. While BC Gas does not explicitly direct its customers on the manner to contract for supply, there is an obligation that the customer will contract in a manner that ensures the gas promised for peak shaving is available. Level 2 is not intended to provide a discounted rate without reasonable assurance that BC Gas will receive access to a shipper's gas. To encourage customers to honour their end of the bargain (without actually directing how it should be done) the terms stipulate that two failures in having gas available for peaking will be overlooked, however, should a third such day occur it will be considered a breach of Level 2 terms and the customer will become

obligated to pay Level 1 rates for the complete contract year.

Peak shaving gas supplies made available from Level 2 service will be used only for core market (BC Gas firm sales) customers.

Q. How would a customer contract with BC Gas if it couldn't ensure less than three days supply interruption but still wanted to minimize its gas delivery costs?

A. In the event that a customer lacks sufficient supply security to be able to take advantage of Level 2 rates, but still wishes to offer BC Gas a peak shaving resource on an as required and as available basis, then BC Gas would provide service at Level 1 rates and negotiate a predetermined purchase price for any gas the customer makes available to BC Gas. This purchase price would recognize the customer's alternative fuel costs during occasions when the customer nevertheless curtails service and provides peak shaving gas to BC Gas.

Q. Why has BC Gas increased the Demand Surcharge tolerance from 102.5% to 110% and provided for a minimum 100 GJ cushion in the event 110% of the authorized quantity is less than 100 GJ.

A. In Phase A BC Gas proposed, and the Commission approved, the introduction of a Demand Surcharge to reinforce the unauthorized overrun provisions which appeared to be inadequate in discouraging unauthorized gas use. The BC Gas submission placed the tolerance at 2.5%, a level that went unchallenged during the hearings and was accordingly approved.

This past winter has, if anything, reinforced the need for such a disincentive mechanism. On the other hand it has also shown that a 2.5% tolerance was too restrictive given the intent BC Gas had in mind when introducing the surcharge provision.

The surcharge was intended to dissuade shippers/customers from repeated use of inordinate amounts of unauthorized overrun gas (as their least cost alternative) during days of curtailment. It was <u>not</u> intended to penalize customers who made a reasonable attempt to curtail to the Company's authorized level but who, through minor misjudgments, unintentionally consumed small amounts of unauthorized overrun gas. Hence we are proposing an adjustment in the tolerance level, including a minimum of 100 GJ for customers curtailed to zero or to a relatively low volume.

In spite of providing this increased tolerance, BC Gas has retained the grace period that grants customers leeway to exceed the 110% level on two occasions before the surcharge would apply on the third incidence.

Q. What are the implications of the new clause 7.3 "Adjustment of Requested Quantity" which replaces the former reference in clause 3.3 of the large industrial - General Terms and Conditions.

A. BC Gas now limits its ability to adjust a shipper's nomination to very specific circumstances; i.e.

1. "to maintain reasonable inventory account quantities", or

2. "during any period of interruption or curtailment",

or

3. "subject to the terms of the ...transportation agreement...when BC Gas wishes to increase the requested quantity..."

Item 3 is at the discretion of the customer. Prior to the start of the contract year, each customer will inform BC Gas whether it will allow the utility to adjust nominations for the purpose of accessing extra supplies. If a customer agrees to do so, a pre-determined price will be entered into the space labelled "Imbalance gas price". If the customer declines to give BC Gas that latitude, the words "Access Denied" will be inserted into the same space. This will signal BC Gas operating personnel to refrain from altering customer nominations for any reason other than those specified in items 1 and 2 above.

Q. What is Rate Schedule 22B?

A. BC Gas will be filing a Rate Schedule 22B which will include a proposal to "grandfather" the existing rates and rate setting methodology for Columbia large industrials. BC Gas has met with the affected customers and discussed the possibility of doing away with the present cost of service allocation model. At present, the model links the industrials in such a way that the rate determination for any one customer is affected by the capacity nominations of remaining members of the group. However, until such time as an acceptable mechanism to separate the customer rates can be settled upon and filed with the Commission for approval, BC Gas proposes to carry forward the existing rates and capacity nominations into a rate schedule 22B.

