BC GAS INC.

RATE DESIGN APPLICATION

PHASE A

PURSUANT TO
BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NO. G-92-91

VOLUME 2

WRITTEN EVIDENCE

October 28, 1991
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BC GAS INC.

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EVIDENCE OF PATRICK D. LLOYD

Q. Please identify yourself and your position with BC Gas?

A. My name is Patrick Lloyd. I have worked for BC Gas since 1980 in areas of law, regulation, corporate development and gas supply. My present title is Senior Vice President, Corporate Development, Gas Supply and Secretary. Legal and Regulatory Affairs as well as Corporate Development, Gas Supply and Corporate Secretarial report to me.

Q. What is your role in this hearing?

A. I am a policy witness; as such I will be answering questions related to BC Gas' broad policies and specifically how the gas supply, marketing and regulatory initiatives contained in this application are consistent with those policies.

Q. What are the primary matters to be determined in this application?

A. The application's primary focus seeks determination of two key matters:

First, Commission approval of a methodology to be used by BC Gas to flow through to various customer classes the gas supply costs contained in new gas purchase contracts.

Second, approval to negotiate the gas sales prices charged to large volume interruptible customers and approval to keep those negotiated gas sales prices confidential. It should be noted that the negotiations will be only with respect to the gas sales prices to large interruptible customers. This application does not seek any change in the utility margin to be charged for transporting the gas, nor does it seek the ability to negotiate changes in the utility margin.

Q. What events have caused BC Gas to seek a new methodology to flow through gas supply costs?

A. BC Gas recently entered into a portfolio of new long-term gas purchase contracts directly with producers. These gas purchase contracts replace the exclusive long term gas purchase arrangements BC Gas had maintained with its pipeline supplier, Westcoast Energy Inc. since natural gas first became available in B.C. In May 1990, Westcoast gave notice to terminate these latter contracts effective October 31, 1991.

The new contracts have been approved, and the initial year prices contained in them have been deemed prudent, by the Commission. However, the structure of the prices contained in these new contracts is different than the structure which previously existed in the contractual arrangements with Westcoast. The change in the structure of the prices gives rise to the need for the Commission to review the methodology for flowing through the gas supply costs to the various customer classes.

Q. What were the policy objectives guiding the contracting of the new gas supply contracts?

A. Four policies guided most of our focus in contracting for the new supply. These were:

i) the desire to develop a portfolio of suppliers to reduce, through diversification, the risk of supply failure. Diversification is one of the most cost effective ways, in a deregulated market, to reduce risk.

ii) the desire to develop competition between suppliers, supply area, pipelines and source of peaking. Competition is one of the most effective ways to ensure we are not paying more than market value.

iii) the desire to develop incentives to ensure that the gas supply system (including production, gathering, processing, transmission and storage) would be utilized in the most efficient manner possible. More efficient utilization of the existing infrastructure is one of the most effective ways of reducing the overall costs to end users;

iv) the desire to remain competitive in both the interruptible sales market and the core market.

Q. Why have these new contracts emerged at this time?

A. The contracts are a product of the market forces that have resulted from federal and provincial governmental policies implementing the deregulation of the natural gas industry. Prior to 1985 the sourcing of gas by LDC's (like BC Gas) was highly regulated. In BC Gas' case our customers were obliged to buy all their gas supply from us at the sales price set by regulated tariff. We were obliged to purchase all our gas supply for our customers from Westcoast at sales prices set by regulated toll.

With the federal/provincial Agreement on Natural Gas Markets and Prices of October 31, 1985 ("the Halloween Agreement"), Canada and B.C. joined the deregulatory initiatives ongoing in the United States. These initiatives were designed to introduce direct market forces into the pricing and supply sourcing of natural gas. End users and LDC's would now be able to contract directly with producers of natural gas and use the facilities of the pipeline and LDC on a service contract basis to move the gas from the producer's wellhead to the end user's burner tip.

It was believed that such direct negotiations between end user and producer would bring the subtleties of each customer's needs directly to the producer so the producer could respond to those needs. This would, over time, result in an improvement in the efficiency of the gas markets in meeting each user's distinctive gas requirements. Direct negotiations contrasted with the previous situation where an end user had to try to explain his distinctive needs to an LDC who (after establishing a tariff with the Commission) had to interpret and communicate that need to Westcoast who (after establishing a toll with the National Energy Board ("NEB")) had to interpret and communicate that need to the British Columbia Petroleum Corporation ("BCPC") who, in turn, had to interpret and communicate that need to the producer. With such a long chain of parties interpreting, communicating and aggregating each customer's requirements, it is little wonder the producer had virtually no opportunity to recognize and respond to customer market signals.

In Canada the Halloween Agreement provided that in making the transition to a deregulated industry, existing contracts could not be abrogated. Like most utilities at the time of the Halloween Agreement BC Gas had long term gas purchase contracts to ensure security of supply for its customers. That meant the 1967 and 1968 long-term Gas Sales Agreements with Westcoast would continue until expiry on October 31, 1991 before BC Gas would be able to buy its base load gas supply directly from producers.

Unlike BC Gas, industrial customers had relatively short term contracts with BC Gas. Consequently within one or two years of the Halloween Agreement many industrial and interruptible customers of BC Gas began purchasing gas directly from producers, brokers or aggregators. They still used BC Gas' pipeline facilities to move their gas to their plants, but they no longer bought the gas from BC Gas. This resulted in BC Gas reducing the volume of gas it purchased.

In order for producers to be able to more readily contract with industrial gas users in this deregulated market, constraints on producers also had to be reduced. Consequently as industrial gas users were being freed to negotiate directly with producers, governments were also reducing mandatory surplus tests and other regulatory constraints on producers' ability to freely negotiate. This meant that new methods were needed to ensure the security of gas supply for those parties that, for all practical purposes, were unable to negotiate directly with producers and, therefore, needed such security. In British Columbia, this resulted in the development of the Core Market Policy.

For provincial utilities like BC Gas the Core Market Policy mandated that the utility execute a portfolio of long-term contracts with sufficient supply to meet the core market's needs. The new long-term supply contracts are the result of that direction.

In the Core Market Policy the government recognized that deregulation has resulted in some customer groups (which are called core market customers) needing a regulatory mandate to direct the utility to enter into contracts to ensure a secure gas supply. The more sophisticated customers (which are called non-core) have many options and therefore no such regulatory mandate is needed or desired.

Put another way , the Core Market Policy recognizes that the utility still has virtual monopoly powers with respect to the merchant function (the gas sales function) for core market customers. The policy recognizes that the utility has no such monopoly power with respect to the gas sales function for non-core customers. The non-core customers have many choices from whom to buy their gas.

With deregulation each non-core customer can now force, through competition, the gas vendors (including the utility, if the utility is to make a sale) to recognize each non-core customer's particular distinctive needs; a far more customer-specific response is mandatory. It is this competition that ensures a customer-specific response that improves the overall value to the user of gas.

Q. Are you saying that when it comes to the merchant function, that is, the gas sales function, regulatory overview of a utility's gas purchases and gas sales should only focus on the best interests of the core market customers?

A. Yes. Regulation should only apply when a monopoly or near monopoly power exists. Core market customers, like residential and commercial gas users, have little practical choice but to buy their gas from the utility. The Core Market Policy recognizes that. So utility regulation should apply to ensure the gas utility does a prudent, cost-effective job in purchasing and managing the gas supply for the interests of core market customers. The long term gas supply assembled for the core market is an asset that must be managed in a way to maximize the benefit to the core market customer.

There is another perspective on why regulation of supply arrangements should only focus on the interests of the core market customers. Long-term supply arrangements are based on long-term contracts with producers, with pipelines or with providers of peak shaving services. These supply arrangements contain long-term financial risks. The core market customer assumes those risks because, for all practical purposes, that customer has no choice if the customer wishes to use gas. The non-core customer, however, can readily switch to another vendor of gas and thereby escape responsibility for the long term financial risks associated with the supply arrangements. Hence, unless a non-core customer has executed an irrevocable long term gas purchase contract with the utility, the utility should only make long term gas supply arrangements based on the core market's demand.

Q. Does the gas supply cost flow-through methodology that BC Gas is proposing in this application recognize that your long-term gas supply contracts are made specifically for the core market customers?

A. Yes. Step one of the proposed methodology allocates almost all of the fixed (demand) charges (ie. the long-term financial risks) to the core market customers. Since BC Gas contracts long-term fixed (demand) charges only for the core market's supply needs, our methodology allocates these charges to the core market.

Step two then allocates these demand charges across the various core market customer classes.

At step three we had to determine "How should BC Gas price gas to the non-core customer?" Should BC Gas price the gas at the incremental cost of that gas? Or should BC Gas price it at more than the incremental cost and make a "profit" on the gas sold and credit that "profit" back to the core market customer?

The methodology proposed in this application is to price the gas sold to large non-core customers at market price in order to make a "profit" on such sales. We then credit that "profit" back to the core market customers. Under the methodology in the application BC Gas believes it can maximize the "profit" to be credited back to the core market customers.

Q. How does BC Gas maximize the "profit" for the benefit of the core market customers?

A. BC Gas will maximize the "profit" to core market customers by achieving the highest price possible from each large non-core customer. This is achieved by negotiating individually with each large non-core customer recognizing that customer's specific ability to change to other gas suppliers or to other fuels. To ensure those individual negotiations proceed most effectively requires confidentiality of each negotiated price.

Again, it's important to stress that such negotiations are with respect to the sales price for gas; the negotiations are not with respect to the utility's margin. The utility's margin for transporting gas from the Westcoast interconnect to the customer's plant is established by the Commission based on cost of service and rate design considerations related to the cost of facilities, not on cost of gas supply considerations.

Q. In negotiating prices to the large non-core customers, what range of prices is fair?

A. The negotiations must result in final prices that ensure a "win-win" situation for both the large non-core customers and the core market.

The range must reflect that "win/win" requirement. Except in special circumstances when the Commission directs us otherwise, BC Gas will price the gas to a large non-core customer above a floor equal to the sum of:

i) the commodity cost of gas under the long term gas purchase contracts,

ii) the Westcoast variable costs,

iii) the cost of fuel gas;

but below a ceiling equivalent to the tariff rate available to smaller non-core customers.

Q. How many large volume interruptible customers does BC Gas have?

A. Approximately fifty. These are the customers whose gas requirements are large enough to be able to readily attract other gas suppliers.

Q. In this application, do you propose negotiating the gas sales price for smaller interruptible industrial customers?

A. No. The published tariff will continue to be applicable to those customers.

. What is the position of BC Gas with regard to the confidentiality of prices contained in its gas purchase contracts?

A. The prices contained in our gas purchase contracts should be kept confidential. Disclosure of those prices will disadvantage the core market as the negotiating position of BC Gas with producers and other suppliers would be compromised.

Q. What is the position of BC Gas with regard to the confidentiality of prices contained in gas sales contracts with parties purchasing from BC Gas?

A. Those prices should also be kept confidential. Producers and other suppliers of gas to consumers on the BC Gas system do not make their prices public. BC Gas will be placed at a competitive disadvantage if its prices are public. If BC Gas is disadvantaged, the benefits to the core market customers will be less than they would otherwise be.

Q. How can the core market be sure BC Gas has negotiated as hard as possible with the large non-core customers in order to maximize the core market's "profit"?

A. We believe there are at least three reasons why BC Gas will be motivated to maximize the core market's "profit":

i) the greater the profit credited back to the core market, the more competitive gas is for potential core market customers and the greater the likelihood BC Gas will gain those potential customers;

ii) general prudency review by the Commission from time to time; and

iii) the proposed 10% sharing of the profit by the Company and its shareholders.

Q. Why are you introducing the idea of sharing 10 percent of the core market's profit with BC Gas' shareholders?

A. Despite the "carrot" of shareholder profit from more competitive pricing and the "stick" of prudency reviews, questions have been raised regarding the extent of the effort that BC Gas might take to maximize the price at which the gas is sold to large non-core customers. Accordingly, BC Gas proposes this incentive be introduced to provide further assurance to the core market customers that BC Gas will attempt to achieve the maximum benefit in its negotiations. The incentive (as non-utility income) would be 10 per cent of the difference between the price at which gas is sold under the negotiated contracts and the cost of that gas.

BC Gas is prepared to consider other mechanisms which provide further incentive to maximize negotiated prices, if such mechanisms are fair, easy to administer, and not subject to periodic debate. We believe behavioral responses by companies are most efficiently implemented by incentives that align the shareholder discipline mechanism inherent in shareholder ownership with the interests of the core market customers.

Q. Your application also seeks to recover costs of some $825,300 incurred by BC Gas in putting the long-term gas supply contracts together. You seek to recover these costs over 11.5 years. Why are these costs amortized over such a period?

A. These costs were incurred by outside parties in helping BC

Gas meet the huge, one-time challenge of fundamentally restructuring the way BC Gas buys its gas. In fact, BC Gas' actual costs of meeting this one time challenge were far greater, they included restructuring and expanding the staffing of our Gas Supply group from late 1988 to 1991. These costs have been absorbed by BC Gas shareholders. It is only the out-of-pocket costs for specialized assistance and external costs incurred for this one-time challenge that BC Gas is seeking to recover. We have applied to recover those costs over the 11.5 year weighted average life of the gas supply contracts in order to match the costs of assembling those contracts with the beneficiaries of those contracts.

We believe our performance in meeting this challenge was exceptional, we believe our customers have benefitted significantly (even financial rating agencies recognize the strength of the results) and we believe the portion of the overall costs that BC Gas is seeking to recover is small when compared to the normal transaction premiums on major projects (especially projects with a worth of $2.5 billion). A charge of approximately $70,000 per year when compared to the transaction size is exceptional value.

BC Gas is also concerned about the behaviourial aspects of a disallowance of these expenditures. Our customers should endorse a regulatory scheme that does not penalize exceptional effort. The thrust of many of the emerging ideas in regulation is to provide incentives to encourage effort over and above reasonable effort. A disallowance in this case would not only fail to recognize those ideas --- it would actually penalize a successful extra effort. The behaviour implications of penalizing successful extra efforts are not in the customer's interest.

Q. Your application provides that the gas prices to the large volume customers should not change (other than changes due to Westcoast costs and revenue requirement application) until November 1, 1992. Why?

A. By the time a determination of this application is rendered, the 1991/92 gas year will be well underway. Customers will have finalized their arrangements for the year. Further, since negotiating gas prices is a key component of this application, this would be unachievable for this year. Certainty and stability of pricing and other contractual provisions would indicate changes be implemented for the year starting November 1, 1992.

Q. Please describe the main deferral accounts that are sought in your application as a result of the new gas contracts entered into and the flow through methodology proposed?

A. There are two main deferral accounts:

i) one to account for any variance from the $1.5 million we believe will be credited back to the core market as a result of benefits to be realized under the new contracts when purchase load factor is high and when our producers use our pipeline space for third party gas movement; and

ii) another account to capture the core market "profit".

EVIDENCE OF GEORGE R. LECHNER

Q. Please state your name and occupation.

A. George R. Lechner. I was Vice President, Gas Supply for BC Gas Inc. and its predecessor companies from November, 1988 to June 30, 1991. Since July, 1991 I have provided consulting services to BC Gas Inc.

Q. Please describe the long term gas purchase contracts into which BC Gas has entered.

A. BC Gas has entered into 21 gas purchase contracts with 14 producers and 3 aggregators for a volume of 13631 10^3m^3/d (480 MMcf/day) which will commence November 1, 1991.

Two different types of contracts have been entered into; a reserve type contract and a deliverability type contract. The two contracts have essentially the same terms and conditions with the one exception which pertains to the supply commitment provided by the supplier.

The reserve based contract requires the seller to exclusively dedicate a volume of reserves to BC Gas based on a reserve to production ratio. The number of days in the term of the contract divided into the reserves to be sold determines the daily contract quantity ("DCQ"). The reserves are evaluated and negotiated between BC Gas and the supplier and a deliverability assessment is made to ensure to the fullest extent possible that the required volume of reserves does exist.

A deliverability type contract requires that the supplier deliver on each and every day to BC Gas the volume of gas requested by buyer up to the DCQ during the term of the contract. If the supplier fails to deliver the daily volume requested by BC Gas on any day, BC Gas is entitled to buy that volume of gas elsewhere and the supplier must reimburse BC Gas for the difference between replacement cost and the contract price. BC Gas has only entered into deliverability contracts with credit worthy suppliers.

Six reserve type contracts provide 3876 10^3m^3/day (137 MMcf/day) of the contracted volume representing 28% of the supply and 15 deliverability type contracts provide 9755 10^3m^3/day of the contracted volume representing 72% of the supply.

The term of the contracts vary from 2 years to 15 years. The reserve contracts contain a 10 to 15 year rolling reserve dedication concept. As of November 1, 1991 the supplier has dedicated sufficient reserves for a 10 year term. The reserve contract provides an option to the supplier to dedicate additional reserves by November 1, 1994 to extend the contract term to 15 years from November 1, 1991. Where additional reserves are dedicated under the reserve contracts, the average volume weighted term for all of the contracts is approximately 13 years. If no additional reserves are dedicated to the contracts, the average volume weighted term for all of the contracts is approximately 12 years.

Q. Please describe the pricing provisions in the long term gas purchase contracts.

A. In structuring the gas price provisions of the contracts, it was apparent to BC Gas that 2 main factors influenced the gas price. The first factor is the annual load factor at which the gas is expected to be taken. The second factor is whether the customer purchasing the gas is a firm customer or an interruptible customer.

Generally speaking, in the eyes of a supplier, a desirable firm gas customer is one that takes gas at an 80% annual load factor or better. High load factor customers taking gas at 80% or better annual load factors are in a good position to negotiate a quality gas supply at competitive prices. BC Gas anticipates that under its present supply configuration given annual normal weather conditions, Burrard Thermal Plant usage of 20 PJ and maintaining its current interruptible sales volume it will be able to take gas at an approximate 80% annual load factor for at least the next 7 years.

The gas purchase contracts require that the parties negotiate a gas price at an 80% annual load factor. As was explained, this is BC Gas' most likely load factor under normal conditions. The contracts call for annual price negotiations unless the parties agree otherwise. The minimum pricing period under the contracts is one year.

Q. Should the gas prices in the long term contracts be kept confidential?

A. It is my view that gas prices in the contracts must be kept strictly confidential. Non confidentiality of prices will have a continuous upward pressure on price severely penalizing BC Gas' gas customers. The lowest prices will undoubtedly rise to meet the higher contract prices at each price negotiation, creating the likelihood of annual price negotiations. Indeed, non confidentiality of price would likely encourage minimum price periods of 1 year. The non confidentiality of an average gas price will also cause upward gas price pressure. Disclosure of BC Gas' average long term gas price will create an "automatic ratchet" whereby prices below the average will rise to the average which will then increase the average and the cycle will endlessly repeat.

Aggregators' gas prices are generally known throughout the producing sector. Nonetheless, BC Gas' gas prices should be kept confidential. BC Gas purchases less than one half of its supply from aggregators. Producers may sell their gas directly to customers for less than what they will sell for to aggregators.

Q. You have said that the parties to the long term gas purchase contracts are required to negotiate a gas price at an 80% annual load factor. In what manner is the 80% load factor price translated into the pricing in the contracts?

A. After an 80% load factor price is negotiated the price is related to a 100% load factor price by a formula in the contract. The 100% load factor price is broken down into a 30% demand or fixed component and a 70% commodity component. The 2 part price structure establishes a relationship between price and load factor and between the value of firm gas and interruptible gas.

It was found that the 70% commodity component of the gas price generally tracked the market value of interruptible gas. The 70% commodity component as a value for interruptible gas is not a precise measurement over the term of the contracts. Market anomalies will occur over the 12 to 13 year average life of the contracts. The 70% commodity value provides a base, over the long term, to establish the cost of interruptible gas. It may not provide an exact price relationship between firm and interruptible gas year by year, but does provide a reasonable long term relationship much in the same way as normalized weather is used in setting rates. It is extremely important that BC Gas remain price competitive in serving its interruptible gas market. Retention of the interruptible gas market confers significant load factor benefit to firm core market customers which will result in more favourable gas prices to them. The 70% commodity component of the gas price as an interruptible gas price will assist BC Gas in competing for interruptible gas customers.

Q. Are there additional pricing arrangements in the gas purchase contracts?

A. A number of the gas purchase contracts contain a price volume incentive adjustment ("VIA"). VIA provides that at a point in the contract year where the annual load factor under a contract reaches 80%, the demand component of the price is no longer required to be paid for the remainder of the year. It is estimated that for the 1991/92 gas year the savings realized through VIA will be $900,000.00

. The price provisions in the contracts include a gas inventory charge ("GIC"). The GIC provides that where BC Gas does not take gas at a 60% annual load factor or better, a GIC of 20% of the contractual gas price will be paid on the volume of gas which is the difference between the volume of gas at a 60% annual load factor and the volume of gas actually taken in the year below a 60% annual load factor. It is highly improbable that BC Gas will incur any GIC. Under its present annual supply configuration and excluding the sale of any Burrard Thermal Plant gas usage, BC Gas would take gas above a 65% annual load factor assuming the warmest year in 30 years.

All of the contracts contain mandatory and binding price arbitration. This ensures that a contract cannot be without a price thus ensuring the gas supply will be available for the term of the contract. Price arbitration under the contracts is "baseball" or final offer type of arbitration. In this type of arbitration, each of the parties submits their final suggested gas price to the arbitrators. The arbitrators must pick one of the prices as the gas price for 1 contract year.

A summary of the contractual price provisions is provided in the Appendix. The Appendix provides the formula through which the 80% annual load factor negotiated gas price is related to a 100% annual load factor price. The Appendix also provides illustrations of the relationship between the 30% demand and 70% commodity price structure and load factor.

Q. What arrangements has BC Gas made for service on the facilities of Westcoast Energy Inc. ("Westcoast")?

A. In the National Energy Board ("NEB") decision RH-1-89, dated September 1989, the NEB decided that the Westcoast facilities capacity of 12688.2 10^3m^3/day (448 MMcf/day) being used to serve BC Gas' core market customer under the gas sales agreement be allocated to BC Gas as service capacity on behalf of its core market customers. This service capacity ensures that BC Gas is able to purchase gas directly from producers and aggregators and have the gas transported to its system for delivery to its core market customers in the post November 1, 1991 period.

BC Gas has assigned the majority of this Westcoast service capacity to its suppliers for the term of the gas purchase contract. This service capacity will be reassigned to BC Gas at the termination of the gas purchase contract. The assignment and reassignment of the Westcoast service capacity is included in a cost of service agreement between BC Gas and its suppliers. There is a cost of service agreement for each gas purchase agreement.

Q. Which of the parties to the cost of service agreements have priority in the use of the Westcoast facilities?

A. The cost of service agreements provide for the priority of use of the Westcoast service. The order of priority is:

(i) To deliver BC Gas' nominated daily quantity on each and every day during the term of the gas purchase contract.

(ii) The supplier may use the capacity to deliver gas to other markets.

(iii) BC Gas may cause gas to be delivered from a supplier other than the supplier who holds the assigned service.

(iv) With the consent of BC Gas, the supplier holding the assigned service may permit a third party to use the Westcoast service.

The cost of service agreement requires that BC Gas will reimburse its supplier for the Westcoast demand toll for service required to deliver the daily contract quantity purchased under the gas purchase contract.

Q. In what manner do the cost of service agreements provide for payment of the Westcoast tolls?

A. BC Gas reimburses all of its suppliers monthly for the Westcoast demand toll in an amount equivalent to a toll based on Westcoast's annual system average shrinkage for raw gas transmission service and annual system average acid for treatment service. The transportation north long-haul service demand tolls and the transportation south service demand tolls are reimbursed monthly by BC Gas. BC Gas reimburses its supplier monthly for the Westcoast commodity toll for the volume of gas delivered each month.

Q. You have said that the supplier to BC Gas may use the Westcoast capacity when the Westcoast service is not required to deliver the nominated daily quantity to BC Gas. Do the cost of service agreements provide for compensation to BC Gas?

A. When a supplier uses the Westcoast service assigned to it by BC Gas to serve other markets, the supplier is equired to reimburse BC Gas for the use of the service. The service agreements provide for one of the following methods of reimbursement:

(i) A fixed formula reimbursement as follows:

- For the winter months of November, December, January and February, 100% of the Westcoast daily demand toll.

- For the shoulder months of March, April, September and October, 50% of the Westcoast daily demand toll.

- For the summer months of May, June, July and August, 25% of the daily demand toll.

(ii) A revenue sharing method wherein the supplier reimburses BC Gas for an amount equal to 50% of the net revenue from the sale of gas to other markets. Net revenue is the total revenue received by the supplier from the sale, less the aggregate of the commodity component of the gas price and other variable costs. In most cases other variable costs will be the Westcoast commodity toll associated with the movement of gas to other markets.

Q. What is the BC Gas forecast of the compensation that BC Gas may receive for use of the Westcoast capacity by suppliers?

A. The amount of Westcoast cost of service recovery by BC Gas from suppliers through the reimbursement methods is expected to be $600,000.00 for the 1991/92 contract year. When BC Gas has gained working experience with these cost of service recovery contractual arrangements, there is likely an opportunity for cost recovery considerably greater than the first year estimate of $600,000.00.

Q. What expenditures were incurred by BC Gas in arranging for its long term supply of natural gas?

A. The recontracting of BC Gas' entire gas supply has been a major undertaking. In order to provide BC Gas core market customers with a diverse secure and competitive gas supply, the supply was contracted from many reliable suppliers with diverse delivery points throughout the gas producing areas. The long term contracting for over 13600 10^3m^3/day of supply represents more gas than the starting volume of Trans Canada Pipelines. BC Gas commenced contracting for its supply in late 1988 / early 1989. It soon became evident that legal gas contracting expertise would be needed and Mr. R.C. Muir was engaged starting May 1, 1989 to assist in the gas purchase contracting. At one point in the contracting process, there were over 100 contracts in 4 different forms sent out to producers.

. As firm long term gas supply arrangements began to be firmed up early in 1991, it became imperative that cost of service arrangements be established between BC Gas and its suppliers in a very short timeframe. Because of his in-depth knowledge of Westcoast service matters and because of the urgency in completing gas supply arrangements, Mr. C.B. Johnson of Russell & DuMoulin was asked to provide legal assistance in preparing all of the cost of service agreements. In the overall supply arrangements, Mr. Johnson worked on cost of service arrangements and Mr. Muir worked on gas purchase arrangements.

The restructuring of BC Gas' gas supply has resulted in providing its core market customers with a high quality long term gas supply with many innovative features which will provide substantial benefits to its customers over the 12 to 13 year life of the gas contracts. As such, the $825,000.00 legal and consulting fees related to the new gas supply arrangements represents a necessary expenditure to accomplish the massive undertaking of recontracting the entire BC Gas core market gas supply. As this expenditure will significantly benefit BC Gas core market customers over a 12 to 13 year period the $825,000 legal and consulting fees should be amortized over the supply life.

Q. Please summarize the effect of the new gas purchase arrangements.

A. The gas purchase contracts and cost of service agreements have been designed by BC Gas to fit the new deregulated era in the gas industry. The provisions of the agreements are an incentive to the parties to efficiently employ all sectors of the industry from the wellhead to the burner tip. Gas suppliers and BC Gas' core market customers both stand to gain significant benefits from the efficient use of the natural gas infrastructure in a win/win situation for both parties.

BC GAS INC.

GAS PRICE METHODOLOGY

ELEMENTS

GAS PRICE (GP)	--	NEGOTIATED AT 80 % LOAD FACTOR
GAS REFERENCE PRICE (GRP)	--	ESTABLISHED AT 100 % LOAD FACTO
GRP BROKEN DOWN INTO	--	30 % DEMAND COMPONENT
		70 % COMMODITY COMPONENT
GAS INVENTORY CHARGE (GIC)	--	20 % OF THE GRP
	--	PAID ON GAS VOLUMES NOT TAKEN BELOW 60 % LF
VOLUME INCENTIVE ADJUSTMENT (VIA)	--	PRICE REDUCTION ON GAS VOLUMES TAKEN ABOVE 80 % LF
	--	Equal to 30 % DEMAND COMPONENT

Post 1991 Gas Purchase Contract Pricing

Equation

$$GRP = \frac{(ALF) \times GP(ALF)}{\text{Demand Fraction} + \{\text{Commodity Fraction} \times ALF\}}$$

Where;

ALF = Annual Load Factor

GP(ALF) = Negotiated Gas Price at the Annual Load Factor

GRP = Gas Reference Price at 100% Load Factor

Demand Fraction = Demand Fraction of Gas Reference Price

Commodity Fraction = Commodity Fraction of Gas Reference Price

Example

ALF = 80%

GP(80) = \$1.43 /GJ

Demand Fraction = 30%

Commodity Fraction = 70%

$$GRP = \frac{0.8 \times \$1.43}{0.3 + \{0.7 \times 0.8\}} = \$1.33\ /GJ$$

30% Demand	= .3 x\$1.33 =	\$0.40 /GJ
70% Commodity	= .7 x\$1.33 =	\$0.93 /GJ

Post 1991 Gas Purchase Contract Pricing

Gas Price	= $1.43 /GJ	@ 80% LF		
Reference Price	= $1.33 /GJ	@ 100% LF		
% Commodity	= 70%	$1.33 x	70% =	$0.93 /GJ
% Demand	= 30%	$1.33 x	30% =	$0.40 /GJ
GIC	= 20%	$1.33 x	20% =	$0.27 /GJ
VIA	= No Demand CoG above 80% LF			

%LF	CCoG	DCoG	Tot.GP	GIC/VIA	TOTAL
1%	$0.93	$39.91	$40.84	$15.70	$56.53
10%	$0.93	$3.99	$4.92	$1.33	$6.25
20%	$0.93	$2.00	$2.93	$0.53	$3.46
30%	$0.93	$1.33	$2.26	$0.27	$2.53
40%	$0.93	$1.00	$1.93	$0.13	$2.06
50%	$0.93	$0.80	$1.73	$0.05	$1.78
60%	$0.93	$0.67	$1.60	$0.00	$1.60
65%	$0.93	$0.61	$1.55	$0.00	$1.55
70%	$0.93	$0.57	$1.50	$0.00	$1.50
75%	$0.93	$0.53	$1.46	$0.00	$1.46
80%	$0.93	$0.50	$1.43	$0.00	$1.43
85%	$0.93	$0.47	$1.40	($0.03)	$1.37
90%	$0.93	$0.44	$1.37	($0.05)	$1.33
95%	$0.93	$0.42	$1.35	($0.07)	$1.28
100%	$0.93	$0.40	$1.33	($0.08)	$1.25

Commodity CoG = % Commodity

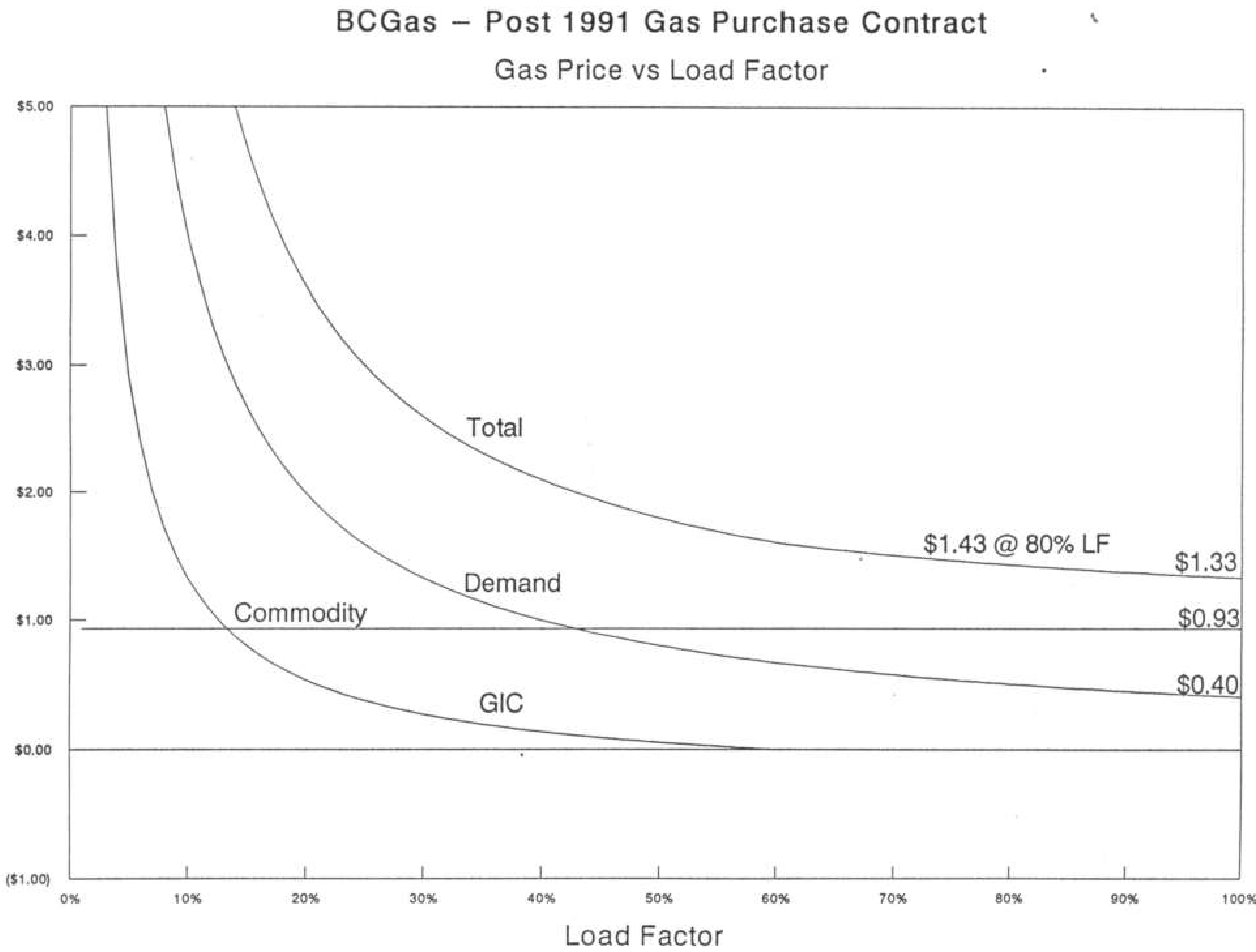
Demand CoG = % Demand / Actual Load Factor

Tot.GP = CCoG + DCoG

GIC (< 60% LF) = (60% LF – ALF) x GIC / ALF

VIA (> 80% LF) = (% Demand / Actual Load Factor * 80% / ALF) less (% Demand / Actual Load Factor)

TOTAL = Tot.GP + GIC – VIA


BCGas – Post 1991 Gas Purchase Contract
Gas Price vs Load Factor
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
($1.00)
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Load Factor
Total
Demand
Commodity
GIC
$1.43 @ 80% LF
$1.33
$0.93
$0.40

EVIDENCE OF HENRY L. DINTER

Q. Please identify yourself and your title at BC Gas.

A. My name is Henry Dinter. I have worked for BC Gas since 1989 in my present capacity as Manager, Industrial Markets. I am responsible for the Company's sales and marketing efforts as they relate to industrial customers.

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 am a member of gas associations in Canada and the United States. Between 1981 and 1989 I held a variety of procurement positions with Weldwood of Canada Ltd., the most recent, 1986 - 1989, as Administrator, Energy and Raw Materials. In this capacity I was responsible for the negotiation and contract administration relating to the company's natural gas, petroleum and chemical requirements. I acted on behalf of Weldwood (Cariboo Pulp & Paper) in arranging the first direct purchase transportation contract in B.C. on May 1, 1986. As member of an industrial bypass committee I took part in negotiations with Inland Natural Gas Co. Ltd. to bring about the first bypass contracts in the Province on November 1, 1988.

Negotiated Rates

Q. Please explain why, in your role as Manager, Industrial Markets for BC Gas, you require the ability to negotiate gas sales prices with large volume interruptible customers.

A. Industrial gas use contributes to the overall efficiency and economic benefits of gas service to all BC Gas customers.

An objective of my department is to maximize industrial gas sales revenue as this contributes to the maintenance of reasonable gas costs to all sales customers.

In meeting this objective, BC Gas has initiated a major review of its transportation services, beginning with those services available to large industrial customers in the Inland Division. The Company's timing in this regard has been advanced as a result of changes which have occurred in the natural gas market in B.C. and the development of a new BC Gas supply portfolio for November 1, 1991. In addition, it is of particular importance that those transportation services which are available to Inland large industrials be made available to Lower Mainland customers as soon as practical.

To some extent, our objectives with respect to transportation services have been overshadowed by immediate concerns with respect to sales. Highly competitive natural gas markets have resulted in producers and marketers, previously content to target only high load factor firm industrial markets in the BC Gas service area, threatening to gain a significant share of our interruptible market. To some extent, it has been fortunate that the Lower Mainland transportation terms have been structured to limit the ability of sales customers to move to transportation until the Company's sales tariffs could be restructured. In Inland Division, requirements imposed under the transportation tariffs have also favoured interruptible sales by the utility over direct purchases from producers.

With the start up of the new gas supply contracts on November 1, 1991, BC Gas is in a good position to respond to competition. However, in order to do so it requires much more flexibility in setting its gas sales prices. Without this flexibility, BC Gas will be unable to prevent some of its most valued sales load from moving to direct purchases, or conversely, will have to price its interruptible sales so low that those sales will make less than an optimal contribution to its gas supply costs.

Interruptible customers by this very nature are excellent loads not only for BC Gas, but for producers and marketers alike. Similar to a utility, other sellers also have surplus gas supply and Westcoast capacity which can be marketed at prices just below those of competitors. Despite lower prices, interruptible sales help to "average down" fixed transportation and other costs. Any contribution to those costs is welcome, with the marketplace and a seller's variable costs setting the extreme boundaries for such price determination.

Once new and more accessible transportation terms become available, the market for domestic interruptible sales will become even more competitive. Rather than continuing to rely on restrictive transportation terms, BC Gas must be in a position to address each customer's specific needs. This is how the "direct purchase" market works. In order to be fair to all parties, BC Gas must operate on a similar basis. Negotiated rates will permit it to both compete for interruptible sales and optimize revenues from those sales.

Confidentiality

Q. Please explain, in your view, why confidentiality is required.

A. Economists suggest that competition is best served when all information is available to all parties. However, the market for domestic gas sales does not occur on this basis. While it is true that short term supply contracts are filed with the Commission, it is not a regulatory requirement for customers to file price information, nor is such information available for public scrutiny. Accordingly, any party competing for interruptible sales that is required to make its pricing, terms and conditions of sale public will be placed at a serious disadvantage to its competitors. Absent confidentiality, such is and would continue to be the case for BC Gas.

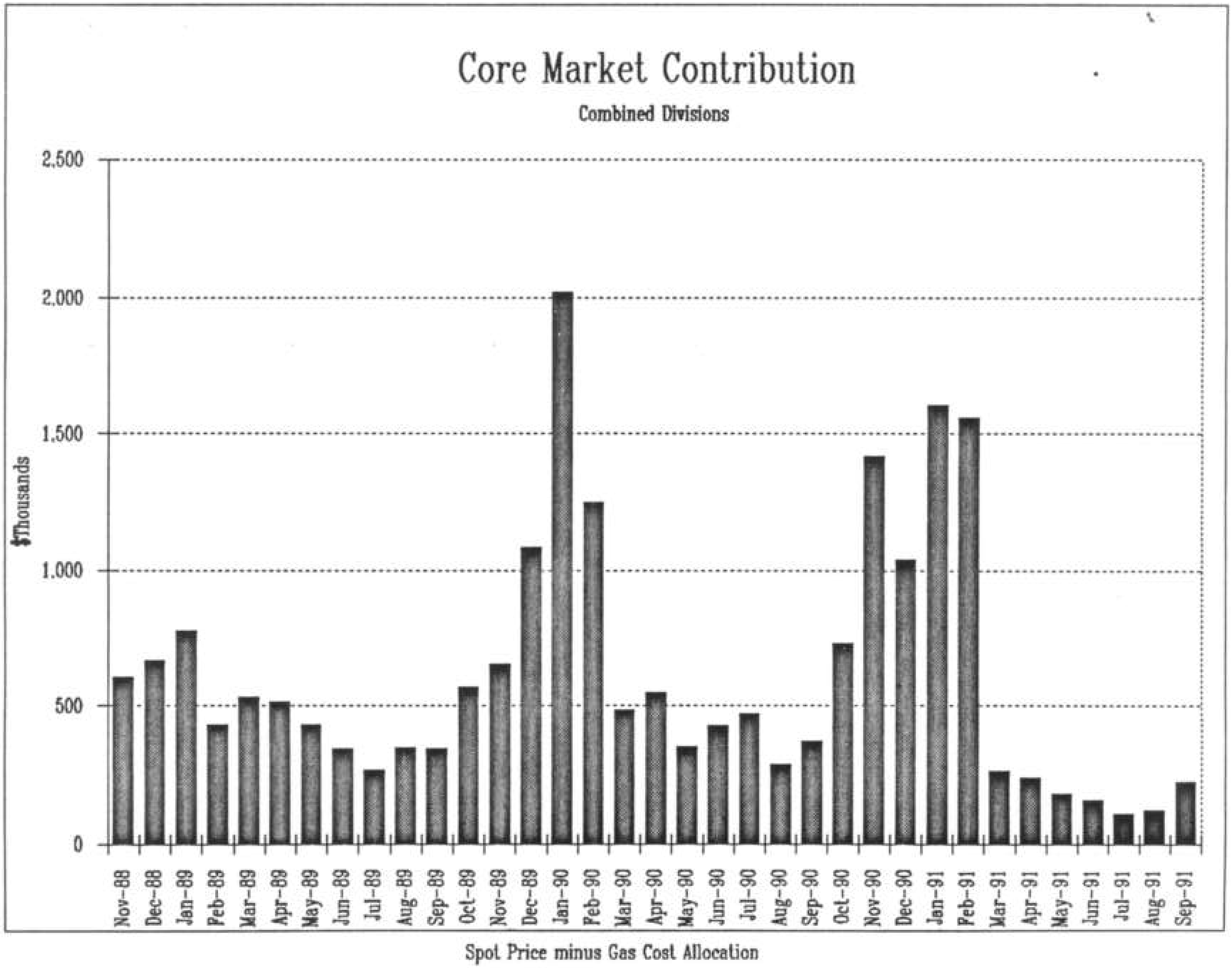
As indicated in the October 15 Application, customers, producers, and marketers would, as they currently do, review BC Gas contracts on file with the Commission with an aim to structuring proposals sufficiently competitive to attract customers away from the utility. Unfortunately, similar opportunity would not be afforded BC Gas. As a result, the utility would be competing for customers without the benefits of being equally informed about a competitor's commercial arrangements.

Without confidentiality, customers would continue to view interruptible sales as a regulated utility function. Customers would, regardless of their specific market alternatives, volume or load characteristics, seek pricing and terms commensurate with the most competitive contract on file. This would place the utility in a defensive position with every customer except the one having the best price. While differentials due to load characteristics, volume and/or market alternatives are explainable, customers do not necessarily accept such rationale. It is the notion of some customers that knowledge of better terms for others must in and of itself translate into similar terms for them - whether or not substantially similar circumstances and conditions exist. I refer the Commission to negotiations that have taken place with bypass customers, and recently, with one of our larger sales customers that has a viable alternative fuel. In both examples, customers have been adamant that they receive terms similar to those made available to others.

In summary, confidentiality is the underpinning for negotiated sales prices. Approval of confidentiality will be a clear signal to large interruptible customers that their gas prices will be market based, either from the utility or the direct market.

Q. Does your application for confidentiality extend to the margin received for transportation.

A. No. This is a major reason for separating sales and transportation functions for large industrial customers. Only the price for gas, which will be sold at the Interconnection Point with Westcoast, will be confidential.


