Westcoast Transmission Company Limited Annual Report 1978

The Westcoast Transmission System

Westcoast Transmission Company Limited is the owner and operator of the first big-inch natural gas pipeline built in Canada. Its 2,500-mile system transmits more energy than is derived from any other source in British Columbia, surpassing even electricity. The natural gas industry in B.C., in which the Company is the major component, contributes more direct revenue to the provincial treasury than any other industry, including forest products and mining.

Investor-owned and federally incorporated and regulated, the Company draws its natural gas supplies from a vast area of western Canada, including British Columbia, Alberta, the Yukon Territory and the Northwest Territories, thus contributing to the economic and social development of the total region.

As the carrier of enormous energy resources, Westcoast is committed to policies which will benefit, in realistic measure, its shareholders, employees, customers, suppliers and gas producers. It is equally concerned that its activities serve the public interest, manifest appropriate sensitivity to environmental issues, comply with government regulation and enhance Canada's trade position and international relations through export sales of natural gas.

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Contents

Information

This report has been prepared for our shareholders, securities regulatory agencies and the stock exchanges. However, it is hoped it may provide a convenient and useful source of information to members of the public and investors. We have attempted to provide all basic and practical material relating to Westcoast's operations in 1978. If further information is required we invite you to write either the Secretary of the Company or the Information Services Department—

Westcoast Transmission Company Limited
1333 West Georgia Street
Vancouver, British Columbia
V6E 3K9
Canada

Annual Meeting

The annual meeting of the shareholders of Westcoast Transmission Company Limited will be held in the Waddington Room of the Hotel Vancouver, in the City of Vancouver, British Columbia, on Thursday, April 19, 1979 at 10 a.m.

Results in Brief

Financial

	1978	1977*
Total Operating Revenues *(increased by 8.2%)*	**$843,902,000**	$780,164,000
Net Income *(increased by 4.9%)*	**44,938,000**	42,850,000
Net Income Applicable to Common Shares *(increased by 5.3%)*	**41,538,000**	39,450,000
— per share *(increased by 1.7%)*	**1.21**	1.19
Cash Flow *(increased by 5.4%)*	**85,805,000**	81,419,000
— per share *(increased by 1.6%)*	**2.49**	2.45
Total Assets *(increased by 16.8%)*	**961,338,000**	823,289,000
Common Shareholders' Equity *(increased by 9.5%)*	**324,646,000**	296,487,000
— per outstanding share *(increased by 6.4%)*	**9.37**	8.81
Common Shares — weighted average *(increased by 3.4%)*	**34,408,106**	33,261,093

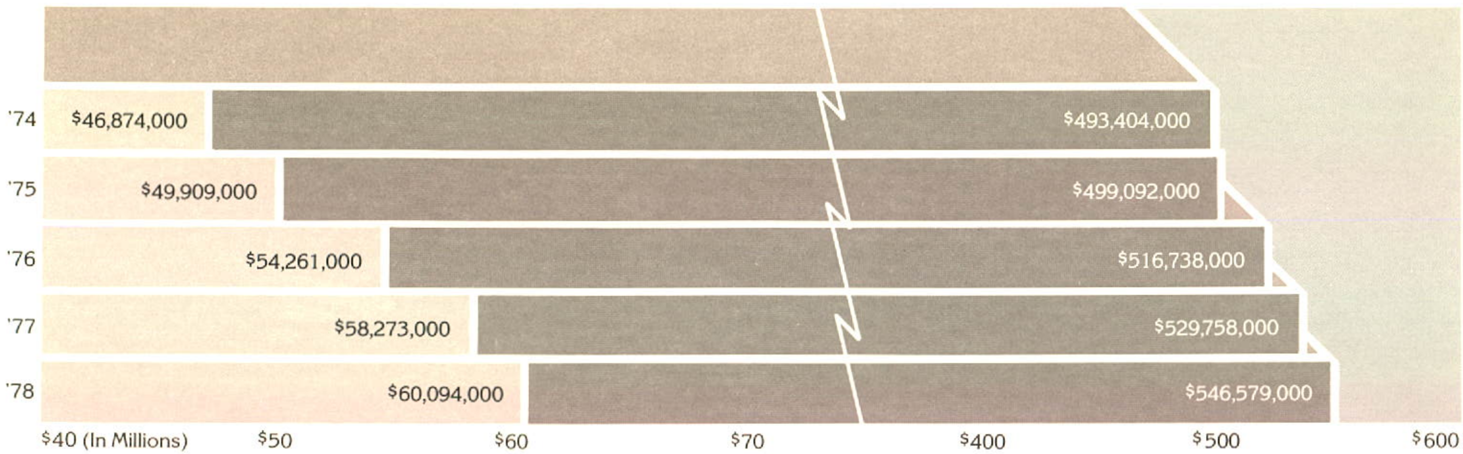
Operating

	1978	1977*
Total Gas Sales, Mcf	**344,449,000**	369,508,000
Total Gas Sales, 10^3m^3	**9 757 496**	10 467 364
Average Daily Sales, Mcf	**944,000**	1,012,000
Average Daily Sales, 10^3m^3	**26 741**	28 668
Peak Day Sales, Mcf	**1,369,000**	1,320,000
Peak Day Sales, 10^3m^3	**38 781**	37 393