Q. Why has there been a linkage between Columbia industrial rates?

A. The mechanism was negotiated between Columbia Natural Gas Limited and the industrials prior to the 1987 Columbia rate design hearing as a means to ensure the industrials, which generally received rate decreases in that hearing, would continue to pay their allocated costs of service. Fording chose not to be included in the rate adjustment mechanism and pays a fixed cost of service amount to BC Gas each year. Similarly Crowsnest Resource has joined the large industrial group after the 1987 hearing and pays a fixed amount each year. These rates are similar in a sense to the Inland "bypass" rates.

Q. Is it proposed that Columbia large industrials will be subject to the terms and conditions of rate schedule 22 Large Volume Transportation Service?

A. Yes. In accordance with BC Gas' initial filing, we propose to make the new rate schedule 22 available as soon as practicable. We have had one meeting with the large industrials to discuss cost allocation and rate design methodology. We expect shortly to begin comparing the current interim transportation arrangements with the terms of the new Schedule 22 with an intended implementation date of November 1, 1993. Most terms are sufficiently common that they will have applicability to all service areas of the Company. Gas moving to the Columbia service area is transported on the pipeline of Alberta Natural Gas. There are expected to be some operational differences between Westcoast (which transports gas to the other service areas) and Alberta Natural Gas for which allowance will have to be provided.

Q. The application refers to negotiated rates for new firm industrial loads. Please describe the process by which BC Gas expects to establish negotiated rates for large volume firm transportation service.

A. It is the intention of BC Gas to begin any negotiations on the basis of the rates being proposed for Rate Schedule 25 General Firm Transportation Service. Negotiations that could result in a discounting of the posted rates would take into account the following;

1. Any peak shaving provisions granted to BC Gas,
2. Costs associated with providing the service, both rolled in and incremental,
3. Project economics of the customer,
4. Volume and load factor,
5. Project life cycle and contract term,
6. Security of revenues,
7. Relationship of negotiated rate to those for other large volume customers, and
8. Contribution toward the costs of service for the utility's other rate classes.

The foregoing is not intended to be all inclusive but rather to highlight those considerations which will influence the establishment of a negotiated rate if there is to be one at all. It is anticipated that such negotiations will be rare, since BC Gas will endeavour to encourage interruptible service whenever practical.

The result of such negotiations will be subject to Commission review and approval.

Schedule 25

Q. Please highlight the significant changes to Rate Schedule 25 and the reasons for those changes.

A. The proposed Rate Schedule 25 is an amalgamation of the current Small Industrial Schedule 25 transportation service provided in the Company's Inland Division and Schedule 2007 which is the transportation service equivalent in the Lower Mainland. The consolidated rate schedule is based largely on the format established for the Inland tariff with some standardization of former Lower Mainland terms.

Rate Changes

1. Rate changes have been incorporated that more closely align rates with the FDC and LRIC studies (as for Schedule 5) and reduce the costs for transportation service administration from $500 to $175. Rates have also been set on a seasonal basis.

Administration & Grouping

2. BC Gas has incorporated provisions which permit customers to group through a customer agent their upstream gas supply and transportation, as well as their nominations and gas management functions. The agent, where designated, will handle the month end allocation and payment of authorized and unauthorized overrun gas. The Company will continue to bill each customer for transportation independently, but the day to day gas management functions will be considerably simplified.

Monthly Balancing

3. The Company has retained monthly balancing as a feature of Rate Schedule 25 transportation service for two reasons:

a) The customer groupings, both in the present and foreseeable future, are expected to remain small enough that their daily swings will be of sufficiently manageable size for BC Gas to absorb them without operating difficulty or significant cost concerns.

b) The rates presently include monthly balancing, since inception of this service in 1988, and the proposed rates in the application adequately recover balancing costs.

Short Term Sales

4. The Company proposes to discontinue the "Short-Term Sales" option which forms a part of the current transportation service. To date there has been only limited use made of this provision. With short term winter peaking supplies becoming scarce and more costly, BC Gas is compelled to withdraw this option. As the contracted quantities of short term sales were extremely small, it is believed the affected parties will not be unduly hurt by this decision.

Authorized overrun sales rates have been standardized based on interruptible pricing in summer months and residential pricing in winter months.

Documentation

5. As with Rate Schedule 22, BC Gas has consolidated the former Schedule 25 Small Industrial Transportation Service tariff with the applicable general terms and conditions into one document. The transportation agreement itself has also been condensed relocating certain provisions to the Rate Schedule. Rate Schedule 25 now also contains a "Table of Contents".