Core Market Contribution
Combined Divisions
$Thousands
2,500
2,000
1,500
1,000
500
0
Nov-88
Dec-88
Jan-89
Feb-89
Mar-89
Apr-89
May-89
Jun-89
Jul-89
Aug-89
Sep-89
Oct-89
Nov-89
Dec-89
Jan-90
Feb-90
Mar-90
Apr-90
May-90
Jun-90
Jul-90
Aug-90
Sep-90
Oct-90
Nov-90
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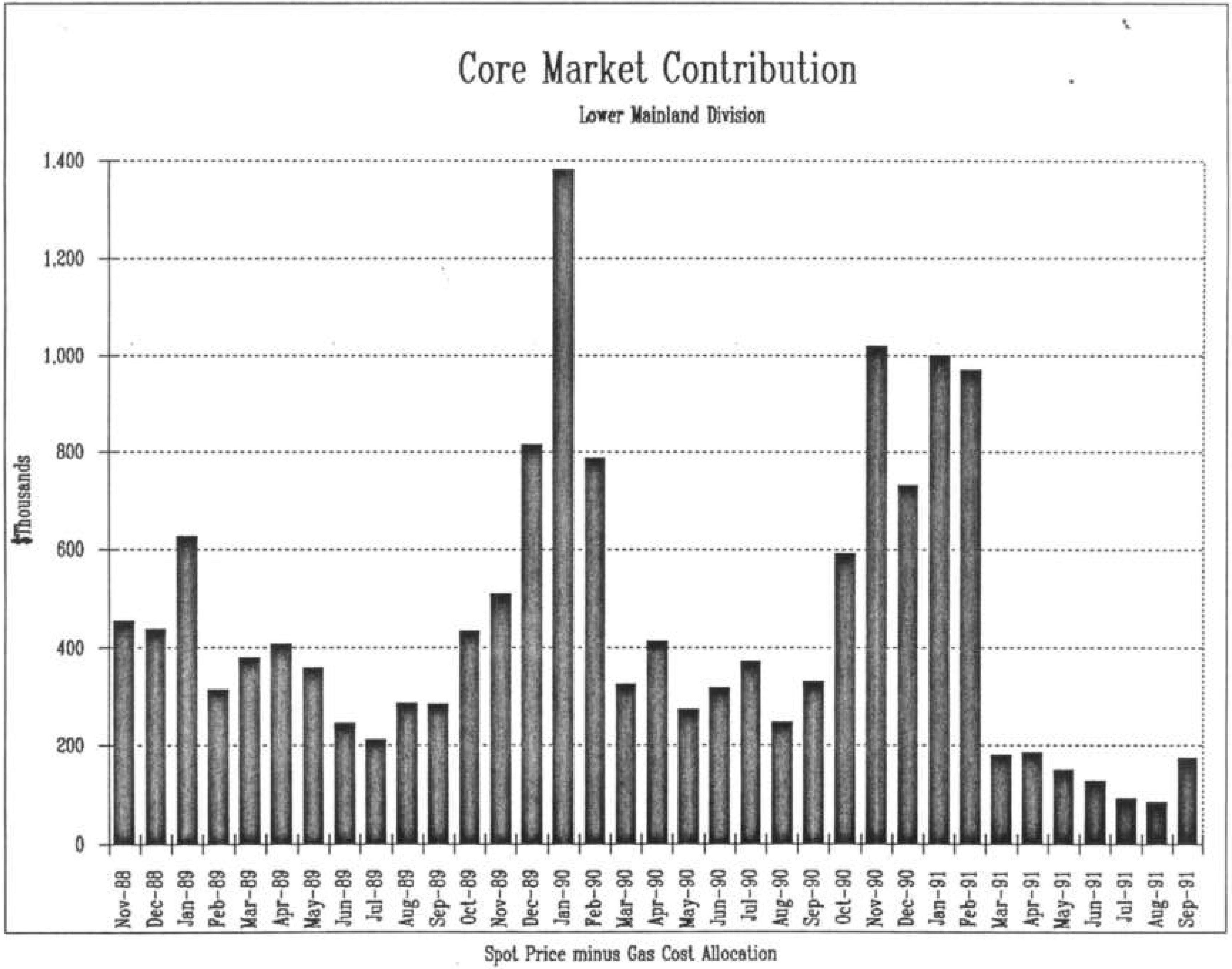
Aug-91
Sep-91
Spot Price minus Gas Cost Allocation


Core Market Contribution
Lower Mainland Division
$Thousands
1,400
1,200
1,000
800
600
400
200
0
Nov-88
Dec-88
Jan-89
Feb-89
Mar-89
Apr-89
May-89
Jun-89
Jul-89
Aug-89
Sep-89
Oct-89
Nov-89
Dec-89
Jan-90
Feb-90
Mar-90
Apr-90
May-90
Jun-90
Jul-90
Aug-90
Sep-90
Oct-90
Nov-90
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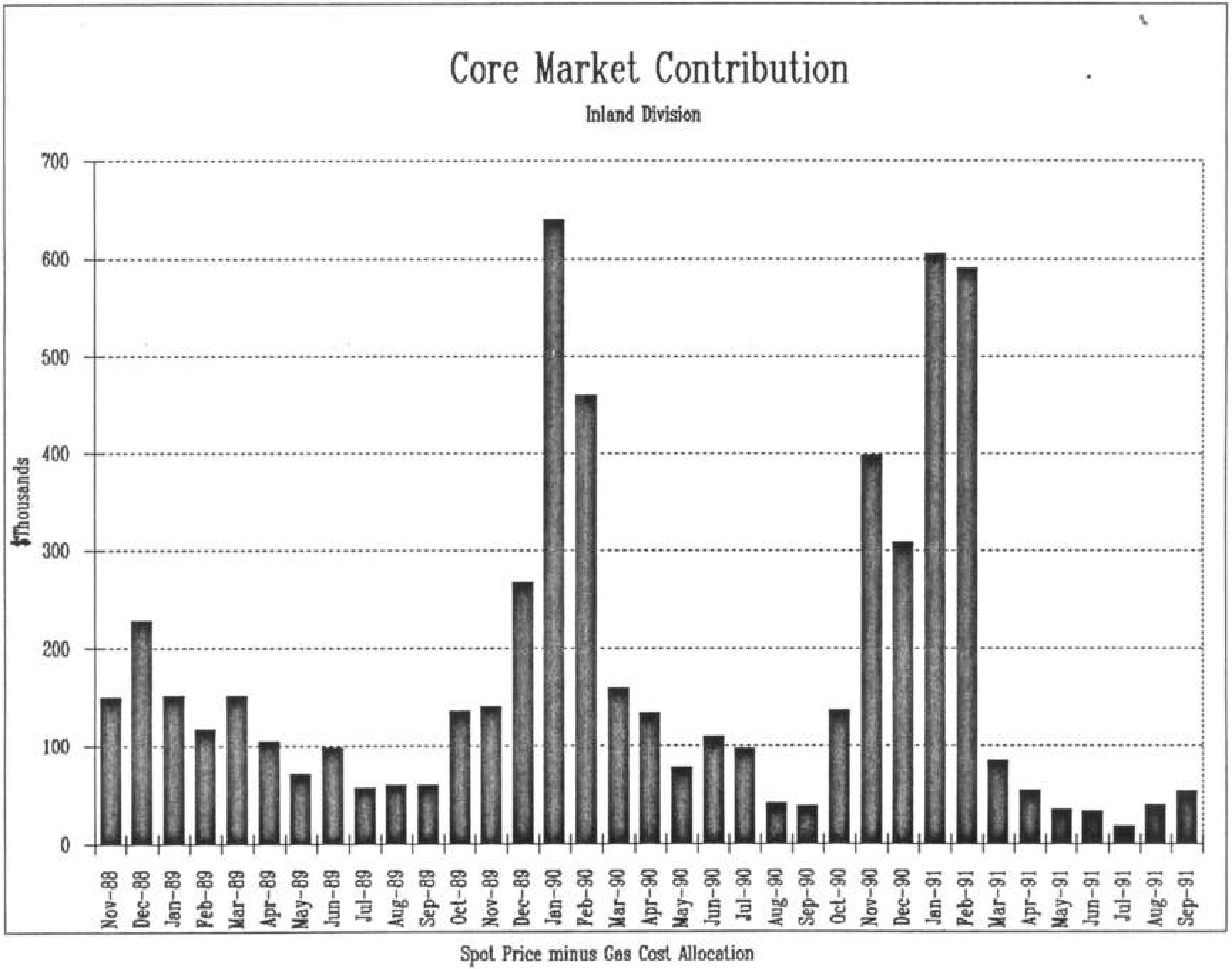
Jul-91
Aug-91
Sep-91
Spot Price minus Gas Cost Allocation


Core Market Contribution
Inland Division
$Thousands
0
100
200
300
400
500
600
700
Nov-88
Dec-88
Jan-89
Feb-89
Mar-89
Apr-89
May-89
Jun-89
Jul-89
Aug-89
Sep-89
Oct-89
Nov-89
Dec-89
Jan-90
Feb-90
Mar-90
Apr-90
May-90
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Sep-90
Oct-90
Nov-90
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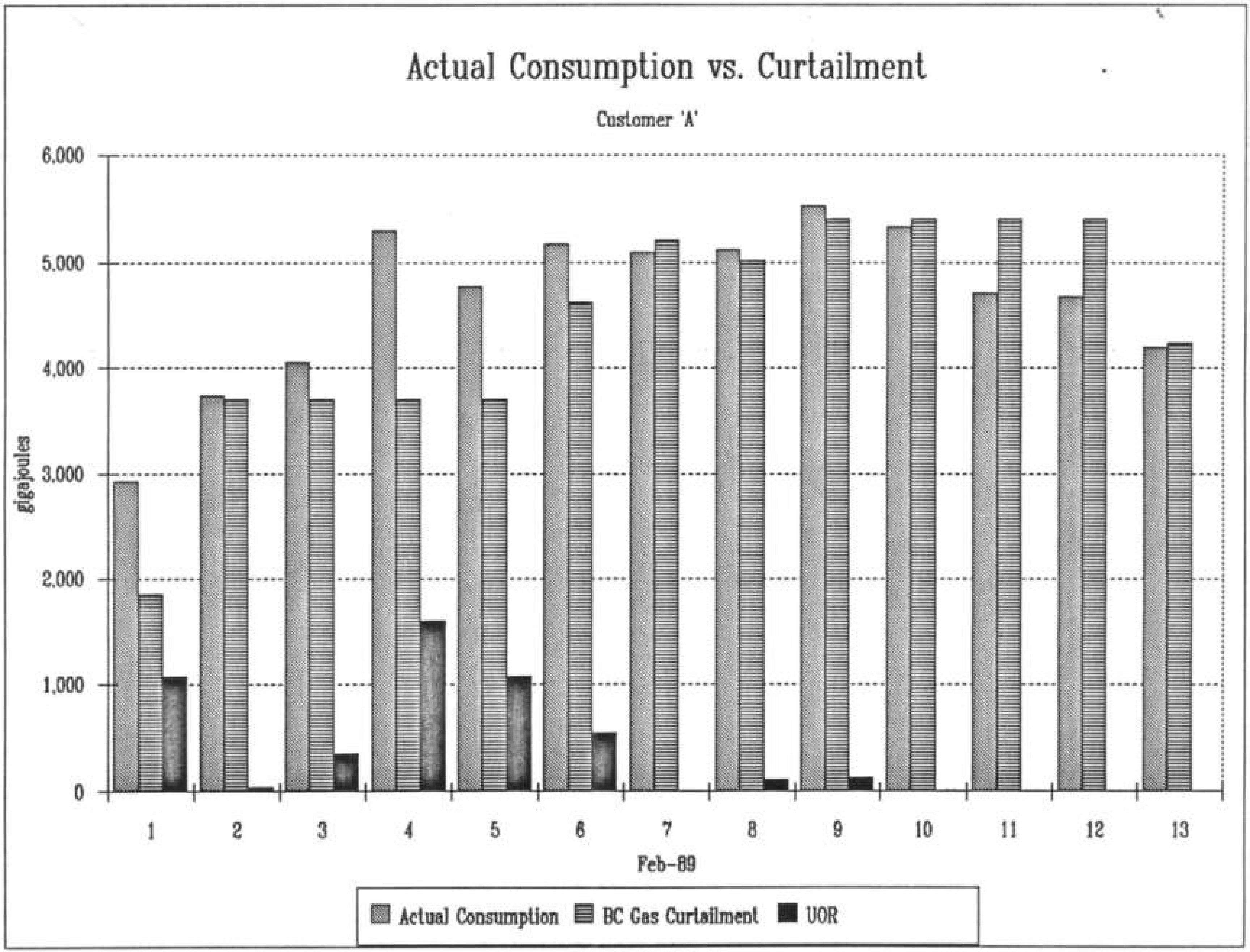
Mar-91
Apr-91
May-91
Jun-91
Jul-91
Aug-91
Sep-91
Spot Price minus Gas Cost Allocation



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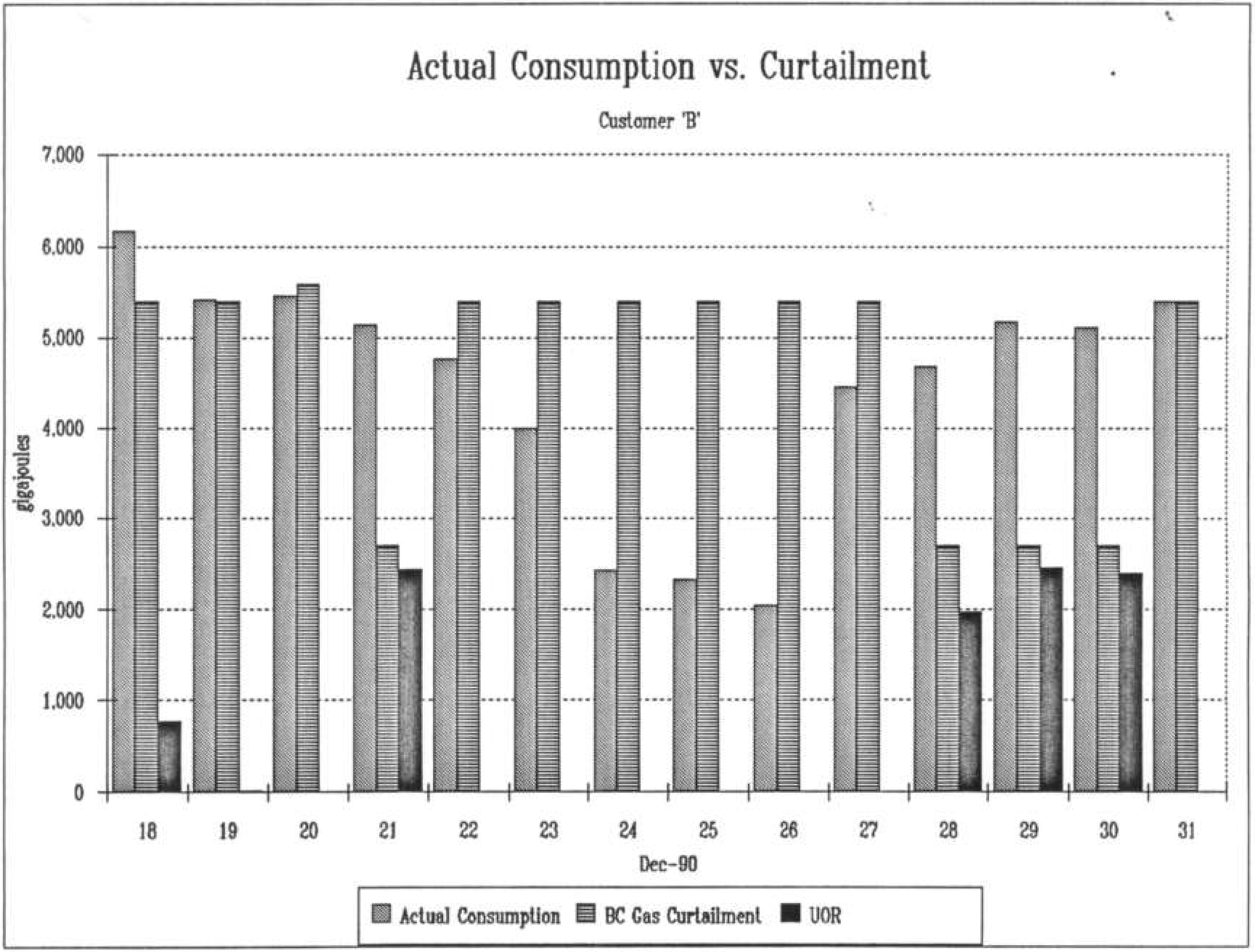

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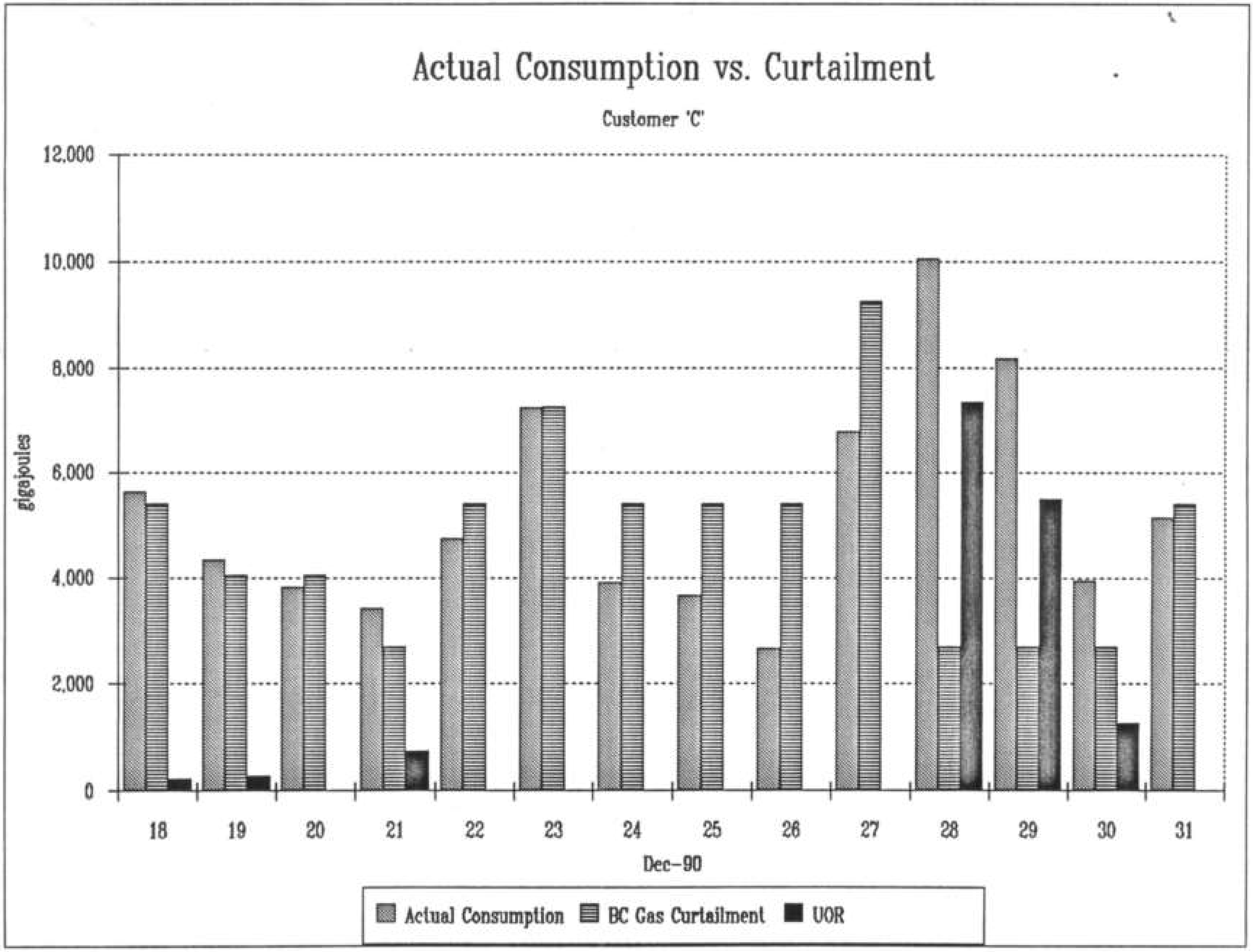
APPENDIX B
PAGE 2



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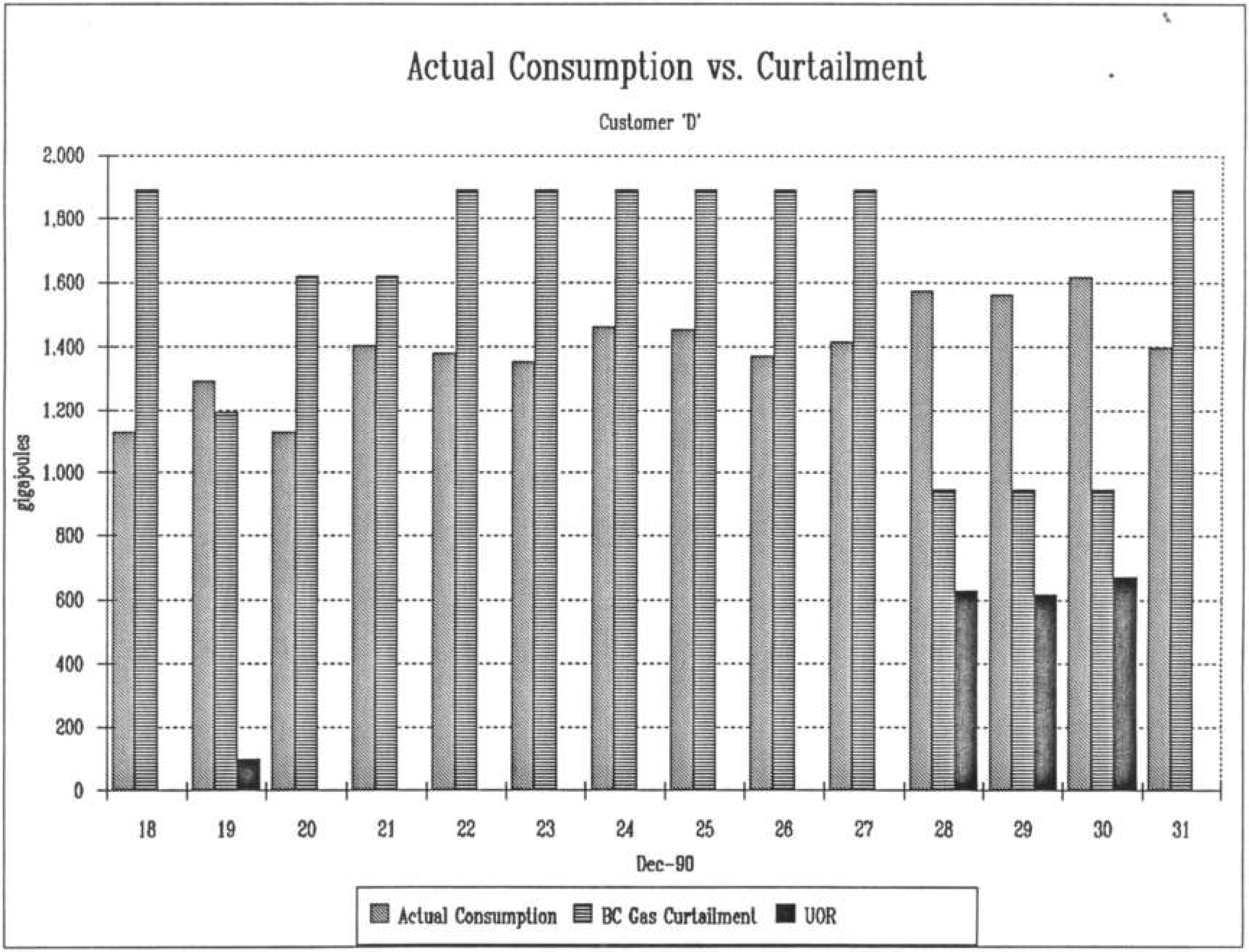

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APPENDIX B
PAGE 4

EVIDENCE OF DANIEL J. REED

Q.. Please state your name, occupation and address.

A. Daniel J. Reed, utility tariff consultant, 1065 East Prospect Street, Seattle, Washington 98102. A summary of my qualifications is attached as Appendix A.

Q. Please explain your engagement by BC Gas.

A. BC Gas created a Rate Department and appointed Stanley P. Crocker as the department manager. I was engaged to assist Mr. Crocker in the organization of the systems necessary to analyze rates and revenue from the Fort Nelson, Columbia, Inland and Lower Mainland Divisions. The purpose of the assignment was to assist in the preparation of a general rate design case. Recently, when Phase A of the Company's rate design was scheduled for hearing, I was asked to address certain rate design policy issues.

Q. What other experience have you had with natural gas rates in British Columbia?

A. I was engaged by BC Hydro Gas Operations as a rate design consultant to assist it in the preparation of a natural gas rate design case in 1986. The case was not filed because the Province decided to privatize Hydro's Gas Operations.

Q. What are the primary pricing policy matters to be considered in Phase A of this proceeding?

A. Foremost are competition for the industrial market and cost of gas allocation to the customer classes. I believe that a modification to the present system of regulation is required to cope with these issues.

Q. Please summarize your testimony.

A. Competition in the natural gas marketplace is what brought us here today. A modification is required to the traditional regulatory practice that compels a full disclosure of prices that BC Gas charges its non-core customers if the Company is to maximize payment in aggregate from non-core customers for their off-peak use of the BC Gas system. Traditional regulatory treatment of industrial service rates is obsolete and, if continued, will work to the detriment of core customers. The Company is proposing a mechanism to maximize such payments, a goal which should be agreed to by all parties except perhaps by those who will provide funds to reduce the cost of core customer service.

The Company had to enter into a new gas supply arrangement because the old form of gas supply was no longer available. Next, the cost of this gas supply must be properly allocated to the customer classes. I believe that the Company has proposed to the Commission the appropriate methodology under which it should spread its gas supply costs among the customer classes.

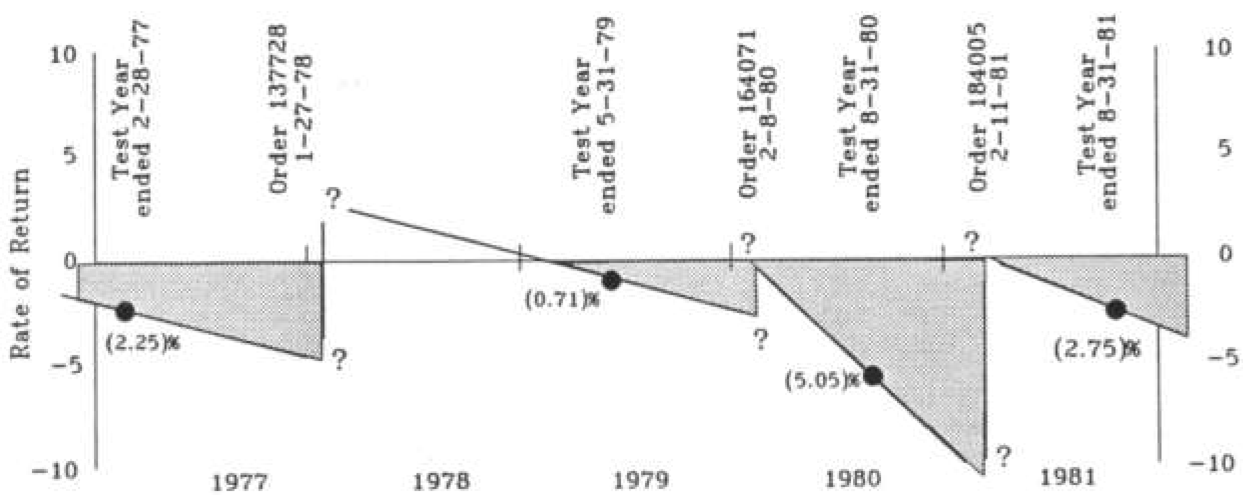
Q. In your view, is it necessary to quickly react to the competitive forces in the industrial service market?

A. Absolutely, and it is apparent that the Commission recognizes this current reality by calling this hearing to deal with, among other things, large volume industrial price design prior to the traditional revenue requirement hearing. Regulatory lag might have been used in the old days as a blunt instrument to bring about certain actions on the part of utilities, but delay in this case would prevent BC Gas from reacting to competitive pressures. This would adversely affect the core customers of BC Gas. The additional and unnecessary loss of BC Gas interruptible industrial loads, which will contribute to maintaining lower rates for core customers, is not in the public interest.

Q. Please offer your perspective as to why the competitive forces have been released in the industry.

A. Competition from energy sources other than natural gas has historically been a significant factor in gas utility rate design. Recently, tumultuous changes have been precipitated by public policies that introduced, or exacerbated, effective competition, depending on your point of view. Whether you are in North America, Europe, Africa, Asia, or Australia, one of the industry's most basic problems has been intra-class transfers. Public utilities are often regulated in a way that causes subsidization of residential customers by the other classes. I will use an example to illustrate the point. The chart below represents the earnings of Oklahoma Natural Gas (ONG) from its residential class during the period of 1977 to 1981, which is prior to the deregulation of the natural gas industry in the United States and here. I was involved in these cases and prepared the diagram as one of my exhibits in 1981.

OKLAHOMA NATURAL GAS COMPANY
Residential Rate of Return
Before Allocation of Income Taxes



Negative Rate of Return Indicates
That Funds Are Not Available
For Return and Income Taxes

The bold dots indicate the Company's calculation of residential class rate of return before allocation of income taxes and return. The Company's return diminished to even lower levels before rate relief and may have rebounded to positive levels after rate relief. Most of the time, ONG did not collect its out-of-pocket cost that was incurred to serve the domestic class. There is an old expression, "nothing is worthless, it can be used as a horrible example." This chart can be used as a horrible example of an excess that eventually changed the industry. These excesses were just too widespread among utilities, it just went too far, and the pendulum started swinging in the other direction. End-users and producers joined together to obtain political relief.

Q. You have been involved in rate and cost analysis work in other jurisdictions. Have you ever been aware of a situation where residential rates were not subsidized?

A. No, but some situations were more extreme than others.

Q. Do you conclude that open access to natural gas systems requires modification of certain regulatory policies.

A. Yes. In a monopoly situation, it is widely held that regulators functioned as a substitute for competition. Now that the public policy has brought intense competition into gas supply and into industrial prices, regulators are either not needed in these sectors of the business or they should adopt new policies relating to managerial oversight. Perseverance in imposing detailed regulation policies on industrial pricing matters, which now must be coped with on a day to day basis by the utility's management, will cause a deterioration of the core market situation.

Government policies regarding competition in the natural gas industry have required utilities to change their ratemaking policies. Concomitant changes in regulatory treatment of competitive factors are needed before extensive damage to the core customers occurs. It may be the devout hope of some people that this tide will eventually turn, but it will require years to undo the competitive changes that have been brought about in the industry. It is a fact of life now, and we must deal with it.

Q. Do you object to the concept of selling system off-peak capacity and gas supply to non-core customers and using the proceeds to reduce the costs borne by core customers?

A. No. It does not seem to me that BC Gas objects either. In this Application, BC Gas explicitly proposes to plow back earnings from non-core customers to the core customers. Now that market competitive forces have been unleashed, direct subsidies cannot be as mandated and quantified as they once were. The best that a local distribution company (LDC) can do now in the industrial market is price at market value, because the customers have options available for natural gas other than BC Gas's sales gas.

Q. What conclusions do you draw about rate regulation of LDC's, given open competition for industrial loads.

A. Let's talk about alternatives. Option 1 is to continue regulation as usual, which means regulated gas prices and open access to gas prices paid by any industrial customer. Option 1 works fine without genuine competition, when customers have no choice but to buy gas, or use alternative energy sources. Now, however, the industrial customer's natural gas market opportunities are practically wide open. Each customer's load profile and energy conversion process is different, hence the market value for each customer is different. Like and contemporaneous service in the industrial sector rarely exists. The factual market value situation is too complex for detailed regulation.

Option 2 is complete deregulation of the industrial market.

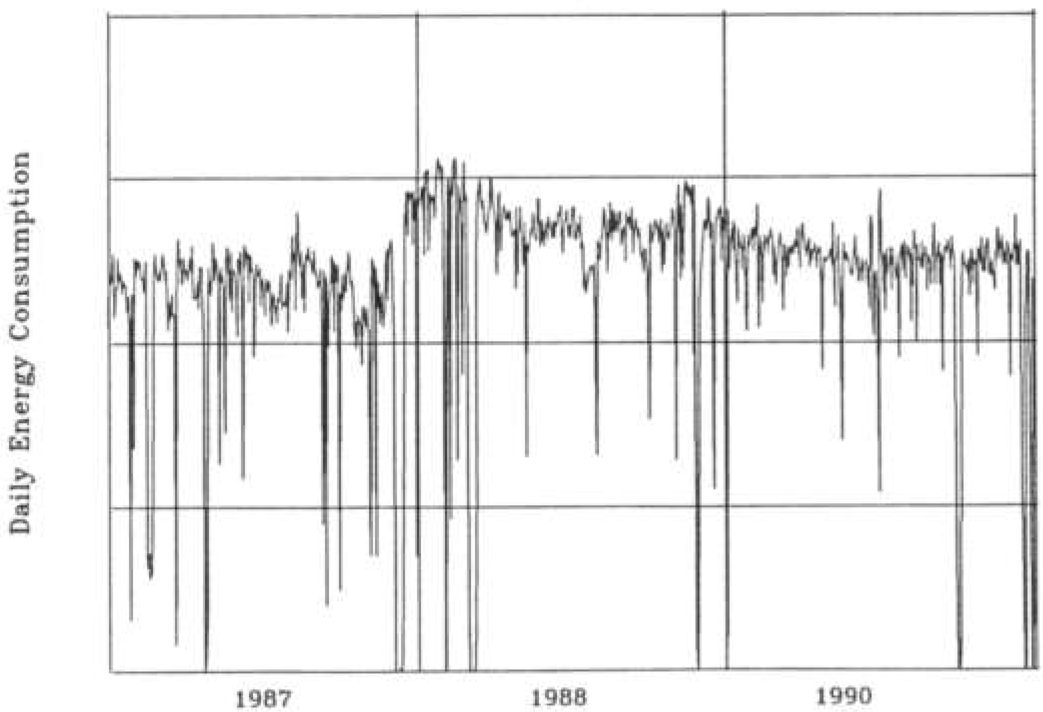
Option 3 is an oversight process whereby the Commission devises a deferral accounting system that monitors the net compensation paid by industrial customers for the use of the BCG system. Such funds are earmarked to defray system cost incurred by non-core customers and, over the long term, perhaps stabilize the core market rates.

I believe that Options 1 and 2 are not viable. Option 3 is logical, and it is the system that BC Gas is proposing. A new regulatory mechanism is needed so that BCG can compete in the marketplace for industrial loads, which are needed to create the desired financial contribution to the domestic class. Market conditions will be bumpy and unstable, but over time the desired results from the proposed procedure can be obtained.

Q. What type of industrial customers loads are being solicited by the competition to BC Gas?

A. Obviously, one of the industrial load characteristics that is prized is the high load factor interruptible customer.

HIGH LOAD FACTOR INTERRUPTIBLE CUSTOMER
Three Year Daily Load Curve

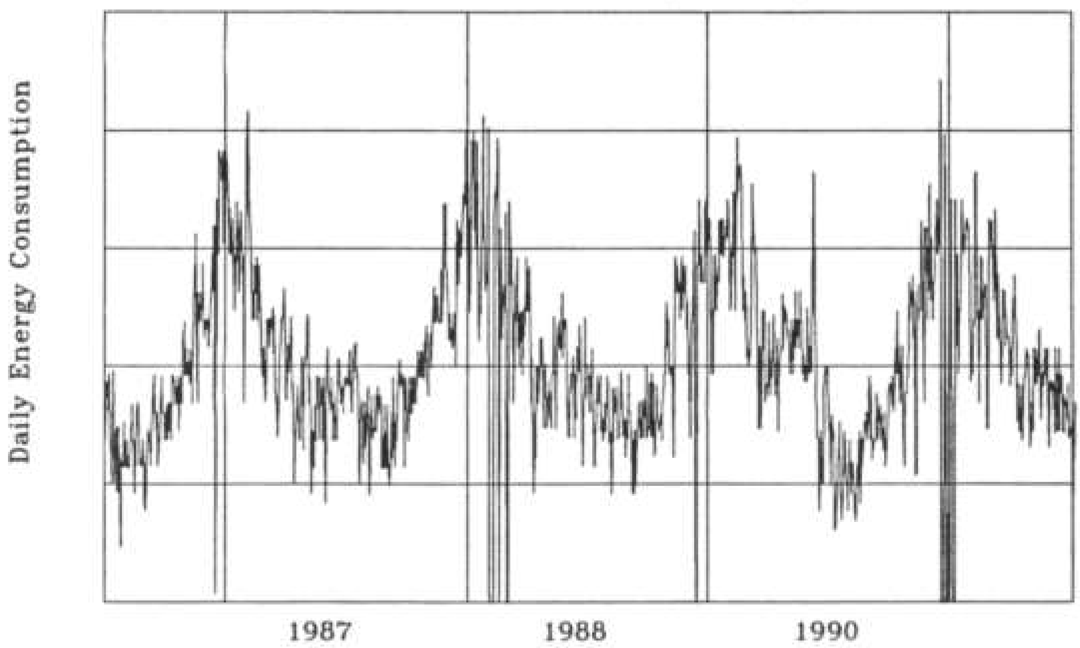


Q. Please continue.

A. Practically all interruptible customers are attractive to BCG's competitors. Once it is identified that a customer is interruptible, they are courted by the Company's competition almost without regard to its load characteristics in today's gas market. As an example, shown below is the load profile of a BC Gas customer that is applying for transportation service. The customer has a relatively low total load and a highly seasonal load characteristic.

INTERRUPTIBLE CUSTOMER THAT IS BEING SOLICTED FOR T-SERVICE

Four Year Load Curve, July 87-July 91



Q. What conclusion do you draw from these facts?

A. Practically any of BC Gas's interruptible customers are fair game to the Company's competition.

Q. What are the criteria of sound tariff design for a natural gas local distribution company, such as BC Gas Inc.

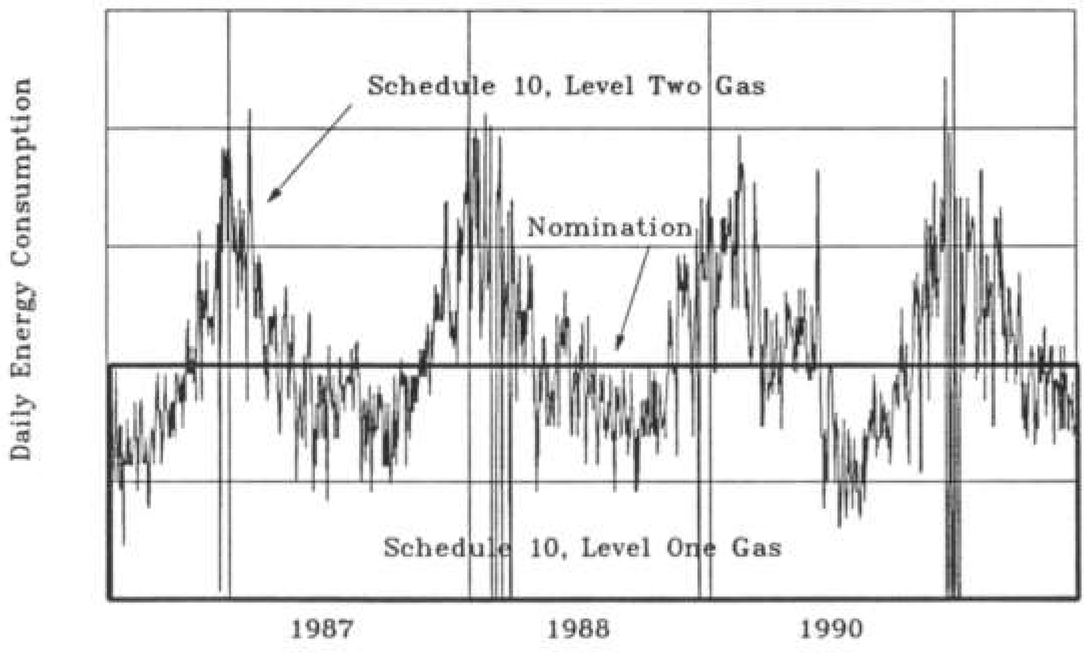
A. Prices for non-core customer service should be market based. Rates for core customer service should be fair, just, and reasonable. The tariff should a) generate as much support of the core customers as possible by the sale of off-peak capacity and gas supply, b) provide equal status for sales and transportation service, c) be cost-based and respond to competitive factors, where applicable and to the extent practicable, d) be feasible to apply, e) provide revenue stability, f) introduce rate changes for the core customers somewhat gradually, g) generate the utility's revenue requirement, h) base non-core service on demand-commodity prices to the extent possible, and i) avoid undue discrimination.

Gas rates might be used to complement certain government policies that combat air pollution -- wood burning stoves and automobiles come to mind -- and develop a market-based economy for gas service. Demand-side management and customer education programs, to the extent possible and practical, should be implemented to promote justified use, discourage wasteful use, and guide off-peak use of natural gas.

Q. How do these factors relate to the proposed Schedule 10?

A. My response will be general, since the details will be addressed by Mr. Dinter and Mr. Van Genderen. The proposed Schedule 10 offers improved options for interruptible sales service. The alternatives that will be available to Schedule 10 customers can be seen by referring to the diagram below. The customer may purchase Level One interruptible gas from BC Gas under a demand-commodity market-based price. The customer will be able to acquire the gas above its nomination under Level Two interruptible sales.

ILLUSTRATION OF SCHEDULE 10 SALES SERVICE



Schedule 10 will replace a number of existing schedules. As such, the proposed schedule will enhance administrative feasibility and tariff understandability.

Gas system operators look at the curtailment of supply as a "gas supply resource" for the core customers. The proposed Schedule 10 curtailment provisions will strengthen the ability of system operators to provide reliable service to core customers. This attribute will assist in directing system off-peak use. The flexible schedule pricing will help the Company to maximize the non-core customers contribution to the core customers.

Q. Will sales under Schedule 10 be at the Westcoast-BC Gas interconnect point and not at the customer meter?

A. Yes. The gas will be moved from the WEI-BCG interconnect point under Schedule 22.

Q. What are the effects of this proposal?

A. The effect is to assure neutrality between the utility sales service and other direct purchase options of non-core customers, which is another pricing principle under gas system deregulation.

Q. Should BCG be required to divulge prices charged to specific customers under Schedule 10 or Schedule 13?

A. No. A natural gas distributor should not be required to disclose to a competitor the exact terms and prices established in an individual gas sales contract negotiated privately with a customer. In today's competitive situation, a commission should have scrutiny of the total support that non-core customers provide to the core customers. When this scrutiny is extended to individual arrangements, the inevitable results will be declining industrial gas prices, lower overall support to the core customers, and lower natural gas royalties to the Province.

Q. Have you reviewed the proposed Schedule 13?

A. Yes. The proposed schedule will further unbundle service offerings on the BC gas system. It will offer interruptible customers a valuable resource of peaking sales service, if and when such gas is available on the BC Gas system. It also will be available to backstop an interruptible customer's own gas supply. It will have market based pricing and the net proceeds under the schedule will help defray the cost of service to the core customers.

Q. Please comment on proposed Schedule 22.

A. The purpose of Schedule 22 is to deliver a non-core customers gas supply from the Westcoast-BC Gas interconnect point to the customers' meter. The gas supply can be sales under Schedules 10 and 13 or the non-core customer's own gas. As indicated before, this is to assure neutrality between the utility sales service and non-core customers' direct purchase options, a pricing principle under gas system deregulation.

Daily balancing during the winter will materially assist the system operators in system control. It will also minimizing the risk of WEI penalties. It will eliminate a number of other schedules, thus simplifying the system administration and reducing risk to the core customers.

In essence, I believe that the Company is proposing reasonable mechanisms that will allow BCG to compete and allow the Commission to monitor and assure itself that the Company's prices are fair and reasonable.

APPENDIX A: TARIFF CONSULTING SERVICES OF DANIEL J. REED

Consulting Practice Overview

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 28 years, I have testified or assisted in rate case preparation in about 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.

Utility Pricing Seminars

I have conducted utility pricing seminars in United States, Canada, Europe, Africa, Asia, and Australia to over 1,300 participants since 1976. My seminars for Canadian utilities have been for the British Columbia Hydro and Power Authority, Gaz Metropolitain, Inc., Alberta Public Utility Commission, and Newfoundland Light & Power Company. The seminar contents include various utility analyses such as bill frequency analysis; forecasting sales and costs; revenue, expense, and rate base calculations; modelling revenue requirements; fully distributed and marginal cost; rate design and demand elasticity measurements; and gas transportation.

Rate and Costing Software Development

I have developed mainframe and microcomputer models for utility rate and cost analysis. I have developed fully integrated rate-making 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.

Education

I received a BSEE from the University of Alabama in 1950. Since starting my practice in 1963, I studied economics at UCLA in 1964-65 and accounting at the University of Washington from 1973-76.

JOINT DIRECT TESTIMONY OF H. L. DINTER AND P. VAN GENDEREN

Q. Mr. Van Genderen, please state your full name, occupation and address.

A. Peter C. Van Genderen, energy consultant, 5095 Pandora Street, Burnaby, B.C. V5B 1L5. A summary of my qualifications is attached as Appendix C.