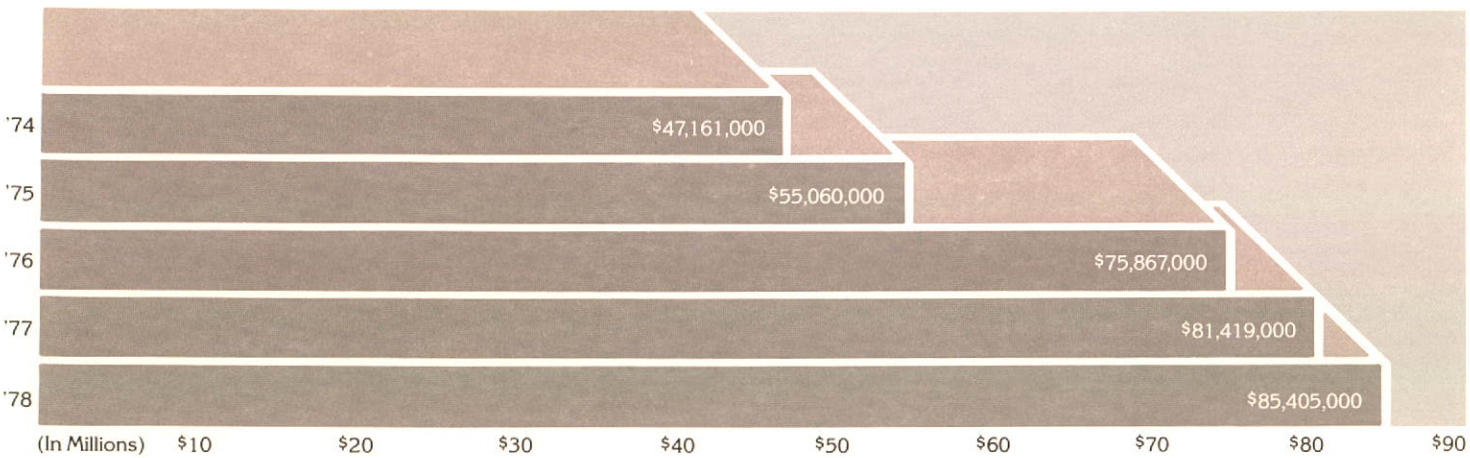
Mcf means one thousand cubic feet, and all gas volumes are expressed at a base pressure of 14.73 pounds per square inch absolute and at a base temperature of 60 degrees Fahrenheit. **10^3m^3** means one thousand cubic meters, and all gas volumes are expressed at a standard temperature of 15 degrees Celsius, and at a standard absolute pressure of 101.325 kilopascals.

*Per share information and weighted average common shares have been restated to give retroactive effect to the three-for-one share split approved by the shareholders at the annual meeting on April 20, 1978.

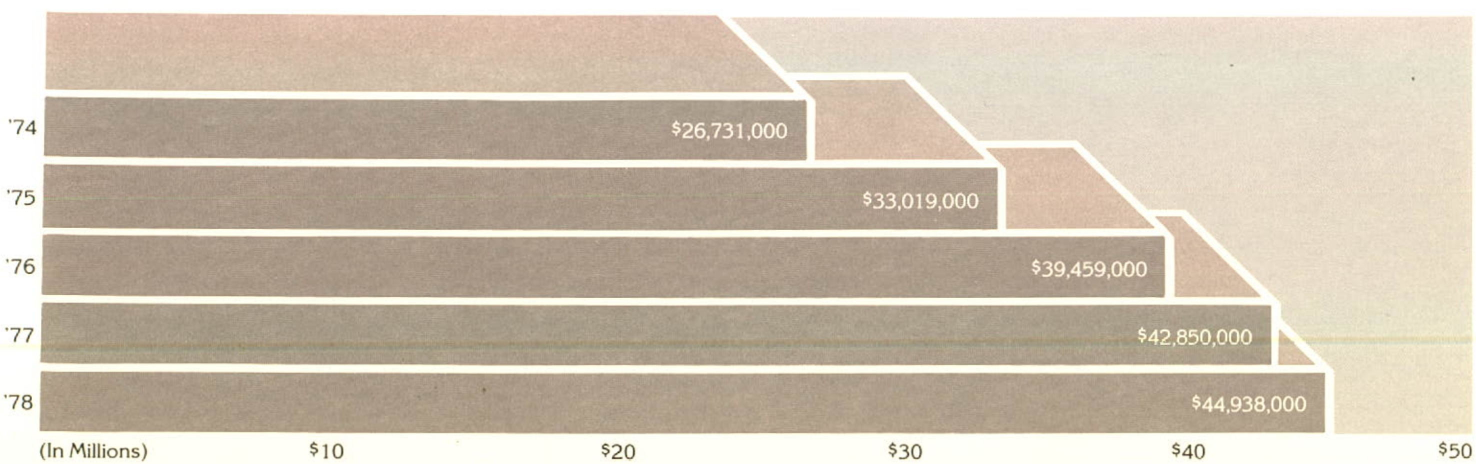
Return on Utility Rate Base and Utility Rate Base