Schedule 27

Q. Please describe the proposed Rate Schedule 27 tariff.

A. Schedule 27 is the proposed interruptible equivalent to Schedule 25 and generally contains the same terms as Schedule 25. Level 1 and Level 2 interruptible transportation are provided (as opposed to firm service) and are the General Service equivalent to Schedule 22 Large Volume Level 1 and Level 2 interruptible transportation.

Schedule 32

Q. What is gas balancing?

A. As described in my earlier comments, balancing by BC Gas refers to meeting differences between gas being ordered by a customer for a particular day and the customer's actual consumption. Dependent on the care taken by customers in ordering their gas, and on the level of variance in their day to day gas requirements, some customers may experience anywhere from minimal imbalances on any given day to imbalances that may be even more than their normal consumption. Customers who consume much more gas than delivered by their suppliers cause BC Gas to utilize its peak shaving resources to meet those requirements. On the other hand, when gas ordered is not consumed (i.e. it's "left on the system") BC Gas must find a way to dispose of this gas and may receive comparably little value from its sale.

Q. Why has BC Gas introduced a gas balancing service at this time? How was the 20% balancing tolerance selected?

A. BC gas chose to introduce rate schedule 32 Large Volume Gas balancing as a substitute for the monthly balancing currently offered during the summer months, but proposed to be eliminated, and the monthly balancing provisions that were also available in winter prior to November 1, 1992.

As indicated by Mr. Hanlon's evidence, daily balancing is and has been a fact of life on the Westcoast system for the past couple of years. Most other utilities and pipelines have also moved this way with one of the most notable and recent cases being Nova effective November 1, 1992.

What sets various LDC's apart from one another is how they handle day to day imbalances for their own supplies as well as those of their transportation customers. No two balancing systems work exactly alike since circumstances for each utility vary quite substantially. The practices of other utilities range from not doing any balancing (for example Centra Gas who have their transportation customers' requirements balanced by Trans-Canada) to those (for example Consumers and Union) who are able to provide firm balancing on an annual basis because of their underground storage capabilities. Balancing provisions are clearly tailored to the operating characteristics and supply diversity unique to each LDC.

Our review of other utilities compelled BC Gas to once again review its own situation and determine what degree of flexibility was available to provide a balancing service that would meet most of our customers needs, but would also institute adequate control limits to encourage customers to take the issue of accurate nominations seriously.

The Company's response is rate schedule 32 - Large Volume Gas Balancing service. It enables customers to maintain an inventory account with the utility sufficient to cover day to day shortfalls of up to 20% of their authorized quantity of gas. This supply will be made available at no charge. As Mr. Hanlon describes in his evidence, "through some care in their nominations" most customers will be within this 20% tolerance for at least 90 - 95% of the time.

While the proposed balancing service is not quite as attractive as the "monthly balancing" provision BC Gas was able to offer when BC Gas was purchasing gas under its long term Westcoast Sales Agreement, we believe it provides the operating flexibility and low or no cost swing supply previously available under monthly balancing.

Q. Why has BC Gas made this balancing available at no charge for the first 20%.

A. For several reasons. In meetings with various customers and customer groups over the past year a repeated claim has been that gas "left on the system" by shippers has value and that BC Gas should recognize this value. BC Gas is prepared to acknowledge that from time to time overdeliveries of gas can be helpful, but the value of this depends on a variety of different circumstances. For example:

1. When, on any day, BC Gas is in a position of oversupply, the additional gas left by Shippers compounds the Company's imbalance with Westcoast which is then left to BC Gas to clear up. This creates no value.

2. During off peak periods, excessive overdeliveries may have the effect of causing BC Gas to back off its own long term suppliers in order to absorb a customers' extra gas. While no single customer normally presents a problem, several at once may do so. This creates no value and may impose a cost.

3. Only during the coldest periods when line packs are low does extra gas at the end of day help BC Gas. Since BC Gas has little, if any, knowledge on most customers' day to day operating plans and practices, it is extremely difficult to predict how much excess gas may be left on the system. Because the volumes are completely unpredictable, plans cannot be made on the basis of gas being left on the system.

4. Assuming one acknowledged day to day value for overdeliveries irrespective of whether BC Gas can or cannot do anything with these supplies, the question becomes... "What is the value of the gas at the time of overdelivery versus what is the value of the gas at the time of return?" Since many customers are to some degree temperature sensitive, it's often the case that extra gas is left on the system during warmer periods while return is desired during colder periods when costs are higher.