Q. Please explain your recent rates assignments on behalf of BC Gas.

A. I have since August, 1989 been providing support to the industrial marketing department and, more recently, to the Regulatory Affairs Department in respect of the negotiation of long term industrial contracts competitive with customer "bypass" options, the development and regulatory approval of industrial tariffs responsive to continuing deregulation of the B.C. gas industry, the development of natural gas tariffs that would permit integration of industrial services across historical BC Gas divisions and recognize gas supply changes on November 1, 1991 and have assisted in the design of a gas cost allocation process for Inland and Lower Mainland Divisions.

Q. Please explain your role in this hearing.

A. Under the direction of Mr. Dinter, with knowledge of his objectives and close working partnership, I have developed the tariffs in this Application. Although much of the material has been prepared by me, the policies and objectives underlying this work are those of BC Gas. In addition to the direct role of Mr. Dinter, the tariffs have been developed in close cooperation with other departments who have important interests. These include Regulatory Affairs, Legal, Gas Control, Measurement and Billing. In addition, I am supporting the principles of the gas cost flow through Application contained under Tab 3 of the Rate Design Application - Phase A.

Q. Please summarize your testimony.

A. We are supporting the introduction of revised and new large volume sales Schedules and transportation tariffs. We will answer specific questions concerning the proposed tariff changes applied for under the "Updated Application" (Tabs 4 through 12 of the Rate Design Application, Phase A).

Q. What changes and new tariff schedules are being applied for.

A. BC Gas is applying for revisions to existing Inland sales and transportation tariffs and to make similar services, terms and conditions available to Lower Mainland customers. The schedules affected are:

- Schedule 10: -Large Volume Sales
- Schedule 13: -Peaking and Backstopping Sales
  -Sales Agreement for Schedules 10 & 13
- Schedule 22: -Large Industrial Transportation Service
  -Transportation Agreement for Schedule 22
- General Terms & Conditions Applicable to Large Industrial Transportation Service

Q. What are the primary reasons for applying for changes in large industrial tariffs at this time?

A. In summary, the rationale for applying for revised tariffs is as follows:

1. Effective November 1, 1991, BC Gas will operate under new gas purchase contracts. These new purchase contracts carry with them an obligation to pay producer demand charges.

2. A major objective of the revised sales schedules is to permit BC Gas to recover from interruptible sales customers a contribution to the fixed costs of the new gas supply arrangements allocated to the core market. The fixed costs of the gas supply for Inland and Lower

Mainland are estimated at some $213,000,000. These costs include Westcoast demand charges, producer demand charges, and other fixed charges for peaking gas supply (See Updated Application, Tab 3, Table B, pages 3 and 3.1, line 43).

3. In order to maximize contributions towards its fixed costs, BC Gas requires the ability to negotiate directly with each customer and needs to maintain confidential sales prices and contracts. The Company wishes to sell gas at the BC Gas/Westcoast interconnect on a basis comparable with the "direct purchase" market. Those changes are reflected in the proposed tariffs.

4. The Company's corresponding proposed transportation tariff is designed to provide a "level playing field" so that BC Gas and the "direct purchase market" can compete on the same basis for interruptible sales.

5. The Company's tariff Applications represent an initial step towards integrating the sales and transportation services within Inland Division and extending those same services to customers on the Lower Mainland Division. Once tariffs for large volume customers are accepted, the Company will be in a better position to proceed with Phase B of the Rate Design and integration of additional tariffs and tariff schedules.

Q. Please explain the rationale for negotiated gas prices mentioned on page 2, Tabs 4 and 5, of the Updated Application as it relates to the gas cost flow through of Tab 3.

A. BC Gas intends to sell interruptible gas at negotiated prices. For the Inland Division, the gas cost methodology indicates a reduction to Schedule 10 customers of $0.22/GJ (the Updated Application, Tab 3, Table B, p. 1.1, Line 40, Column 10). The reduction in costs recognizes the forecast variable costs that will be experienced under the new gas supply portfolio. Negotiated gas prices will be at the market value for interruptible sales, which may be higher or lower than the existing gas cost assignments.

For the Lower Mainland Division, Schedule 2501 customers eligible for Schedule 22 service effective November 1, 1992 will have a more viable option to obtain a $0.78/GJ rate for transportation across the BC Gas system. This contrasts with the $1.20/GJ margin presently imbedded in the sales rate. For those customers seeking to utilize our proposed Schedules 10 and 13, BC Gas will negotiate a sales price at the Interconnection with Westcoast. The difference between the negotiated sales prices and the variable gas costs will represent the contribution by new Schedule 10 Lower Mainland sales customers to the gas supply costs of BC Gas.

Q. Please explain why changes to industrial sales rates should not occur until November 1, 1992, as indicated per Tab 2, page 2, item K of the Updated Application.

A. In its letter of October 1, 1991 accompanying Order 6-92-91 the Commission recognized the concern of BC Gas that interruptible customers require a level of assurance of the price of gas throughout the contract year. In concluding gas sales contracts with Inland large industrial accounts and Lower Mainland 2501/2502 customers, the BC Gas Marketing Department conveyed the Commission's recognition that gas price certainty was necessary in order that customers could evaluate their options for the gas year commencing November 1, 1991.

Given that customers will have made their decisions on the basis of existing rates, and will have committed to one year agreements, it would be inappropriate to change gas sales prices until November 1, 1992. Increases in prices would be unfair to interruptible customers; decreases in prices would place an additional burden on the core market.

Q. If the BC Gas proposals had been approved for the contract year commencing November 1, 1991, what is the estimate of the contribution Inland and Lower Mainland large volumes sales customers could make towards fixed costs (a "Core Market Contribution").

A. An initial estimate of the potential Core Market Contribution is $7.7 million. This estimate is based upon spot market prices for exports from Huntingdon, B.C. over the twelve months ending September, 1991 less BC Gas' cost of gas per calculations under Tab 3 of the Updated Application. The estimate assumes sales of 100% of interruptible volumes. However, not all of this volume would be realized. (Please see Appendix A for a monthly analysis of the potential contribution.)

Q. To what extent is the estimated Core Market Contribution affected by monthly balancing in summer months and daily balancing in winter months?

A. On the basis of daily balancing year round, the Core Market Contribution could increase by $125,000; with monthly balancing year round, the Contribution could decrease by $210,000. These estimates are based solely on Inland Division sales volume changes, and do not consider Lower Mainland nominations. They also do not include recovery of incremental costs incurred when gas is made available on a daily basis by the Company when operating over its long-term contract demand but, under monthly balancing, those delivered volumes are not credited as a sale by BC Gas.

Q. To what extent do you believe that this contribution will be affected should the Commission determine that each large

volume customer must make a minimum contribution toward
fixed costs of say $0.05/GJ?

A. Any minimum contribution, however small, will have an
impact on the ability of BC Gas to compete for markets.

In the event the Commission were to determine that a
minimum contribution is required, BC Gas suggests it be
assessed on a customer's total sales volumes (e.g. $0.05/GJ
times a volume of 1,000,000 GJ = $50,000.). We do not
support the concept that a minimum contribution be imbedded
in the unit gas price. The BC Gas proposal will provide
the Marketing Department with greater flexibility to retain
customers who may otherwise seek to benefit from low spot
market prices during certain periods and low field prices
on regular supply contracts.

Q. Do you believe that customer Core Market Contributions
could be achieved at higher than forecast spot market
prices if you are permitted to negotiate individually with
Buyers?

A. Yes, subject to Schedule 10 and 13 approval and
confidentiality.

Q. Do you believe that the forecast Core Market Contribution
will be considerably affected by confidentiality of the
utility's gas costs and Sales Agreements with large volume
users.

A. Yes.

<u>Schedule 10</u>

Q. Please describe Schedule 10.

A. Schedule 10 will permit BC Gas to sell interruptible gas to
industrial users at negotiated prices. Sales will take
place at the Interconnection Point with Westcoast. Two
levels of interruptibility are proposed:

- •Level 1 - A high level of sales service reliability that requires payment of demand charges to BC Gas to recover the costs of obtaining firm service capacity on Westcoast from November 1 through March 31.

- •Level 2 - A lower level of sales service reliability that is essentially equivalent to the Authorized Overrun sales previously made by BC Gas utilizing BCPC/Canwest supply.

Q. Please indicate the major changes that have been made to Schedule 10 of Inland Division.
A. BC Gas is proposing to sell gas at the Interconnection Point with Westcoast, rather than the customer's meter, at negotiated and confidential prices. The qualifications and terms of Schedule 10 have been made consistent with those objectives and with the proposed Schedule 22 transportation service which will move gas from the Interconnection Point to the customer.

Q. Can you further define Level 1 service?
A. Level 1 sales service is comparable to a direct purchase option whereby a Shipper arranges firm gas supply and capacity on Westcoast for at least the five (5) winter months November through March, but desires to move that gas interruptibly across the BC Gas system. Our Level 1 sales proposal, in conjunction with Level 1 transportation, will permit a Shipper to choose between supply of this gas from either the Company or the direct purchase market.

Q. In view of the differences in service level between Level 1 sales available under the existing Schedule 10 and that proposed under Schedule 22, will this issue be revisited during Phase B of Rate Design?
A. Yes, service levels are expected to be more fully addressed under Rate Design - Phase B. A number of parties have

expressed opposition to BC Gas selling its gas into firm markets at this time. Given this opposition, BC Gas is no longer applying in Phase A to sell into the firm industrial market at negotiated prices and does not wish at this time to generally provide a sales service level which matches that of firm service.

Q. Can you further define Level 2 service?

A. Level 2 sales service is comparable to a direct purchase option whereby a Shipper arranges for gas supply at the Interconnection Point, on any commercial arrangement available to it whether firm or interruptible, but which is subject to curtailment or interruption when the gas supplier requires the gas for other purposes.

<u>Schedule 13</u>

Q. Please describe Schedule 13.

A. Schedule 13 will permit BC Gas to sell interruptible peaking gas to customers to supplement their other gas supply arrangements. Gas supplied by the utility on days when it is required to utilize Jackson Prairie Storage or LNG will be considered peaking gas. Under Schedule 13, BC Gas will also provide an interruptible backup supply in order to backstop a Shipper's "direct purchase" arrangements.

<u>Schedule 22</u>

Q. Please describe Schedule 22.

A. The proposed Schedule 22 will be used to transport all of a Shipper's gas supply for a large industrial user from the Westcoast Interconnection Point to the Shipper's End User. Under Schedule 22 there will be no differentiation in service whether gas is obtained from the direct purchase market or from BC Gas at the Company's Interconnection

Point with Westcoast.

Q. Please outline the major changes you have introduced in proposed Schedule 22 relative to the existing Inland Division Schedule 22.

A. The major changes are listed under Tab 9, page 2, of the Updated Application. The main points about the proposed Schedule we would like to address are as follows:

1. <u>Integration</u>

Schedule 22 combines current Schedules 20, 21 and 22 under one Schedule, and, as indicated, permits transportation of Schedule 10 and 13 sales gas, as well as direct purchase gas, to the Shipper's End User.

2. <u>Replacement of Reserves Tests with Failure to Deliver Charge</u>

Schedule 22 permits BC Gas to access a Shipper's gas under certain circumstances in order to augment the gas supplies contracted directly for the core market. Reserves tests and consultants reports on gas supply, and statutory declarations by producers are eliminated in favour of a Failure to Deliver Surcharge in the event a Shipper's gas supply is not available when called upon by the Company for its core market gas supply.

On days when BC Gas curtails its firm Schedule 22 transportation service, and a Shipper fails to deliver sufficient gas to the Interconnection Point, the Failure to Deliver Surcharge is equal to historical Westcoast Unauthorized Overrun ("UOR") penalties. On days when BC Gas curtails Level 1 transportation service, and Shipper fails to deliver its gas, the Failure to Deliver Surcharge is BC Gas' cost of alternative gas supply.

3. Uniform Balancing

Rather than day after balancing under Schedule 21 and monthly balancing under Schedule 22, the integrated Schedule 22 provides for monthly gas balancing in summer months and daily gas balancing in winter months. This is similar to balancing requirements contained in existing Lower Mainland transportation Schedules 2008, 2009, 2010 and 2011, however imbalance costs will be generally less.

4. New Rate for Imbalance Quantities

This provision is being introduced to permit BC Gas to recover potential Westcoast costs relating to gas nominated by a Shipper but not utilized on the day it is nominated.

5. Level 1 Transportation

Level 1 transportation has been introduced under our proposed Schedule 22. In exchange for BC Gas' right to access a Shipper's gas under Level 1, BC Gas is proposing to give Level 1 transportation service a higher level priority than has applied to historical interruptible transportation service (Level 2) in Inland and Lower Mainland Divisions.

6. Gas Purchase Option & Return Period

When BC Gas increases a Shipper's nomination in order to access a Shipper's gas supply, the Company will reimburse the Shipper a reasonable price for this gas or will be returning the gas within 30 days. Other gas that BC Gas accumulates in inventory on behalf of a Shipper, due to overnomination by a Shipper or due to curtailments by BC Gas, will be returned within 90 days.

The existing return period for gas held in inventory is 180 days for Inland Division customers and an unspecified time period on the Coast.

7. Changes in UOR Provisions

We have introduced a Demand Surcharge to deal with instances where customers are not adhering to BC Gas curtailment notices.

Q. Can you explain why BC Gas is introducing daily balancing during winter months under Schedule 22?

A. Effective November 1, 1991, BC Gas and its direct purchase transportation customers will be subject to daily gas balancing on the Westcoast system. Sales gas from Westcoast to BC Gas will no longer be available to accept swings in daily use. Under the proposed Schedule 22, BC Gas is offering to absorb costs related to those swings during summer months.

In winter months BC Gas is subject to curtailment by Westcoast on a daily basis. It also has much higher commodity costs. During winter months BC Gas is not proposing to absorb the related gas costs. Sales will therefore be recorded on a daily basis when a Shipper exceeds its authorized Daily Nomination for direct purchase gas.

Q. Why is BC Gas entitled to access a customer's firm gas under Schedule 22?

A. Inland Division has historically had a right to curtail a large industrial customer to fifty percent (50%) of its firm nomination for up to five (5) days in a Contract Year. This has permitted a lower peak day pipeline capacity on the Company's major transmission facilities and has contributed to lower gas costs. Now that customers are able to contract directly with producers, BC Gas requires access to a Shipper's gas in order to continue to effect the historical efficiencies the Inland Division has realized. Pacific Northern Gas has a similar curtailment provision in its large industrial tariffs.

Customers that do not wish to be curtailed have historically received service under a small industrial tariff schedule on Inland Division, i.e. Schedule 25. In the Lower Mainland, large industrial customers are generally able to curtail their natural gas requirements, and may therefore prefer to nominate for Level 1 or 2 interruptible service rather than firm service. In this case, the access provision for firm gas does not apply. However, the proposed Schedule 22 does permit Lower Mainland large industrials to nominate a percentage of their requirements as firm, should this be of interest, and the large industrial firm service on the Lower Mainland will be subject to the same provision as has historically applied to Inland Division customers.

Q. When will Level 1 transportation be curtailed?

A. Subject to capacity being available on the BC Gas system, Level 1 transportation will be curtailed when BC Gas requires gas supply delivered at the Interconnection Point for its core market on a basis similar to the Company's curtailment of its large industrial firm service. However, Level 1 service will be subject to complete interruption.

Q. Is BC Gas proposing to access a Shipper's Level 1 gas during periods of curtailment under Schedule 22?

A. Yes. On occasions when BC Gas is required to curtail Level 1 service to maintain its core market service priorities, BC Gas will access a Shipper's gas. Any nominations for Level 1 service will therefore have a beneficial impact on the gas supply demand requirements of the Company's core market. This is because BC Gas will be able to reduce its nominations for core market supply by the volumes it can rely upon from Level 1 Shippers, just as it does with 1/2 firm MDTV nominations.

Notwithstanding this benefit to the core market, a Shipper transporting Level 1 gas will under the proposed Schedule 22 also benefit. A Shipper will receive a higher priority than under Level 2 interruptible transportation, without paying a higher transportation rate. Each Shipper will be in a position to nominate for all three service levels (firm, level 1 and level 2) according to its requirements and most economic alternative.

Q. Do the same principles apply to Company's access to Level 2 gas.

A. Yes, to the extent that a Shipper's gas is available at the Interconnection Point BC Gas would utilize this gas when Level 2 transportation is being curtailed by the Company. Under Level 2 there is no obligation by Shipper to ensure this gas is available at the Interconnection Point. However, when it is available, changes in conditions on the BC Gas system could at any time permit those volumes to be delivered.

Q. Please explain why Level 1 transportation does not have a specific maximum number of days interruption, as currently available under Schedule 10.

A. There are several reasons which must be addressed.

1. Pending Rate Design - Phase B, it is desirable to retain historical service levels to the extent reasonable, permitting BC gas to offer Level 1 transportation at the same rate as Level 2.

2. An "equivalent to firm" service level might lead to substitution of Level 1 service for firm service. Without demand charges applicable to Level 1 transportation, BC Gas and its other markets would be at greater risk in recovering costs-of-service.

3. Under Lower Mainland Schedule 2010, Shippers must pay a rate of $1.20/GJ in order to limit interruptions by BC Gas to periods when facilities will not permit transportation to occur. Similarly, firm transportation under Schedule 22 requires payment of demand charges. The proposed Level 1 service level is consistent with the reduced costs and obligations applicable under Level 1 transportation in comparison with other services provided by the Company.

4. Level 1 nominations will create benefits in the overall gas requirements of the core market. Those benefits are maximized by permitting the Company greater flexibility during extreme weather conditions. This is particularly important in B.C. given the lack of gas storage close to the markets of BC Gas. The absence of significant gas storage facilities close to markets is one of the causes of the high fixed gas supply costs applicable to the core market ($1.92/GJ for Lower Mainland Division, $1.70/GJ for Inland Division, per Updated Application, Tab 3, Table B, page 1, line 16, Column 8 and page 1.1, line 20, Column 9).

Q. Will BC Gas redirect gas supply from direct purchase transportation customers to its own industrial sales customers in order to equalize service availability.

A. No. Large industrial curtailments and access to their gas supply will be limited to occasions when BC Gas either does not have sufficient capacity on its system or requires the gas supply to serve its core market.

BC Gas will enforce this policy to the extent possible. However, BC Gas will still need to deal with its own operational concerns and those of its customers. Consequently, we have not explicitly incorporated this policy in the tariffs.

Q. Please explain what happens to a Shipper's gas the Company utilizes during a curtailment.

A. BC Gas is proposing to return this gas to the Shipper within 90 days. This is only half of the time period permitted under existing Schedule 22.

Q. BC Gas is also proposing to return overnominations by Shippers within 90 days. Why is this time period so long.

A. Again, it is a reduction of 50 percent in the maximum number of days gas may be held by the Company. On the basis of the proposed Schedule 22, unless and until a Rate for Imbalance Gas is approved at a level which discourages overnomination, the 90 day maximum inventory period is the only control BC Gas has to ensure a Shipper nominates reasonably. If, for instance, this were reduced to 30 days a Shipper would have an incentive to nominate a maximum volume on each day to avoid the likelihood of being required to purchase "imbalance gas" from the Company. There would be no incentive to nominate properly. In addition, BC Gas requires at least 90 days to return gas to Shippers in order to avoid incremental commodity costs associated with the return of excess gas.

Q. Is the proposal to reduce the return period conditional upon approval in principle of a new Rate for Imbalance Quantities.

A. Yes, without the ability to collect costs of potential Westcoast penalties, BC Gas is opposed to a reduction in return periods.

Q. Please indicate what price BC Gas is willing to pay for gas nominated under Special Provision 7 of Schedule 22.

A. The price to be paid will depend upon our negotiations with a Shipper. However, in general, BC Gas will propose to pay no less than the Company's commodity cost for long term supply and no more than Company's commodity cost for short term winter supply. In the event the parties are unable to agree on a price, or a Shipper is prevented by contract or other reason from selling gas, any gas taken will be returned within 30 days.

Q. Please explain the basis and requirement for a Demand Surcharge.

A. The Demand Surcharge is equal to the rate methodology approved by the Commission for firm service not subject to 1/2 day curtailments under Inland's 1987 Rate Design Order. In its Application dated December 5, 1989 that introduced Schedule 20, BC Gas requested a 30 percent decrease in the rate in order to recognize more economic means to secure firm service on the Westcoast system during winter months. The lower rate will continue to apply when a customer nominates in advance for firm service not subject to curtailment.

For the most part, the Inland Division large industrial customers have been cooperative in assisting BC Gas in obtaining sufficient gas supply for the core market during critically cold periods. This cooperation has also been helpful to industrials in dealing with operating concerns of their facilities. Notwithstanding this general operational cooperation, a number of circumstances have occurred which point to a reluctance by large industrial Shippers to nominate for gas supply in a way which ensures the core market will have access to all its required gas supply during cold periods (please refer to Appendix B which illustrates examples of unauthorized gas use by customers). We are therefore reintroducing the rate methodology approved in 1987 which will apply if curtailment notices are violated on more than one occasion each Contract Year.

Q. Please explain the rationale for the Lower Mainland firm Schedule 22 rate of $1.55/GJ in view of the utility's right to 5 days of 1/2 firm curtailment.

A. The firm transportation rate of $1.55/GJ is equivalent to that available under Lower Mainland Division Schedules 2006 and 2007. There is currently no separate "large industrial firm" rate on the Lower Mainland.

A Lower Mainland large industrial customer that nominates for firm gas under Schedule 22, but does not wish to be subject to 1/2 firm curtailments, may nominate for firm curtailment buyout and pay a Monthly Firm Buyout Surcharge. (See Updated Application, Tab 10, Original Sheet No. 22.05, <u>Rate For Optional Firm Curtailment Buyout</u>). Pending the resolution of appropriate Lower Mainland large industrial firm rates under Rate Design - Phase B, BC Gas proposes to provide a credit to a Lower Mainland customer's Commodity Rate on the Monthly Firm Volume transported. The credit permitted will be the Monthly Firm Buyout Surcharge up to a maximum amount equal to the firm service Commodity Rate payments due under Schedule 22.

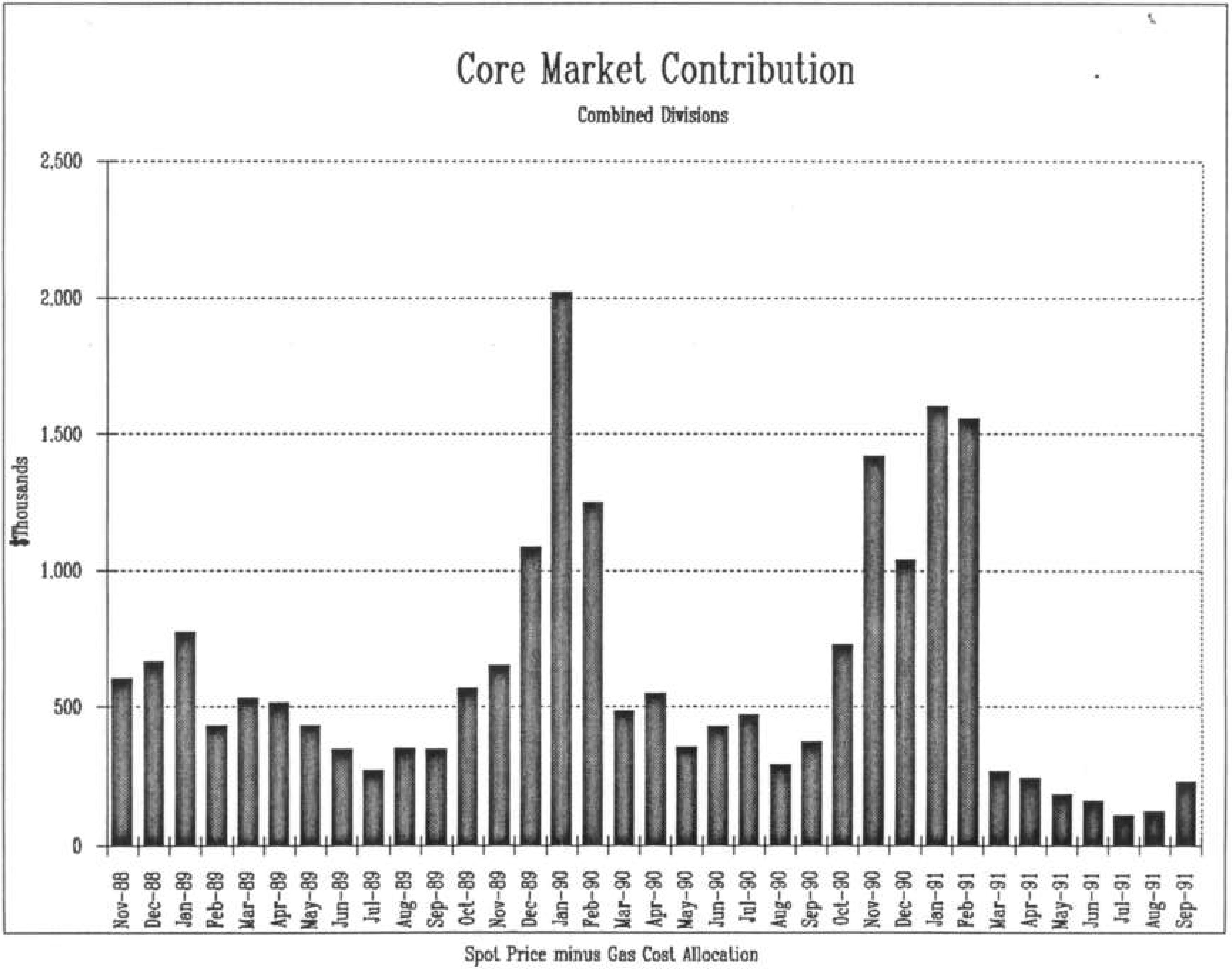
Under this proposal, customers will continue to be subject to $1.55 for firm service without curtailments. The advantage of Schedule 22 (over say 2006 or 2007) is that large industrial customers could nominate a percentage of their requirements as firm gas, just as they do presently on Inland Division, with the balance of their nomination being for interruptible gas. Once a rate for large industrial firm transportation has been approved for the Lower Mainland under Phase B, the credit mechanism will cease to apply.

Q. Why has BC Gas restricted the new sales and transportation services to those customers consuming either 28.3 10^3M^3/day or 360,000 GJ/year.

A. It is not proposed to restrict negotiated sales to large volume customers only. In fact, Schedule 10 contemplates service to any customer who:

> "in the absence of the sale of gas to Buyer under this Schedule, ...might reasonably be expected to contract directly with other Gas Suppliers for such gas."

The basic structure of Schedule 22, the related Transportation Agreement and the General Terms and Conditions Applicable to Large Industrial Transportation will be used in designing integrated transportation services for customers with lower consumptions. Acceptance of our large industrial tariffs and the gas flow through methodology will assist us in preparation of additional service schedules in relation to Phase B of Rate Design.


Core Market Contribution
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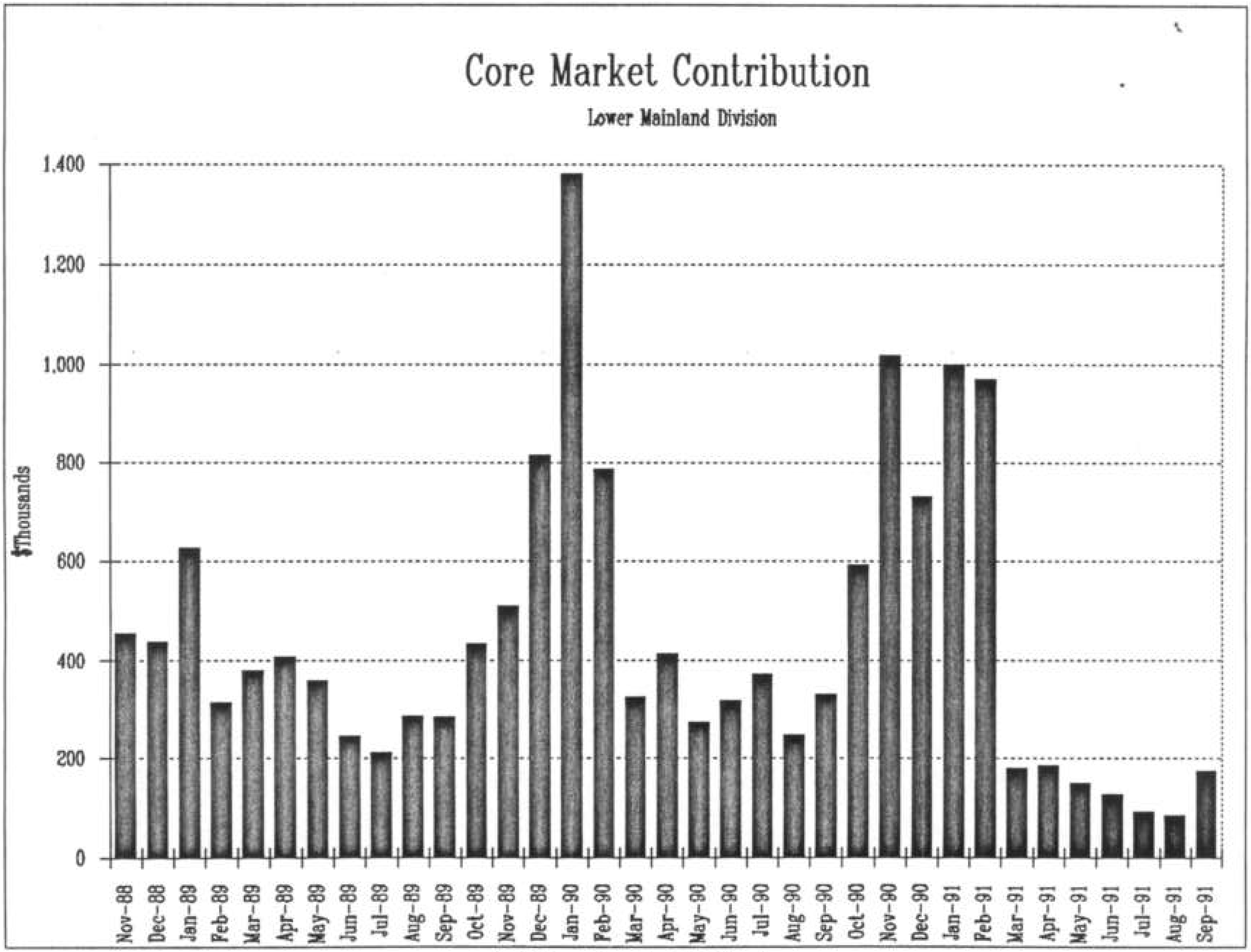

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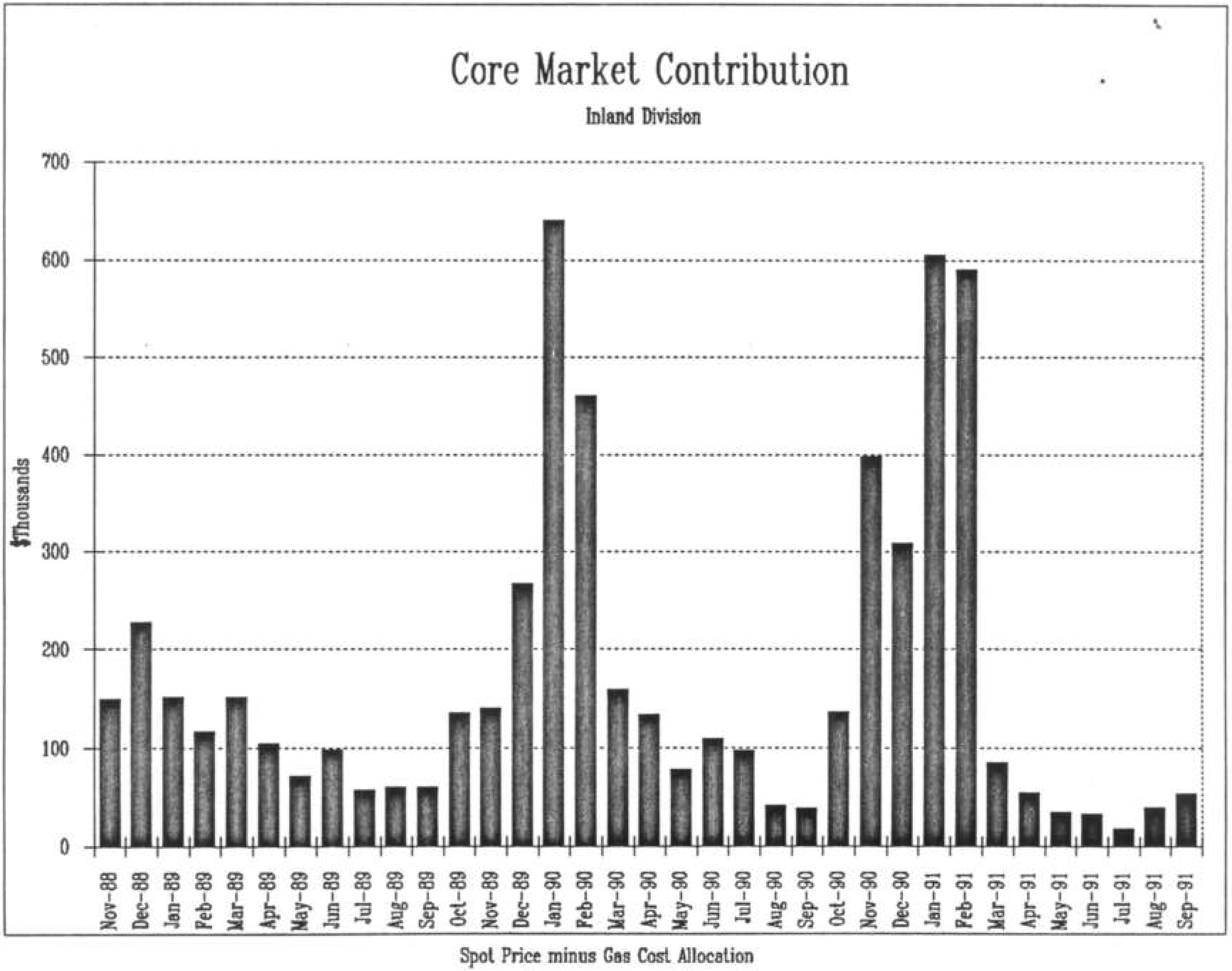

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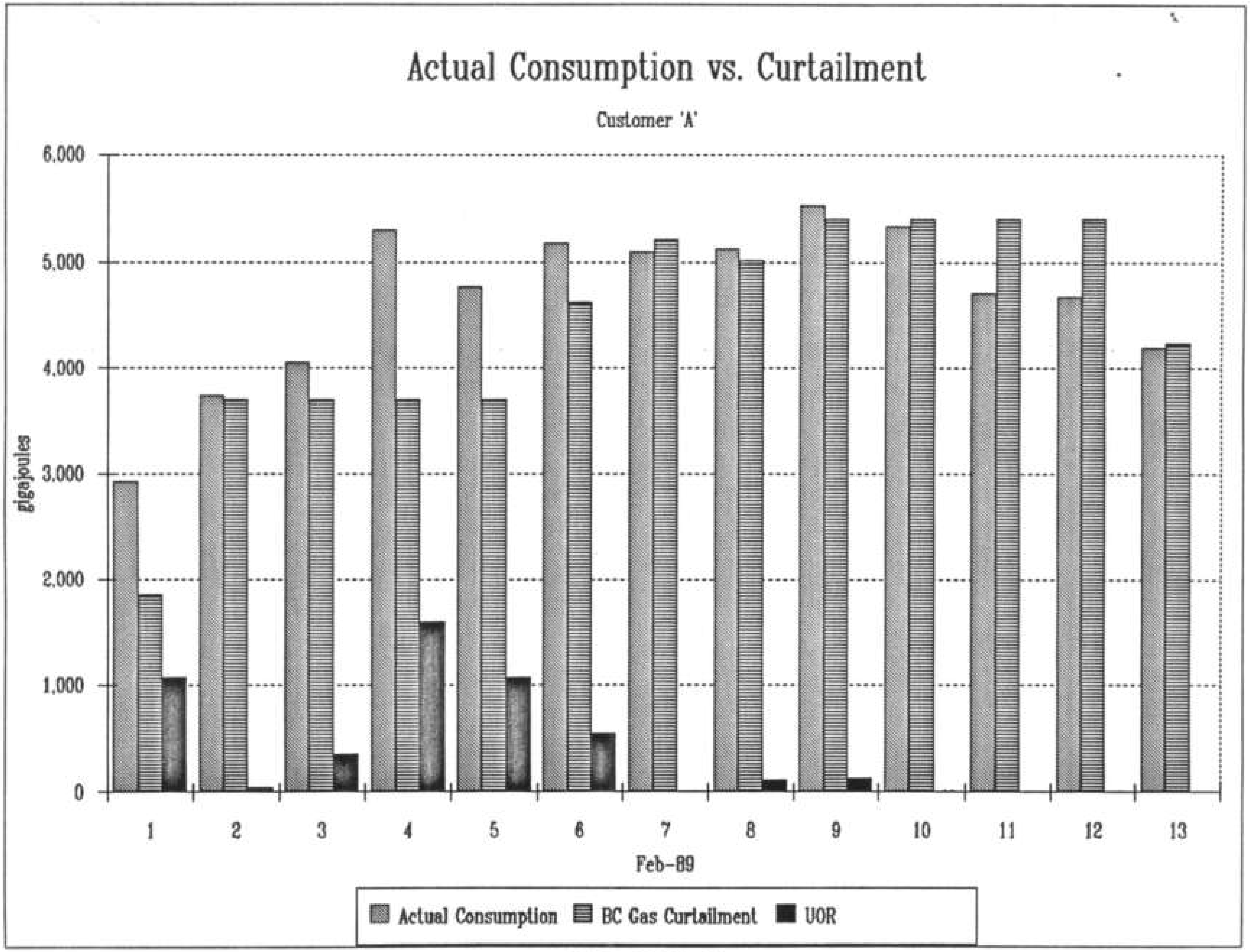

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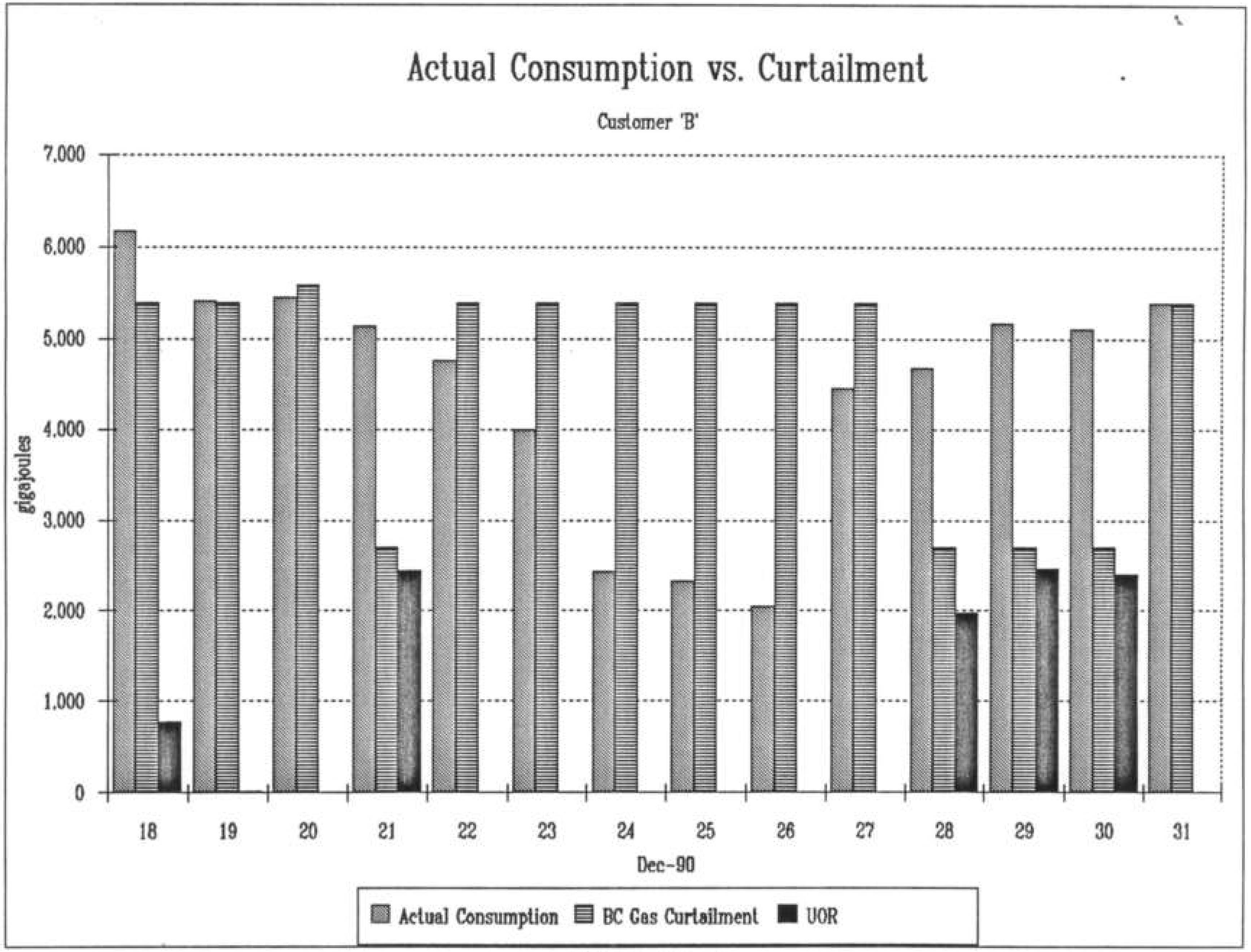

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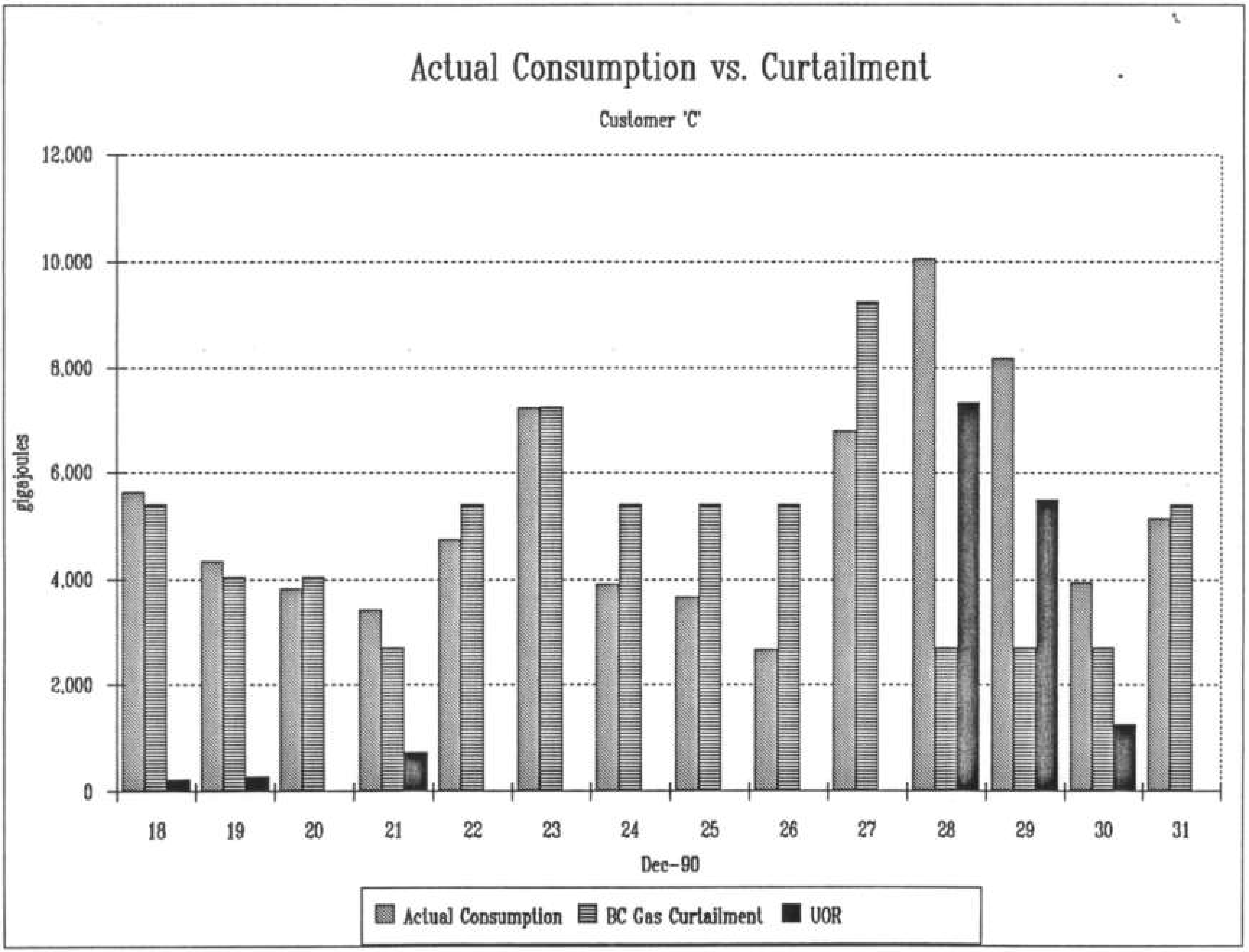
APPENDIX B
PAGE 2



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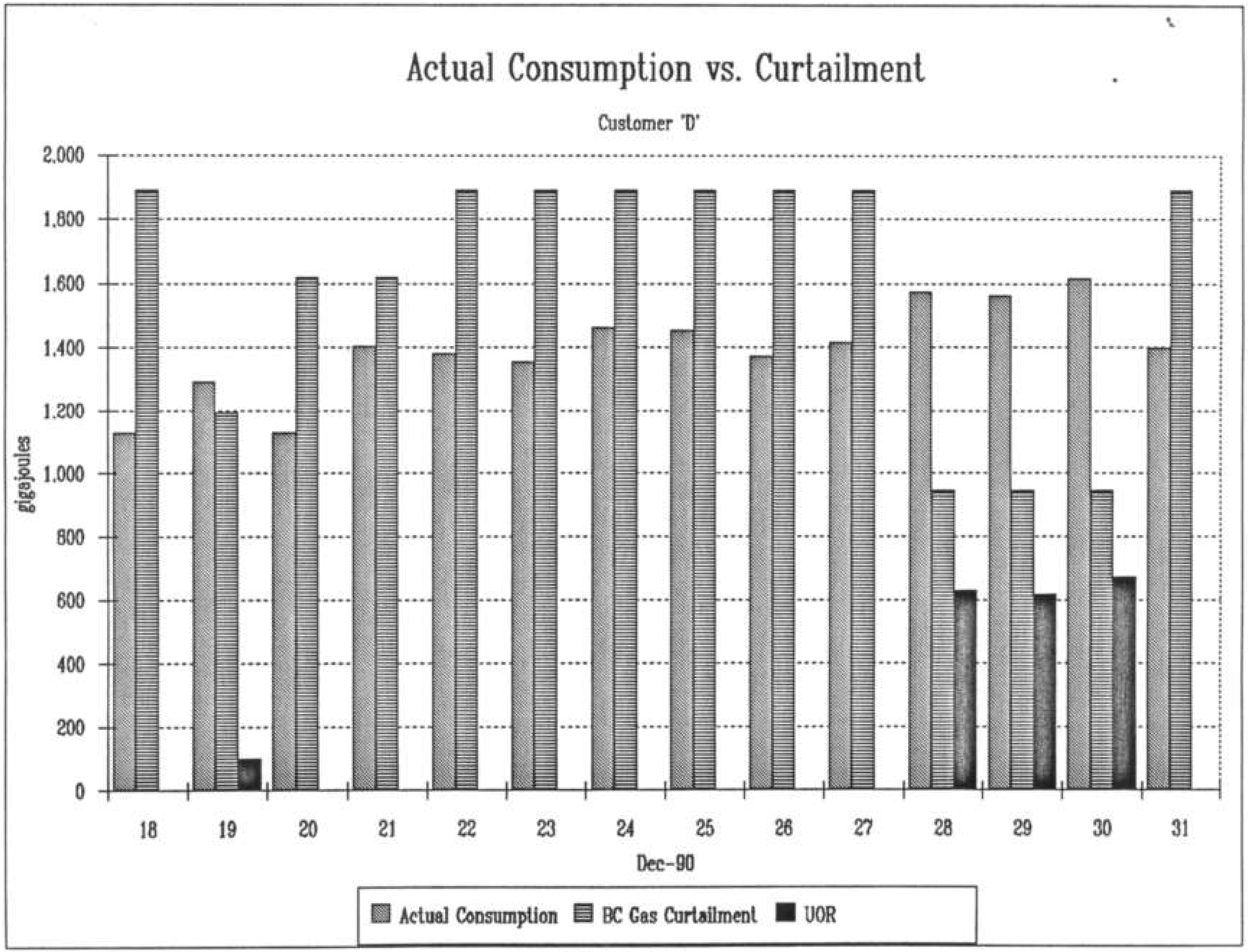

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APPENDIX C

Curriculum vitae - Peter C. Van Genderen
Van Genderen & Associates Engineering.

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.

I established a consulting practice in 1987, which until now has focused on serving energy clients in British Columbia. Although a significant majority of my practice has been in connection with BC Gas Inc. and its predecessor Inland Natural Gas Co. Ltd., I have also been engaged by the Ministry of Energy, Mines and Petroleum Resources, BC Petroleum Corporation, Centra Gas and Inland Pacific Energy Corp., in various capacities.

In addition to rates work on behalf of BC Gas since 1989, I was engaged for Inland's 1987 Rate Design Hearing on the gas deregulation issues prevalent at that time. I assisted in the development of the original Inland transportation tariffs, provided gas supply and planning expertise, assisted as a witness for the tariff panel and assisted in responses to written questions of intervenors.

Other work on behalf of BC Gas/Inland has included support for possible manufacturing development in B.C., development of initiatives and a Five Year Corporate Plan in conjunction with the purchase of Lower Mainland assets, marketing, gas supply and executive assistance with respect to Applications relating to the Vancouver Island Pipeline project and assistance with respect to pipeline and gas supply hearings before the National Energy Board.

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.

I am a professional engineer registered in the Provinces of B.C. and Ontario.

<u>**EVIDENCE OF BRIAN HANLON**</u>

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, both for the Lower Mainland and Inland systems.

As a result of my duties, I am aware of the facts relating to gas control and system operations for both the Lower Mainland and the Inland Divisions.

Q. What is the purpose of your testimony in this proceeding?

A. I will testify to the impact that changes in gas supply contracting and in Westcoast (WEI) operating practice have had and will have on the operation and control of the BC Gas system. I will testify on industry and Westcoast trends in matters relating to gas control operation. I will also address operating matters such as system balancing.

Q. Please summarize your testimony.

A. Higher system throughput and new supply and delivery contracts are forcing both Westcoast and BC Gas to review their gas management practices. One important area is the control of downstream loads on both the WEI and BCG systems. Both of our companies want to maximize their throughput, yet be able to maintain the necessary control of their systems. Where possible, tariffs should be designed to help elicit the appropriate responses from our customers in achieving these goals. One group of customers should not, by lack of tariff conditions, be allowed to operate to the economic disadvantage of any other group operating on either the WEI or BC Gas system. My department does its best to match supply and demand on a daily basis but we have no control over customer demand with the exception of curtailment. It is reasonable to expect that the tariffs of BC Gas should encourage its large volume customers to nominate their loads accurately. It is reasonable to expect that tariffs should discourage large variations in loads and/or unauthorized take that would shift costs onto other customers.

Q. Please describe some of the changes you have experienced in the gas transmission and distribution business.

A. The natural gas transmission and distribution industry is undergoing rapid change as a result of deregulation. Five to ten years ago, gas operations and contract administration in North America were relatively simple for a local distribution company (LDC) such as BC Gas. Historically, LDC's typically obtained all of their gas supply from a transmission pipeline under one or two gas sales contracts. Usually all of the customers within the LDC's designated service area were supplied by the LDC. Terms and conditions for the supply of gas were relatively lax and generally speaking, LDC's had to devote relatively few resources to their gas supply operations.

Deregulation of the gas industry, which allows many customers to avail themselves of gas supply and transportation options that were not previously available, has brought about extensive changes. Starting November 1, 1991, for example, we will have about thirty different system supply contracts to administer with many different options as to how the gas will be transported on the Westcoast, Northwest Pipeline and Alberta Natural Gas systems. We will have well over one hundred contracts with BC Gas customers that require daily administration for the supply of gas obtained from BCG, and another seventy for the transportation of gas other than that obtained from BCG. In addition to the gas supply contract changes, LDC's have been impacted by pipeline companies, like Westcoast, which have significantly tightened the terms and conditions for the scheduling and transportation of gas to their customers, like BC Gas. The general trend in this regard is that LDC's are facing greater controls and reduced flexibility. We work in a marketplace that is described as being open access. In practice, however, from BC Gas's perspective, it is becoming increasingly constrained.

Q. Please describe the trends in, and impact of, authorized overrun availability on the WEI system in the last eight or ten years.

A. I think it is fair to say that supply availability has been to a large degree a function of transportation capacity availability. Eight or ten years ago there was an excess of capacity and authorized overrun was readily available to the LDC's. In these earlier years BC Gas experienced curtailment from its supplier only on the very coldest days whereas in recent years BC Gas has been effectively curtailed each and every day of the winter. In earlier years with large overrun availability BC Gas didn't need to curtail its customers very often. With high utilization of Westcoast capacity, the additional supply resource resulting from BC Gas curtailing its customers could be quite critical to BC Gas and likely will be required for every normal or colder than normal year.

Q. Please describe some of the changes that will come into effect in the contract year beginning November 1, 1991.

A. BC Gas will no longer be operating under sales agreements. When BC Gas operated under the contract demands of the sales agreements, those agreements handled imbalances created by BC Gas or by BC Gas' transportation service customers. Without sales agreements, effective November 1, 1991, BC Gas will operate with WEI under transportation service agreements. Under a transportation service agreement, WEI no longer will be involved in the merchant function of buying and selling gas and the responsibility for managing imbalances will shift to the parties who either supply or use the gas.

Q. On approximately how many days was WEI responsible for handling imbalances created by both BC Gas sales customers and BC Gas' transportation service customers when BC Gas operated below its Contract Demand under the WEI-BCG sales agreements?

A. Whenever BC Gas was below its Contract Demand, Westcoast was responsible for obtaining and managing the supply. This meant that for some 300 days each year Westcoast handled all of BC Gas' balancing requirements.

Q. Please explain what an imbalance is by using an example.

A. An LDC or other shipper would be in an imbalance condition if its daily supply was either greater or less than its daily consumption. As an example, if a shipper was authorized to take 100 units for a given day, and it took say either 90 or 110 units it would be in an imbalance position of 10 units.

Q. Are there other changes being proposed by WEI?

A. At the time of this writing, Westcoast is proposing new and more stringent penalties for its customers not being in balance at the end of the day. New penalties are being proposed for leaving gas on the Westcoast system and also higher penalties will possibly be applied to unauthorized overrun. Balancing is, of course, an important issue and on November 1 Westcoast will be operating using daily balancing. Previous day shotgunning will not be available and this will effectively require BC Gas to handle all balancing on its system including that of its large volume transportation service customers. Large volume customers on the Inland system are currently allowed to balance monthly. Continuation of monthly balancing would allow those transportation customers to swing on the core market gas supply. This will transfer the operational risks to BC Gas and to core market customers.

Q. What is shotgunning?

A. Shotgunning is a term that describes those supplies which are deemed to be the first through the meter of the LDC's system. Shotgunning has historically meant that balancing of non-system supply and demand, i. e., transportation service usage, was to be handled by the downstream pipeline. The exception is previous day shotgunning where the upstream pipeline handles the balancing. I have attached a diagram that describes previous day shotgunning.

Q. Please comment on the restrictions WEI has imposed or is planning to impose on hourly rates of take and what is the impact?

A. As recently as 1985 Westcoast used to allow the LDC an hourly take of up to seven percent of its daily authorized volume but then in 1986 they reduced it to the current rate of five percent. They are now proposing a 4.5 percent maximum hourly rate of take. The impact of these hourly restrictions is such that the BC Gas core load, because it is so temperature sensitive, requires all the useable line pack. Unless and until BC Gas obtains storage in the Lower Mainland area it will be very difficult to stay within the hourly take criteria.

Q. Do you conclude that since both Westcoast and Northwest Pipelines are moving out of the merchant function BC gas will have a new business relationship with these companies? If so, how will that impact?

A. Yes, there will be a new business relationship. Westcoast, for example, will be dealing with shippers on its system and won't differentiate between transportation service customer supplies and LDC system supplies. WEI will be moving some of the responsibilities it previously handled, such as arranging supply, over to the shippers. Shippers and LDC's will also have the responsibility of sorting out whose gas didn't arrive whenever the nomination volume isn't fully authorized. This has been a problem in both the U.S. and in Canada.

Q. In your opinion, should the Commission assume that BC Gas operating problems will be made worse when transportation service customers takes vary from their approved daily gas nominations.

A. Yes.

Q. Why should daily balancing be required of large volume transportation service customers on the BCG system?

A. 1. Westcoast will be operating with its shippers using daily balancing. This effectively will require BC Gas to manage its total system supply and demand on a daily basis for all customers whether they be sales or transport.

2. Effective November 1, 1991 BC Gas will no longer have a Sales Agreement with Westcoast and hence Westcoast will no longer be responsible for obtaining or managing supply for BC Gas during any part of the year.

3. Westcoast is proposing new and more stringent penalties for not being in balance. Penalties for leaving gas on the

system and/or for unauthorized overrun have the potential to increase BC Gas' costs substantially.

4. BC Gas, because of load growth, has less useable line pack to handle swings. Current and proposed restrictions on hourly rates of take by Westcoast mean that line pack will be increasingly needed to handle hourly flow rate fluctuations of the core customers.

5. Transportation service volumes are increasing and hence the swings by these customers have the potential to be larger creating larger imbalances.

6. There is increasingly higher utilization of firm capacity on the Westcoast system and as a result, BC Gas will have less access to additional supply which would help us to buffer imbalances created by transport customers.

Q. In your opinion, should the Commission assume that inevitably there will be significant costs which will result from transportation service customers incurring large daily imbalances?

A. Yes.

Q. Do you have any data relating to the accuracy by which large industrial transportation service customers are able to forecast their daily demands?

A. Yes. A graph and tables are attached that provide that information.

Q. If shippers for all transportation service customers operate independently of BC Gas on the Westcoast system, what is the approximate range of potential penalty costs from WEI they might incur as a result of forecasting errors?

A. If we assume the customers' nomination match the estimated demand, then a conservative estimate is two to three million dollars per year.

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 all 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 Administration

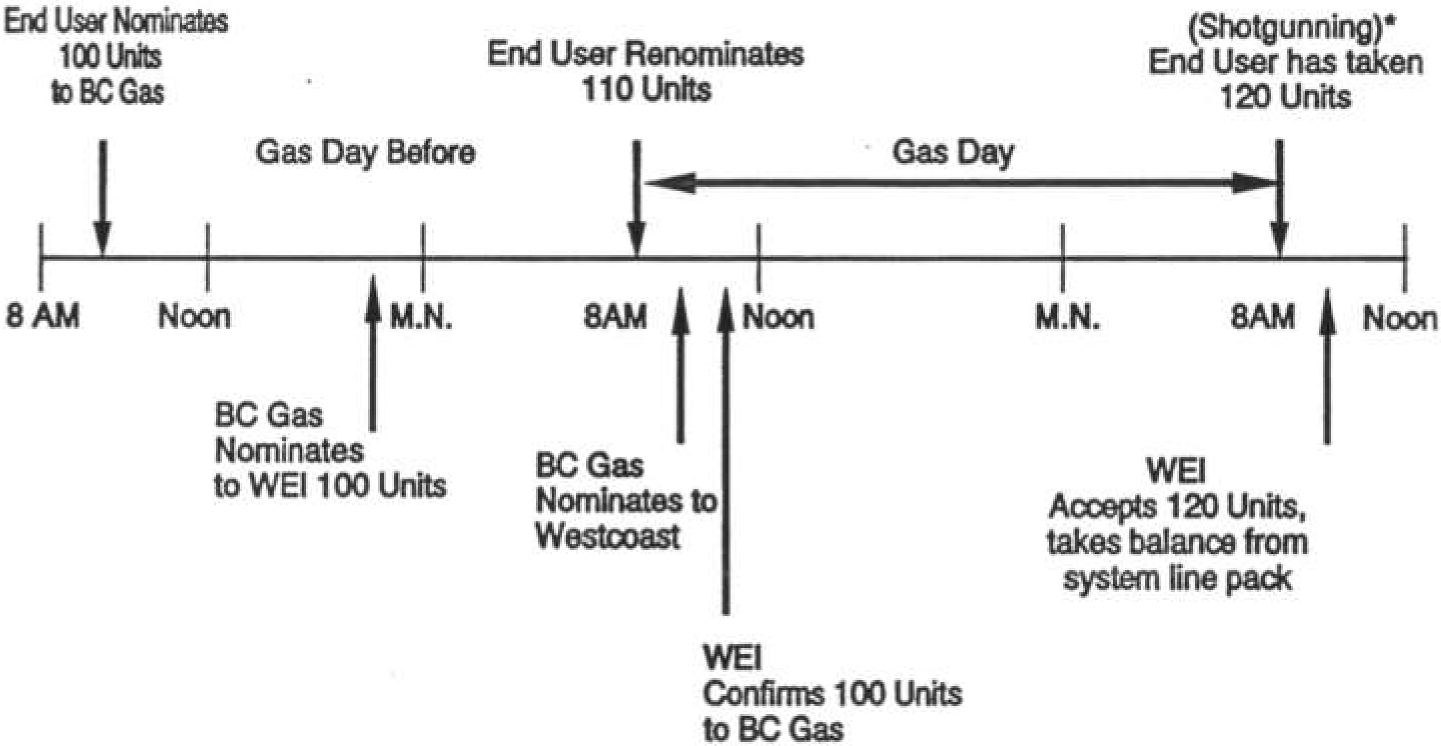
BC GAS INC.

1988-Present Manager, Gas Supply Administration

I am a delegate to the 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.

WEI Nomination Process and Previous Day Shotgunning

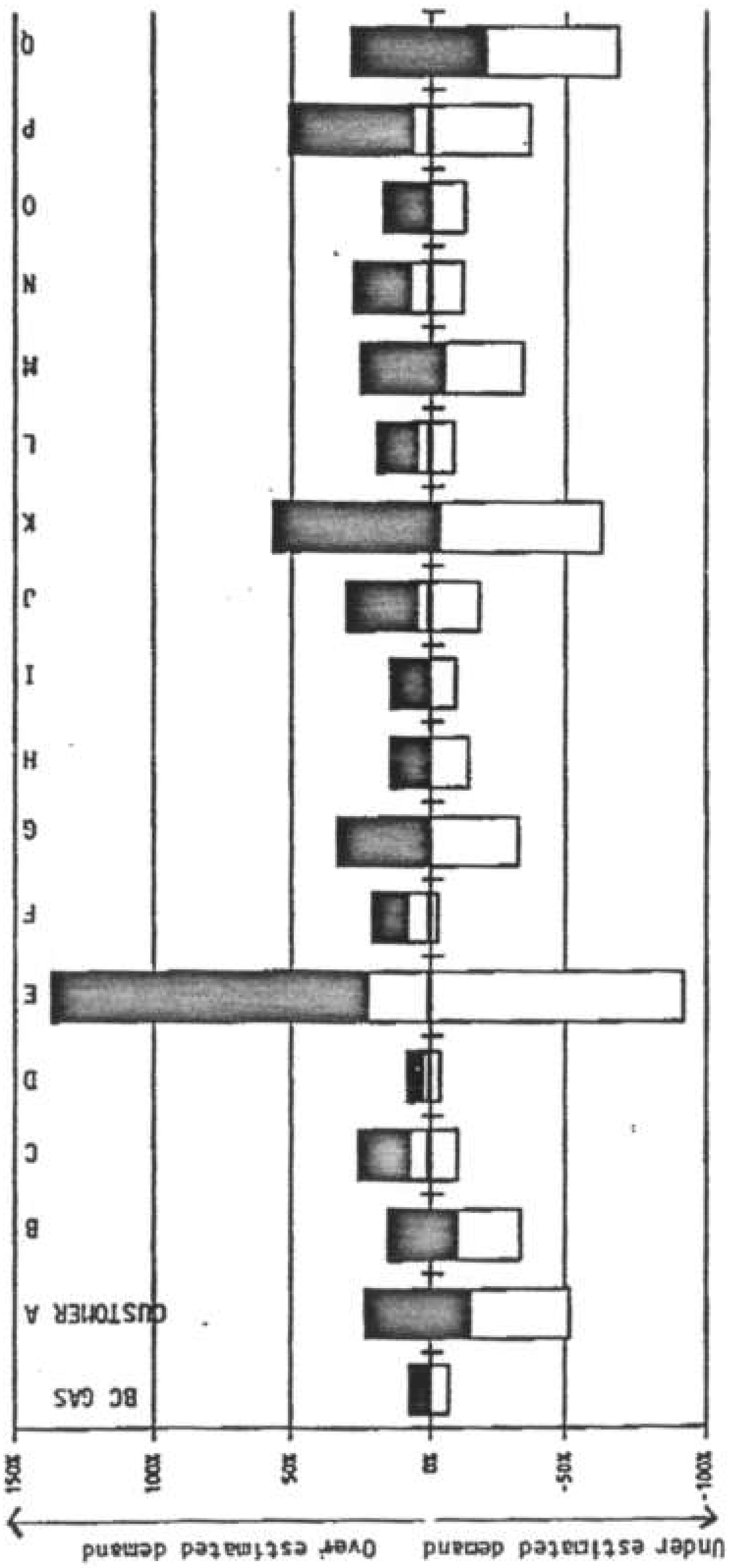


NOMINATION PROCESS:

• Day Before	1 pm	End User nominates to BC Gas.
	2 pm	BC Gas nominates to WEI.
• Gas Day	8 am	End User renominates to BC Gas and BC Gas renominates to WEI.
	11 am	WEI confirms renomination.
• Day After	8 am	Telemetered volume different than nomination, automatically accepted by WEI (Previous Day Shotgunning).

* Shotgunning is only for end users, not for BC Gas.

NOMINATION ACCURACY
(One Standard Deviation of Observations)



BC Gas Inc.
Gas Supply Adm.

24-Oct-91

LOAD FORECASTING CAPABILITY
LARGE INDUSTRIAL TRANSPORT CUSTOMERS
(Calendar Year 1990)

CATEGORY		FORECAST Annual Average ($10^3m^3/d$)	ACTUALS Annual Average ($10^3m^3/d$)	FORECAST Mean Deviation ($10^3m^3/d$)	Standard Deviation ($10^3m^3/d$)	% Error
T-CUSTOMERS (Interior)						
Customer	A	218.6	249.8	-31.2	82.2	37.6%
Customer	B	77.1	84.8	-7.7	18.9	24.5%
Customer	C	190.2	176.3	14.0	34.6	18.2%
Customer	D	55.4	54.1	1.3	3.3	6.0%
Customer	E	4.1	3.2	0.9	4.7	114.6%
Customer	F	141.4	129.2	12.2	16.8	11.9%
Customer	G	166.9	167.3	-0.3	55.9	33.5%
Customer	H	13.2	13.2	0.0	1.9	14.4%
Customer	I	29.1	28.5	0.6	3.4	11.7%
Customer	J	39.3	37.3	2.1	9.4	23.9%
Customer	K	3.0	3.1	-0.1	1.8	60.0%
Customer	L	37.5	35.7	1.8	5.2	13.9%
Customer	M	274.3	288.2	-13.9	80.9	29.5%
Customer	N	320.7	297.1	23.6	63.4	19.8%
Customer	O	79.5	78.2	1.3	11.6	14.6%
Customer	P	4.5	4.2	0.3	2.0	44.4%
Customer	Q	233.2	281.3	-48.1	113.6	48.7%

BC Gas Inc.
Gas Supply Adm.

24-Oct-91

LOAD FORECASTING CAPABILITY
FORECASTING INTERIOR AND COASTAL SYSTEMS
(Calendar Year 1990)

CATEGORY		*FORECAST*	*ACTUALS*		*FORECAST*	
		Annual Average	Annual Average	Mean Deviation	Standard Deviation	% Error
COASTAL						
• Total Demand	(1)	9,048 $10^3m^3/d$	9,035 $10^3m^3/d$	13 $10^3m^3/d$	670 $10^3m^3/d$	7%
• Weather		10.3 °C	10.3 °C	0 °C	1.2 °C (4)	
• Industrial Sales	(2)	1,496 $10^3m^3/d$	1,521 $10^3m^3/d$	−25 $10^3m^3/d$	136 $10^3m^3/d$	9%
INTERIOR						
• Total Demand	(1)	3,992 $10^3m^3/d$	4,006 $10^3m^3/d$	−14 $10^3m^3/d$	290 $10^3m^3/d$	7%
• Weather		7.9 °C	7.9 °C	0 °C	1.9 °C (5)	
• Industrial−T	(3)	1,885 $10^3m^3/d$	1,932 $10^3m^3/d$	−47 $10^3m^3/d$	216 $10^3m^3/d$	11%

1) Includes all categories of sales and transport (ie. including Large Industrial T−Service).
2) Industrial Sales → BC Gas performs the forecast on customer behalf.
3) Large Industrial transport customers.
4) 1.2 °C on Coastal system is, over a year, roughly equal to 400 $10^3m^3/d$
5) 1.9 °C on Interior system is, over a year, roughly equal to 150 $10^3m^3/d$

Evidence of G. M. Engbloom

Q. Please state your occupation and address.

A. I am President and principal consultant of Confer Consulting Ltd. (Confer), an energy economic consulting firm located at 4000, 350 - 7 Ave. S. W., Calgary.

Q. Please state your academic, professional and business experience.

A. I received a B.Sc. in Chemical Engineering from the University of Alberta and an M.A. in Economics from Queen's University, and am a member of several professional organizations.

Since 1977 when Confer was formed, my consulting activities have focused on energy related matters, including analysis of natural gas demand, supply and pricing. In recent years, several consulting tasks have involved evaluation of gas supply and sales contracts for buyers and sellers as well as participation in gas price arbitrations.

Also, several consulting tasks have resulted in appearances before the Alberta Energy Resources Conservation Board, the Ontario Energy Board, the British Columbia Utilities Commission, the National Energy Board and gas price arbitration panels.

Q. What is the purpose of your evidence?

A. Confer was asked by BC Gas Inc. (BC Gas) to respond to five matters detailed in a terms of reference prepared by BC Gas. The remainder of this evidence presents Confer's response to each matter identified by BC Gas.

Terms of Reference, Item 1:

How does the commodity price resulting from the 70% commodity/30% demand relationship found in the gas purchase contracts executed by BC Gas compare with the price of interruptible gas in the markets served by gas from British Columbia?

Response:

Table 1 shows the gas cost on a monthly and unit basis using the price provision (Article V) in the gas purchase contracts executed by BC Gas. In this example, a price of $ 1.35 per GJ (Line 1, Column 6) is used for Gas Price (GP). Column 10 of the table shows the commodity price at the inlet to Westcoast facilities (plant inlet) to be $ 0.88 per GJ.

Column 1, Table 2 shows the plant inlet cost for BC Gas (from Table 1) and for average prices reported by the British Columbia Ministry of Energy, Mines and Petroleum Resources (MEMPR) in its publication Natural Gas Market Update. When preparing this evidence, the most recent publication was the September, 1991 issue containing data up to and including February, 1991.

Column 2, Table 2 shows the reported average price at the plant inlet for interruptible sales to markets in British Columbia, and is generally based on actual contract prices. Column 3 shows the average prices for interruptible sales to the export market and is based on contract prices at the international border adjusted to the plant inlet by the volume weighted average toll for interruptible Westcoast service.

Line 16, Table 2 shows the arithmetic average of the prices for the calender year 1990. At the plant inlet, the 1990 average prices indicate the BC Gas commodity cost is below the average market prices, but in some months the market prices for interruptible sales to domestic and export consumers are below the BC Gas commodity cost.

Columns 5 to 9, Table 2 show interruptible prices at the point where Westcoast delivers gas. The BC Gas commodity cost at Huntingdon is shown in Column 5 and is the sum of the plant inlet cost and Westcoast's 1990 commodity toll for firm service. For deliveries to the Inland division, out-of-pocket costs are about $ 0.02 per GJ lower.

Column 6 is the average reported delivered price for all interruptible markets in British Columbia. Column 7 is the average reported price for all interruptible export sales to the U.S. served by gas from British Columbia and assumed to be exported at Huntingdon. Both series of reported average delivered prices are higher than the delivered commodity cost of BC Gas.

The reported prices for domestic interruptible sales, as shown in Column 6, are a combination of the average plant inlet price (Column 2) and the volume weighted average Westcoast interruptible toll. The domestic weighted average toll varies monthly with different volumes, gas supply and delivery points.

To estimate specific interruptible prices for sales to the Inland and Lower Mainland divisions, Columns 8 and 9, Table 2 are derived by adding the average reported plant inlet prices for domestic sales to the appropriate Westcoast interruptible toll. In Column 8 the toll to the Inland region is used and in Column 9 the Lower Mainland toll is used. Again, both series of prices are higher than the delivered commodity cost of BC Gas.

Given similar and competitive plant inlet prices, the reason for the significant differences between the BC Gas delivered commodity cost and the other delivered price estimates is the availability and use by BC Gas of under utilized firm Westcoast service. The incremental commodity toll for this service is substantially below the interruptible Westcoast toll. However, while the delivered prices on Table 2 indicate the BC Gas commodity cost provides a competitive advantage, other parties with access to under utilized firm Westcoast service have the same advantage and can be equally as competitive.

The comparisons made here are for a BC Gas price effective November 1, 1991 and for market prices during the months shown on Table 2. Interruptible price data for future months is not available, but, generally prices for interruptible gas sales during the latter portion of 1991 are about $ 0.10 to 0.20 per GJ below those in the same period in 1990. Such a price decline narrows or eliminates any difference between the commodity cost of BC Gas at the plant inlet and average market prices.

In conclusion, the commodity price resulting from the 70% commodity/30% demand relationship found in the gas purchase contracts executed by BC Gas is competitive with average market prices at the plant inlet for interruptible sales of gas from British Columbia.

A competitive plant inlet price resulting from the 70% commodity/30% demand relationship, in combination with access to under utilized firm Westcoast capacity, provides BC Gas with flexibility to meet competitive market conditions for interruptible sales from the Westcoast system.

Terms of Reference, Item 2:

How does the 70% commodity/30% demand relationship found in the gas purchase contracts compare to price adjustments made for load factor in other gas purchase contracts?

Figure 1 illustrates three relationships between load factor and price. Line AB represents a constant price relationship above some minimum annual load factor agreed to by the contracting parties. Such a relationship is typical of many long term gas supply and purchase contracts. Examples of long term contracts directly between producers and local distribution companies which follow a constant price relationship are: the Provincial Gas Division of SaskEnergy Corporation in Saskatchewan (minimum annual load factor of 80%), The Consumers' Gas Company Ltd. in Ontario (80%) and Union Gas Limited in Ontario (90%).

Line AC represents a constant present value relationship where price decreases as load factor increases such that the present value of gas production remains unchanged. Confer is not aware of any contracts which explicitly link prices and load factor through present value estimates.

Line AD represents a constant revenue relationship where, above a minimum annual load factor, the price declines with increasing load factor such that the seller's revenue remains constant.

Lines AB and AC bracket likely relationships between price to load factor. This is because it is unlikely sellers would agree to lower their present value with increasing load factor, making line AC a 'floor', and it is also unlikely buyers would agree to increase price with increased load factor, making line AB a 'ceiling'.

Column 7, Table 1 shows that under the BC Gas gas purchase contracts the total unit price decreases as load factor increases reaching the lowest price at 100% load factor. This type of relationship would be represented by a line to the left of AB in Figure 1, and it results because of the demand component in the price provision.

Confer is aware of other contracts for long term gas supply with demand components or other pricing mechanisms which also result in relationships to the left of line AB. Canadian Western Natural Gas Company Limited (Canadian Western) and Northwestern Utilities Limited (Northwestern) are sister companies purchasing and distributing gas in Alberta. They have gas price provisions in long term contracts with one price for winter purchases and a lower price of summer purchases. If a contract load factor is relatively low, gas purchases are mainly in the winter months at the winter price. As the contract load factor increases, more gas is purchased at the lower summer price, causing the average unit price to decrease.

The above discussion relates to load factors above an agreed upon minimum annual level which is often in the range of 80%. In many gas supply and purchase contracts, there is a distinctly different adjustment mechanism for load factors below the minimum load factor. Such mechanisms include take-or-pay and gas inventory charges, and they have the effect of increasing the buyer's average cost of gas under the contract when the load factor decreases below the minimum level.

The price adjustment mechanisms in the long term gas purchase contracts of BC Gas increase the buyer's average cost of gas across all load factors. From load factors from 100% down to 60%, the 70% commodity/30% demand mechanism adjusts average cost to load factor, and below 60% this mechanism is supplemented by a gas inventory charge.

In conclusion, at annual load factors above minimum levels, often in the range of 80%, the 70% commodity/30% demand relationship found in the gas purchase contracts of BC Gas provides a price adjustment which is more responsive to changes in load factor than the relationships in many other long term contracts. At load factors below minimum levels, virtually all long term gas contracts, including the BC Gas contracts, have adjustments which make the average price responsive to lower load factors.

Terms of Reference , Item 3:

In the market places served by gas from British Columbia are the load characteristics of a purchaser normally recognized in the pricing of interruptible gas sold to that purchaser?

In a competitive situation, such as the sale of gas to an interruptible purchaser, a seller must recognize the purchaser's load characteristics to be successful.

A possibility of interruptible is one load characteristic interruptible purchasers have in common. Other load characteristics can vary considerably among purchasers, including factors such as uniformity of demand (steady or with swings on daily, weekly or monthly basis), seasonality, size, location, alternative gas supplies and transportation, alternative energy costs, efficiency of fuel use equipment and others. Each of these factors can affect the price of gas sold under interruptible supply arrangements, and sellers typically try to assess these factors in bidding to successfully make the sale.

Not only is this assessment made to understand the purchaser's situation and ability to pay, but also to allow the seller to determine if there are circumstances within the seller's gas supply situation which make the sale more or less difficult than other potential sellers. In other words, sellers must investigate whether they have any tactical or strategic advantages or disadvantages which may make the interruptible sale more or less attractive given the particular load characteristics of the purchaser.

In conclusion, sellers in the market places served by gas from British Columbia must recognize the load characteristics of a purchaser to successfully compete in these markets.

Terms of Reference, Item 4:

In markets in which producers, aggregators and brokers sell gas from British Columbia, are interruptible gas prices normally kept confidential by the parties to the gas sale?

A price in a specific contract for interruptible gas supply and purchase is almost always kept confidential until at least such time as knowledge of the price cannot materially affect the competitive position of the seller or buyer.

Contract provisions for interruptible gas sales to buyers with typical load characteristics are often similar, making price the focal point of competition. A seller must have a confidential bid price to avoid other suppliers offering a slightly lower price and securing the sale.

Given the intense competition and large number of transactions, price settlements at any point in time will be in a narrow range for interruptible sales with similar conditions and typical load characteristics. The range of settled prices is widely known among industry participants even though full disclosure of specific contract prices and parties is confidential.

Through time, changing market conditions, and particularly those affecting the immediate and near term, cause the general level of price settlements to vary, sometimes quickly and significantly. Examples of price volatility are shown on Table 2 where the average plant inlet price for domestic sales varied between $ 0.86 and 1.30 per GJ.

Where the load characteristics of the interruptible purchaser are distinctive and not typical, competition among sellers is also very aggressive, particularly among those sellers with gas supply situations which fit well with such load characteristics. For these distinctive loads, often the general price level as well as the specific contract price is not available from market participants until it becomes immaterial.

Keeping contract prices confidential extends to sales by aggregators where the gas supply to the aggregator is under contract with producers who are themselves bidding on the same market opportunity with other gas under their control. Although aggregators usually need producer approval for sales, in the case of aggregator sales to competitive short term markets the approvals are usually of a blanket nature and are not specific to a particular contract.

Much of the above discussion deals with confidential prices from a seller's perspective, but purchasers may also have an interest in maintaining confidential prices, particularly where the purchaser's energy costs are an important competitive factor in the market for its production.

Certain gas prices are made available through regulatory and other publications. For example, in long term contracts for supply of Canadian gas to the U.S., government regulations cause pricing provisions to be disclosed and prices in these contracts are reported by Canadian and U.S. authorities. Short term import prices for Canadian gas are reported by U.S. authorities and some Canadian authorities. In instances where there is limited market activity or distinct characteristics, price information is often withheld to maintain confidentiality.

Private publications also report prices, usually on a more current but limited basis than those reported by governments. These publications typically rely on telephone surveys of selected market participants, and the resulting prices are indicative of the general market price level.

Where publication of prices for interruptible gas sales does occur, techniques such as delays in publishing or averaging are used to reduce the commercial competitive value of the published prices.

Terms of Reference, Item 5:

Could a seller with either a fixed rate or non-confidential prices maximize revenue from interruptible sales?

A seller with a fixed rate for interruptible sales will not sell gas when other suppliers offer prices lower than the fixed rate. If purchasers seek the fixed rate supply it is because market forces cause the bid prices from other suppliers to be higher than the fixed rate. Thus a seller with a fixed rate is not able to maximize revenue because:

- it is not able to compete at market prices below the fixed rate and therefore receives no revenue, and
- when the bid prices of other suppliers are above the seller's fixed rate, the seller is not able to charge full market value and therefore receives less than maximum revenue.

Where a seller must provide non-confidential prices when bidding for interruptible sales, the seller's competitive ability to maximize revenue is diminished or even eliminated. Other suppliers who can keep prices confidential will bid below the seller's non-confidential price, in which case the seller receives no revenue. If the seller's non-confidential price is so low as to prevent other suppliers from bidding, then the seller will make sales, but may not maximize revenue.

Where a seller is able to keep prices confidential through the bidding process but must make prices available immediately after successfully securing an interruptible sale, revenue maximizing can be diminished. This is because other interruptible purchasers will seek the lowest non-confidential price even if their load characteristics are different from those of the low price sale. Purchasers would state that if the seller wants their business, the purchaser's price must not exceed the lowest price for interruptible sales to any other purchaser. Thus, a purchaser with load characteristics which lead to a legitimate low price would set the price for all other purchasers even if they have load characteristics which would command a higher price in the competitive market.

TABLE 1

BC GAS
ILLUSTRATIVE

GAS COST AND LOAD FACTOR

NE										
1					GP:	1.35 $/GJ				
2					DCQ:	100 10^3M^3				
3					DAYS:	30				
4					GHV:	38.56 GJ/10^3M^3				
5										
6			COST				COST			
7	LOAD									
8	FACTOR	QUANTITY	TOTAL	DEMAND	GIC	COMMODITY	TOTAL	DEMAND	GIC	COMMODITY
9										
10	%	GJ	$	$	$	$	$/GJ	$/GJ	$/GJ	$/GJ
11	100	115680	145273	43582		101691	1.256	0.377	0.000	0.879
12	99	114523	144256	43582		100674	1.260	0.381	0.000	0.879
13	98	113366	143239	43582		99657	1.264	0.384	0.000	0.879
14	97	112210	142222	43582		98640	1.267	0.388	0.000	0.879
15	96	111053	141205	43582		97623	1.272	0.392	0.000	0.879
16	95	109896	140188	43582		96606	1.276	0.397	0.000	0.879
17	94	108739	139171	43582		95589	1.280	0.401	0.000	0.879
18	93	107582	138154	43582		94572	1.284	0.405	0.000	0.879
19	92	106426	137137	43582		93556	1.289	0.410	0.000	0.879
20	91	105269	136120	43582		92539	1.293	0.414	0.000	0.879
21	90	104112	135103	43582		91522	1.298	0.419	0.000	0.879
22	89	102955	134087	43582		90505	1.302	0.423	0.000	0.879
23	88	101798	133070	43582		89488	1.307	0.428	0.000	0.879
24	87	100642	132053	43582		88471	1.312	0.433	0.000	0.879
25	86	99485	131036	43582		87454	1.317	0.438	0.000	0.879
26	85	98328	130019	43582		86437	1.322	0.443	0.000	0.879
27	84	97171	129002	43582		85420	1.328	0.449	0.000	0.879
28	83	96014	127985	43582		84403	1.333	0.454	0.000	0.879
29	82	94858	126968	43582		83386	1.339	0.459	0.000	0.879
30	81	93701	125951	43582		82370	1.344	0.465	0.000	0.879
31	80	92544	124934	43582		81353	1.350	0.471	0.000	0.879
32	79	91387	123917	43582		80336	1.356	0.477	0.000	0.879
33	78	90230	122901	43582		79319	1.362	0.483	0.000	0.879
34	77	89074	121884	43582		78302	1.368	0.489	0.000	0.879
35	76	87917	120867	43582		77285	1.375	0.496	0.000	0.879
36	75	86760	119850	43582		76268	1.381	0.502	0.000	0.879
37	74	85603	118833	43582		75251	1.388	0.509	0.000	0.879
38	73	84446	117816	43582		74234	1.395	0.516	0.000	0.879
39	72	83290	116799	43582		73217	1.402	0.523	0.000	0.879
40	71	82133	115782	43582		72200	1.410	0.531	0.000	0.879
41	70	80976	114765	43582		71184	1.417	0.538	0.000	0.879
42	69	79819	113748	43582		70167	1.425	0.546	0.000	0.879
43	68	78662	112732	43582		69150	1.433	0.554	0.000	0.879
44	67	77506	111715	43582		68133	1.441	0.562	0.000	0.879
45	66	76349	110698	43582		67116	1.450	0.571	0.000	0.879
46	65	75192	109681	43582		66099	1.459	0.580	0.000	0.879
47	64	74035	108664	43582		65082	1.468	0.589	0.000	0.879
48	63	72878	107647	43582		64065	1.477	0.598	0.000	0.879
49	62	71722	106630	43582		63048	1.487	0.608	0.000	0.879
50	61	70565	105613	43582		62031	1.497	0.618	0.000	0.879
51	60	69408	104596	43582		61014	1.507	0.628	0.000	0.879
52	59	68251	103874	43582	295	59998	1.522	0.639	0.004	0.879
53	58	67094	103152	43582	589	58981	1.537	0.650	0.009	0.879
54	57	65938	102429	43582	884	57964	1.553	0.661	0.013	0.879
55	56	64781	101707	43582	1178	56947	1.570	0.673	0.018	0.879
56	55	63624	100985	43582	1473	55930	1.587	0.685	0.023	0.879
57	54	62467	100262	43582	1767	54913	1.605	0.698	0.028	0.879
58	53	61310	99540	43582	2062	53896	1.624	0.711	0.034	0.879
59	52	60154	98818	43582	2357	52879	1.643	0.725	0.039	0.879
60	51	58997	98095	43582	2651	51862	1.663	0.739	0.045	0.879
61	50	57840	97373	43582	2946	50845	1.683	0.753	0.051	0.879
MN	1	2	3	4	5	6	7	8	9	10

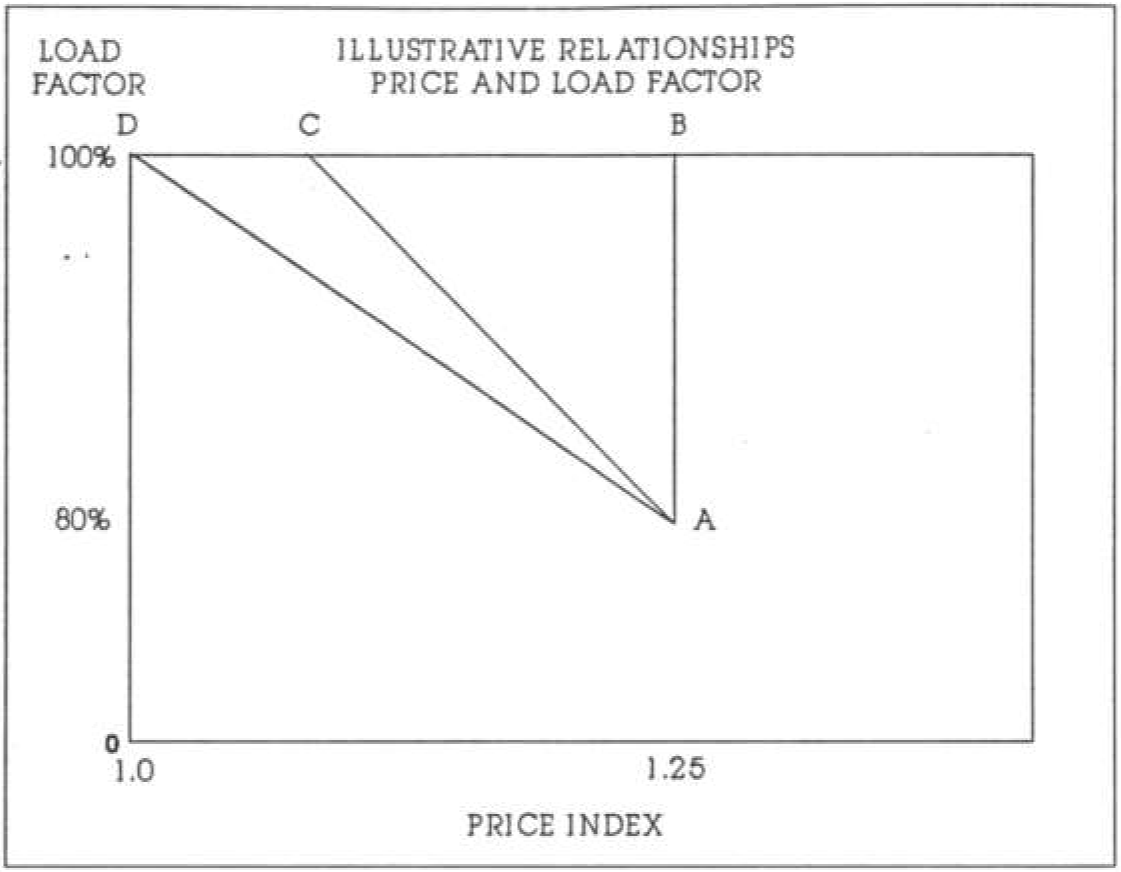
TABLE 2

COMPARISON OF INTERRUPTIBLE PRICES

BC GAS AND MARKET AVERAGES

	PLANT INLET PRICES				DELIVERED PRICES				
		AVERAGE REPORTED PRICES (MEMPR)				AVERAGE REPORTED PRICES (MEMPR)		MEMPR PLANT INLET PRICES PLUS WEI INTERRUPTIBLE TOLL	
MONTH	BC GAS COMMODITY	DOMESTIC	HUNT'N EXPORT		BC GAS COMMODITY @ HNUT'N	DOMESTIC	HUNT'N EXPORT	DOMESTIC INLAND	DOMESTIC LWR MNLD
	$/GJ	$/GJ	$/GJ		$/GJ	$/GJ	$/GJ	$/GJ	$/GJ
JANUARY, 1990	0.88	1.08	1.26		0.92	1.41	1.84	1.90	2.14
FEBRUARY	0.88	1.11	1.11		0.92	1.44	1.69	1.93	2.17
MARCH	0.88	0.95	0.97		0.92	1.38	1.57	1.77	2.01
APRIL	0.88	0.89	0.94		0.92	1.31	1.58	1.55	1.69
MAY	0.88	0.88	1.04		0.92	1.26	1.67	1.54	1.68
JUNE	0.88	0.88	0.91		0.92	1.27	1.59	1.54	1.68
JULY	0.88	0.86	1.00		0.92	1.27	1.61	1.52	1.66
AUGUST	0.88	0.89	0.83		0.92	1.30	1.49	1.55	1.69
SEPTEMBER	0.88	0.91	0.74		0.92	1.31	1.54	1.57	1.71
OCTOBER	0.88	1.00	0.92		0.92	1.43	1.54	1.66	1.80
NOVEMBER	0.88	0.92	1.09		0.92	1.35	1.80	1.74	1.98
DECEMBER	0.88	1.13	1.21		0.92	1.53	1.80	1.95	2.19
JANUARY, 1991	0.88	1.30	1.27		0.92	1.59	1.97	1.97	2.09
FEBRUARY	0.88	1.14	1.11		0.92	1.57	1.86	1.81	1.93
1990 AVERAGE	0.88	0.96	1.00		0.92	1.36	1.64	1.69	1.87
COLUMN	1	2	3	4	5	6	7	8	9

Figure 1


LOAD
FACTOR
ILLUSTRATIVE RELATIONSHIPS
PRICE AND LOAD FACTOR
D
C
B
100%
80%
A
0
1.0
1.25
PRICE INDEX

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BRITISH COLUMBIA LOAD FACTOR ANALYSIS

Prepared for
BC Gas Inc.
October 1991

SPROULE ASSOCIATES LIMITED

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BRITISH COLUMBIA LOAD FACTOR ANALYSIS

INTRODUCTION

This report has been prepared at the request of Mr. Patrick D. Lloyd of BC Gas Inc. for the purpose of addressing several issues pertaining to the load factor and price in a gas supply purchase contract in British Columbia. This report consists of an analysis which determines, from the producer's perspective, the relationship between the load factor of a natural gas purchase in British Columbia and the price in a long-term gas purchase contract. This load factor/price relationship is then compared with a gas purchase contract which combines a demand charge and a commodity charge in its purchase price. The purpose of the comparison is to determine if a demand/commodity pricing structure is a reasonable approximation for the load factor/price relationship. As well, this report addresses the question of whether or not, in Sproule's opinion, it is reasonable for a gas distribution utility to fully allocate the costs associated with a 30 percent demand charge in a long-term base load gas purchase contract to the firm customers of the utility as a cost associated with the supply of natural gas for the firm customers.