To summarize the above, while BC Gas is unable to specifically value overdeliveries with any degree of accuracy, the Company is prepared to acknowledge that from time to time some value can be attributed to such supplies, and accordingly has taken this into consideration.

A second aspect that did not go unrecognized is the value of the peak shaving benefits the Inland large industrials provide BC Gas by way of the half-firm curtailment provision. This value is significant, although may be less than discussed in Phase A. Creative new supply agreements have enabled BC Gas to contract for "needle-peaking" supplies similar to the 1/2 day firm supplies available from the industrials. Nonetheless, BC Gas considers the operational flexibility and cost savings of these curtailment rights to be of significant value.

It is believed the foregoing provide sufficient value to permit a fairly large tolerance, i.e. 20%, while nevertheless remaining at a level that encourages customers to make a reasonable attempt at forecasting their daily requirements.

Fort Nelson

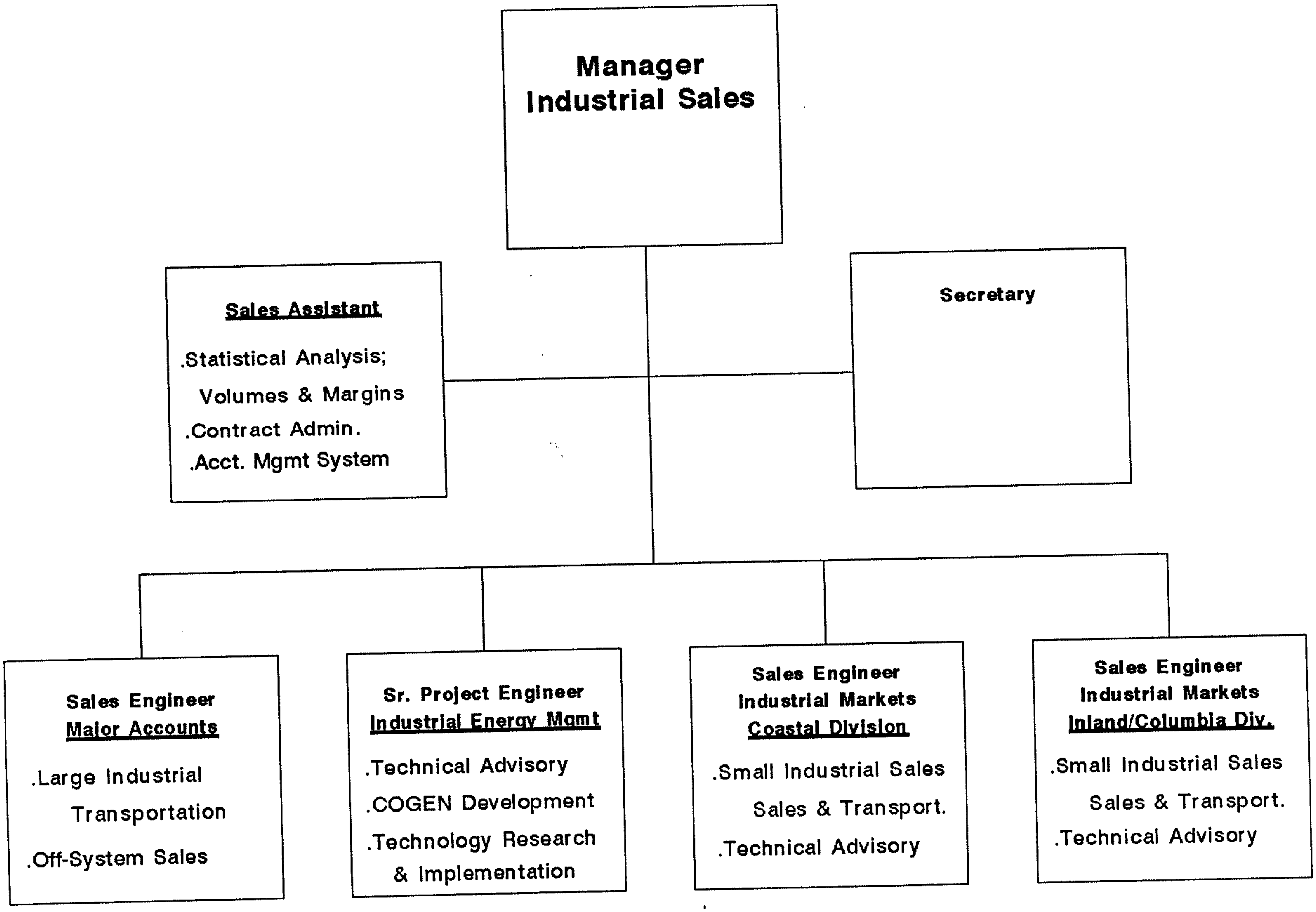
Q. Does BC Gas propose to make transportation service available in Fort Nelson.