SUMMARY AND CONCLUSIONS

The Producer's Load Factor/Price Relationship

The initial purpose of this study was to determine the impact that a British Columbia producer's contract load factor would have on the negotiated price in a natural gas sales contract. Since the deregulation of the natural gas industry in November of 1986, natural gas producers and buyers have been able to freely enter into contracts which include pricing provisions acceptable to both parties. The producer now has many options in ultimately deciding where to market his gas production, and in a competitive marketplace, the intelligent producer will choose a market which best serves his interests. Given the option of differing load factors in various markets, it is our opinion that the negotiated gas price should give consideration to the specific load factor included in a contract; thereby allowing the producer to be indifferent to which market and load factor he could choose to accept. The present worth value of the producer's production income measured at some specified discount rate should therefore be constant regardless of what load factor is included in his gas purchase contract.

Given this premise, Sproule analyzed the impact of load factor on the negotiated natural gas contract commodity price. Figure S-1 presents an illustration of the load factor/price relationship for two cases generated from a typical B.C. reservoir. The first assumed that a producer would contract his reserves at a daily contract rate based on a rate-of-take equal to 1 MMCFPD of production for every 3.65 BCF of reserves. The second case assumed that a producer would contract his reserves at a daily contract rate based on a rate-of-take equal to 1 MMCFPD of production for every 3.0 BCF of reserves.

In both cases, the unit price of the producer contract increases as the load factor decreases in order for the producer to remain revenue neutral. However, when a producer has the opportunity to optimize the deliverability of the reservoir through a higher rate-of-take, the incremental increase is minimized.

At the request of BC Gas, Sproule developed its load factor analysis on the basis of an illustrative price forecast which began in 1992 with a price of $1.43 per MCF. This price was used in conjunction with an 80 percent load factor and both the 1 MMCFPD per 3.65 BCF case and the 1 MMCFPD per 3.0 BCF case.

It is Sproule's understanding that the 1 MMCFPD per 3.65 BCF case is representative of the BC Gas reserve dedication contract and the 1 MMCFPD per 3.0 BCF case was developed to be representative of the corporate warranty contracts that BC Gas has with some producers. The advantage of a corporate warranty, from the producer's perspective, is the opportunity to optimize the production of reserves rather than operate within the restrictions of a reserve-based contract. Given Sproule's knowledge of reservoir production in British Columbia and discussions with several producers in the province, a rate-of-take of 1 MMCFPD per 3.0 BCF was determined as a reasonable representation of the producer's average optimum production level. From the consumer's perspective, a corporate warranty provides a contract that is backed by the corporation's pool of diverse reserves with a commitment to buy gas, if necessary, from other producers should their own reserves fail to meet contract commitments. It is Sproule's opinion that a corporate warranty contract with a large, financially stable corporation which controls a substantial volume of uncontracted gas reserves provides a similar supply security as a reserve-based contract and therefore can command a comparable price.

Load Factor/Price Versus Demand/Commodity

The second issue that Sproule investigated dealt with the compatibility between the producer's load factor/price relationship and a contract pricing mechanism that included a demand component and a commodity component. Sproule calculated the unit revenue to accrue to the producer for a range of load factors, assuming the contract price at a 100 percent load factor was composed of a 30 percent demand charge and a 70 percent commodity charge.

The results of this calculation, in combination with the producer's load factor/price relationship, are illustrated in Figure S-2. The graph illustrates quite clearly that the demand/commodity contract price follows the same trend as the producer's load factor/price relationship through the rate of increase is not as great as the producer's load factor/price relationship. Sproule recognizes that the comparison assumes an average reservoir and average costs. The results, in actuality, will vary from producer to producer depending on the specifics of the producer's reserves and costs. This aside, it is Sproule's opinion that a producer would accept the demand/commodity contract price as representative of the producer's load factor/price relationship.

Full Cost Allocation

The final issue that Sproule was requested to address is the reasonableness of a fully allocated 30 percent demand charge that is associated with a long-term, base load gas purchase contract.

The question of reasonableness is a complex issue. The distribution utility must develop a gas supply portfolio that serves its customer's need for peak day deliverability, fluctuating annual requirement, and security of supply; all of which must be accomplished in the most cost effective manner. The development of this cost effective supply portfolio involves the integration of several gas supply options including long-term reserve based contracts, corporate warranties, deliverability contracts, spot purchases, and storage. Determining whether or not the full cost allocation of a 30 percent demand charge is reasonable in comparison with all the gas supply options available to a distribution company is beyond the scope of this report. Sproule's position on reasonableness will deal strictly with the magnitude of the demand charge and assumes that the demand charge is part of a long-term gas purchase contract that also includes reserve dedication or contract terms of a similar nature.

As previously mentioned, the gas cost curve that incorporates a 30 percent demand charge follows the same trend as the producer's load factor/price relationship. However, at each point along the curve, the gas price that results from a 30 percent demand/70 percent commodity pricing structure is less than the price required to keep the producer revenue neutral. The producer is not entirely compensated for the impact of a reduced load factor. Since a 1 MMCFPD per 3.0 BCF rate-of-take allows the producer to operate his reservoir in the most cost effective manner, the producer has reached his maximum level of efficiency. In consideration of the producer's economic position, a gas purchase contract, with a 30 percent demand/70 percent commodity pricing mechanism, contains the optimum price that the buyer can reasonably expect to achieve. A producer would require a larger demand component if he is to remain revenue neutral. As an alternative, the producer might negotiate for other contract concessions. There is also an inherent simplicity in a purchase contract that utilizes a demand/commodity pricing structure. The producer is automatically compensated for the actual load factor of the purchase and the distributing utility has the flexibility to match his supply to his market. Based on the foregoing, Sproule is of the opinion that it is reasonable for a gas distribution utility to fully allocate the costs associated with a 30 percent demand charge in a long-term, base load gas purchase contract to the firm customers of the utility as a cost associated with the supply of natural gas for the firm customers.

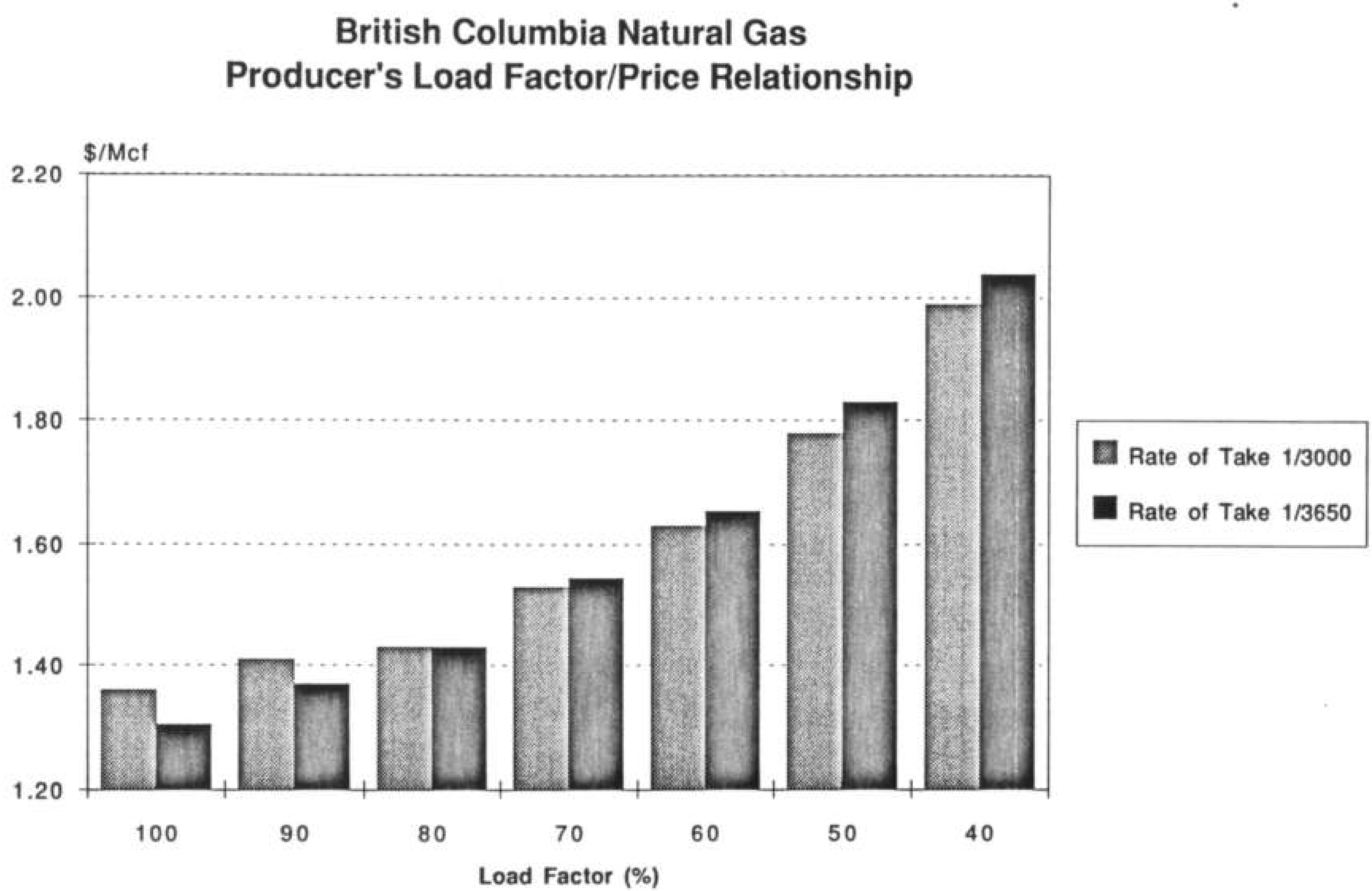

FIGURE S-1

SPROULE ASSOCIATES LIMITED

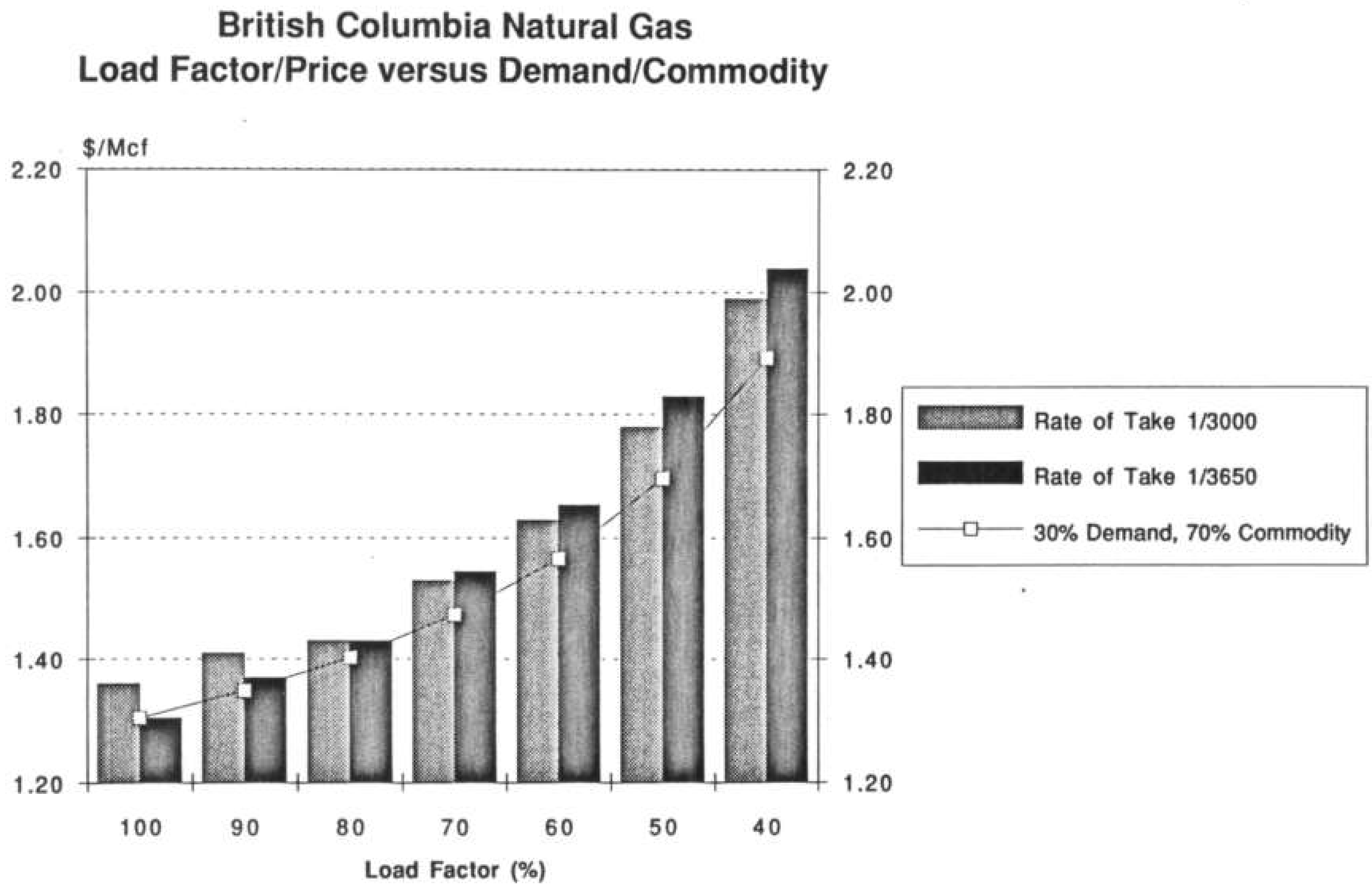
British Columbia Natural Gas
Load Factor/Price versus Demand/Commodity
$/Mcf
2.20
2.00
1.80
1.60
1.40
1.20
100
90
80
70
60
50
40
Load Factor (%)
Rate of Take 1/3000
Rate of Take 1/3650
30% Demand, 70% Commodity

FIGURE S-2

DISCUSSION

The first step in our analysis was to determine the reserve and production characteristics of a typical B.C. gas-producing property. Data included in the annual reserve summary published by the British Columbia Ministry of Energy, Mines and Petroleum Resources was used to determine the average reserves per well, wells per field, and natural gas liquid and sulphur content of the gas stream. Because the majority of the province's gas production is purchased as a raw gas stream at the fieldgate prior to delivery into the pipeline and processing facilities of Westcoast Transmission, and because the producer is not generally required to provide capital investment for processing and compression facilities, it was decided that an analysis of reservoirs with differing natural gas liquid or sulphur content would not provide substantially different results in our analysis. Average well productivity was determined from an analysis of published well test data in representative B.C. gas fields. Operating and capital costs were estimated based upon historical data taken from the non-confidential files of Sproule Associates Limited. Table 1 summarizes the input parameters used in our reserves model.

Table 1

Average B.C. Reservoir Model

- 6.5 BCF per well
- 8 wells
- 52.0 BCF of marketable gas reserves
- Initial deliverability - 7,300 MCFPD per well
- LPG recovery rate - 9.4 barrels per MMCF
- C_5+ recovery rate - 4.3 barrels per MMCF

The reservoir was assumed to be a tank type model, and the development of the reservoir was optimized through scheduled well tie-ins that were produced at their deliverability. The contract rate was maintained until the eighth well was tied-in and the reservoir could no longer sustain the necessary production. Thereafter, production was forecast to decline to the field's economic limit.

Having established an average B.C. reservoir, Sproule determined the value of the reservoir to the producer based on the illustrative example provided by B.C. Gas; a 1992 gas price of $1.43 per MCF at an 80 percent load factor, and a reserve-based contract with a rate-of-take equal to 1 MMCFPD per 3,650 MMCF MMCF (rate-of-take equal to 1/3650). Sproule assumed that the 1992 gas price would increased at a constant rate of 7 percent per year. A present worth value determined at a discount rate of 12 percent after tax was then assigned to this illustrative case. The next step was to vary the load factor of the producer's production, and through an iterative process, determine the gas price that resulted in the same present worth value as the illustrative case. The scheduling of well connections and applicable capital expenditures was determined for each load factor based upon a deliverability analysis of the reservoir model.

The second case was developed to be representative of a BC Gas corporate warranty contract. The advantage of a corporate warranty, from the producer's perspective, is the opportunity to optimize the production of reserves rather than operate within the restrictions of a reserve-based contract. Given Sproule's knowledge of reservoir production in British Columbia, and discussions with several producers in the province, a rate-of-take of 1/3000 was determined as a reasonable representation of the producer's average optimum production level. From the consumer's perspective, a corporate warranty provides a contract that is backed by the corporation's pool of diverse reserves with a commitment to buy gas, if necessary, from other producers should their own reserves fail to meet contract commitments. It is Sproule's opinion that a corporate warranty contract with a large, financially stable corporation which controls a substantial volume of uncontracted gas reserves and is under a long-term agreement, provides a similar supply security as a reserve-based contract and therefore can command a comparable price. Therefore, Sproule established the value of this second case on the basis of $1.43 per MCF escalating at 7 percent per year, an 80 percent load factor and a rate-of-take equal to 1/3000. Once again, the load factor of the producer's production was varied, and through an iterative process, appropriate gas price determined.

The results of both cases are summarized in Table 2 below. As well, Table 2 contains the unit revenue to accrue to the producer for a range of load factors, assuming the contract price at a 100 percent load factor was composed of a 30 percent demand charge and a 70 percent commodity charge. Individual cash flow forecasts for each load factor for the 1/3650 rate-of-take case are presented in Tables 3 through 9.

Table 2

	Producer's Load Factor/Price Relationship		
Load Factor	Rate-of-Take 1/3650	Rate-of-Take 1/3000	Producer Revenue 30% Demand/70% Commodity
100%	1.31	1.36	1.31
90%	1.37	1.41	1.35
80%	1.43	1.43	1.40
70%	1.55	1.53	1.47
60%	1.66	1.63	1.57
50%	1.83	1.78	1.70
40%	2.04	1.99	1.89

TABLE 3

PROVEN DEVELOPED,
PRODUCING
RESERVES

TYPICAL B.C. GAS FIELD
80% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

SUMMARY OF RESERVES AND PRESENT WORTH
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

RESERVES

	OIL	SOLUTION GAS	NON-ASSOC ASSOC GAS	ETHANE	PROPANE	BUTANES	PENTANES PLUS	TOTAL NGL	SULPHUR
	MBBL	MMCF	MMCF	MBBL	MBBL	MBBL	MBBL	MBBL	MLT
GROSS	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. INT.	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. NET	0.0	0	42483	0.0	0.0	391.0	178.9	569.9	65.0

PRESENT WORTH

DISCOUNT RATE	TOTAL NET CAPITAL	BEFORE TAX NET REV	ALB ROY TAX CR.	WGML/LOAN OVERHEAD	BEFORE TAX CASH FLOW	INCOME TAXES	AFTER TAX CASH FLOW
%	M$	M$	M$	M$	M$	M$	M$
0.0	4239	96360	0	0	96360	40501	55859
10.0	3192	48544	0	0	48544	20430	28114
12.0	3050	43442	0	0	43442	18306	25136
15.0	2866	37252	0	0	37252	15735	21517
18.0	2709	32385	0	0	32385	13717	18668
20.0	2618	29699	0	0	29699	12605	17094
25.0	2425	24412	0	0	24412	10418	13994
30.0	2274	20568	0	0	20568	8831	11737

USES $1.43/MMCF + 7% ESCALATION

TABLE 3

TYPICAL B.C. GAS FIELD
80% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

PROVEN DEVELOPED, PRODUCING RESERVES

PRODUCTION AND PRICE FORECAST (MAJOR PRODUCTS AND SULPHUR)
(PRODN START : JAN 1,1992)

	NON-ASSOC / ASSOC PIPELINE GAS						SULPHUR			
YEAR	WELLS	DAILY	GROSS	CO.INT	CO.NET	PRICE	GROSS	CO.INT	CO.NET	PRICE
		MCF/D	MMCF	MMCF	MMCF	$/MCF	MLT	MLT	MLT	$/LT
1992	3.0	11400	4161	4161	3531	1.43	6.2	6.2	5.2	60.00
1993	4.0	11400	4161	4161	3504	1.53	6.2	6.2	5.2	65.00
1994	5.0	11400	4161	4161	3479	1.64	6.2	6.2	5.2	70.00
1995	5.0	11400	4161	4161	3455	1.75	6.2	6.2	5.2	75.00
1996	6.0	11400	4161	4161	3433	1.87	6.2	6.2	5.2	80.00
1997	6.0	11400	4161	4161	3413	2.01	6.2	6.2	5.2	85.00
1998	7.0	11400	4161	4161	3394	2.15	6.2	6.2	5.2	90.00
1999	8.0	11400	4161	4161	3376	2.30	6.2	6.2	5.2	95.00
2000	8.0	10267	3748	3748	3026	2.46	5.6	5.6	4.7	100.00
2001	8.0	8297	3028	3028	2434	2.63	4.5	4.5	3.8	105.00
2002	8.0	6705	2447	2447	1958	2.81	3.7	3.7	3.1	110.00
2003	8.0	5418	1978	1978	1576	3.01	3.0	3.0	2.5	115.00
2004	8.0	4378	1598	1598	1269	3.22	2.4	2.4	2.0	120.00
2005	8.0	3538	1291	1291	1021	3.45	1.9	1.9	1.6	125.00
2006	8.0	2859	1044	1044	823	3.69	1.6	1.6	1.3	131.50
2007	8.0	2311	843	843	663	3.95	1.3	1.3	1.1	138.32
2008	8.0	1867	682	682	534	4.22	1.0	1.0	0.9	145.49
2009	8.0	1509	551	551	430	4.52	0.8	0.8	0.7	153.02
2010	8.0	1219	445	445	347	4.83	0.7	0.7	0.6	160.92
SUBT			50943	50943	41664		76.4	76.4	63.7	
4YR			1057	1057	819		1.6	1.6	1.3	
TOTL			52000	52000	42483		78.0	78.0	65.0	

USES $1.43/MMCF + 7% ESCALATION

PRODUCTION AND PRICE FORECAST (NGL's)
(PRODN START : JAN 1,1992)

	BUTANES				PENTANES PLUS			
YEAR	GROSS	CO.INT	CO.NET	PRICE	GROSS	CO.INT	CO.NET	PRICE
	MBBL	MBBL	MBBL	$/BBL	MBBL	MBBL	MBBL	$/BBL
1992	39.1	39.1	31.3	11.43	17.9	17.9	14.3	20.84
1993	39.1	39.1	31.3	12.60	17.9	17.9	14.3	23.11
1994	39.1	39.1	31.3	14.02	17.9	17.9	14.3	25.26
1995	39.1	39.1	31.3	15.54	17.9	17.9	14.3	27.60
1996	39.1	39.1	31.3	17.20	17.9	17.9	14.3	30.11
1997	39.1	39.1	31.3	18.99	17.9	17.9	14.3	32.83
1998	39.1	39.1	31.3	20.93	17.9	17.9	14.3	35.77
1999	39.1	39.1	31.3	23.05	17.9	17.9	14.3	38.94
2000	35.2	35.2	28.2	24.90	16.1	16.1	12.9	41.77
2001	28.5	28.5	22.8	26.34	13.0	13.0	10.4	44.02
2002	23.0	23.0	18.4	27.88	10.5	10.5	8.4	46.38
2003	18.6	18.6	14.9	29.49	8.5	8.5	6.8	48.86
2004	15.0	15.0	12.0	31.19	6.9	6.9	5.5	51.46
2005	12.1	12.1	9.7	32.97	5.6	5.6	4.4	54.19
2006	9.8	9.8	7.8	34.75	4.5	4.5	3.6	57.03
2007	7.9	7.9	6.3	36.63	3.6	3.6	2.9	60.02
2008	6.4	6.4	5.1	38.59	2.9	2.9	2.3	63.16
2009	5.2	5.2	4.1	40.66	2.4	2.4	1.9	66.45
2010	4.2	4.2	3.3	42.82	1.9	1.9	1.5	69.91
SUBT	478.9	478.9	383.1		219.1	219.1	175.2	
4YR	9.9	9.9	7.9		4.5	4.5	3.7	
TOTL	488.8	488.8	391.0		223.6	223.6	178.9	

TABLE 3

TYPICAL B.C. GAS FIELD
80% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	REVENUE OIL	REVENUE GAS	REVENUE NGL	REVENUE SUL	REVENUE ROY	REVENUE OTHER	ROYALTIES CROWN	ROYALTIES PROD	ROYALTIES RES	ROYALTIES SUL	GCA	MIN TAXES	LEASE EXP	PLANT EXP	OPER INC	NPI
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	5950	820	374	0	0	1065	0	0	62	0	0	474	0	5543	0
1993	0	6367	906	406	0	0	1187	0	0	68	0	0	542	0	5883	0
1994	0	6812	1000	437	0	0	1317	0	0	73	0	0	615	0	6245	0
1995	0	7289	1102	468	0	0	1456	0	0	78	0	0	645	0	6679	0
1996	0	7800	1211	499	0	0	1606	0	0	83	0	0	728	0	7093	0
1997	0	8346	1330	531	0	0	1766	0	0	88	0	0	764	0	7587	0
1998	0	8930	1459	562	0	0	1938	0	0	94	0	0	858	0	8060	0
1999	0	9555	1598	593	0	0	2122	0	0	99-	0	0	960	0	8565	0
2000	0	9208	1550	562	0	0	2084	0	0	94	0	0	957	0	8186	0
2001	0	7962	1323	477	0	0	1828	0	0	79	0	0	911	0	6943	0
2002	0	6884	1129	404	0	0	1602	0	0	67	0	0	877	0	5871	0
2003	0	5953	964	341	0	0	1402	0	0	57	0	0	853	0	4945	0
2004	0	5147	822	288	0	0	1226	0	0	48	0	0	838	0	4145	0
2005	0	4451	701	242	0	0	1071	0	0	40	0	0	832	0	3451	0
2006	0	3848	597	206	0	0	934	0	0	34	0	0	832	0	2850	0
2007	0	3327	508	175	0	0	815	0	0	29	0	0	839	0	2328	0
2008	0	2877	432	149	0	0	710	0	0	25	0	0	851	0	1873	0
2009	0	2488	368	126	0	0	618	0	0	21	0	0	868	0	1475	0
2010	0	2151	313	107	0	0	538	0	0	18	0	0	891	0	1125	0
SUBT	0	115344	18135	6947	0	0	25287	0	0	1158	3	0	15135	0	98849	0
4YR	0	5948	833	285	0	0	1505	0	0	48	0	0	3764	0	1751	0
TOTL	0	121292	18968	7232	0	0	26791	0	0	1205	3	0	18899	0	100600	0

USES $1.43/MMCF + 7% ESCALATION

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	INTANGIBLE CEE	INTANGIBLE CDE	TANGIBLE CL 41	TANGIBLE PLANT	TANGIBLE OTHER	CEDIP COGPE	TOTAL CAP	NET REV	CUM NETREV	ARTC	OVHD	LOAN REPMT PRIN	LOAN REPMT INT	WGML REPMT	CASH FLOW	CUM CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	270	1080	0	0	0	1350	-1350	-1350	0	0	0	0	0	-1350	-1350
1992	0	0	0	0	0	0	0	5543	4193	0	0	0	0	0	5543	4193
1993	0	99	397	0	0	0	496	5387	9579	0	0	0	0	0	5387	9579
1994	0	104	417	0	0	0	521	5724	15304	0	0	0	0	0	5724	15304
1995	0	0	0	0	0	0	0	6679	21983	0	0	0	0	0	6679	21983
1996	0	115	459	0	0	0	574	6519	28502	0	0	0	0	0	6519	28502
1997	0	0	0	0	0	0	0	7587	36089	0	0	0	0	0	7587	36089
1998	0	127	507	0	0	0	633	7427	43517	0	0	0	0	0	7427	43517
1999	0	133	532	0	0	0	665	7900	51417	0	0	0	0	0	7900	51417
2000	0	0	0	0	0	0	0	8186	59603	0	0	0	0	0	8186	59603
2001	0	0	0	0	0	0	0	6943	66547	0	0	0	0	0	6943	66547
2002	0	0	0	0	0	0	0	5871	72418	0	0	0	0	0	5871	72418
2003	0	0	0	0	0	0	0	4945	77363	0	0	0	0	0	4945	77363
2004	0	0	0	0	0	0	0	4145	81508	0	0	0	0	0	4145	81508
2005	0	0	0	0	0	0	0	3451	84959	0	0	0	0	0	3451	84959
2006	0	0	0	0	0	0	0	2850	87809	0	0	0	0	0	2850	87809
2007	0	0	0	0	0	0	0	2328	90137	0	0	0	0	0	2328	90137
2008	0	0	0	0	0	0	0	1873	92010	0	0	0	0	0	1873	92010
2009	0	0	0	0	0	0	0	1475	93484	0	0	0	0	0	1475	93484
2010	0	0	0	0	0	0	0	1125	94610	0	0	0	0	0	1125	94610
SUBT	0	848	3392	0	0	0	4239	94610		0	0	0	0	0	94610	
4YR	0	0	0	0	0	0	0	1750		0	0	0	0	0	1750	
TOTL	0	848	3392	0	0	0	4239	96360		0	0	0	0	0	96360	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
NET REVENUE	48544	43442	37252	32385	29699	24412	20568
CASH FLOW	48544	43442	37252	32385	29699	24412	20568

TABLE 3

TYPICAL B.C. GAS FIELD
80% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX RESINC	LEASE EXP	PROD ROY	C.C.A.	RES ALLOW	OTHER INC	RES ROY	---CAPITAL CEE	WRITEOFF--- CDE	COGPE	DEBT INT	NPI+ OVHD	DEPL	TAXREV ADJ.
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	135	-34	0	0	0	81	0	0	0	0	0
1992	6770	474	0	236	1515	0	0	0	57	0	0	0	0	0
1993	7273	542	0	227	1626	0	0	0	69	0	0	0	0	0
1994	7813	615	0	272	1732	0	0	0	80	0	0	0	0	0
1995	8391	645	0	256	1872	0	0	0	56	0	0	0	0	0
1996	9011	728	0	249	2008	0	0	0	74	0	0	0	0	0
1997	9676	764	0	244	2167	0	0	0	52	0	0	0	0	0
1998	10388	858	0	247	2321	0	0	0	74	0	0	0	0	0
1999	11153	960	0	315	2470	0	0	0	92	0	0	0	0	0
2000	10758	957	0	303	2375	0	0	0	64	0	0	0	0	0
2001	9285	911	0	227	2037	0	0	0	45	0	0	0	0	0
2002	8014	877	0	170	1742	0	0	0	31	0	0	0	0	0
2003	6916	853	0	128	1484	0	0	0	22	0	0	0	0	0
2004	5969	838	0	96	1259	0	0	0	15	0	0	0	0	0
2005	5152	832	0	72	1062	0	0	0	11	0	0	0	0	0
2006	4445	832	0	54	890	0	0	0	8	0	0	0	0	0
2007	3835	839	0	40	739	0	0	0	5	0	0	0	0	0
2008	3309	851	0	30	607	0	0	0	4	0	0	0	0	0
2009	2856	868	0	23	491	0	0	0	3	0	0	0	0	0
2010	2464	891	0	17	389	0	0	0	2	0	0	0	0	0
SUBT	133479	15135	0	3340	28751	0	0	0	844	0	0	0	0	0
17YR	6781	3764	0	51	742	0	0	0	4	0	0	0	0	0
TOTL	140260	18899	0	3391	29493	0	0	0	848	0	0	0	0	0

USES $1.43/MMCF + 7% ESCALATION

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX INC	FED TAXES	PRVTAX RESINC	PRVTAX INC	PROV TAXES	PRVROY TAXREB	PROC INC	PL EXP SULROY	PLANT CCA	PROC TAXINC	PROC TAXES	INVTAX CREDIT	BEFORE TAX CF	TOTAL INCTAX	AFTER TAX CF	CUM AT CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	-182	-53	0	-182	-26	5	0	0	0	0	0	0	-1350	-83	-1267	-1267
1992	4488	1294	6770	4488	628	-63	374	62	0	312	134	0	5543	2119	3423	2156
1993	4809	1387	7273	4809	673	-62	406	68	0	338	145	0	5387	2267	3120	5276
1994	5115	1475	7813	5115	716	-58	437	73	0	364	156	0	5724	2405	3319	8596
1995	5561	1604	8391	5561	779	-58	468	78	0	390	167	0	6679	2608	4072	12667
1996	5952	1716	9011	5952	833	-56	499	83	0	416	178	0	6519	2784	3735	16402
1997	6449	1860	9676	6449	903	-56	531	88	0	442	189	0	7587	3008	4579	20981
1998	6888	1987	10388	6888	964	-54	562	94	0	468	201	0	7427	3205	4222	25203
1999	7317	2110	11153	7317	1024	-49	593	99	0	494	212	0	7900	3395	4506	29708
2000	7060	2036	10758	7060	988	-41	562	94	0	468	201	0	8186	3266	4920	34629
2001	6065	1749	9285	6065	849	-29	477	79	0	397	170	0	6943	2798	4145	38774
2002	5194	1498	8014	5194	727	-20	404	67	0	337	144	0	5871	2389	3483	42257
2003	4430	1278	6916	4430	620	-11	341	57	0	284	122	0	4945	2031	2915	45171
2004	3761	1085	5969	3761	527	-5	288	48	0	240	103	0	4145	1718	2426	47598
2005	3175	916	5152	3175	445	1	242	40	0	202	86	0	3451	1445	2005	49603
2006	2662	768	4445	2662	373	6	206	34	0	172	73	0	2850	1208	1643	51246
2007	2212	638	3835	2212	310	11	175	29	0	146	62	0	2328	999	1328	52574
2008	1817	524	3309	1817	254	14	149	25	0	124	53	0	1873	817	1055	53629
2009	1471	424	2856	1471	206	18	126	21	0	105	45	0	1475	657	817	54446
2010	1166	336	2464	1166	163	21	107	18	0	90	38	0	1125	517	609	55055
SUBT	85409	24632	133479	85409	11957	-485	6947	1158	0	5789	2480	0	94610	39555	55055	
17YR	2221	640	6781	2221	311	107	285	48	0	238	102	0	1750	946	804	
TOTL	87630	25272	140260	87630	12268	-379	7232	1206	0	6027	2582	0	96360	40501	55859	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
TOTAL INC TAX	20430	18306	15735	13717	12605	10418	8831
AFTER TAX CF	28114	25136	21517	18668	17094	13994	11737

TABLE 3

TYPICAL B.C. GAS FIELD
80% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	PRODn MONTHS	BUTn REC RATE	PENT+ REC RATE	SUL REC RATE	W.I. %	CR ROY PRICE $/vol	CROWN GAS %	CROWN BYPs %	G.C.A. RATE $/Mcf
1991	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	12.0	9.40	4.30	1.50	100.00	1.19	15.149	20.00	0.00
1993	12.0	9.40	4.30	1.50	100.00	1.27	15.7934	20.00	0.00
1994	12.0	9.40	4.30	1.50	100.00	1.36	16.3957	20.00	0.00
1995	12.0	9.40	4.30	1.50	100.00	1.45	16.9586	20.00	0.00
1996	12.0	9.40	4.30	1.50	100.00	1.56	17.4847	20.00	0.00
1997	12.0	9.40	4.30	1.50	100.00	1.66	17.9763	20.00	0.00
1998	12.0	9.40	4.30	1.50	100.00	1.78	18.4358	20.00	0.00
1999	12.0	9.40	4.30	1.50	100.00	1.91	18.8653	20.00	0.00
2000	12.0	9.40	4.30	1.50	100.00	2.04	19.2666	20.00	0.00
2001	12.0	9.40	4.30	1.50	100.00	2.18	19.6417	20.00	0.00
2002	12.0	9.40	4.30	1.50	100.00	2.33	19.9922	20.00	0.00
2003	12.0	9.40	4.30	1.50	100.00	2.50	20.3198	20.00	0.00
2004	12.0	9.40	4.30	1.50	100.00	2.67	20.626	20.00	0.00
2005	12.0	9.40	4.30	1.50	100.00	2.86	20.9122	20.00	0.00
2006	12.0	9.40	4.30	1.50	100.00	3.06	21.1796	20.00	0.00
2007	12.0	9.40	4.30	1.50	100.00	3.27	21.4295	20.00	0.00
2008	12.0	9.40	4.30	1.50	100.00	3.50	21.6631	20.00	0.00
2009	12.0	9.40	4.30	1.50	100.00	3.75	21.8814	20.00	0.00
2010	12.0	9.40	4.30	1.50	100.00	4.01	22.0854	20.00	0.001
TOTL									

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	Prod Ex WL-GAS M$/W/M	Prod Ex VAR-GAS $/Mcf	-GROSS INTANG-- --INVESTMENT--- Cur M$	Fut M$	-GRSS TAN CL41- --INVESTMENT--- Cur M$	Fut M$	RES ALLOW %	FED Inc Tax %	PROV Inc Tax %
1991	3.30	0.08	270	270	1080	1080	25.00	28.84	14.00
1992	3.47	0.084	0	0	0	0	25.00	28.84	14.00
1993	3.64	0.088	90	99	360	397	25.00	28.84	14.00
1994	3.82	0.093	90	104	360	417	25.00	28.84	14.00
1995	4.01	0.097	0	0	0	0	25.00	28.84	14.00
1996	4.21	0.102	90	115	360	459	25.00	28.84	14.00
1997	4.42	0.107	0	0	0	0	25.00	28.84	14.00
1998	4.64	0.113	90	127	360	507	25.00	28.84	14.00
1999	4.88	0.118	90	133	360	532	25.00	28.84	14.00
2000	5.12	0.124	0	0	0	0	25.00	28.84	14.00
2001	5.38	0.13	0	0	0	0	25.00	28.84	14.00
2002	5.64	0.137	0	0	0	0	25.00	28.84	14.00
2003	5.93	0.144	0	0	0	0	25.00	28.84	14.00
2004	6.22	0.151	0	0	0	0	25.00	28.84	14.00
2005	6.53	0.158	0	0	0	0	25.00	28.84	14.00
2006	6.86	0.166	0	0	0	0	25.00	28.84	14.00
2007	7.20	0.175	0	0	0	0	25.00	28.84	14.00
2008	7.56	0.183	0	0	0	0	25.00	28.84	14.00
2009	7.94	0.193	0	0	0	0	25.00	28.84	14.00
2010	8.34	0.202	0	0	0	0	25.00	28.84	14.00
TOTL			720	848	2880	3392			

NEW ECONOMIC LIMIT IS 477.00
Province code: 2 (B.C.) PR_CODE_G 0
Type reserve code: 1 (Proven Developed, Producing)

TABLE 4

PROVEN DEVELOPED,
PRODUCING
RESERVES

TYPICAL B.C. GAS FIELD
100% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

SUMMARY OF RESERVES AND PRESENT WORTH
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

RESERVES

	OIL	SOLUTION GAS	NON-ASSOC ASSOC GAS	ETHANE	PROPANE	BUTANES	PENTANES PLUS	TOTAL NGL	SULPHUR
	MBBL	MMCF	MMCF	MBBL	MBBL	MBBL	MBBL	MBBL	MLT
GROSS	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. INT.	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. NET	0.0	0	43104	0.0	0.0	391.0	178.9	569.9	65.0

PRESENT WORTH

DISCOUNT RATE	TOTAL NET CAPITAL	BEFORE TAX NET REV	ALB ROY TAX CR.	WGML/LOAN OVERHEAD	BEFORE TAX CASH FLOW	INCOME TAXES	AFTER TAX CASH FLOW
%	M$	M$	M$	M$	M$	M$	M$
0.0	4091	81385	0	0	81385	33741	47644
10.0	3274	47423	0	0	47423	19810	27613
12.0	3152	43285	0	0	43285	18115	25170
15.0	2989	38074	0	0	38074	15980	22094
18.0	2846	33810	0	0	33810	14234	19576
20.0	2760	31387	0	0	31387	13242	18145
25.0	2574	26453	0	0	26453	11221	15232
30.0	2420	22713	0	0	22713	9689	13024

USES $1.305/MMCF + 7% ESCALATION

TABLE 4

TYPICAL B.C. GAS FIELD
100% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

PROVEN DEVELOPED,
PRODUCING
RESERVES

PRODUCTION AND PRICE FORECAST (MAJOR PRODUCTS AND SULPHUR)
(PRODN START : JAN 1,1992)

	NON-ASSOC / ASSOC PIPELINE GAS						SULPHUR			
YEAR	WELLS	DAILY	GROSS	CO. INT	CO.NET	PRICE	GROSS	CO. INT	CO.NET	PRICE
		MCF/D	MMCF	MMCF	MMCF	$/MCF	MLT	MLT	MLT	$/LT
1992	3.0	14250	5201	5201	4421	1.31	7.8	7.8	6.5	60.00
1993	4.0	14250	5201	5201	4421	1.40	7.8	7.8	6.5	65.00
1994	5.0	14250	5201	5201	4391	1.49	7.8	7.8	6.5	70.00
1995	6.0	14250	5201	5201	4359	1.60	7.8	7.8	6.5	75.00
1996	7.0	14250	5201	5201	4329	1.71	7.8	7.8	6.5	80.00
1997	8.0	14250	5201	5201	4301	1.83	7.8	7.8	6.5	85.00
1998	8.0	14250	5201	5201	4275	1.96	7.8	7.8	6.5	90.00
1999	8.0	12195	4451	4451	3638	2.10	6.7	6.7	5.6	95.00
2000	8.0	8857	3233	3233	2628	2.24	4.8	4.8	4.0	100.00
2001	8.0	6432	2348	2348	1899	2.40	3.5	3.5	2.9	105.00
2002	8.0	4671	1705	1705	1372	2.57	2.6	2.6	2.1	110.00
2003	8.0	3392	1238	1238	992	2.75	1.9	1.9	1.5	115.00
2004	8.0	2463	899	899	717	2.94	1.3	1.3	1.1	120.00
2005	8.0	1789	653	653	519	3.14	1.0	1.0	0.8	125.00
2006	8.0	1299	474	474	376	3.36	0.7	0.7	0.6	131.50
2007	8.0	944	344	344	272	3.60	0.5	0.5	0.4	138.32
2008	8.0	685	246	246	193	3.85	0.4	0.4	0.3	145.49
SUBT			52000	52000	43104		78.0	78.0	65.0	
TOTL			52000	52000	43104		78.0	78.0	65.0	

USES $1.306/MMCF + 7% ESCALATION

PRODUCTION AND PRICE FORECAST (NGL's)
(PRODN START : JAN 1,1992)

	BUTANES				PENTANES PLUS			
YEAR	GROSS	CO. INT	CO.NET	PRICE	GROSS	CO. INT	CO.NET	PRICE
	MBBL	MBBL	MBBL	$/BBL	MBBL	MBBL	MBBL	$/BBL
1992	48.9	48.9	39.1	11.43	22.4	22.4	17.9	20.84
1993	48.9	48.9	39.1	12.60	22.4	22.4	17.9	23.11
1994	48.9	48.9	39.1	14.02	22.4	22.4	17.9	25.26
1995	48.9	48.9	39.1	15.54	22.4	22.4	17.9	27.60
1996	48.9	48.9	39.1	17.20	22.4	22.4	17.9	30.11
1997	48.9	48.9	39.1	18.99	22.4	22.4	17.9	32.83
1998	48.9	48.9	39.1	20.93	22.4	22.4	17.9	35.77
1999	41.8	41.8	33.5	23.05	19.1	19.1	15.3	38.94
2000	30.4	30.4	24.3	24.90	13.9	13.9	11.1	41.77
2001	22.1	22.1	17.7	26.34	10.1	10.1	8.1	44.02
2002	16.0	16.0	12.8	27.88	7.3	7.3	5.9	46.38
2003	11.6	11.6	9.3	29.49	5.3	5.3	4.3	48.86
2004	8.5	8.5	6.8	31.19	3.9	3.9	3.1	51.46
2005	6.1	6.1	4.9	32.97	2.8	2.8	2.2	54.19
2006	4.5	4.5	3.6	34.75	2.0	2.0	1.6	57.03
2007	3.2	3.2	2.6	36.63	1.5	1.5	1.2	60.02
2008	2.3	2.3	1.8	38.59	1.1	1.1	0.8	63.16
SUBT	488.8	488.8	391.0		223.6	223.6	178.9	
TOTL	488.8	488.8	391.0		223.6	223.6	178.9	

TABLE 4

TYPICAL B.C. GAS FIELD
100% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	REVENUE OIL	REVENUE GAS	REVENUE NGL	REVENUE SUL	REVENUE ROY	REVENUE OTHER	ROYALTIES CROWN	ROYALTIES PROD	ROYALTIES RES	ROYALTIES SUL	GCA	MIN TAXES	LEASE EXP	PLANT EXP	OPER INC	NPI
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	6788	1025	468	0	0	1223	0	0	78	0	0	562	0	6418	0
1993	0	7263	1133	507	0	0	1316	0	0	85	0	0	633	0	6869	0
1994	0	7771	1250	546	0	0	1460	0	0	91	0	0	711	0	7306	0
1995	0	8315	1377	585	0	0	1621	0	0	98	0	0	795	0	7764	0
1996	0	8897	1514	624	0	0	1794	0	0	104	0	0	885	0	8253	0
1997	0	9520	1663	663	0	0	1980	0	0	111	0	0	982	0	8774	0
1998	0	10186	1823	702	0	0	2179	0	0	117	0	0	1031	0	9385	0
1999	0	9328	1710	634	0	0	2047	0	0	106	0	0	994	0	8526	0
2000	0	7248	1337	485	0	0	1624	0	0	81	0	0	893	0	6473	0
2001	0	5632	1026	370	0	0	1283	0	0	62	0	0	822	0	4862	0
2002	0	4377	787	281	0	0	1011	0	0	47	0	0	775	0	3612	0
2003	0	3401	603	214	0	0	796	0	0	36	0	0	747	0	2639	0
2004	0	2643	463	162	0	0	627	0	0	27	0	0	733	0	1881	0
2005	0	2054	355	122	0	0	492	0	0	20	0	0	731	0	1287	0
2006	0	1596	271	94	0	0	386	0	0	16	0	0	737	0	821	0
2007	0	1240	207	71	0	0	303	0	0	12	0	0	752	0	452	0
2008	0	947	156	54	0	0	233	0	0	9	0	0	759	0	155	0
SUBT	0	97206	16700	6583	0	0	20377	0	0	1097	2	0	13541	0	85476	0
TOTL	0	97206	16700	6583	0	0	20377	0	0	1097	2	0	13541	0	85476	0

USES $1.305/MMCF + 7% ESCALATION

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	INTANGIBLE CEE	INTANGIBLE CDE	TANGIBLE CL 41	TANGIBLE PLANT	TANGIBLE OTHER	CEDIP COGPE	TOTAL CAP	NET REV	CUM NETREV	ARTC	OVHD	LOAN REPMT PRIN	LOAN REPMT INT	WGML REPMT	CASH FLOW	CUM CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	270	1080	0	0	0	1350	-1350	-1350	0	0	0	0	0	-1350	-1350
1992	0	0	0	0	0	0	0	6418	5068	0	0	0	0	0	6418	5068
1993	0	99	397	0	0	0	496	6373	11441	0	0	0	0	0	6373	11441
1994	0	104	417	0	0	0	521	6785	18226	0	0	0	0	0	6785	18226
1995	0	109	438	0	0	0	547	7217	25443	0	0	0	0	0	7217	25443
1996	0	115	459	0	0	0	574	7678	33121	0	0	0	0	0	7678	33121
1997	0	121	482	0	0	0	603	8171	41292	0	0	0	0	0	8171	41292
1998	0	0	0	0	0	0	0	9385	50677	0	0	0	0	0	9385	50677
1999	0	0	0	0	0	0	0	8526	59202	0	0	0	0	0	8526	59202
2000	0	0	0	0	0	0	0	6473	65676	0	0	0	0	0	6473	65676
2001	0	0	0	0	0	0	0	4862	70537	0	0	0	0	0	4862	70537
2002	0	0	0	0	0	0	0	3612	74149	0	0	0	0	0	3612	74149
2003	0	0	0	0	0	0	0	2639	76788	0	0	0	0	0	2639	76788
2004	0	0	0	0	0	0	0	1881	78669	0	0	0	0	0	1881	78669
2005	0	0	0	0	0	0	0	1287	79956	0	0	0	0	0	1287	79956
2006	0	0	0	0	0	0	0	821	80777	0	0	0	0	0	821	80777
2007	0	0	0	0	0	0	0	452	81229	0	0	0	0	0	452	81229
2008	0	0	0	0	0	0	0	155	81385	0	0	0	0	0	155	81385
SUBT	0	818	3273	0	0	0	4091	81385		0	0	0	0	0	81385	
TOTL	0	818	3273	0	0	0	4091	81385		0	0	0	0	0	81385	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
NET REVENUE	47423	43285	38074	33810	31387	26453	22713
CASH FLOW	47423	43285	38074	33810	31387	26453	22713

TABLE 4

TYPICAL B.C. GAS FIELD
100% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX RESINC	LEASE EXP	PROD ROY	C.C.A.	RES ALLOW	OTHER INC	RES ROY	---CAPITAL WRITEOFF--- CEE	CDE	COGPE	DEBT INT	NPI+ OVHD	DEPL	TAXREV ADJ.
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	135	-34	0	0	0	81	0	0	0	0	0
1992	7813	562	0	236	1754	0	0	0	57	0	0	0	0	0
1993	8396	633	0	227	1884	0	0	0	69	0	0	0	0	0
1994	9022	711	0	272	2010	0	0	0	80	0	0	0	0	0
1995	9692	795	0	311	2147	0	0	0	89	0	0	0	0	0
1996	10412	885	0	345	2295	0	0	0	97	0	0	0	0	0
1997	11183	982	0	377	2456	0	0	0	104	0	0	0	0	0
1998	12010	1031	0	343	2659	0	0	0	73	0	0	0	0	0
1999	11038	994	0	257	2447	0	0	0	51	0	0	0	0	0
2000	8586	893	0	193	1875	0	0	0	36	0	0	0	0	0
2001	6658	822	0	145	1423	0	0	0	25	0	0	0	0	0
2002	5164	775	0	108	1070	0	0	0	17	0	0	0	0	0
2003	4004	747	0	81	794	0	0	0	12	0	0	0	0	0
2004	3105	733	0	61	578	0	0	0	9	0	0	0	0	0
2005	2408	731	0	46	408	0	0	0	6	0	0	0	0	0
2006	1867	737	0	34	274	0	0	0	4	0	0	0	0	0
2007	1447	752	0	26	168	0	0	0	3	0	0	0	0	0
2008	1103	759	0	19	81	0	0	0	2	0	0	0	0	0
SUBT	113906	13541	0	3215	24287	0	0	0	813	0	0	0	0	0
18YR	0	0	0	58	-14	0	0	0	5	0	0	0	0	0
TOTL	113906	13541	0	3273	24273	0	0	0	818	0	0	0	0	0

USES $1.305/MMCF + 7% ESCALATION

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX INC	FED TAXES	PRVTAX RESINC	PRVTAX INC	PROV TAXES	PRVROY TAXREB	PROC INC	PL EXP SULROY	PLANT CCA	PROC TAXINC	PROC TAXES	INVTAX CREDIT	BEFORE TAX CF	TOTAL INCTAX	AFTER TAX CF	CUM AT CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	-182	-53	0	-182	-26	5	0	0	0	0	0	0	-1350	-83	-1267	-1267
1992	5204	1501	7813	5204	729	-74	468	78	0	390	167	0	6418	2471	3947	2680
1993	5582	1610	8396	5582	782	-80	507	85	0	423	181	0	6373	2652	3721	6401
1994	5949	1716	9022	5949	833	-77	546	91	0	455	195	0	6785	2821	3964	10365
1995	6352	1832	9692	6352	889	-74	585	98	0	488	209	0	7217	3003	4214	14579
1996	6790	1958	10412	6790	951	-70	624	104	0	520	223	0	7678	3202	4477	19055
1997	7264	2095	11183	7264	1017	-67	663	111	0	553	237	0	8171	3415	4755	23810
1998	7904	2280	12010	7904	1107	-67	702	117	0	585	251	0	9385	3704	5681	29492
1999	7289	2102	11038	7289	1020	-56	634	106	0	529	226	0	8526	3406	5120	34612
2000	5590	1612	8586	5590	783	-35	485	81	0	404	173	0	6473	2603	3870	38482
2001	4244	1224	6658	4244	594	-20	370	62	0	308	132	0	4862	1970	2892	41375
2002	3193	921	5164	3193	447	-8	281	47	0	234	100	0	3612	1476	2135	43510
2003	2370	683	4004	2370	332	0	214	36	0	178	76	0	2639	1091	1548	45058
2004	1725	497	3105	1725	241	7	162	27	0	135	58	0	1881	790	1091	46148
2005	1218	351	2408	1218	170	12	122	20	0	102	44	0	1287	554	734	46882
2006	817	236	1867	817	114	16	94	16	0	78	33	0	821	368	453	47335
2007	500	144	1447	500	70	19	71	12	0	60	26	0	452	221	232	47567
2008	241	70	1103	241	34	21	54	9	0	45	19	0	155	101	54	47621
SUBT	72049	20779	113906	72049	10087	-548	6583	1097	0	5486	2350	0	81385	33764	47621	
18YR	-48	-14	0	-48	-7	2	0	0	0	0	0	0	0	-23	23	
TOTL	72001	20765	113906	72001	10080	-546	6583	1097	0	5486	2350	0	81385	33741	47644	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
TOTAL INC TAX	19810	18115	15980	14234	13242	11221	9689
AFTER TAX CF	27613	25170	22094	19676	18145	15232	13024

TABLE 4

TYPICAL B.C. GAS FIELD
100% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	PRODn MONTHS	BUTn REC RATE	PENT+ REC RATE	SUL REC RATE	W.I. %	CR ROY PRICE $/vol	CROWN GAS %	CROWN BYPs %	G.C.A. RATE $/Mcf
1991	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	12.0	9.40	4.30	1.50	100.00	1.08	15.00	20.00	0.00
1993	12.0	9.40	4.30	1.50	100.00	1.16	15.00	20.00	0.00
1994	12.0	9.40	4.30	1.50	100.00	1.24	15.5715	20.00	0.00
1995	12.0	9.40	4.30	1.50	100.00	1.33	16.1884	20.00	0.00
1996	12.0	9.40	4.30	1.50	100.00	1.42	16.7648	20.00	0.00
1997	12.0	9.40	4.30	1.50	100.00	1.52	17.3036	20.00	0.00
1998	12.0	9.40	4.30	1.50	100.00	1.63	17.8071	20.00	0.00
1999	12.0	9.40	4.30	1.50	100.00	1.74	18.2776	20.00	0.00
2000	12.0	9.40	4.30	1.50	100.00	1.86	18.7174	20.00	0.00
2001	12.0	9.40	4.30	1.50	100.00	1.99	19.1284	20.00	0.00
2002	12.0	9.40	4.30	1.50	100.00	2.13	19.5126	20.00	0.00
2003	12.0	9.40	4.30	1.50	100.00	2.28	19.8715	20.00	0.00
2004	12.0	9.40	4.30	1.50	100.00	2.44	20.2071	20.00	0.00
2005	12.0	9.40	4.30	1.50	100.00	2.61	20.5206	20.00	0.00
2006	12.0	9.40	4.30	1.50	100.00	2.79	20.8136	20.00	0.00
2007	12.0	9.40	4.30	1.50	100.00	2.99	21.0875	20.00	0.00
2008	11.8	9.40	4.30	1.50	100.00	3.20	21.3435	20.00	0.00
2009	0.0	0.00	0.00	0.00	0.00	3.42	0.00	0.00	0.00
2010	0.0	0.00	0.00	0.00	0.00	3.66	0.00	0.00	0.00
TOTL									

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	Prod Ex WL-GAS M$/W/M	Prod Ex VAR-GAS $/Mcf	-GROSS INTANG-- --INVESTMENT--- Cur M$	Fut M$	-GRSS TAN CL41- --INVESTMENT--- Cur M$	Fut M$	RES. ALLOW %	FED Inc Tax %	PROV Inc Tax %
1991	3.30	0.08	270	270	1080	1080	25.00	28.84	14.00
1992	3.47	0.084	0	0	0	0	25.00	28.84	14.00
1993	3.64	0.088	90	99	360	397	25.00	28.84	14.00
1994	3.82	0.093	90	104	360	417	25.00	28.84	14.00
1995	4.01	0.097	90	109	360	438	25.00	28.84	14.00
1996	4.21	0.102	90	115	360	459	25.00	28.84	14.00
1997	4.42	0.107	90	121	360	482	25.00	28.84	14.00
1998	4.64	0.113	0	0	0	0	25.00	28.84	14.00
1999	4.88	0.118	0	0	0	0	25.00	28.84	14.00
2000	5.12	0.124	0	0	0	0	25.00	28.84	14.00
2001	5.38	0.13	0	0	0	0	25.00	28.84	14.00
2002	5.64	0.137	0	0	0	0	25.00	28.84	14.00
2003	5.93	0.144	0	0	0	0	25.00	28.84	14.00
2004	6.22	0.151	0	0	0	0	25.00	28.84	14.00
2005	6.53	0.158	0	0	0	0	25.00	28.84	14.00
2006	6.86	0.166	0	0	0	0	25.00	28.84	14.00
2007	7.20	0.175	0	0	0	0	25.00	28.84	14.00
2008	7.56	0.183	0	0	0	0	25.00	28.84	14.00
2009	0.00	0.00	0	0	0	0	25.00	28.84	14.00
2010	0.00	0.00	0	0	0	0	25.00	28.84	14.00
TOTL			720	818	2880	3273			

NEW ECONOMIC LIMIT IS 585.20
Province code: 2 (B.C.)
Type reserve code: 1 (Proven Developed, Producing)

PR_CODE_G 0

TABLE 5

PROVEN DEVELOPED,
PRODUCING
RESERVES

TYPICAL B.C. GAS FIELD
90% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

SUMMARY OF RESERVES AND PRESENT WORTH
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

RESERVES

	OIL	SOLUTION GAS	NON-ASSOC ASSOC GAS	ETHANE	PROPANE	BUTANES	PENTANES PLUS	TOTAL NGL	SULPHUR
	MBBL	MMCF	MMCF	MBBL	MBBL	MBBL	MBBL	MBBL	MLT
GROSS	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. INT.	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. NET	0.0	0	42773	0.0	0.0	391.0	178.9	569.9	65.0

PRESENT WORTH

DISCOUNT RATE	TOTAL NET CAPITAL	BEFORE TAX NET REV	ALB ROY TAX CR.	WGML/LOAN OVERHEAD	BEFORE TAX CASH FLOW	INCOME TAXES	AFTER TAX CASH FLOW
%	M$	M$	M$	M$	M$	M$	M$
0.0	4178	88481	0	0	88481	36994	51487
10.0	3224	47934	0	0	47934	20105	27829
12.0	3089	43342	0	0	43342	18205	25137
15.0	2911	37674	0	0	37674	15863	21811
18.0	2758	33132	0	0	33132	13988	19144
20.0	2668	30690	0	0	30690	12940	17650
25.0	2475	25502	0	0	25502	10844	14658
30.0	2321	21724	0	0	21724	9288	12436

USES $1.37/MMCF + 7% ESCALATION

TABLE 5

TYPICAL B.C. GAS FIELD
90% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

PROVEN DEVELOPED,
PRODUCING
RESERVES

PRODUCTION AND PRICE FORECAST (MAJOR PRODUCTS AND SULPHUR)
(PRODN START : JAN 1,1992)

YEAR	NON-ASSOC / ASSOC PIPELINE GAS						SULPHUR			
	WELLS	DAILY	GROSS	CO.INT	CO.NET	PRICE	GROSS	CO.INT	CO.NET	PRICE
		MCF/D	MMCF	MMCF	MMCF	$/MCF	MLT	MLT	MLT	$/LT
1992	3.0	12825	4681	4681	3979	1.37	7.0	7.0	5.9	60.00
1993	4.0	12825	4681	4681	3961	1.47	7.0	7.0	5.9	65.00
1994	5.0	12825	4681	4681	3931	1.57	7.0	7.0	5.9	70.00
1995	5.0	12825	4681	4681	3904	1.68	7.0	7.0	5.9	75.00
1996	6.0	12825	4681	4681	3878	1.80	7.0	7.0	5.9	80.00
1997	7.0	12825	4681	4681	3854	1.92	7.0	7.0	5.9	85.00
1998	8.0	12825	4681	4681	3832	2.06	7.0	7.0	5.9	90.00
1999	8.0	11436	4174	4174	3398	2.20	6.3	6.3	5.2	95.00
2000	8.0	9051	3304	3304	2675	2.35	5.0	5.0	4.1	100.00
2001	8.0	7163	2615	2615	2107	2.52	3.9	3.9	3.3	105.00
2002	8.0	5669	2069	2069	1660	2.69	3.1	3.1	2.6	110.00
2003	8.0	4487	1638	1638	1308	2.88	2.5	2.5	2.0	115.00
2004	8.0	3551	1296	1296	1031	3.09	1.9	1.9	1.6	120.00
2005	8.0	2811	1026	1026	813	3.30	1.5	1.5	1.3	125.00
2006	8.0	2224	812	812	641	3.53	1.2	1.2	1.0	131.50
2007	8.0	1761	643	643	506	3.78	1.0	1.0	0.8	138.32
2008	8.0	1393	509	509	399	4.04	0.8	0.8	0.6	145.49
2009	8.0	1103	403	403	315	4.33	0.6	0.6	0.5	153.02
2010	8.0	873	319	319	249	4.63	0.5	0.5	0.4	160.92
SUBT			51573	51573	42442		77.4	77.4	64.5	
2YR			427	427	331		0.6	0.6	0.5	
TOTL			52000	52000	42773		78.0	78.0	65.0	

USES $1.37/MMCF + 7% ESCALATION

PRODUCTION AND PRICE FORECAST (NGL's)
(PRODN START : JAN 1,1992)

YEAR	BUTANES				PENTANES PLUS			
	GROSS	CO.INT	CO.NET	PRICE	GROSS	CO.INT	CO.NET	PRICE
	MBBL	MBBL	MBBL	$/BBL	MBBL	MBBL	MBBL	$/BBL
1992	44.0	44.0	35.2	11.43	20.1	20.1	16.1	20.84
1993	44.0	44.0	35.2	12.60	20.1	20.1	16.1	23.11
1994	44.0	44.0	35.2	14.02	20.1	20.1	16.1	25.26
1995	44.0	44.0	35.2	15.54	20.1	20.1	16.1	27.60
1996	44.0	44.0	35.2	17.20	20.1	20.1	16.1	30.11
1997	44.0	44.0	35.2	18.99	20.1	20.1	16.1	32.83
1998	44.0	44.0	35.2	20.93	20.1	20.1	16.1	35.77
1999	39.2	39.2	31.4	23.05	17.9	17.9	14.4	38.94
2000	31.1	31.1	24.8	24.90	14.2	14.2	11.4	41.77
2001	24.6	24.6	19.7	26.34	11.2	11.2	9.0	44.02
2002	19.5	19.5	15.6	27.88	8.9	8.9	7.1	46.38
2003	15.4	15.4	12.3	29.49	7.0	7.0	5.6	48.86
2004	12.2	12.2	9.7	31.19	5.6	5.6	4.5	51.46
2005	9.6	9.6	7.7	32.97	4.4	4.4	3.5	54.19
2006	7.6	7.6	6.1	34.75	3.5	3.5	2.8	57.03
2007	6.0	6.0	4.8	36.63	2.8	2.8	2.2	60.02
2008	4.8	4.8	3.8	38.59	2.2	2.2	1.7	63.16
2009	3.8	3.8	3.0	40.66	1.7	1.7	1.4	66.45
2010	3.0	3.0	2.4	42.82	1.4	1.4	1.1	69.91
SUBT	484.8	484.8	387.8		221.8	221.8	177.4	
2YR	4.0	4.0	3.2		1.8	1.8	1.5	
TOTL	488.8	488.8	391.0		223.6	223.6	178.9	

TABLE 5

TYPICAL B.C. GAS FIELD
90% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

	REVENUE						ROYALTIES					MIN	LEASE	PLANT	OPER	
YEAR	OIL	GAS	NGL	SUL	ROY	OTHER	CROWN	PROD	RES	SUL	GCA	TAXES	EXP	EXP	INC	NPI
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	6413	922	421	0	0	1146	0	0	70	0	0	518	0	6022	0
1993	0	6862	1020	456	0	0	1260	0	0	76	0	0	588	0	6415	0
1994	0	7342	1125	492	0	0	1401	0	0	82	0	0	663	0	6814	0
1995	0	7858	1239	527	0	0	1553	0	0	88	0	0	696	0	7286	0
1996	0	8406	1363	562	0	0	1715	0	0	94	0	0	781	0	7742	0
1997	0	8995	1496	597	0	0	1889	0	0	99	0	0	873	0	8227	0
1998	0	9624	1641	632	0	0	2075	0	0	105	0	0	973	0	8745	0
1999	0	9182	1603	595	0	0	2028	0	0	99	0	0	961	0	8292	0
2000	0	7776	1367	496	0	0	1752	0	0	83	0	0	901	0	6902	0
2001	0	6585	1142	412	0	0	1506	0	0	69	0	0	857	0	5708	0
2002	0	5577	955	341	0	0	1294	0	0	57	0	0	825	0	4698	0
2003	0	4723	798	283	0	0	1110	0	0	47	0	0	804	0	3843	0
2004	0	3999	667	233	0	0	951	0	0	39	0	0	793	0	3117	0
2005	0	3387	557	192	0	0	814	0	0	32	0	0	790	0	2501	0
2006	0	2868	464	160	0	0	696	0	0	27	0	0	794	0	1977	0
2007	0	2429	387	133	0	0	594	0	0	22	0	0	804	0	1529	0
2008	0	2057	323	111	0	0	507	0	0	18	0	0	819	0	1146	0
2009	0	1742	269	92	0	0	433	0	0	15	0	0	840	0	815	0
2010	0	1475	224	77	0	0	369	0	0	13	0	0	865	0	530	0
SUBT	0	107300	17563	6812	0	0	23091	0	0	1135	3	0	15144	0	92308	0
2YR	0	2175	323	111	0	0	548	0	0	18	0	0	1691	0	351	0
TOTL	0	109475	17886	6922	0	0	23639	0	0	1154	3	0	16835	0	92658	0

USES $1.37/MMCF + 7% ESCALATION

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

	INTANGIBLE		TANGIBLE			CEDIP	TOTAL	NET	CUM			LOAN REPMT		NGML	CASH	CUM
YEAR	CEE	CDE	CL 41	PLANT	OTHER	COGPE	CAP	REV	NETREV	ARTC	DVHD	PRIN	INT	REPMT	FLOW	CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	270	1080	0	0	0	1350	-1350	-1350	0	0	0	0	0	-1350	-1350
1992	0	0	0	0	0	0	0	6022	4672	0	0	0	0	0	6022	4672
1993	0	99	397	0	0	0	496	5919	10591	0	0	0	0	0	5919	10591
1994	0	104	417	0	0	0	521	6293	16884	0	0	0	0	0	6293	16884
1995	0	0	0	0	0	0	0	7286	24170	0	0	0	0	0	7286	24170
1996	0	115	459	0	0	0	574	7167	31337	0	0	0	0	0	7167	31337
1997	0	121	482	0	0	0	603	7624	38961	0	0	0	0	0	7624	38961
1998	0	127	507	0	0	0	633	8111	47073	0	0	0	0	0	8111	47073
1999	0	0	0	0	0	0	0	8292	55365	0	0	0	0	0	8292	55365
2000	0	0	0	0	0	0	0	6902	62267	0	0	0	0	0	6902	62267
2001	0	0	0	0	0	0	0	5708	67975	0	0	0	0	0	5708	67975
2002	0	0	0	0	0	0	0	4698	72672	0	0	0	0	0	4698	72672
2003	0	0	0	0	0	0	0	3843	76515	0	0	0	0	0	3843	76515
2004	0	0	0	0	0	0	0	3117	79632	0	0	0	0	0	3117	79632
2005	0	0	0	0	0	0	0	2501	82133	0	0	0	0	0	2501	82133
2006	0	0	0	0	0	0	0	1977	84110	0	0	0	0	0	1977	84110
2007	0	0	0	0	0	0	0	1529	85639	0	0	0	0	0	1529	85639
2008	0	0	0	0	0	0	0	1146	86785	0	0	0	0	0	1146	86785
2009	0	0	0	0	0	0	0	815	87600	0	0	0	0	0	815	87600
2010	0	0	0	0	0	0	0	530	88130	0	0	0	0	0	530	88130
SUBT	0	836	3342	0	0	0	4178	88130		0	0	0	0	0	88130	
2YR	0	0	0	0	0	0	0	351		0	0	0	0	0	351	
TOTL	0	836	3342	0	0	0	4178	88481		0	0	0	0	0	88481	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
NET REVENUE	47934	43342	37674	33132	30590	25502	21724
CASH FLOW	47934	43342	37674	33132	30590	25502	21724

TABLE 5

TYPICAL B.C. GAS FIELD
90% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX RESINC	LEASE EXP	PROD ROY	C.C.A.	RES ALLOW	OTHER INC	RES ROY	---CAPITAL WRITEOFF--- CEE	CDE	COGPE	DEBT INT	NPI+ OVHD	DEPL	TAXREV ADJ.
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	135	-34	0	0	0	81	0	0	0	0	0
1992	7336	518	0	236	1645	0	0	0	57	0	0	0	0	0
1993	7882	588	0	227	1767	0	0	0	69	0	0	0	0	0
1994	8468	663	0	272	1883	0	0	0	80	0	0	0	0	0
1995	9096	696	0	256	2036	0	0	0	56	0	0	0	0	0
1996	9769	781	0	249	2185	0	0	0	74	0	0	0	0	0
1997	10491	873	0	305	2328	0	0	0	88	0	0	0	0	0
1998	11265	973	0	352	2485	0	0	0	99	0	0	0	0	0
1999	10786	961	0	327	2374	0	0	0	70	0	0	0	0	0
2000	9143	901	0	246	1999	0	0	0	49	0	0	0	0	0
2001	7728	857	0	184	1672	0	0	0	34	0	0	0	0	0
2002	6532	825	0	138	1392	0	0	0	24	0	0	0	0	0
2003	5521	804	0	104	1153	0	0	0	17	0	0	0	0	0
2004	4666	793	0	78	949	0	0	0	12	0	0	0	0	0
2005	3944	790	0	58	774	0	0	0	8	0	0	0	0	0
2006	3333	794	0	44	624	0	0	0	6	0	0	0	0	0
2007	2816	804	0	33	495	0	0	0	4	0	0	0	0	0
2008	2380	819	0	25	384	0	0	0	3	0	0	0	0	0
2009	2011	840	0	18	288	0	0	0	2	0	0	0	0	0
2010	1699	865	0	14	205	0	0	0	1	0	0	0	0	0
SUBT	124863	15144	0	3301	26605	0	0	0	832	0	0	0	0	0
17YR	2497	1691	0	41	191	0	0	0	3	0	0	0	0	0
TOTL	127361	16835	0	3342	26796	0	0	0	836	0	0	0	0	0

USES $1.37/MMCF + 7% ESCALATION

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX INC	FED TAXES	PRVTAX RESINC	PRVTAX INC	PROV TAXES	PRVROY TAXREB	PROC INC	PL EXP SULROY	PLANT CCA	PROC TAXINC	PROC TAXES	INVTAX CREDIT	BEFORE TAX CF	TOTAL INCTAX	AFTER TAX CF	CUM AT CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	-182	-53	0	-182	-26	5	0	0	0	0	0	0	-1350	-83	-1267	-1267
1992	4879	1407	7336	4879	683	-70	421	70	0	351	150	0	6022	2311	3712	2445
1993	5231	1509	7882	5231	732	-71	456	76	0	380	163	0	5919	2475	3444	5888
1994	5570	1606	8468	5570	780	-68	492	82	0	410	175	0	6293	2629	3663	9552
1995	6052	1745	9096	6052	847	-68	527	88	0	439	188	0	7286	2848	4438	13990
1996	6480	1869	9769	6480	907	-66	562	94	0	468	201	0	7167	3043	4125	18114
1997	6897	1989	10491	6897	966	-62	597	99	0	497	213	0	7624	3229	4394	22509
1998	7356	2121	11265	7356	1030	-57	632	105	0	527	226	0	8111	3434	4677	27186
1999	7053	2034	10786	7053	987	-48	595	99	0	496	212	0	8292	3282	5010	32196
2000	5948	1715	9143	5948	833	-35	496	83	0	413	177	0	6902	2760	4143	36338
2001	4981	1436	7728	4981	697	-23	412	69	0	343	147	0	5708	2304	3404	39742
2002	4153	1198	6532	4153	581	-14	341	57	0	285	122	0	4698	1915	2783	42525
2003	3443	993	5521	3443	482	-6	283	47	0	235	101	0	3843	1582	2261	44786
2004	2835	818	4666	2835	397	0	233	39	0	194	83	0	3117	1298	1820	46605
2005	2314	667	3944	2314	324	6	192	32	0	160	69	0	2501	1054	1447	48052
2006	1866	538	3333	1866	261	10	160	27	0	133	57	0	1977	846	1131	49183
2007	1481	427	2816	1481	207	14	133	22	0	111	48	0	1529	668	861	50044
2008	1149	331	2380	1149	161	17	111	18	0	92	40	0	1146	515	631	50675
2009	862	249	2011	862	121	20	92	15	0	77	33	0	815	382	433	51108
2010	614	177	1699	614	86	23	77	13	0	64	27	0	530	268	262	51370
SUBT	78982	22778	124863	78982	11057	-492	6812	1135	0	5677	2432	0	88130	36760	51370	
17YR	571	165	2497	571	80	50	111	18	0	92	39	0	351	234	117	
TOTL	79553	22943	127361	79553	11137	-442	6922	1154	0	5769	2471	0	88481	36994	51487	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
TOTAL INC TAX	20106	18205	15863	13988	12940	10844	9288
AFTER TAX CF	27829	25137	21811	19144	17650	14658	12436

TABLE 5

TYPICAL B.C. GAS FIELD
90% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	PRODn MONTHS	BUTn REC RATE	PENT+ REC RATE	SUL REC RATE	W.I. %	CR ROY PRICE $/vol	CROWN GAS %	CROWN BYPs %	G.C.A. RATE $/Mcf
1991	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	12.0	9.40	4.30	1.50	100.00	1.14	15.00	20.00	0.00
1993	12.0	9.40	4.30	1.50	100.00	1.22	15.3902	20.00	0.00
1994	12.0	9.40	4.30	1.50	100.00	1.30	16.0189	20.00	0.00
1995	12.0	9.40	4.30	1.50	100.00	1.39	16.6064	20.00	0.00
1996	12.0	9.40	4.30	1.50	100.00	1.49	17.1555	20.00	0.00
1997	12.0	9.40	4.30	1.50	100.00	1.59	17.6687	20.00	0.00
1998	12.0	9.40	4.30	1.50	100.00	1.71	18.1483	20.00	0.00
1999	12.0	9.40	4.30	1.50	100.00	1.83	18.5966	20.00	0.00
2000	12.0	9.40	4.30	1.50	100.00	1.95	19.0155	20.00	0.00
2001	12.0	9.40	4.30	1.50	100.00	2.09	19.407	20.00	0.00
2002	12.0	9.40	4.30	1.50	100.00	2.24	19.7729	20.00	0.00
2003	12.0	9.40	4.30	1.50	100.00	2.39	20.1149	20.00	0.00
2004	12.0	9.40	4.30	1.50	100.00	2.56	20.4344	20.00	0.00
2005	12.0	9.40	4.30	1.50	100.00	2.74	20.7331	20.00	0.00
2006	12.0	9.40	4.30	1.50	100.00	2.93	21.0123	20.00	0.00
2007	12.0	9.40	4.30	1.50	100.00	3.14	21.2732	20.00	0.00
2008	12.0	9.40	4.30	1.50	100.00	3.36	21.517	20.00	0.00
2009	12.0	9.40	4.30	1.50	100.00	3.59	21.7448	20.00	0.00
2010	12.0	9.40	4.30	1.50	100.00	3.84	21.9578	20.00	0.001
TOTL									

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	Prod Ex WL-GAS M$/W/M	Prod Ex VAR-GAS $/Mcf	-GROSS INTANG-- --INVESTMENT--- Cur M$	Fut M$	-GRSS TAN CL41- --INVESTMENT--- Cur M$	Fut M$	RES. ALLOW %	FED Inc Tax %	PROV Inc Tax %
1991	3.30	0.08	270	270	1080	1080	25.00	28.84	14.00
1992	3.47	0.084	0	0	0	0	25.00	28.84	14.00
1993	3.64	0.088	90	99	360	397	25.00	28.84	14.00
1994	3.82	0.093	90	104	360	417	25.00	28.84	14.00
1995	4.01	0.097	0	0	0	0	25.00	28.84	14.00
1996	4.21	0.102	90	115	360	459	25.00	28.84	14.00
1997	4.42	0.107	90	121	360	482	25.00	28.84	14.00
1998	4.64	0.113	90	127	360	507	25.00	28.84	14.00
1999	4.88	0.118	0	0	0	0	25.00	28.84	14.00
2000	5.12	0.124	0	0	0	0	25.00	28.84	14.00
2001	5.38	0.13	0	0	0	0	25.00	28.84	14.00
2002	5.64	0.137	0	0	0	0	25.00	28.84	14.00
2003	5.93	0.144	0	0	0	0	25.00	28.84	14.00
2004	6.22	0.151	0	0	0	0	25.00	28.84	14.00
2005	6.53	0.158	0	0	0	0	25.00	28.84	14.00
2006	6.86	0.166	0	0	0	0	25.00	28.84	14.00
2007	7.20	0.175	0	0	0	0	25.00	28.84	14.00
2008	7.56	0.183	0	0	0	0	25.00	28.84	14.00
2009	7.94	0.193	0	0	0	0	25.00	28.84	14.00
2010	8.34	0.202	0	0	0	0	25.00	28.84	14.00
TOTL			720	836	2880	3342			

NEW ECONOMIC LIMIT IS 501.30
Province code: 2 (B.C.) PR_CODE_G 0
Type reserve code: 1 (Proven Developed, Producing)

TABLE 6

PROVEN DEVELOPED,
PRODUCING
RESERVES

TYPICAL B.C. GAS FIELD
70% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

SUMMARY OF RESERVES AND PRESENT WORTH
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

RESERVES

	OIL	SOLUTION GAS	NON-ASSOC ASSOC GAS	ETHANE	PROPANE	BUTANES	PENTANES PLUS	TOTAL NGL	SULPHUR
	MBBL	MMCF	MMCF	MBBL	MBBL	MBBL	MBBL	MBBL	MLT
GROSS	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. INT.	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. NET	0.0	0	42020	0.0	0.0	391.0	178.9	569.9	65.0

PRESENT WORTH

DISCOUNT RATE	TOTAL NET CAPITAL	BEFORE TAX NET REV	ALB ROY TAX CR.	WGML/LOAN OVERHEAD	BEFORE TAX CASH FLOW	INCOME TAXES	AFTER TAX CASH FLOW
%	M$	M$	M$	M$	M$	M$	M$
0.0	4239	112418	0	0	112418	47838	64580
10.0	3192	49483	0	0	49483	20956	28527
12.0	3050	43609	0	0	43609	18488	25121
15.0	2866	36711	0	0	36711	15599	21112
18.0	2709	31461	0	0	31461	13407	18054
20.0	2618	28629	0	0	28629	12227	16402
25.0	2425	23190	0	0	23190	9965	13225
30.0	2274	19343	0	0	19343	8369	10974

USES $1.545/MMCF + 7% ESCALATION

TABLE 6

TYPICAL B.C. GAS FIELD
70% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

PROVEN DEVELOPED, PRODUCING RESERVES

PRODUCTION AND PRICE FORECAST (MAJOR PRODUCTS AND SULPHUR)
(PRODN START : JAN 1, 1992)

YEAR	NON-ASSOC / ASSOC PIPELINE GAS WELLS	DAILY	GROSS	CO. INT	CO. NET	PRICE	SULPHUR GROSS	CO. INT	CO. NET	PRICE
		MCF/D	MMCF	MMCF	MMCF	$/MCF	MLT	MLT	MLT	$/LT
1992	3.0	9975	3641	3641	3063	1.55	5.5	5.5	4.6	60.00
1993	4.0	9975	3641	3641	3041	1.65	5.5	5.5	4.6	65.00
1994	5.0	9975	3641	3641	3021	1.77	5.5	5.5	4.6	70.00
1995	5.0	9975	3641	3641	3002	1.89	5.5	5.5	4.6	75.00
1996	6.0	9975	3641	3641	2984	2.03	5.5	5.5	4.6	80.00
1997	6.0	9975	3641	3641	2967	2.17	5.5	5.5	4.6	85.00
1998	7.0	9975	3641	3641	2952	2.32	5.5	5.5	4.6	90.00
1999	8.0	9975	3641	3641	2937	2.48	5.5	5.5	4.6	95.00
2000	8.0	9254	3378	3378	2712	2.65	5.1	5.1	4.2	100.00
2001	8.0	7949	2901	2901	2320	2.84	4.4	4.4	3.6	105.00
2002	8.0	6828	2492	2492	1985	3.04	3.7	3.7	3.1	110.00
2003	8.0	5865	2141	2141	1698	3.25	3.2	3.2	2.7	115.00
2004	8.0	5038	1839	1839	1454	3.48	2.8	2.8	2.3	120.00
2005	8.0	4328	1580	1580	1245	3.72	2.4	2.4	2.0	125.00
2006	8.0	3718	1357	1357	1066	3.98	2.0	2.0	1.7	131.50
2007	8.0	3193	1166	1166	913	4.26	1.7	1.7	1.5	138.32
2008	8.0	2743	1001	1001	782	4.56	1.5	1.5	1.3	145.49
2009	8.0	2356	860	860	670	4.88	1.3	1.3	1.1	153.02
2010	8.0	2024	739	739	574	5.22	1.1	1.1	0.9	160.92
SUBT			48580	48580	39384		72.9	72.9	60.7	
10YR			3420	3420	2636		5.1	5.1	4.3	
TOTL			52000	52000	42020		78.0	78.0	65.0	

USES $1.545/MMCF + 7% ESCALATION

PRODUCTION AND PRICE FORECAST (NGL's)
(PRODN START : JAN 1, 1992)

YEAR	BUTANES GROSS	CO. INT	CO. NET	PRICE	PENTANES PLUS GROSS	CO. INT	CO. NET	PRICE
	MBBL	MBBL	MBBL	$/BBL	MBBL	MBBL	MBBL	$/BBL
1992	34.2	34.2	27.4	11.43	15.7	15.7	12.5	20.84
1993	34.2	34.2	27.4	12.60	15.7	15.7	12.5	23.11
1994	34.2	34.2	27.4	14.02	15.7	15.7	12.5	25.26
1995	34.2	34.2	27.4	15.54	15.7	15.7	12.5	27.60
1996	34.2	34.2	27.4	17.20	15.7	15.7	12.5	30.11
1997	34.2	34.2	27.4	18.99	15.7	15.7	12.5	32.83
1998	34.2	34.2	27.4	20.93	15.7	15.7	12.5	35.77
1999	34.2	34.2	27.4	23.06	15.7	15.7	12.5	38.94
2000	31.8	31.8	25.4	24.90	14.5	14.5	11.6	41.77
2001	27.3	27.3	21.8	26.34	12.5	12.5	10.0	44.02
2002	23.4	23.4	18.7	27.88	10.7	10.7	8.6	46.38
2003	20.1	20.1	16.1	29.49	9.2	9.2	7.4	48.86
2004	17.3	17.3	13.8	31.19	7.9	7.9	6.3	51.46
2005	14.8	14.8	11.9	32.97	6.8	6.8	5.4	54.19
2006	12.8	12.8	10.2	34.75	5.8	5.8	4.7	57.03
2007	11.0	11.0	8.8	36.63	5.0	5.0	4.0	60.02
2008	9.4	9.4	7.5	38.59	4.3	4.3	3.4	63.16
2009	8.1	8.1	6.5	40.66	3.7	3.7	3.0	66.45
2010	6.9	6.9	5.6	42.82	3.2	3.2	2.5	69.91
SUBT	456.7	456.7	365.3		208.9	208.9	167.1	
10YR	32.1	32.1	25.7		14.7	14.7	11.8	
TOTL	488.8	488.8	391.0		223.6	223.6	178.9	