A. Yes. Subsequent to the Commission's Decision on the tariffs filed within this Rate Design application, BC Gas intends to adopt the final approved version of Rate Schedule 25 for use in the Company's Fort Nelson service territory, subject to minor changes where appropriate, to deal with rate differentials and operating procedures unique to the Fort Nelson area.

Q. Does this complete your written evidence.

A. Yes it does.

BC Gas Inc.
Industrial Sales



Appendix A

BC GAS INC.

WRITTEN EVIDENCE OF

HANK W. PETRANIK

Q. Please identify yourself and your position with BC Gas Inc.

A. My name is Hank Petranik. I joined BC Gas in April of 1991 and currently hold the position of Manager, Gas Purchasing. I am responsible for the negotiation, implementation and administration of the gas supply contracts which constitute the core market supply.

A. I graduated from the University of Waterloo with a Bachelor of Applied Science in Chemical Engineering. The bulk of my experience prior to joining BC Gas has been in the oil and gas industry, including assignments in the petroleum refining, reservoir engineering and pipeline operations areas. My most recent experience involved a variety of positions related to the marketing of crude oil, sulphur, natural gas and natural gas liquids.

I have previously testified in regulatory proceedings before the National Energy Board, the Alberta Energy Resources Conservation Board, the New York State Public Service Commission, as well as the British Columbia Utilities Commission.

Q. What is the nature of your evidence?

A. I will answer questions respecting those issues in the Application which relate to the costs associated with gas supply.

Q. Does that complete your direct evidence?

A. Yes.

BC GAS INC.

WRITTEN EVIDENCE OF

JOHN K. THRASHER

Q. Please state your name and position with BC Gas.

A. My name is John Thrasher. I presently hold the position of Manager, Gas Supply Planning with BC Gas.

Q. How long have you held this position?

A. For the past six years.

Q. What are your main responsibilities in this position?

A. I am responsible for preparing the short and long term gas supply plans for BC Gas. This includes the management of gas supply issues related to core market direct sales (Buy-Sells). I am also responsible for managing the development of large scale gas supply projects.

Q. Have you previously testified before regulatory bodies or commissions?

A. Yes. I have appeared as a witness before the British Columbia Utilities Commission, the National Energy Board and the Ontario Energy Board.

Q. What subjects will you be addressing at this hearing?

A. I will respond to questions that relate to Buy-Sell arrangements for interruptible sales customers..

Q. Does this complete your direct evidence?

A. Yes it does.

BC GAS INC.

WRITTEN EVIDENCE OF

B.E. HANLON

Q. Please state your name, occupation, and address.

A. I am Brian Hanlon, 3777 Lougheed Highway, Burnaby, British Columbia, V5C 3Y3. I am the Manager of Gas Supply Administration of BC Gas Inc.

Q. Are your qualifications attached and marked Appendix A?

A. Yes.

Q. Mr. Hanlon, will you please describe your duties with BC Gas.

A. I am in charge of the day-to-day administration of gas purchase contracts that BC Gas has with its suppliers and the sales and transportation contracts that BC Gas has with its customers. My responsibilities include managing customer nominations, the ordering of gas into the BC Gas system, the scheduling of injections and withdrawals from storage and the controlling of transmission system pressures.

As a result of my duties, I am aware of the facts relating to gas control and system operations of BC Gas.

Q. What is the purpose of your testimony in this proceeding?

A. I will address the impact on gas control and system operations of the proposed industrial rate schedules and also address the Burrard Thermal curtailment priority.