TABLE 6

TYPICAL B.C. GAS FIELD
70% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

	REVENUE						ROYALTIES									
YEAR	OIL	GAS	NGL	SUL	ROY	OTHER	CROWN	PROD	RES	SUL	GCA	MIN TAXES	LEASE EXP	PLANT EXP	OPER INC	NPI
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	5625	717	328	0	0	1037	0	0	55	0	0	431	0	5148	0
1993	0	6019	793	355	0	0	1150	0	0	59	0	0	496	0	5462	0
1994	0	6440	875	382	0	0	1272	0	0	64	0	0	566	0	5796	0
1995	0	6891	964	410	0	0	1403	0	0	68	0	0	595	0	6199	0
1996	0	7373	1060	437	0	0	1542	0	0	73	0	0	675	0	6580	0
1997	0	7890	1164	464	0	0	1692	0	0	77	0	0	709	0	7039	0
1998	0	8442	1276	492	0	0	1853	0	0	82	0	0	800	0	7475	0
1999	0	9033	1399	519	0	0	2025	0	0	86	0	0	898	0	7940	0
2000	0	8966	1397	507	0	0	2045	0	0	84	0	0	911	0	7830	0
2001	0	8241	1268	457	0	0	1905	0	0	76	0	0	894	0	7091	0
2002	0	7575	1150	411	0	0	1773	0	0	69	0	0	883	0	6412	0
2003	0	6962	1043	369	0	0	1648	0	0	62	0	0	876	0	5789	0
2004	0	6399	946	331	0	0	1530	0	0	55	0	0	875	0	5216	0
2005	0	5881	858	296	0	0	1419	0	0	49	0	0	877	0	4689	0
2006	0	5406	776	268	0	0	1315	0	0	45	0	0	884	0	4205	0
2007	0	4968	702	242	0	0	1218	0	0	40	0	0	895	0	3759	0
2008	0	4567	635	219	0	0	1128	0	0	36	0	0	910	0	3347	0
2009	0	4197	574	197	0	0	1043	0	0	33	0	0	928	0	2965	0
2010	0	3858	519	178	0	0	964	0	0	30	0	0	950	0	2612	0
SUBT	0	124733	18118	6861	0	0	27963	0	0	1144	3	0	15053	0	105555	0
10YR	0	23989	2995	1024	0	0	6114	0	0	171	0	0	10621	0	11102	0
TOTL	0	148722	21113	7885	0	0	34078	0	0	1314	3	0	25674	0	116657	0

USES $1.545/MMCF + 7% ESCALATION

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

	INTANGIBLE		TANGIBLE									LOAN REPMT				
YEAR	CEE	CDE	CL 41	PLANT	OTHER	CEDIP COGPE	TOTAL CAP	NET REV	CUM NETREV	ARTC	OVHD	PRIN	INT	WGML REPMT	CASH FLOW	CUM CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	270	1080	0	0	0	1350	-1350	-1350	0	0	0	0	0	-1350	-1350
1992	0	0	0	0	0	0	0	5148	3798	0	0	0	0	0	5148	3798
1993	0	99	397	0	0	0	496	4966	8764	0	0	0	0	0	4966	8764
1994	0	104	417	0	0	0	521	5275	14039	0	0	0	0	0	5275	14039
1995	0	0	0	0	0	0	0	6199	20238	0	0	0	0	0	6199	20238
1996	0	115	459	0	0	0	574	6006	26244	0	0	0	0	0	6006	26244
1997	0	0	0	0	0	0	0	7039	33283	0	0	0	0	0	7039	33283
1998	0	127	507	0	0	0	633	6842	40125	0	0	0	0	0	6842	40125
1999	0	133	532	0	0	0	665	7276	47401	0	0	0	0	0	7276	47401
2000	0	0	0	0	0	0	0	7830	55231	0	0	0	0	0	7830	55231
2001	0	0	0	0	0	0	0	7091	62321	0	0	0	0	0	7091	62321
2002	0	0	0	0	0	0	0	6412	68734	0	0	0	0	0	6412	68734
2003	0	0	0	0	0	0	0	5789	74523	0	0	0	0	0	5789	74523
2004	0	0	0	0	0	0	0	5216	79739	0	0	0	0	0	5216	79739
2005	0	0	0	0	0	0	0	4689	84428	0	0	0	0	0	4689	84428
2006	0	0	0	0	0	0	0	4205	88633	0	0	0	0	0	4205	88633
2007	0	0	0	0	0	0	0	3759	92392	0	0	0	0	0	3759	92392
2008	0	0	0	0	0	0	0	3347	95739	0	0	0	0	0	3347	95739
2009	0	0	0	0	0	0	0	2965	98704	0	0	0	0	0	2965	98704
2010	0	0	0	0	0	0	0	2612	101316	0	0	0	0	0	2612	101316
SUBT	0	848	3392	0	0	0	4239	101316		0	0	0	0	0	101316	
10YR	0	0	0	0	0	0	0	11102		0	0	0	0	0	11102	
TOTL	0	848	3392	0	0	0	4239	112418		0	0	0	0	0	112418	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
NET REVENUE	49483	43609	36711	31461	28629	23190	19343
CASH FLOW	49483	43609	36711	31461	28629	23190	19343

TABLE 6

TYPICAL B.C. GAS FIELD
70% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX RESINC	LEASE EXP	PROD ROY	C.C.A.	RES ALLOW	OTHER INC	RES ROY	---CAPITAL WRITEOFF--- CEE	CDE	COGPE	DEBT INT	NPI+ OVHD	DEPL	TAXREV ADJ.
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	135	-34	0	0	0	81	0	0	0	0	0
1992	6343	431	0	236	1419	0	0	0	57	0	0	0	0	0
1993	6812	496	0	227	1522	0	0	0	69	0	0	0	0	0
1994	7316	566	0	272	1619	0	0	0	80	0	0	0	0	0
1995	7855	595	0	256	1751	0	0	0	56	0	0	0	0	0
1996	8433	675	0	249	1877	0	0	0	74	0	0	0	0	0
1997	9053	709	0	244	2025	0	0	0	52	0	0	0	0	0
1998	9718	800	0	247	2168	0	0	0	74	0	0	0	0	0
1999	10431	898	0	315	2305	0	0	0	92	0	0	0	0	0
2000	10364	911	0	303	2288	0	0	0	64	0	0	0	0	0
2001	9509	894	0	227	2097	0	0	0	45	0	0	0	0	0
2002	8725	883	0	170	1918	0	0	0	31	0	0	0	0	0
2003	8005	876	0	128	1750	0	0	0	22	0	0	0	0	0
2004	7345	875	0	96	1594	0	0	0	15	0	0	0	0	0
2005	6739	877	0	72	1447	0	0	0	11	0	0	0	0	0
2006	6182	884	0	54	1311	0	0	0	8	0	0	0	0	0
2007	5671	895	0	40	1184	0	0	0	5	0	0	0	0	0
2008	5202	910	0	30	1065	0	0	0	4	0	0	0	0	0
2009	4772	928	0	23	955	0	0	0	3	0	0	0	0	0
2010	4377	950	0	17	853	0	0	0	2	0	0	0	0	0
SUBT	142851	15053	0	3340	31114	0	0	0	844	0	0	0	0	0
17YR	26983	10621	0	51	4078	0	0	0	4	0	0	0	0	0
TOTL	169834	25674	0	3391	35192	0	0	0	848	0	0	0	0	0

USES $1.545/MMCF + 7% ESCALATION

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX INC	FED TAXES	PRVTAX RESINC	PRVTAX INC	PROV TAXES	PRVROY TAXREB	PROC INC	PL EXP SULROY	PLANT CCA	PROC TAXINC	PROC TAXES	INVTAX CREDIT	BEFORE TAX CF	TOTAL INCTAX	AFTER TAX CF	CUM AT CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	-182	-53	0	-182	-26	5	0	0	0	0	0	0	-1350	-83	-1267	-1267
1992	4200	1211	6343	4200	588	-54	328	55	0	273	117	0	5148	1970	3179	1911
1993	4498	1297	6812	4498	630	-52	355	59	0	296	127	0	4966	2106	2860	4771
1994	4778	1378	7316	4778	669	-49	382	64	0	319	136	0	5275	2232	3043	7814
1995	5197	1499	7855	5197	728	-49	410	68	0	341	146	0	6199	2422	3778	11591
1996	5558	1603	8433	5558	778	-47	437	73	0	364	156	0	6006	2584	3422	15013
1997	6024	1737	9053	6024	843	-47	464	77	0	387	166	0	7039	2793	4247	19260
1998	6430	1854	9718	6430	900	-44	492	82	0	410	175	0	6842	2974	3868	23128
1999	6822	1967	10431	6822	955	-39	519	86	0	432	185	0	7276	3147	4129	27257
2000	6799	1961	10364	6799	952	-34	507	84	0	422	181	0	7830	3127	4703	31960
2001	6246	1801	9509	6246	874	-27	457	76	0	381	163	0	7091	2866	4225	36184
2002	5722	1650	8725	5722	801	-20	411	69	0	343	147	0	6412	2619	3794	39978
2003	5229	1508	8005	5229	732	-14	369	62	0	308	132	0	5789	2386	3403	43381
2004	4765	1374	7345	4765	667	-9	331	55	0	276	118	0	5216	2169	3048	46428
2005	4332	1249	6739	4332	606	-4	296	49	0	247	106	0	4689	1965	2724	49152
2006	3925	1132	6182	3925	550	1	268	45	0	223	96	0	4206	1776	2429	51581
2007	3546	1023	5671	3546	496	5	242	40	0	202	86	0	3759	1601	2158	53739
2008	3193	921	5202	3193	447	9	219	36	0	182	78	0	3347	1437	1910	55649
2009	2863	826	4772	2863	401	12	197	33	0	164	70	0	2965	1285	1680	57329
2010	2556	737	4377	2556	358	16	178	30	0	149	64	0	2612	1143	1469	58798
SUBT	92500	26677	142851	92500	12960	-442	6861	1144	0	5718	2449	0	101316	42518	58798	
17YR	12230	3527	26983	12230	1712	285	1024	171	0	853	366	0	11102	5320	5782	
TOTL	104729	30204	169834	104729	14662	-157	7885	1314	0	6571	2815	0	112418	47838	64580	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
TOTAL INC TAX	20956	18488	15599	13407	12227	9965	8369
AFTER TAX CF	28527	25121	21112	18054	16402	13225	10974

TABLE 6

TYPICAL B.C. GAS FIELD
70% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	PRODn MONTHS	BUTn REC RATE	PENT+ REC RATE	SUL REC RATE	W.I. %	CR ROY PRICE $/vol	CROWN GAS %	CROWN BYPs %	G.C.A. RATE $/Mcf
1991	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	12.0	9.40	4.30	1.50	100.00	1.28	15.8822	20.00	0.00
1993	12.0	9.40	4.30	1.50	100.00	1.37	16.4787	20.00	0.00
1994	12.0	9.40	4.30	1.50	100.00	1.47	17.0362	20.00	0.00
1995	12.0	9.40	4.30	1.50	100.00	1.57	17.5572	20.00	0.00
1996	12.0	9.40	4.30	1.50	100.00	1.68	18,0441	20.00	0.00
1997	12.0	9.40	4.30	1.50	100.00	1.80	18.4991	20.00	0.00
1998	12.0	9.40	4.30	1.50	100.00	1.92	18.9244	20.00	0.00
1999	12.0	9.40	4.30	1.50	100.00	2.06	19.3219	20.00	0.00
2000	12.0	9.40	4.30	1.50	100.00	2.20	19.6934	20.00	0.00
2001	12.0	9.40	4.30	1.50	100.00	2.36	20.0405	20.00	0.00
2002	12.0	9.40	4.30	1.50	100.00	2.52	20.365	20.00	0.00
2003	12.0	9.40	4.30	1.50	100.00	2.70	20.6682	20.00	0.00
2004	12.0	9.40	4.30	1.50	100.00	2.89	20.9516	20.00	0.00
2005	12.0	9.40	4.30	1.50	100.00	3.09	21.2164	20.00	0.00
2006	12.0	9.40	4.30	1.50	100.00	3.31	21.464	20.00	0.00
2007	12.0	9.40	4.30	1.50	100.00	3.54	21.6953	20.00	0.00
2008	12.0	9.40	4.30	1.50	100.00	3.79	21.9115	20.00	0.00
2009	12.0	9.40	4.30	1.50	100.00	4.05	22.1135	20.00	0.00
2010	12.0	9.40	4.30	1.50	100.00	4.33	22.3024	20.00	0.001
TOTL									

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	Prod Ex WL-GAS M$/W/M	Prod Ex VAR-GAS $/Mcf	-GROSS INTANG-- --INVESTMENT--- Cur M$	Fut M$	-GRSS TAN CL41- --INVESTMENT--- Cur M$	Fut M$	RES. ALLOW %	FED Inc Tax %	PROV Inc Tax %
1991	3.30	0.08	270	270	1080	1080	25.00	28.84	14.00
1992	3.47	0.084	0	0	0	0	25.00	28.84	14.00
1993	3.64	0.088	90	99	360	397	25.00	28.84	14.00
1994	3.82	0.093	90	104	360	417	25.00	28.84	14.00
1995	4.01	0.097	0	0	0	0	25.00	28.84	14.00
1996	4.21	0.102	90	115	360	459	25.00	28.84	14.00
1997	4.42	0.107	0	0	0	0	25.00	28.84	14.00
1998	4.64	0.113	90	127	360	507	25.00	28.84	14.00
1999	4.88	0.118	90	133	360	532	25.00	28.84	14.00
2000	5.12	0.124	0	0	0	0	25.00	28.84	14.00
2001	5.38	0.13	0	0	0	0	25.00	28.84	14.00
2002	5.64	0.137	0	0	0	0	25.00	28.84	14.00
2003	5.93	0.144	0	0	0	0	25.00	28.84	14.00
2004	6.22	0.151	0	0	0	0	25.00	28.84	14.00
2005	6.53	0.158	0	0	0	0	25.00	28.84	14.00
2006	6.86	0.166	0	0	0	0	25.00	28.84	14.00
2007	7.20	0.175	0	0	0	0	25.00	28.84	14.00
2008	7.56	0.183	0	0	0	0	25.00	28.84	14.00
2009	7.94	0.193	0	0	0	0	25.00	28.84	14.00
2010	8.34	0.202	0	0	0	0	25.00	28.84	14.00
TOTL			720	848	2880	3392			

Province code: 2 (B.C.) PR_CODE_G 0
Type reserve code: 1 (Proven Developed, Producing)

TABLE 7

PROVEN DEVELOPED,
PRODUCING
RESERVES

TYPICAL B.C. GAS FIELD
80% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

SUMMARY OF RESERVES AND PRESENT WORTH
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

RESERVES

	OIL	SOLUTION GAS	NON-ASSOC ASSOC GAS	ETHANE	PROPANE	BUTANES	PENTANES PLUS	TOTAL NGL	SULPHUR
	MBBL	MMCF	MMCF	MBBL	MBBL	MBBL	MBBL	MBBL	MLT
GROSS	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. INT.	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. NET	0.0	0	41624	0.0	0.0	391.0	178.9	569.9	65.0

PRESENT WORTH

DISCOUNT RATE	TOTAL NET CAPITAL	BEFORE TAX NET REV	ALB ROY TAX CR.	WGAL/LOAN OVERHEAD	BEFORE TAX CASH FLOW	INCOME TAXES	AFTER TAX CASH FLOW
%	M$	M$	M$	M$	M$	M$	M$
0.0	4441	133648	0	0	133648	57391	76257
10.0	3075	50487	0	0	50487	21465	29022
12.0	2901	43759	0	0	43759	18614	25145
15.0	2680	36114	0	0	36114	15387	20727
18.0	2499	30488	0	0	30488	13021	17467
20.0	2395	27522	0	0	27522	11776	15746
25.0	2184	21962	0	0	21962	9447	12515
30.0	2025	18139	0	0	18139	7851	10288

USES $1.655/MMCF + 7% ESCALATION

TABLE 7

TYPICAL B.C. GAS FIELD
60% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

PROVEN DEVELOPED, PRODUCING RESERVES

PRODUCTION AND PRICE FORECAST (MAJOR PRODUCTS AND SULPHUR)
(PRODN START : JAN 1, 1992)

YEAR	NON-ASSOC / ASSOC PIPELINE GAS						SULPHUR			
	WELLS	DAILY	GROSS	CO. INT	CO. NET	PRICE	GROSS	CO. INT	CO. NET	PRICE
		MCF/D	MMCF	MMCF	MMCF	$/MCF	MLT	MLT	MLT	$/LT
1992	3.0	8550	3121	3121	2606	1.65	4.7	4.7	3.9	60.00
1993	3.0	8550	3121	3121	2589	1.77	4.7	4.7	3.9	65.00
1994	4.0	8550	3121	3121	2573	1.89	4.7	4.7	3.9	70.00
1995	4.0	8550	3121	3121	2557	2.03	4.7	4.7	3.9	75.00
1996	5.0	8550	3121	3121	2543	2.17	4.7	4.7	3.9	80.00
1997	5.0	8550	3121	3121	2530	2.32	4.7	4.7	3.9	85.00
1998	6.0	8550	3121	3121	2518	2.48	4.7	4.7	3.9	90.00
1999	7.0	8550	3121	3121	2506	2.66	4.7	4.7	3.9	95.00
2000	8.0	8550	3121	3121	2495	2.84	4.7	4.7	3.9	100.00
2001	8.0	8043	2936	2936	2338	3.04	4.4	4.4	3.7	105.00
2002	8.0	7107	2594	2594	2068	3.26	3.9	3.9	3.2	110.00
2003	8.0	6281	2292	2292	1812	3.48	3.4	3.4	2.9	115.00
2004	8.0	5550	2026	2026	1596	3.73	3.0	3.0	2.5	120.00
2005	8.0	4905	1790	1790	1406	3.99	2.7	2.7	2.2	125.00
2006	8.0	4334	1582	1582	1239	4.27	2.4	2.4	2.0	131.50
2007	8.0	3830	1398	1398	1092	4.57	2.1	2.1	1.7	138.32
2008	8.0	3385	1235	1235	962	4.89	1.9	1.9	1.5	145.49
2009	8.0	2991	1092	1092	848	5.23	1.6	1.6	1.4	153.02
2010	8.0	2643	965	965	748	5.59	1.4	1.4	1.2	160.92
SUBT			45997	45997	37015		69.0	69.0	57.5	
14YR			6003	6003	4609		9.0	9.0	7.5	
TOTL			52000	52000	41624		78.0	78.0	65.0	

USES $1.665/MMCF + 7% ESCALATION

PRODUCTION AND PRICE FORECAST (NGL's)
(PRODN START : JAN 1, 1992)

YEAR	BUTANES				PENTANES PLUS			
	GROSS	CO. INT	CO. NET	PRICE	GROSS	CO. INT	CO. NET	PRICE
	MBBL	MBBL	MBBL	$/BBL	MBBL	MBBL	MBBL	$/BBL
1992	29.3	29.3	23.5	11.43	13.4	13.4	10.7	20.84
1993	29.3	29.3	23.5	12.60	13.4	13.4	10.7	23.11
1994	29.3	29.3	23.5	14.02	13.4	13.4	10.7	25.26
1995	29.3	29.3	23.5	15.54	13.4	13.4	10.7	27.60
1996	29.3	29.3	23.5	17.20	13.4	13.4	10.7	30.11
1997	29.3	29.3	23.5	18.99	13.4	13.4	10.7	32.83
1998	29.3	29.3	23.5	20.93	13.4	13.4	10.7	35.77
1999	29.3	29.3	23.5	23.05	13.4	13.4	10.7	38.94
2000	29.3	29.3	23.5	24.90	13.4	13.4	10.7	41.77
2001	27.6	27.6	22.1	26.34	12.6	12.6	10.1	44.02
2002	24.4	24.4	19.5	27.88	11.2	11.2	8.9	46.38
2003	21.5	21.5	17.2	29.49	9.9	9.9	7.9	48.86
2004	19.0	19.0	15.2	31.19	8.7	8.7	7.0	51.46
2005	16.8	16.8	13.5	32.97	7.7	7.7	6.2	54.19
2006	14.9	14.9	11.9	34.75	6.8	6.8	5.4	57.03
2007	13.1	13.1	10.5	36.63	6.0	6.0	4.8	60.02
2008	11.6	11.6	9.3	38.59	5.3	5.3	4.3	63.16
2009	10.3	10.3	8.2	40.66	4.7	4.7	3.8	66.45
2010	9.1	9.1	7.3	42.82	4.1	4.1	3.3	69.91
SUBT	432.4	432.4	345.9		197.8	197.8	158.2	
14YR	56.4	56.4	45.1		25.8	25.8	20.7	
TOTL	488.8	488.8	391.0		223.6	223.6	178.9	

TABLE 7

TYPICAL B.C. GAS FIELD
80% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

	REVENUE						ROYALTIES									
YEAR	OIL	GAS	NGL	SUL	ROY	OTHER	CROWN	PROD	RES	SUL	GCA	MIN TAXES	LEASE EXP	PLANT EXP	OPER INC	NPI
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	5165	615	281	0	0	975	0	0	47	0	0	387	0	4652	0
1993	0	5526	680	304	0	0	1078	0	0	51	0	0	406	0	4976	0
1994	0	5913	750	328	0	0	1189	0	0	55	0	0	472	0	5276	0
1995	0	6327	826	351	0	0	1307	0	0	59	0	0	496	0	5643	0
1996	0	6770	909	374	0	0	1436	0	0	62	0	0	571	0	5985	0
1997	0	7244	998	398	0	0	1571	0	0	66	0	0	600	0	6403	0
1998	0	7751	1094	421	0	0	1717	0	0	70	0	0	686	0	6794	0
1999	0	8294	1199	445	0	0	1874	0	0	74	0	0	778	0	7211	0
2000	0	8874	1291	468	0	0	2037	0	0	78*	0	0	879	0	7640	0
2001	0	8932	1282	462	0	0	2076	0	0	77	0	0	899	0	7625	0
2002	0	8446	1197	428	0	0	1985	0	0	71	0	0	897	0	7118	0
2003	0	7986	1117	395	0	0	1897	0	0	66	0	0	898	0	6637	0
2004	0	7551	1042	365	0	0	1811	0	0	61	0	0	903	0	6184	0
2005	0	7140	972	336	0	0	1727	0	0	56	0	0	911	0	5754	0
2006	0	6751	905	312	0	0	1646	0	0	52	0	0	922	0	5349	0
2007	0	6384	842	290	0	0	1567	0	0	48	0	0	936	0	4965	0
2008	0	6036	784	270	0	0	1492	0	0	45	0	0	953	0	4600	0
2009	0	5708	729	251	0	0	1419	0	0	42	0	0	973	0	4254	0
2010	0	5397	678	233	0	0	1349	0	0	39	0	0	996	0	3925	0
SUBT	0	132195	17910	6712	0	0	30151	0	0	1119	3	0	14561	0	110989	0
14YR	0	50496	5700	1946	0	0	12918	0	0	324	1	0	17801	0	27100	0
TOTL	0	182691	23611	8658	0	0	43070	0	0	1443	4	0	32362	0	138089	0

USES $1.655/MMCF + 7% ESCALATION

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

	INTANGIBLE		TANGIBLE									LOAN REPMT				
YEAR	CEE	CDE	CL 41	PLANT	OTHER	CEDIP COGPE	TOTAL CAP	NET REV	CUM NETREV	ARTC	OVHD	PRIN	INT	NGML REPMT	CASH FLOW	CUM CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	270	1080	0	0	0	1350	-1350	-1350	0	0	0	0	0	-1350	-1350
1992	0	0	0	0	0	0	0	4652	3302	0	0	0	0	0	4652	3302
1993	0	0	0	0	0	0	0	4976	8278	0	0	0	0	0	4976	8278
1994	0	104	417	0	0	0	521	4755	13033	0	0	0	0	0	4755	13033
1995	0	0	0	0	0	0	0	5643	18675	0	0	0	0	0	5643	18675
1996	0	115	459	0	0	0	574	5411	24086	0	0	0	0	0	5411	24086
1997	0	0	0	0	0	0	0	6403	30489	0	0	0	0	0	6403	30489
1998	0	127	507	0	0	0	633	6161	36649	0	0	0	0	0	6161	36649
1999	0	133	532	0	0	0	665	6546	43195	0	0	0	0	0	6546	43195
2000	0	140	558	0	0	0	698	6941	50137	0	0	0	0	0	6941	50137
2001	0	0	0	0	0	0	0	7625	57762	0	0	0	0	0	7625	57762
2002	0	0	0	0	0	0	0	7118	64880	0	0	0	0	0	7118	64880
2003	0	0	0	0	0	0	0	6637	71517	0	0	0	0	0	6637	71517
2004	0	0	0	0	0	0	0	6184	77701	0	0	0	0	0	6184	77701
2005	0	0	0	0	0	0	0	5754	83455	0	0	0	0	0	5754	83455
2006	0	0	0	0	0	0	0	5349	88803	0	0	0	0	0	5349	88803
2007	0	0	0	0	0	0	0	4965	93768	0	0	0	0	0	4965	93768
2008	0	0	0	0	0	0	0	4600	98368	0	0	0	0	0	4600	98368
2009	0	0	0	0	0	0	0	4254	102623	0	0	0	0	0	4254	102623
2010	0	0	0	0	0	0	0	3925	106548	0	0	0	0	0	3925	106548
SUBT	0	888	3553	0	0	0	4441	106548		0	0	0	0	0	106548	
14YR	0	0	0	0	0	0	0	27100		0	0	0	0	0	27100	
TOTL	0	888	3553	0	0	0	4441	133648		0	0	0	0	0	133648	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
NET REVENUE	50487	43759	36114	30488	27522	21962	18139
CASH FLOW	50487	43759	36114	30488	27522	21962	18139

TABLE 7

TYPICAL B.C. GAS FIELD
60% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX RESINC	LEASE EXP	PROD ROY	C.C.A.	RES ALLOW	OTHER INC	RES ROY	---CAPITAL CEE	WRITEOFF--- CDE	COGPE	DEBT INT	NPI+ OVHD	DEPL	TAXREV ADJ.
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	135	-34	0	0	0	81	0	0	0	0	0
1992	5780	387	0	236	1289	0	0	0	57	0	0	0	0	0
1993	6206	406	0	177	1406	0	0	0	40	0	0	0	0	0
1994	6663	472	0	185	1502	0	0	0	59	0	0	0	0	0
1995	7153	496	0	191	1617	0	0	0	41	0	0	0	0	0
1996	7679	571	0	201	1727	0	0	0	63	0	0	0	0	0
1997	8242	600	0	208	1858	0	0	0	44	0	0	0	0	0
1998	8845	686	0	219	1985	0	0	0	69	0	0	0	0	0
1999	9492	778	0	294	2105	0	0	0	88	0	0	0	0	0
2000	10166	879	0	357	2232	0	0	0	104	0	0	0	0	0
2001	10214	899	0	338	2245	0	0	0	73	0	0	0	0	0
2002	9643	897	0	253	2123	0	0	0	51	0	0	0	0	0
2003	9103	898	0	190	2004	0	0	0	36	0	0	0	0	0
2004	8593	903	0	142	1887	0	0	0	25	0	0	0	0	0
2005	8112	911	0	107	1774	0	0	0	17	0	0	0	0	0
2006	7656	922	0	80	1664	0	0	0	12	0	0	0	0	0
2007	7226	936	0	60	1558	0	0	0	9	0	0	0	0	0
2008	6820	953	0	45	1456	0	0	0	6	0	0	0	0	0
2009	6437	973	0	34	1358	0	0	0	4	0	0	0	0	0
2010	6075	996	0	25	1264	0	0	0	3	0	0	0	0	0
SUBT	150105	14561	0	3477	33017	0	0	0	881	0	0	0	0	0
19YR	56196	17801	0	76	9580	0	0	0	7	0	0	0	0	0
TOTL	206302	32362	0	3553	42597	0	0	0	888	0	0	0	0	0

USES $1.655/MMCF + 7% ESCALATION

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX INC	FED TAXES	PRVTAX RESINC	PRVTAX INC	PROV TAXES	PRVROY TAXREB	PROC INC	PL EXP SULROY	PLANT CCA	PROC TAXINC	PROC TAXES	INVTAX CREDIT	BEFORE TAX CF	TOTAL INCTAX	AFTER TAX CF	CUM AT CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	-182	-53	0	-182	-26	5	0	0	0	0	0	0	-1350	-83	-1267	-1267
1992	3811	1099	5780	3811	534	-44	281	47	0	234	100	0	4652	1777	2876	1608
1993	4177	1206	6206	4177	585	-46	304	51	0	254	109	0	4976	1944	3032	4640
1994	4446	1282	6663	4446	622	-44	328	55	0	273	117	0	4755	2066	2689	7329
1995	4809	1387	7153	4809	673	-43	351	59	0	293	125	0	5643	2229	3414	10743
1996	5117	1476	7679	5117	716	-41	374	62	0	312	134	0	5411	2367	3044	13787
1997	5531	1595	8242	5531	774	-40	398	66	0	332	142	0	6403	2552	3851	17638
1998	5886	1698	8845	5886	824	-38	421	70	0	351	150	0	6161	2710	3451	21089
1999	6227	1796	9492	6227	872	-32	445	74	0	371	159	0	6546	2859	3688	24777
2000	6593	1902	10166	6593	923	-27	468	78	0	390	167	0	6941	3019	3922	28699
2001	6661	1921	10214	6661	933	-24	462	77	0	385	165	0	7625	3042	4583	33282
2002	6319	1822	9643	6319	885	-19	428	71	0	357	153	0	7118	2879	4238	37520
2003	5976	1723	9103	5976	837	-15	395	66	0	330	141	0	6637	2716	3921	41442
2004	5636	1625	8593	5636	789	-11	365	61	0	304	130	0	6184	2555	3628	45070
2005	5303	1530	8112	5303	742	-7	336	56	0	280	120	0	5754	2398	3356	48426
2006	4979	1436	7656	4979	697	-2	312	52	0	260	111	0	5349	2247	3102	51528
2007	4664	1345	7226	4664	653	1	290	48	0	242	104	0	4965	2100	2864	54392
2008	4361	1258	6820	4361	611	5	270	45	0	225	96	0	4600	1959	2641	57033
2009	4069	1173	6437	4069	570	9	251	42	0	209	89	0	4254	1824	2430	59463
2010	3788	1092	6075	3788	530	12	233	39	0	194	83	0	3925	1694	2231	61694
SUBT	98169	28312	150105	98169	13744	-402	6712	1119	0	5593	2396	0	106548	44853	61694	
19YR	28733	8287	56196	28733	4023	467	1946	324	0	1622	695	0	27100	12538	14563	
TOTL	126902	36598	206302	126902	17766	66	8658	1443	0	7215	3091	0	133648	57391	76257	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
TOTAL INC TAX	21465	18614	15387	13021	11776	9447	7851
AFTER TAX CF	29022	25145	20727	17467	15746	12515	10288

TABLE 7

TYPICAL B.C. GAS FIELD
60% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	PRODn MONTHS	BUTn REC RATE	PENT+ REC RATE	SUL REC RATE	W.I. %	LH ROY PRICE $/vol	CROWN GAS %	CROWN BYPs %	G.C.A. RATE $/Mcf
1991	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	12.0	9.40	4.30	1.50	100.00	1.37	16.4882	20.00	0.00
1993	12.0	9.40	4.30	1.50	100.00	1.47	17.0451	20.00	0.00
1994	12.0	9.40	4.30	1.50	100.00	1.57	17.5655	20.00	0.00
1995	12.0	9.40	4.30	1.50	100.00	1.68	18.0519	20.00	0.00
1996	12.0	9.40	4.30	1.50	100.00	1.80	18.5064	20.00	0.00
1997	12.0	9.40	4.30	1.50	100.00	1.93	18.9312	20.00	0.00
1998	12.0	9.40	4.30	1.50	100.00	2.06	19.3282	20.00	0.00
1999	12.0	9.40	4.30	1.50	100.00	2.21	19.6993	20.00	0.00
2000	12.0	9.40	4.30	1.50	100.00	2.36	20.0461	20.00	0.00
2001	12.0	9.40	4.30	1.50	100.00	2.53	20.3702	20.00	0.00
2002	12.0	9.40	4.30	1.50	100.00	2.70	20.673	20.00	0.00
2003	12.0	9.40	4.30	1.50	100.00	2.89	20.9561	20.00	0.00
2004	12.0	9.40	4.30	1.50	100.00	3.09	21.2207	20.00	0.00
2005	12.0	9.40	4.30	1.50	100.00	3.31	21.4679	20.00	0.00
2006	12.0	9.40	4.30	1.50	100.00	3.54	21.699	20.00	0.00
2007	12.0	9.40	4.30	1.50	100.00	3.79	21.9149	20.00	0.00
2008	12.0	9.40	4.30	1.50	100.00	4.06	22.1168	20.00	0.00
2009	12.0	9.40	4.30	1.50	100.00	4.34	22.3064	20.00	0.00
2010	12.0	9.40	4.30	1.50	100.00	4.64	22.4817	20.00	0.001
TOTL									

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	Prod Ex WL-GAS M$/W/M	Prod Ex VAR-GAS $/Mcf	-GROSS INTANG-- --INVESTMENT--- Cur M$	Fut M$	-GRSS TAN CL41- --INVESTMENT--- Cur M$	Fut M$	RES. ALLOW %	FED Inc Tax %	PROV Inc Tax %
1991	3.30	0.08	270	270	1080	1080	25.00	28.84	14.00
1992	3.47	0.084	0	0	0	0	25.00	28.84	14.00
1993	3.64	0.088	0	0	0	0	25.00	28.84	14.00
1994	3.82	0.093	90	104	360	417	25.00	28.84	14.00
1995	4.01	0.097	0	0	0	0	25.00	28.84	14.00
1996	4.21	0.102	90	115	360	459	25.00	28.84	14.00
1997	4.42	0.107	0	0	0	0	25.00	28.84	14.00
1998	4.64	0.113	90	127	360	507	25.00	28.84	14.00
1999	4.88	0.118	90	133	360	532	25.00	28.84	14.00
2000	5.12	0.124	90	140	360	558	25.00	28.84	14.00
2001	5.38	0.13	0	0	0	0	25.00	28.84	14.00
2002	5.64	0.137	0	0	0	0	25.00	28.84	14.00
2003	5.93	0.144	0	0	0	0	25.00	28.84	14.00
2004	6.22	0.151	0	0	0	0	25.00	28.84	14.00
2005	6.53	0.158	0	0	0	0	25.00	28.84	14.00
2006	6.86	0.166	0	0	0	0	25.00	28.84	14.00
2007	7.20	0.175	0	0	0	0	25.00	28.84	14.00
2008	7.56	0.183	0	0	0	0	25.00	28.84	14.00
2009	7.94	0.193	0	0	0	0	25.00	28.84	14.00
2010	8.34	0.202	0	0	0	0	25.00	28.84	14.00
TOTL			720	888	2880	3553			

Province code: 2 (B.C.) PR_CODE_G 0
Type reserve code: 1 (Proven Developed, Producing)

TABLE 8

PROVEN DEVELOPED,
PRODUCING
RESERVES

TYPICAL B.C. GAS FIELD
50% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

SUMMARY OF RESERVES AND PRESENT WORTH
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

RESERVES

	OIL	SOLUTION GAS	NON-ASSOC ASSOC GAS	ETHANE	PROPANE	BUTANES	PENTANES PLUS	TOTAL NGL	SULPHUR
	MBBL	MMCF	MMCF	MBBL	MBBL	MBBL	MBBL	MBBL	MLT
GROSS	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. INT.	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. NET	0.0	0	41151	0.0	0.0	391.0	178.9	569.9	65.0

PRESENT WORTH

DISCOUNT RATE	TOTAL NET CAPITAL	BEFORE TAX NET REV	ALB ROY TAX CR.	WGML/LOAN OVERHEAD	BEFORE TAX CASH FLOW	INCOME TAXES	AFTER TAX CASH FLOW
%	M$	M$	M$	M$	M$	M$	M$
0.0	4570	176531	0	0	176531	76660	99871
10.0	3014	51942	0	0	51942	22204	29738
12.0	2828	43962	0	0	43962	18798	25164
15.0	2595	35311	0	0	35311	15123	20188
18.0	2407	29226	0	0	29226	12548	16678
20.0	2303	26114	0	0	26114	11235	14879
25.0	2094	20453	0	0	20453	8852	11601
30.0	1941	16685	0	0	16685	7271	9414

USES $1.83/MMCF + 7% ESCALATION

TABLE 8

TYPICAL B.C. GAS FIELD
50% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

PROVEN DEVELOPED, PRODUCING RESERVES

PRODUCTION AND PRICE FORECAST (MAJOR PRODUCTS AND SULPHUR)
(PRODN START : JAN 1,1992)

YEAR	NON-ASSOC / ASSOC PIPELINE GAS WELLS	DAILY	GROSS	CO. INT	CO.NET	PRICE	SULPHUR GROSS	CO. INT	CO.NET	PRICE
		MCF/D	MMCF	MMCF	MMCF	$/MCF	MLT	MLT	MLT	$/LT
1992	3.0	7125	2601	2601	2151	1.83	3.9	3.9	3.3	60.00
1993	3.0	7125	2601	2601	2138	1.96	3.9	3.9	3.3	65.00
1994	4.0	7125	2601	2601	2125	2.10	3.9	3.9	3.3	70.00
1995	4.0	7125	2601	2601	2114	2.24	3.9	3.9	3.3	75.00
1996	4.0	7125	2601	2601	2103	2.40	3.9	3.9	3.3	80.00
1997	5.0	7125	2601	2601	2093	2.57	3.9	3.9	3.3	85.00
1998	5.0	7125	2601	2601	2084	2.75	3.9	3.9	3.3	90.00
1999	6.0	7125	2601	2601	2075	2.94	3.9	3.9	3.3	95.00
2000	7.0	7125	2601	2601	2067	3.14	3.9	3.9	3.3	100.00
2001	8.0	7125	2601	2601	2059	3.36	3.9	3.9	3.3	105.00
2002	8.0	6801	2482	2482	1959	3.60	3.7	3.7	3.1	110.00
2003	8.0	6193	2260	2260	1778	3.85	3.4	3.4	2.8	115.00
2004	8.0	5639	2058	2058	1614	4.12	3.1	3.1	2.6	120.00
2005	8.0	5134	1874	1874	1465	4.41	2.8	2.8	2.3	125.00
2006	8.0	4675	1706	1706	1331	4.72	2.6	2.6	2.1	131.50
2007	8.0	4257	1554	1554	1209	5.05	2.3	2.3	1.9	138.32
2008	8.0	3876	1415	1415	1098	5.40	2.1	2.1	1.8	145.49
2009	8.0	3529	1288	1288	997	5.78	1.9	1.9	1.6	153.02
2010	8.0	3213	1173	1173	906	6.19	1.8	1.8	1.5	160.92
SUBT			41817	41817	33366		62.7	62.7	52.3	
21YR			10183	10183	7785		15.3	15.3	12.7	
TOTL			52000	52000	41151		78.0	78.0	65.0	

USES $1.83/MMCF + 7% ESCALATION

PRODUCTION AND PRICE FORECAST (NGL's)
(PRODN START : JAN 1,1992)

YEAR	BUTANES GROSS	CO. INT	CO.NET	PRICE	PENTANES PLUS GROSS	CO. INT	CO.NET	PRICE
	MBBL	MBBL	MBBL	$/BBL	MBBL	MBBL	MBBL	$/BBL
1992	24.4	24.4	19.6	11.43	11.2	11.2	8.9	20.84
1993	24.4	24.4	19.6	12.60	11.2	11.2	8.9	23.11
1994	24.4	24.4	19.6	14.02	11.2	11.2	8.9	25.26
1995	24.4	24.4	19.6	15.54	11.2	11.2	8.9	27.60
1996	24.4	24.4	19.6	17.20	11.2	11.2	8.9	30.11
1997	24.4	24.4	19.6	18.99	11.2	11.2	8.9	32.83
1998	24.4	24.4	19.6	20.93	11.2	11.2	8.9	35.77
1999	24.4	24.4	19.6	23.05	11.2	11.2	8.9	38.94
2000	24.4	24.4	19.6	24.90	11.2	11.2	8.9	41.77
2001	24.4	24.4	19.6	26.34	11.2	11.2	8.9	44.02
2002	23.3	23.3	18.7	27.88	10.7	10.7	8.5	46.38
2003	21.2	21.2	17.0	29.49	9.7	9.7	7.8	48.86
2004	19.3	19.3	15.5	31.19	8.8	8.8	7.1	51.46
2005	17.6	17.6	14.1	32.97	8.1	8.1	6.4	54.19
2006	16.0	16.0	12.8	34.75	7.3	7.3	5.9	57.03
2007	14.6	14.6	11.7	36.63	6.7	6.7	5.3	60.02
2008	13.3	13.3	10.6	38.59	6.1	6.1	4.9	63.16
2009	12.1	12.1	9.7	40.66	5.5	5.5	4.4	66.45
2010	11.0	11.0	8.8	42.82	5.0	5.0	4.0	69.91
SUBT	393.1	393.1	314.5		179.8	179.8	143.8	
21YR	95.7	95.7	76.5		43.8	43.8	35.1	
TOTL	488.8	488.8	391.0		223.6	223.6	178.9	

TABLE 8

TYPICAL B.C. GAS FIELD
50% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	REVENUE OIL	REVENUE GAS	REVENUE NGL	REVENUE SUL	REVENUE ROY	REVENUE OTHER	ROYALTIES CROWN	ROYALTIES PROD	ROYALTIES RES	ROYALTIES SUL	GCA	MIN TAXES	LEASE EXP	PLANT EXP	OPER INC	NPI
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	4759	512	234	0	0	926	0	0	39	0	0	343	0	4198	0
1993	0	5092	566	254	0	0	1020	0	0	42	0	0	360	0	4490	0
1994	0	5449	625	273	0	0	1121	0	0	46	0	0	424	0	4757	0
1995	0	5830	689	293	0	0	1229	0	0	49	0	0	445	0	5088	0
1996	0	6238	757	312	0	0	1345	0	0	52	0	0	468	0	5443	0
1997	0	6675	831	332	0	0	1469	0	0	55	0	0	544	0	5770	0
1998	0	7142	912	351	0	0	1602	0	0	59	0	0	571	0	6174	0
1999	0	7642	999	371	0	0	1744	0	0	62	0	0	658	0	6548	0
2000	0	8177	1076	390	0	0	1893	0	0	65	0	0	753	0	6932	0
2001	0	8749	1136	410	0	0	2048	0	0	68	0	0	855	0	7324	0
2002	0	8937	1146	410	0	0	2114	0	0	68	0	0	882	0	7429	0
2003	0	8707	1101	390	0	0	2079	0	0	65	0	0	894	0	7161	0
2004	0	8483	1059	370	0	0	2042	0	0	62	0	0	908	0	6900	0
2005	0	8264	1017	351	0	0	2006	0	0	59	0	0	924	0	6645	0
2006	0	8052	976	337	0	0	1968	0	0	56	0	0	942	0	6398	0
2007	0	7844	936	322	0	0	1929	0	0	54	0	0	963	0	6157	0
2008	0	7643	897	309	0	0	1891	0	0	51	0	0	986	0	5921	0
2009	0	7446	860	296	0	0	1852	0	0	49	0	0	1010	0	5690	0
2010	0	7254	825	283	0	0	1813	0	0	47	0	0	1038	0	5464	0
SUBT	0	138383	16921	6286	0	0	32089	0	0	1048	3	0	13968	0	114488	0
21YR	0	113610	10984	3744	0	0	29165	0	0	624	2	0	31938	0	66613	0
TOTL	0	251993	27905	10030	0	0	61254	0	0	1672	5	0	45906	0	181101	0

USES $1.83/MMCF + 7% ESCALATION

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	INTANGIBLE CEE	INTANGIBLE CDE	TANGIBLE CL 41	TANGIBLE PLANT	TANGIBLE OTHER	CEDIP COGPE	TOTAL CAP	NET REV	CUM NETREV	ARTC	OVHD	LOAN REPMT PRIN	LOAN REPMT INT	WGML REPMT	CASH FLOW	CUM CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	270	1080	0	0	0	1350	-1350	-1350	0	0	0	0	0	-1350	-1350
1992	0	0	0	0	0	0	0	4198	2848	0	0	0	0	0	4198	2848
1993	0	0	0	0	0	0	0	4490	7337	0	0	0	0	0	4490	7337
1994	0	104	417	0	0	0	521	4236	11573	0	0	0	0	0	4236	11573
1995	0	0	0	0	0	0	0	5088	16661	0	0	0	0	0	5088	16661
1996	0	0	0	0	0	0	0	5443	22105	0	0	0	0	0	5443	22105
1997	0	121	482	0	0	0	603	5167	27271	0	0	0	0	0	5167	27271
1998	0	0	0	0	0	0	0	6174	33445	0	0	0	0	0	6174	33445
1999	0	133	532	0	0	0	665	5883	39328	0	0	0	0	0	5883	39328
2000	0	140	558	0	0	0	698	6234	45562	0	0	0	0	0	6234	45562
2001	0	147	586	0	0	0	733	6591	52153	0	0	0	0	0	6591	52153
2002	0	0	0	0	0	0	0	7429	59582	0	0	0	0	0	7429	59582
2003	0	0	0	0	0	0	0	7161	66743	0	0	0	0	0	7161	66743
2004	0	0	0	0	0	0	0	6900	73643	0	0	0	0	0	6900	73643
2005	0	0	0	0	0	0	0	6645	80288	0	0	0	0	0	6645	80288
2006	0	0	0	0	0	0	0	6398	86686	0	0	0	0	0	6398	86686
2007	0	0	0	0	0	0	0	6157	92843	0	0	0	0	0	6157	92843
2008	0	0	0	0	0	0	0	5921	98764	0	0	0	0	0	5921	98764
2009	0	0	0	0	0	0	0	5690	104454	0	0	0	0	0	5690	104454
2010	0	0	0	0	0	0	0	5464	109918	0	0	0	0	0	5464	109918
SUBT	0	914	3656	0	0	0	4570	109918		0	0	0	0	0	109918	
21YR	0	0	0	0	0	0	0	66613		0	0	0	0	0	66613	
TOTL	0	914	3656	0	0	0	4570	176531		0	0	0	0	0	176531	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
NET REVENUE	51942	43962	35311	29226	26114	20453	16685
CASH FLOW	51942	43962	35311	29226	26114	20453	16685

TABLE 8

TYPICAL B.C. GAS FIELD
50% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX RESINC	LEASE EXP	PROD ROY	C.C.A.	RES ALLOW	OTHER INC	RES ROY	---CAPITAL WRITEOFF--- CEE	CDE	COGPE	DEBT INT	NPI+ OVHD	DEPL	TAXREV ADJ.
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	135	-34	0	0	0	81	0	0	0	0	0
1992	5272	343	0	236	1173	0	0	0	57	0	0	0	0	0
1993	5659	360	0	177	1280	0	0	0	40	0	0	0	0	0
1994	6074	424	0	185	1366	0	0	0	59	0	0	0	0	0
1995	6519	445	0	191	1471	0	0	0	41	0	0	0	0	0
1996	6995	468	0	143	1596	0	0	0	29	0	0	0	0	0
1997	7506	544	0	168	1699	0	0	0	56	0	0	0	0	0
1998	8054	571	0	186	1824	0	0	0	40	0	0	0	0	0
1999	8641	658	0	206	1944	0	0	0	68	0	0	0	0	0
2000	9253	753	0	291	2052	0	0	0	89	0	0	0	0	0
2001	9886	855	0	361	2167	0	0	0	106	0	0	0	0	0
2002	10082	882	0	344	2214	0	0	0	74	0	0	0	0	0
2003	9808	894	0	258	2164	0	0	0	52	0	0	0	0	0
2004	9541	908	0	194	2110	0	0	0	36	0	0	0	0	0
2005	9282	924	0	145	2053	0	0	0	26	0	0	0	0	0
2006	9028	942	0	109	1994	0	0	0	18	0	0	0	0	0
2007	8780	963	0	82	1934	0	0	0	13	0	0	0	0	0
2008	8540	986	0	61	1873	0	0	0	9	0	0	0	0	0
2009	8306	1010	0	46	1812	0	0	0	6	0	0	0	0	0
2010	8079	1038	0	34	1752	0	0	0	4	0	0	0	0	0
SUBT	155305	13968	0	3553	34446	0	0	0	904	0	0	0	0	0
21YR	124594	31938	0	103	23138	0	0	0	10	0	0	0	0	0
TOTL	279898	45906	0	3656	57584	0	0	0	914	0	0	0	0	0

USES $1.83/MMCF + 7% ESCALATION

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX INC	FED TAXES	PRVTAX RESINC	PRVTAX INC	PROV TAXES	PRVROY TAXREB	PROC INC	PL EXP SULROY	PLANT CCA	PROC TAXINC	PROC TAXES	INVTAX CREDIT	BEFORE TAX CF	TOTAL INCTAX	AFTER TAX CF	CUM AT CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	-182	-53	0	-182	-26	5	0	0	0	0	0	0	-1350	-83	-1267	-1267
1992	3462	999	5272	3462	485	-35	234	39	0	195	84	0	4198	1601	2596	1329
1993	3801	1096	5659	3801	532	-36	254	42	0	211	91	0	4490	1755	2734	4063
1994	4040	1165	6074	4040	566	-34	273	46	0	228	97	0	4236	1862	2373	6437
1995	4370	1260	6519	4370	612	-34	293	49	0	244	104	0	5088	2011	3078	9514
1996	4760	1373	6995	4760	666	-35	312	52	0	260	111	0	5443	2186	3258	12772
1997	5039	1453	7506	5039	706	-32	332	55	0	276	118	0	5167	2309	2857	15629
1998	5433	1567	8054	5433	761	-31	351	59	0	293	125	0	6174	2484	3690	19319
1999	5765	1663	8641	5765	807	-28	371	62	0	309	132	0	5883	2630	3253	22572
2000	6068	1750	9253	6068	849	-22	390	65	0	325	139	0	6234	2761	3473	26045
2001	6396	1845	9886	6396	895	-17	410	68	0	341	146	0	6591	2903	3688	29733
2002	6568	1894	10082	6568	920	-14	410	68	0	341	146	0	7429	2974	4455	34188
2003	6440	1857	9808	6440	902	-12	390	65	0	325	139	0	7161	2910	4251	38439
2004	6293	1815	9541	6293	881	-9	370	62	0	309	132	0	6900	2838	4062	42501
2005	6134	1769	9282	6134	859	-7	351	59	0	293	125	0	6645	2760	3885	46386
2006	5964	1720	9028	5964	835	-4	337	56	0	280	120	0	6398	2679	3719	50105
2007	5789	1670	8780	5789	811	-1	322	54	0	269	115	0	6157	2596	3561	53666
2008	5611	1618	8540	5611	786	2	309	51	0	257	110	0	5921	2512	3409	57075
2009	5431	1566	8306	5431	760	6	296	49	0	246	106	0	5690	2427	3263	60339
2010	5251	1514	8079	5251	735	9	283	47	0	236	101	0	5464	2342	3122	63461
SUBT	102434	29542	155305	102434	14341	-330	6286	1048	0	5238	2244	0	109918	46457	63461	
21YR	69405	19994	124594	69405	9717	843	3744	624	0	3120	1335	0	66613	30203	36410	
TOTL	171838	49536	279898	171838	24057	513	10030	1672	0	8358	3579	0	176531	76660	99871	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
TOTAL INC TAX	22204	18798	15123	12548	11235	8852	7271
AFTER TAX CF	29738	25164	20188	16678	14879	11601	9414

TABLE 8

TYPICAL B.C. GAS FIELD
50% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	PRODn MONTHS	BUTn REC RATE	PENT+ REC RATE	SUL REC RATE	W.I. %	CR ROY PRICE $/vol	CROWN GAS %	CROWN BYPs %	G.C.A. RATE $/Mcf
1991	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	12.0	9.40	4.30	1.50	100.00	1.52	17.3022	20.00	0.00
1993	12.0	9.40	4.30	1.50	100.00	1.63	17.8058	20.00	0.00
1994	12.0	9.40	4.30	1.50	100.00	1.74	18.2764	20.00	0.00
1995	12.0	9.40	4.30	1.50	100.00	1.86	18.7163	20.00	0.00
1996	12.0	9.40	4.30	1.50	100.00	1.99	19.1274	20.00	0.00
1997	12.0	9.40	4.30	1.50	100.00	2.13	19.5116	20.00	0.00
1998	12.0	9.40	4.30	1.50	100.00	2.28	19.8706	20.00	0.00
1999	12.0	9.40	4.30	1.50	100.00	2.44	20.2062	20.00	0.00
2000	12.0	9.40	4.30	1.50	100.00	2.61	20.5198	20.00	0.00
2001	12.0	9.40	4.30	1.50	100.00	2.79	20.8129	20.00	0.00
2002	12.0	9.40	4.30	1.50	100.00	2.99	21.0868	20.00	0.00
2003	12.0	9.40	4.30	1.50	100.00	3.20	21.3428	20.00	0.00
2004	12.0	9.40	4.30	1.50	100.00	3.42	21.5821	20.00	0.00
2005	12.0	9.40	4.30	1.50	100.00	3.66	21.8057	20.00	0.00
2006	12.0	9.40	4.30	1.50	100.00	3.92	22.0147	20.00	0.00
2007	12.0	9.40	4.30	1.50	100.00	4.19	22.21	20.00	0.00
2008	12.0	9.40	4.30	1.50	100.00	4.48	22.3925	20.00	0.00
2009	12.0	9.40	4.30	1.50	100.00	4.80	22.5631	20.00	0.00
2010	12.0	9.40	4.30	1.50	100.00	5.13	22.7225	20.00	0.001
TOTL									

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	Prod Ex WL-GAS M$/W/M	Prod Ex VAR-GAS $/Mcf	-GROSS INTANG-- --INVESTMENT--- Cur M$	Fut M$	-GRSS TAN CL41- --INVESTMENT--- Cur M$	Fut M$	RES. ALLOW %	FED Inc Tax %	PROV Inc Tax %
1991	3.30	0.08	270	270	1080	1080	25.00	28.84	14.00
1992	3.47	0.084	0	0	0	0	25.00	28.84	14.00
1993	3.64	0.088	0	0	0	0	25.00	28.84	14.00
1994	3.82	0.093	90	104	360	417	25.00	28.84	14.00
1995	4.01	0.097	0	0	0	0	25.00	28.84	14.00
1996	4.21	0.102	0	0	0	0	25.00	28.84	14.00
1997	4.42	0.107	90	121	360	482	25.00	28.84	14.00
1998	4.64	0.113	0	0	0	0	25.00	28.84	14.00
1999	4.88	0.118	90	133	360	532	25.00	28.84	14.00
2000	5.12	0.124	90	140	360	558	25.00	28.84	14.00
2001	5.38	0.13	90	147	360	586	25.00	28.84	14.00
2002	5.64	0.137	0	0	0	0	25.00	28.84	14.00
2003	5.93	0.144	0	0	0	0	25.00	28.84	14.00
2004	6.22	0.151	0	0	0	0	25.00	28.84	14.00
2005	6.53	0.158	0	0	0	0	25.00	28.84	14.00
2006	6.86	0.166	0	0	0	0	25.00	28.84	14.00
2007	7.20	0.175	0	0	0	0	25.00	28.84	14.00
2008	7.56	0.183	0	0	0	0	25.00	28.84	14.00
2009	7.94	0.193	0	0	0	0	25.00	28.84	14.00
2010	8.34	0.202	0	0	0	0	25.00	28.84	14.00
TOTL			720	914	2880	3656			

Province code: 2 (B.C.) PR_CODE_G 0
Type reserve code: 1 (Proven Developed, Producing)

TABLE 9

PROVEN DEVELOPED,
PRODUCING
RESERVES

TYPICAL B.C. GAS FIELD
40% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

SUMMARY OF RESERVES AND PRESENT WORTH
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

RESERVES	OIL	SOLUTION GAS	NON-ASSOC ASSOC GAS	ETHANE	PROPANE	BUTANES	PENTANES PLUS	TOTAL NGL	SULPHUR
	MBBL	MMCF	MMCF	MBBL	MBBL	MBBL	MBBL	MBBL	MLT
GROSS	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. INT.	0.0	0	52000	0.0	0.0	488.8	223.6	712.4	78.0
CO. NET	0.0	0	40721	0.0	0.0	391.0	178.9	569.9	65.0

PRESENT WORTH

DISCOUNT RATE	TOTAL NET CAPITAL	BEFORE TAX NET REV	ALB ROY TAX CR.	WGAL/LOAN OVERHEAD	BEFORE TAX CASH FLOW	INCOME TAXES	AFTER TAX CASH FLOW
%	M$	M$	M$	M$	M$	M$	M$
0.0	5794	240885	0	0	240885	104984	135901
10.0	3137	53693	0	0	53693	23077	30616
12.0	2878	44118	0	0	44118	18970	25148
15.0	2576	34225	0	0	34225	14743	19482
18.0	2349	27596	0	0	27596	11921	15675
20.0	2229	24318	0	0	24318	10529	13789
25.0	2003	18563	0	0	18563	8093	10470
30.0	1850	14887	0	0	14887	6543	8344

USES $2.04/MMCF + 7% ESCALATION

TABLE 9

TYPICAL B.C. GAS FIELD
40% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

PROVEN DEVELOPED,
PRODUCING
RESERVES

PRODUCTION AND PRICE FORECAST (MAJOR PRODUCTS AND SULPHUR)
(PRODN START : JAN 1,1992)

	NON-ASSOC / ASSOC PIPELINE GAS						SULPHUR			
YEAR	WELLS	DAILY	GROSS	CO. INT	CO.NET	PRICE	GROSS	CO. INT	CO.NET	PRICE
		MCF/D	MMCF	MMCF	MMCF	$/MCF	MLT	MLT	MLT	$/LT
1992	3.0	5700	2081	2081	1704	2.04	3.1	3.1	2.6	60.00
1993	3.0	5700	2081	2081	1695	2.18	3.1	3.1	2.6	65.00
1994	3.0	5700	2081	2081	1686	2.34	3.1	3.1	2.6	70.00
1995	4.0	5700	2081	2081	1678	2.50	3.1	3.1	2.6	75.00
1996	5.0	5700	2081	2081	1670	2.67	3.1	3.1	2.6	80.00
1997	5.0	5700	2081	2081	1663	2.86	3.1	3.1	2.6	85.00
1998	5.0	5700	2081	2081	1656	3.06	3.1	3.1	2.6	90.00
1999	5.0	5700	2081	2081	1650	3.28	3.1	3.1	2.6	95.00
2000	5.0	5700	2081	2081	1644	3.51	3.1	3.1	2.6	100.00
2001	6.0	5700	2081	2081	1639	3.75	3.1	3.1	2.6	105.00
2002	6.0	5700	2081	2081	1633	4.01	3.1	3.1	2.6	110.00
2003	7.0	5700	2081	2081	1629	4.29	3.1	3.1	2.6	115.00
2004	7.0	5700	2081	2081	1624	4.59	3.1	3.1	2.6	120.00
2005	8.0	5700	2081	2081	1620	4.92	3.1	3.1	2.6	125.00
2006	8.0	5468	1996	1996	1550	5.26	3.0	3.0	2.5	131.50
2007	8.0	5028	1835	1835	1422	5.63	2.8	2.8	2.3	138.32
2008	8.0	4624	1688	1688	1306	6.02	2.5	2.5	2.1	145.49
2009	8.0	4253	1552	1552	1198	6.44	2.3	2.3	1.9	153.02
2010	8.0	3911	1427	1427	1100	6.90	2.1	2.1	1.8	160.92
SUBT			37626	37626	29766		56.4	56.4	47.0	
26YR			14374	14374	10955		21.6	21.6	18.0	
TOTL			52000	52000	40721		78.0	78.0	65.0	

USES $2.04/MMCF + 7% ESCALATION

PRODUCTION AND PRICE FORECAST (NGL's)
(PRODN START : JAN 1,1992)

	BUTANES				PENTANES PLUS			
YEAR	GROSS	CO. INT	CO.NET	PRICE	GROSS	CO. INT	CO.NET	PRICE
	MBBL	MBBL	MBBL	$/BBL	MBBL	MBBL	MBBL	$/BBL
1992	19.6	19.6	15.6	11.43	8.9	8.9	7.2	20.84
1993	19.6	19.6	15.6	12.60	8.9	8.9	7.2	23.11
1994	19.6	19.6	15.6	14.02	8.9	8.9	7.2	25.26
1995	19.6	19.6	15.6	15.54	8.9	8.9	7.2	27.60
1996	19.6	19.6	15.6	17.20	8.9	8.9	7.2	30.11
1997	19.6	19.6	15.6	18.99	8.9	8.9	7.2	32.83
1998	19.6	19.6	15.6	20.93	8.9	8.9	7.2	35.77
1999	19.6	19.6	15.6	23.06	8.9	8.9	7.2	38.94
2000	19.6	19.6	15.6	24.90	8.9	8.9	7.2	41.77
2001	19.6	19.6	15.6	26.34	8.9	8.9	7.2	44.02
2002	19.6	19.6	15.6	27.88	8.9	8.9	7.2	46.38
2003	19.6	19.6	15.6	29.49	8.9	8.9	7.2	48.86
2004	19.6	19.6	15.6	31.19	8.9	8.9	7.2	51.46
2005	19.6	19.6	15.6	32.97	8.9	8.9	7.2	54.19
2006	18.8	18.8	15.0	34.75	8.6	8.6	6.9	57.03
2007	17.3	17.3	13.8	36.63	7.9	7.9	6.3	60.02
2008	15.9	15.9	12.7	38.59	7.3	7.3	5.8	63.16
2009	14.6	14.6	11.7	40.66	6.7	6.7	5.3	66.45
2010	13.4	13.4	10.7	42.82	6.1	6.1	4.9	69.91
SUBT	353.7	353.7	282.9		161.8	161.8	129.4	
26YR	135.1	135.1	108.1		61.8	61.8	49.5	
TOTL	488.8	488.8	391.0		223.6	223.6	178.9	

TABLE 9

TYPICAL B.C. GAS FIELD
40% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

	REVENUE						ROYALTIES									
YEAR	OIL	GAS	NGL	SUL	ROY	OTHER	CROWN	PROD	RES	SUL	GCA	MIN TAXES	LEASE EXP	PLANT EXP	OPER INC	NPI
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	4244	410	187	0	0	850	0	0	31	0	0	300	0	3661	0
1993	0	4541	453	203	0	0	933	0	0	34	0	0	314	0	3916	0
1994	0	4859	500	218	0	0	1022	0	0	36	0	0	330	0	4190	0
1995	0	5199	551	234	0	0	1117	0	0	39	0	0	395	0	4434	0
1996	0	5563	606	250	0	0	1219	0	0	42	0	0	465	0	4693	0
1997	0	5953	665	265	0	0	1328	0	0	44	0	0	488	0	5022	0
1998	0	6369	729	281	0	0	1445	0	0	47	0	0	513	0	5375	0
1999	0	6815	799	296	0	0	1571	0	0	49.	0	0	538	0	5753	0
2000	0	7292	861	312	0	0	1702	0	0	52	0	0	565	0	6146	0
2001	0	7803	909	328	0	0	1839	0	0	55	0	0	658	0	6487	0
2002	0	8349	960	343	0	0	1986	0	0	57	0	0	691	0	6918	0
2003	0	8933	1014	359	0	0	2143	0	0	60	0	0	797	0	7307	0
2004	0	9559	1070	374	0	0	2311	0	0	62	0	0	837	0	7794	0
2005	0	10228	1130	390	0	0	2490	0	0	65	0	0	957	0	8236	0
2006	0	10498	1141	394	0	0	2572	0	0	66	0	0	991	0	8405	0
2007	0	10330	1106	381	0	0	2545	0	0	63	0	0	1012	0	8196	0
2008	0	10165	1071	368	0	0	2518	0	0	61	0	0	1036	0	7990	0
2009	0	10002	1037	356	0	0	2489	0	0	59	0	0	1061	0	7786	0
2010	0	9842	1004	345	0	0	2460	0	0	57	0	0	1089	0	7584	0
SUBT	0	146547	16015	5885	0	0	34539	0	0	981	3	0	13037	0	119893	0
26YR	0	202933	16901	5754	0	0	52089	0	0	959	3	0	45757	0	126787	0
TOTL	0	349480	32917	11639	0	0	86628	0	0	1940	5	0	58794	0	246680	0

USES $2.04/MMCF + 7% ESCALATION

FORECAST OF REVENUE BEFORE INCOME TAXES
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

	INTANGIBLE		TANGIBLE									LOAN REPMT				
YEAR	CEE	CDE	CL 41	PLANT	OTHER	CEDIP COGPE	TOTAL CAP	NET REV	CUM NETREV	ARTC	OVHD	PRIN	INT	WGML REPMT	CASH FLOW	CUM CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	270	1080	0	0	0	1350	-1350	-1350	0	0	0	0	0	-1350	-1350
1992	0	0	0	0	0	0	0	3661	2311	0	0	0	0	0	3661	2311
1993	0	0	0	0	0	0	0	3916	6227	0	0	0	0	0	3916	6227
1994	0	0	0	0	0	0	0	4190	10417	0	0	0	0	0	4190	10417
1995	0	109	438	0	0	0	547	3887	14303	0	0	0	0	0	3887	14303
1996	0	115	459	0	0	0	574	4119	18422	0	0	0	0	0	4119	18422
1997	0	0	0	0	0	0	0	5022	23445	0	0	0	0	0	5022	23445
1998	0	0	0	0	0	0	0	5375	28820	0	0	0	0	0	5375	28820
1999	0	0	0	0	0	0	0	5753	34572	0	0	0	0	0	5753	34572
2000	0	0	0	0	0	0	0	6146	40718	0	0	0	0	0	6146	40718
2001	0	147	586	0	0	0	733	5754	46472	0	0	0	0	0	5754	46472
2002	0	0	0	0	0	0	0	6918	53390	0	0	0	0	0	6918	53390
2003	0	162	647	0	0	0	808	6499	59889	0	0	0	0	0	6499	59889
2004	0	0	0	0	0	0	0	7794	67683	0	0	0	0	0	7794	67683
2005	0	356	1426	0	0	0	1782	6454	74137	0	0	0	0	0	6454	74137
2006	0	0	0	0	0	0	0	8405	82543	0	0	0	0	0	8405	82543
2007	0	0	0	0	0	0	0	8196	90739	0	0	0	0	0	8196	90739
2008	0	0	0	0	0	0	0	7990	98728	0	0	0	0	0	7990	98728
2009	0	0	0	0	0	0	0	7786	106514	0	0	0	0	0	7786	106514
2010	0	0	0	0	0	0	0	7584	114098	0	0	0	0	0	7584	114098
SUBT	0	1159	4636	0	0	0	5794	114098		0	0	0	0	0	114098	
26YR	0	0	0	0	0	0	0	126787		0	0	0	0	0	126787	
TOTL	0	1159	4636	0	0	0	5794	240885		0	0	0	0	0	240885	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
NET REVENUE	53693	44118	34225	27596	24318	18563	14887
CASH FLOW	53693	44118	34225	27596	24318	18563	14887

TABLE 9

TYPICAL B.C. GAS FIELD
40% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX RESINC	LEASE EXP	PROD ROY	C.C.A.	RES ALLOW	OTHER INC	RES ROY	---CAPITAL WRITEOFF--- CEE	CDE	COGPE	DEBT INT	NPI+ OVHD	DEPL	TAXREV ADJ.
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	0	0	0	135	-34	0	0	0	81	0	0	0	0	0
1992	4654	300	0	236	1030	0	0	0	57	0	0	0	0	0
1993	4994	314	0	177	1126	0	0	0	40	0	0	0	0	0
1994	5359	330	0	133	1224	0	0	0	28	0	0	0	0	0
1995	5750	395	0	154	1300	0	0	0	52	0	0	0	0	0
1996	6169	465	0	228	1369	0	0	0	71	0	0	0	0	0
1997	6618	488	0	228	1475	0	0	0	50	0	0	0	0	0
1998	7099	513	0	171	1604	0	0	0	35	0	0	0	0	0
1999	7614	538	0	128	1737	0	0	0	24	0	0	0	0	0
2000	8153	565	0	96	1873	0	0	0	17	0	0	0	0	0
2001	8712	658	0	146	1977	0	0	0	56	0	0	0	0	0
2002	9309	691	0	182	2109	0	0	0	39	0	0	0	0	0
2003	9947	797	0	218	2233	0	0	0	76	0	0	0	0	0
2004	10629	837	0	244	2387	0	0	0	53	0	0	0	0	0
2005	11357	957	0	361	2510	0	0	0	144	0	0	0	0	0
2006	11639	991	0	449	2550	0	0	0	101	0	0	0	0	0
2007	11436	1012	0	337	2522	0	0	0	71	0	0	0	0	0
2008	11236	1036	0	253	2487	0	0	0	49	0	0	0	0	0
2009	11039	1061	0	189	2447	0	0	0	35	0	0	0	0	0
2010	10846	1089	0	142	2404	0	0	0	24	0	0	0	0	0
SUBT	162562	13037	0	4209	36329	0	0	0	1102	0	0	0	0	0
26YR	219835	45757	0	426	43413	0	0	0	57	0	0	0	0	0
TOTL	382397	58794	0	4635	79742	0	0	0	1159	0	0	0	0	0

USES $2.04/MMCF + 7% ESCALATION

FORECAST OF INCOME TAXES AND REVENUE
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	FEDTAX INC	FED TAXES	PRVTAX RESINC	PRVTAX INC	PROV TAXES	PRVROY TAXREB	PROC INC	PL EXP SULROY	PLANT CCA	PROC TAXINC	PROC TAXES	INVTAX CREDIT	BEFORE TAX CF	TOTAL INCTAX	AFTER TAX CF	CUM AT CF
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
1991	-182	-53	0	-182	-26	5	0	0	0	0	0	0	-1350	-83	-1267	-1267
1992	3032	874	4654	3032	424	-25	187	31	0	156	67	0	3661	1391	2270	1003
1993	3337	963	4994	3337	467	-27	203	34	0	169	72	0	3916	1529	2387	3390
1994	3644	1051	5359	3644	510	-28	218	36	0	182	78	0	4190	1668	2522	5912
1995	3848	1110	5750	3848	539	-26	234	39	0	195	84	0	3887	1758	2129	8040
1996	4036	1164	6169	4036	565	-21	250	42	0	208	89	0	4119	1839	2280	10320
1997	4376	1262	6618	4376	613	-21	265	44	0	221	95	0	5022	1990	3032	13352
1998	4776	1377	7099	4776	669	-22	281	47	0	234	100	0	5375	2169	3206	16559
1999	5186	1496	7614	5186	726	-23	296	49	0	247	106	0	5753	2351	3402	19961
2000	5601	1615	8153	5601	784	-24	312	52	0	260	111	0	6146	2535	3611	23571
2001	5875	1694	8712	5875	823	-19	328	55	0	273	117	0	5754	2653	3101	26673
2002	6288	1813	9309	6288	880	-17	343	57	0	286	123	0	6918	2833	4085	30757
2003	6624	1910	9947	6624	927	-13	359	60	0	299	128	0	6499	2978	3520	34278
2004	7108	2050	10629	7108	995	-11	374	62	0	312	134	0	7794	3190	4605	38882
2005	7385	2130	11357	7385	1034	-3	390	65	0	325	139	0	6454	3306	3148	42030
2006	7549	2177	11639	7549	1057	3	394	66	0	328	141	0	8405	3371	5034	47064
2007	7494	2161	11436	7494	1049	3	381	63	0	317	136	0	8196	3343	4853	51917
2008	7411	2137	11236	7411	1038	4	368	61	0	307	132	0	7990	3302	4687	56604
2009	7307	2107	11039	7307	1023	6	356	59	0	297	127	0	7786	3251	4534	61138
2010	7187	2073	10846	7187	1006	8	345	57	0	287	123	0	7584	3194	4390	65529
SUBT	107885	31114	162562	107885	15104	-251	5885	981	0	4904	2101	0	114098	48570	65529	
26YR	130182	37356	219835	130182	18226	1214	5754	959	0	4795	2047	0	126787	56414	70372	
TOTL	238067	68470	382397	238067	33329	963	11639	1940	0	9699	4148	0	240885	104984	135901	

PRESENT WORTH M$	10.0%	12.0%	15.0%	18.0%	20.0%	25.0%	30.0%
TOTAL INC TAX	23077	18970	14743	11921	10529	8093	6543
AFTER TAX CF	30616	25148	19482	15675	13789	10470	8344

TABLE 9

TYPICAL B.C. GAS FIELD
40% LOAD FACTOR
100 PCT WI SUB TO CROWN ROYALTY

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	PRODn MONTHS	BUTn REC RATE	PENT+ REC RATE	SUL REC RATE	W.I. %	CR ROY PRICE $/vol	CROWN GAS %	CROWN BYPs %	G.C.A. RATE $/Mcf
1991	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	12.0	9.40	4.30	1.50	100.00	1.69	18.0946	20.00	0.00
1993	12.0	9.40	4.30	1.50	100.00	1.81	18.5464	20.00	0.00
1994	12.0	9.40	4.30	1.50	100.00	1.94	18.9686	20.00	0.00
1995	12.0	9.40	4.30	1.50	100.00	2.07	19.3631	20.00	0.00
1996	12.0	9.40	4.30	1.50	100.00	2.22	19.7319	20.00	0.00
1997	12.0	9.40	4.30	1.50	100.00	2.37	20.0766	20.00	0.00
1998	12.0	9.40	4.30	1.50	100.00	2.54	20.3986	20.00	0.00
1999	12.0	9.40	4.30	1.50	100.00	2.72	20.6997	20.00	0.00
2000	12.0	9.40	4.30	1.50	100.00	2.91	20.981	20.00	0.00
2001	12.0	9.40	4.30	1.50	100.00	3.11	21.2439	20.00	0.00
2002	12.0	9.40	4.30	1.50	100.00	3.33	21.4897	20.00	0.00
2003	12.0	9.40	4.30	1.50	100.00	3.56	21.7193	20.00	0.00
2004	12.0	9.40	4.30	1.50	100.00	3.81	21.9339	20.00	0.00
2005	12.0	9.40	4.30	1.50	100.00	4.08	22.1345	20.00	0.00
2006	12.0	9.40	4.30	1.50	100.00	4.37	22.322	20.00	0.00
2007	12.0	9.40	4.30	1.50	100.00	4.67	22.4972	20.00	0.00
2008	12.0	9.40	4.30	1.50	100.00	5.00	22.6609	20.00	0.00
2009	12.0	9.40	4.30	1.50	100.00	5.35	22.8139	20.00	0.00
2010	12.0	9.40	4.30	1.50	100.00	5.72	22.9569	20.00	0.001
TOTL									

ENGINEERING DETAIL OF FORECAST
(AS OF NOV 1,1991 ; PRODN START JAN 1,1992)

YEAR	Prod Ex WL-GAS M$/W/M	Prod Ex VAR-GAS $/Mcf	-GROSS INTANG-- --INVESTMENT--- Cur M$	Fut M$	-GRSS TAN CL41- --INVESTMENT--- Cur M$	Fut M$	RES ALLOW %	FED Inc Tax %	PROV Inc Tax %
1991	3.30	0.08	270	270	1080	1080	25.00	28.84	14.00
1992	3.47	0.084	0	0	0	0	25.00	28.84	14.00
1993	3.64	0.088	0	0	0	0	25.00	28.84	14.00
1994	3.82	0.093	0	0	0	0	25.00	28.84	14.00
1995	4.01	0.097	90	109	360	438	25.00	28.84	14.00
1996	4.21	0.102	90	115	360	459	25.00	28.84	14.00
1997	4.42	0.107	0	0	0	0	25.00	28.84	14.00
1998	4.64	0.113	0	0	0	0	25.00	28.84	14.00
1999	4.88	0.118	0	0	0	0	25.00	28.84	14.00
2000	5.12	0.124	0	0	0	0	25.00	28.84	14.00
2001	5.38	0.13	90	147	360	586	25.00	28.84	14.00
2002	5.64	0.137	0	0	0	0	25.00	28.84	14.00
2003	5.93	0.144	90	162	360	647	25.00	28.84	14.00
2004	6.22	0.151	0	0	0	0	25.00	28.84	14.00
2005	6.53	0.158	180	356	720	1426	25.00	28.84	14.00
2006	6.86	0.166	0	0	0	0	25.00	28.84	14.00
2007	7.20	0.175	0	0	0	0	25.00	28.84	14.00
2008	7.56	0.183	0	0	0	0	25.00	28.84	14.00
2009	7.94	0.193	0	0	0	0	25.00	28.84	14.00
2010	8.34	0.202	0	0	0	0	25.00	28.84	14.00
TOTL			810	1159	3240	4636			

Province code: 2 (B.C.) PR_CODE_G 0
Type reserve code: 1 (Proven Developed, Producing)

APPENDIX A

ABBREVIATIONS

The following abbreviations may be used in various places throughout the report:

A&S	Alberta and Southern Gas Co. Ltd.
Ac.Ft.	acre-feet
AOF	absolute open flow
ARTC	Alberta Royalty Tax Credit
Bbl	barrel
BCF	billion cubic feet
BOPD	barrels of oil per day
BPAF	barrels per acre-foot
BPD	barrels per day
BPM	barrels per month
BTU	British thermal unit
BWPD	barrels of water per day
Cr or C	Crown
DCQ	daily contract quantity
^{o}C	degrees, Celsius
^{o}F	degrees, Fahrenheit
^{o}K	degrees, Kelvin
^{o}R	degrees, Rankin
DSU	drilling spacing unit
GCA	gas cost allowance
GOR	gas-oil ratio
GORR	gross overriding royalty
Ha.m.	hectare-metre
J	Joule
kPa	kilopascals
LPG	liquid petroleum gas
LT	long tons
m^3	cubic metres
MBbls	thousands of barrels
M$	thousand dollars
MM$	million dollars
MCF	thousand cubic feet
MCFPD	thousand cubic feet per day
MJ/m^3	Mega Joule per cubic metre
MMCF	million cubic feet
MMCFPD	million cubic feet per day
MPR	maximum permissive rate
MRL	maximum rate limitation
NC	'new' Crown
NCI	net carried interest
NGL	natural gas liquids
NPI	net profits interest
OC	'old' Crown
P. & N. G.	petroleum and natural gas
PSU	production spacing unit
PVT	pressure-volume-temperature
psia	pounds per square inch absolute
psig	pounds per square inch gauge
RI	royalty interest
SCF	standard cubic feet
STB	stock tank barrel
t	tonnes
TJ/d	Tera Joule per day
WGML	Western Gas Marketing Limited
WI	working interest
WOR	water-oil ratio

APPENDIX B

Following is a brief description of the output pages from Sproule Associates Limited's Oil and Gas Property Economic Evaluation System. The output consists of several different reports, and the title of each report and its corresponding output data are described in the following pages.

In each report, the cash flow streams are presented on an annual basis for a number of years and the remaining years in the project are presented as a lump sum.

SUMMARY OF RESERVES AND PRESENT WORTH (H4)

GRAND TOTALS

AS OF:	Effective date of the evaluation.
PRODN START:	Production start date for the evaluation.
RESERVES:	
GROSS:	Gross reserves for all products.
CO. INT.:	Company interest reserves for all products.
CO. NET:	Net Company interest reserves for all products.
PRESENT WORTH:	
DISCOUNT RATE:	Present worth values are presented at seven chosen discount rates.
TOTAL NET CAPITAL:	Company interest in capital expenses.
BEFORE TAX NET REV:	Net revenue before Alberta Royalty Tax Credit, WGML Repayments, Loan Repayments, Overhead and Income Taxes.
ALB ROY TAX CR:	Alberta Royalty Tax Credit.
WGML/LOAN, OVERHEAD:	WGML, A&S and Other Repayments, Loan Repayments, and Overhead.

PRESENT WORTH (H4) - Continued

BEFORE TAX CASH FLOW:	Cash flow before income taxes including the Alberta Royalty Tax Credit, WGML Repayments, Loan Repayments and Overhead.
INCOME TAXES:	Total federal and provincial income taxes less all appropriate credits and rebates (if requested).
AFTER TAX CASH FLOW:	Cash flow after income taxes (if requested).
ACQUISITION VALUE:	Cash flow after income taxes including tax advantage of COGPE write-off (if requested).

SUMMARY OF RESERVES AND PRESENT WORTH (H8)

YEARLY SUMMARY

CO. INT.:	Total Company interest oil and gas reserves and production forecast.
CO. NET:	Total net Company interest oil and gas reserves and production forecast.
OIL REV.:	Company working interest oil production times oil price.
GAS REV.:	Company working interest solution and non-associated gas production times gas price.
OTHER REV.:	Revenue from all by-products (NGL and sulphur) plus royalty interest income, gas processing income and revenue from other sources.
TOTAL ROY. & MIN. TAXES:	Total lessor and overriding royalties plus all freehold mineral taxes less applicable Gas Cost Allowance (excludes sulphur royalties).
TOTAL OPER. EXPEN.:	Total operating expenses relating to lease, gathering, compression and processing.

RESERVES AND PRESENT WORTH (H8) - Continued

OTHER EXPEN.:	Other expenses including net profit expenses and plant expenses, and sulphur royalties.
TOTAL CAP.:	Total Intangible, Tangible and Canadian Oil and Gas Property Expense, net of incentives.
NET REV.:	Sum of all revenues less royalties and mineral taxes, operating expenses, other expenses and all capital.
ARTC, LOANS, OVHD.:	Alberta Royalty Tax Credit, Loan Repayments, WGML Repayments, and Overhead.
CASH FLOW:	Net revenue plus ARTC, less WGML Repayments, Loan and Overhead.
TOTAL INC. TAX:	Total federal and provincial income taxes less all appropriate credits and rebates (if requested).
AFTER TAX CF.:	Cash flow after income taxes (if requested).
DISCOUNTED CASH STREAMS:	Present worth values of respective cash flow streams are presented at three discount rates.

PRODUCTION AND PRICE FORECAST (H1)

PRODN START: Production start date for the evaluation.

OIL, ASSOC/NON-ASSOC PIPELINE GAS

WELLS: Number of wells on production.

DAILY: Gross daily production rate.

OIL, SOLUTION GAS, ASSOC/NON-ASSOC PIPELINE GAS, ETHANE, PROPANE, BUTANES, PENTANES PLUS AND SULPHUR

GROSS: Gross yearly production.

CO. INT.: Company interest yearly production.

CO. NET: Net Company interest yearly production.

PRICE: Price received for the product.

Notes:

OIL QUALITY ADJ: Oil quality price adjustment in dollars per barrel.

GAS HEATING VALUE: Gas price heating value adjustment in MBTU/SCF.

TRUCKING COSTS: Trucking costs in dollars per barrel.

FORECAST OF REVENUE BEFORE INCOME TAXES (H2)

AS OF: Effective date of the evaluation.

PRODN START: Production start date for the evaluation.

REVENUE:

OIL: Company working interest oil production times oil price.

GAS: Company working interest in solution and/or associated and non-associated gas production times gas price.

NGL: Company working interest natural gas liquids (ethane, propane, butanes, and pentanes plus) production times respective by-product price.

SUL: Company working interest sulphur production times sulphur price.

ROY: Revenue from Company overriding royalty interests and freehold production income.

OTHER: Other income including custom gas processing revenue.

FORECAST OF REVENUE BEFORE INCOME TAXES (H2) - Continued

ROYALTIES:

CROWN:	Crown royalties - Lessor royalties paid to the Crown.
PROD:	Production royalties - Lessor royalties payable to freehold owners or overriding royalty owners. These royalties are deducted before resource allowances in income tax calculations.
RES:	Resource royalties - Lessor royalties payable to freehold owners or overriding royalty owners. These royalties are deducted after resource allowances in income tax calculations.
SUL:	Lessor royalties paid on sulphur production.
GCA:	Total Gas Cost Allowance charged to applicable Crown, freehold and overriding royalty owners.
MIN TAXES:	Freehold mineral and freehold production taxes paid.
LEASE EXP:	Lease operating expense - sum of all operating costs relating to lease, gathering and compression.
PLANT EXP.:	Processing plant operating costs associated with processing income.
OPER INC.:	Operating income, sum of all revenue less all royalties, mineral taxes, lease expenses, plant expenses.
NPI:	Net profits interest expense.

FORECAST OF REVENUE BEFORE INCOME TAXES (H2) - Page 2

INTANGIBLE:

CEE:	Capital investments classified as Canadian Exploration Expense.
CDE:	Capital investments classified as Canadian Development Expense.

TANGIBLE:

CL 41:	Tangible capital investments under a Capital Cost Allowance Class 41, tax depreciation of 25 percent declining balance.
PLANT:	Tangible capital investments for a processing plant, Capital Cost Allowance Class 39, tax depreciation of 25 percent declining balance.
OTHER:	Tangible capital investments under a Capital Cost Allowance classification other than Class 41 and Class 39.
COGPE:	Canadian Oil and Gas Property Expense.

TOTAL CAP:	Total Intangible and Tangible capital costs plus Canadian Oil and Gas Property Expense.
NET REV:	Net Revenue - Operating income less Net Profits Interests less total Capital.
CUM NET REV:	Cumulative net revenue.

FORECAST OF REVENUE BEFORE INCOME TAXES (H2) - Page 2 - Continued

ARTC:	Alberta Royalty Tax Credit.
OVHD:	Overhead expenses.
LOAN REPMT:	
PRIN:	Loan principal repayment.
INT:	Loan interest payments.
WGML REPMT:	Western Gas Marketing Limited Topgas repayments and repayments to other gas purchasers.
CASH FLOW:	Net revenue plus ARTC less Overhead, Principle and Interest payments, and WGML repayments.
CUM CF:	Cumulative cash flow.
PRESENT WORTH:	Present worth of net revenue and cash flow are presented at seven discount rates.

FORECAST OF INCOME TAXES AND REVENUE (H3)

AS OF:	Effective date of the evaluation.
PRODN START:	Production start date for the evaluation.
FED TAX RES INC.:	Resource income subject to Federal Income Tax - Production revenue plus Federal Income Tax adjustment.
LEASE EXP:	Lease operating expense.
PROD. ROY:	Production royalties.
C.C.A.:	Capital Cost Allowance - tax depreciation on tangible investments, excluding Class 39.
RES ALLOW:	Resource Allowance.
OTHER INC.:	Other revenue, including resource royalties received, net of GCA.
RES ROY:	Resource royalties paid, net of GCA.

FORECAST OF INCOME TAXES AND REVENUE (H3) - Continued

CAPITAL WRITEOFF

CEE:	Capital writeoff for Canadian Exploration Expense.
CDE:	Capital writeoff for Canadian Development Expense.
COGPE:	Capital writeoff for Canadian Oil and Gas Property Expense.
DEBT INT:	Interest on debt.
NPI & OVHD:	Net Profits Interests and Overhead costs not allocated elsewhere.
DEPL:	Depletion allowance.
TAX REV ADJ.:	Taxable revenue adjustment - any adjustment required in the calculated taxable revenue.

FORECAST OF INCOME TAXES AND REVENUE (H3) - Page 2

FED TAX INC.:	Federal taxable net income - income subject to Federal Income Tax.
FED TAXES:	Federal Income Tax payable.
PRV TAX RES INC:	Resource income subject to Provincial Income Tax - production revenue plus Provincial Income Tax adjustment.
PRV TAX INC:	Provincial taxable net income - income subject to Provincial Income Tax.
PROV TAXES:	Provincial income tax payable.
PRV ROY TAX REB:	Provincial Royalty Tax Rebate.
PROC INC:	Processing revenue, including sulphur revenue.
PL EXP SUL ROY:	Plant operating expense and sulphur royalties.
PLANT CCA:	Plant Capital Cost Allowance - tax depreciation on tangible investments for a processing plant, if there is processing income.
PROC TAX INC.:	Processing taxable net income - processing income subject to income tax.
PROC TAXES:	Processing taxes paid.
INV TAX CREDIT:	Investment Tax Credit.
BEFORE TAX CF:	Cash flow before income taxes.

FORECAST OF INCOME TAXES AND REVENUE (H3) - Page 2 - Continued

TOTAL INC TAX:	Total income tax payable.
AFTER TAX CF:	Cash flow after income taxes - includes Investment Tax Credit and Provincial Royalty Tax Rebate.
CUM AT CF:	Cumulative cash flow after income taxes.
PRESENT WORTH:	Present worth of income taxes and cash flow after income taxes are presented at seven different discount rates. Present worth of Acquisition Value may be presented.