Q. Why is BC Gas requesting amendments to the priorities under the Burrard Agreement?

A. The gas supply environment under which we currently operate has changed substantially from that when the Burrard Agreement was signed. Understandably, the Burrard Agreement contemplated that changes in the priority of Burrard Thermal supply might be required (section 6.03). The amendments requested by BC Gas deal with two issues mentioned in section 6.03 (storage injection and interruptible sales) in the context of current supply, sales and operating conditions. In the present environment storage (notably Aitken Creek) is fundamental to optimizing both supply economics and supply (operations) balancing. Off-system interruptible sales provide benefits to the firm customers which, without amendment to Burrard Thermal priority, might be lost as a result of having to reserve for Burrard Thermal all of the Lower Mainland valley whether Burrard was going to use it or not.

Q. What practical impact might the requested amendments have on the administration of the Burrard Agreement?

A. The amendments requested by BC Gas do not change the spirit or intent of the Agreement in that BC Gas still intends to make available to B.C. Hydro an absolute minimum of 20 PJ of Burrard Thermal seasonal gas supply. The amendment requiring that Burrard Thermal nominate its seasonal gas requirements in advance of each month is unlikely to have any significant impact on B.C. Hydro but it will provide BC Gas with the ability to schedule its off-system sales with some degree of reliability. Operationally, the changes will resolve some of the current supply scheduling problems which are related to the uncertainty of the Burrard Thermal take.

Q. Is daily balancing for large industrials still a requirement for BC Gas? Does Westcoast still require BC Gas to balance daily on its system?

A. Daily balancing is still a requirement for BC Gas in order to manage its transmission system pressures in an effective manner. Westcoast has not changed its position that LDC's must manage (i.e. correct) imbalances on a day to day basis.

Q. Doesn't BC Gas have a pipeline balancing arrangement with Westcoast which allows it to run imbalances? Why can't industrials operate and make use of that agreement at no charge?

A. At present there is no formal agreement between Westcoast and BC Gas, however there is an operating understanding between the two companies that either party may run daily imbalances, given prior authorization by the other party. The important operating aspect of this "agreement" is that BC Gas has to be prepared to increase or decrease its daily purchase from the level authorized in order to assist Westcoast when required. Correspondingly, Westcoast is prepared to increase or decrease its delivery to BC Gas to assist BC Gas only when conditions allow it to do so. The co-operative aspect of the agreement effectively increases the throughput of the two systems. What is important to realise is that BC Gas brings to the table (i.e. for pipeline to pipeline balancing) both storage and a Burrard Swing Agreement; which when used for managing imbalances have associated costs. Industrials have, on the other hand, little or no ability (or desire) to adjust takes on a daily basis for balancing purposes. It follows that if industrial customers are to share in the Westcoast-BC Gas pipeline to pipeline benefits they should be prepared to share some of the costs.

Q. Do you agree with the 20% tolerance for balancing for the industrials under rate schedule 32?

A. The 20% balancing tolerance, from a BC Gas system operations perspective, is quite liberal. However, the intent of the tolerance is to encourage accurate nominations yet still allow most customers a workable operating tolerance. Based on past experience the large majority of the customers will, through some care on their part, be able to stay within the balance tolerance for at least 90% to 95% of the time. It is the suggestion of BC Gas that it operate for one year with a 20% tolerance to determine whether this level of tolerance is appropriate.

APPENDIX A: QUALIFICATIONS OF BRIAN HANLON

I graduated from the University of British Columbia in 1968 with a Bachelor of Science in Mathematics. I had honour standing of four years. After graduation, I was employed by BC Hydro in various capacities. The chronology of my work is:

B.C. HYDRO

1968-1972	Programmer/Senior Systems Analyst
1972-1974	Supervisor Gas Control & Measurement Accounting
1975-1984	Superintendent Gas Control & Measurement Accounting
1984-1988	Superintendent Gas Supply Adminstration

BC GAS INC.

1988-Present Manager, Gas Supply Administration

I am a delegate to Westcoast Energy Operating Task Force. This committee is responsible for issues relating to scheduling (i.e. nominations and authorizations) and operations (i.e. gathering, processing and transportation) on the Westcoast system.

I am a member of the Canadian Gas Association and Pacific Coast Gas Association. I have served on CGA and PCGA committees dealing with gas control, supply, and scheduling problems.

BC GAS INC.

WRITTEN EVIDENCE OF

B.E. HANLON

EVIDENCE TO BE FILED AT A LATER DATE