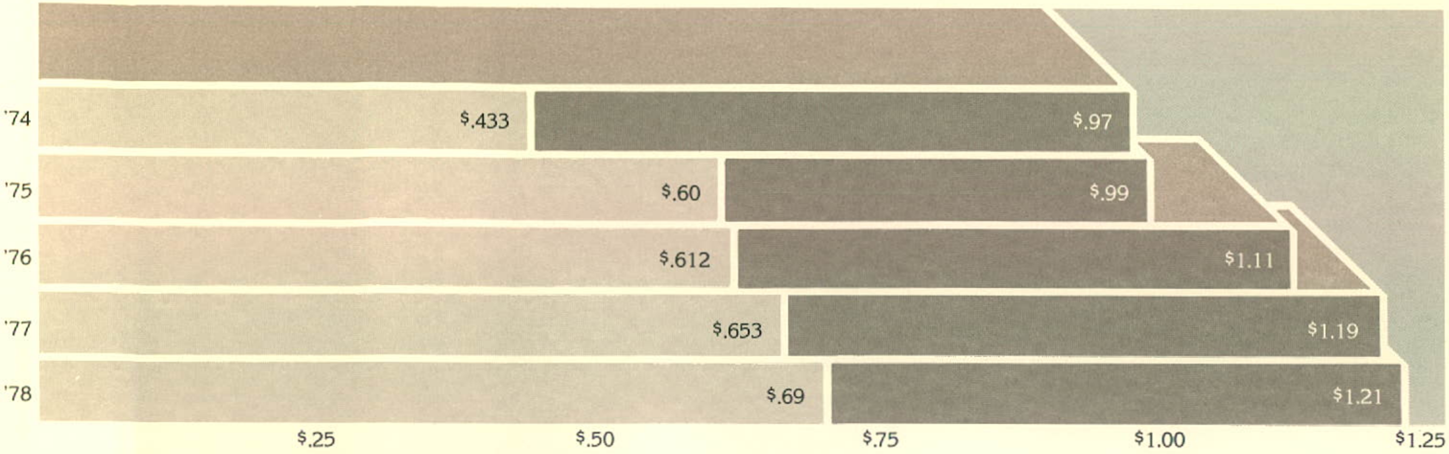
Cash Flow



Net Income

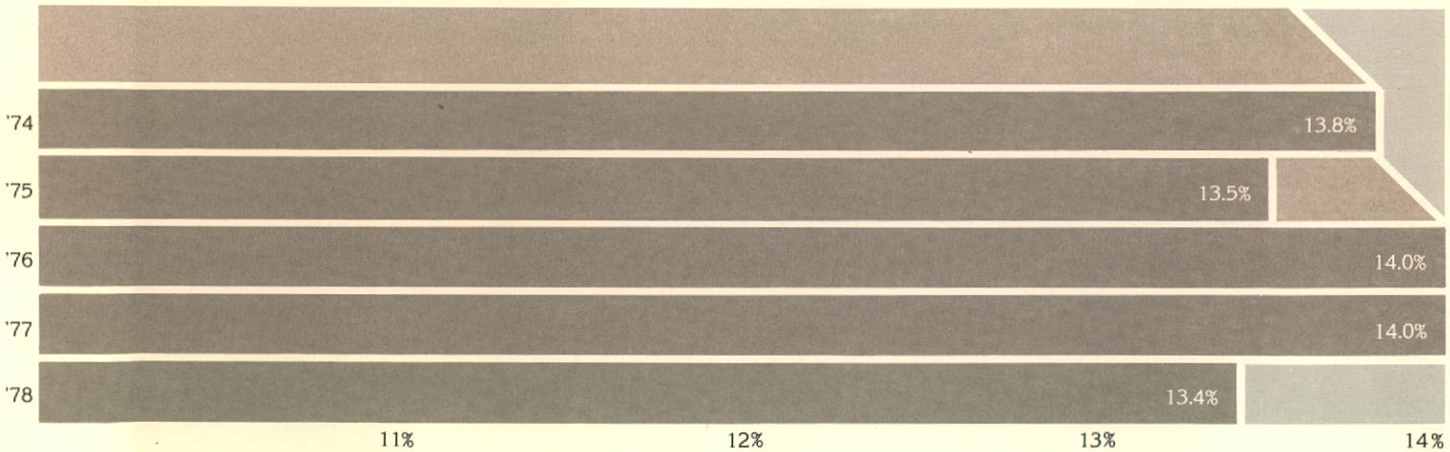


*Dividends Paid per Common Share
*Earnings per Common Share

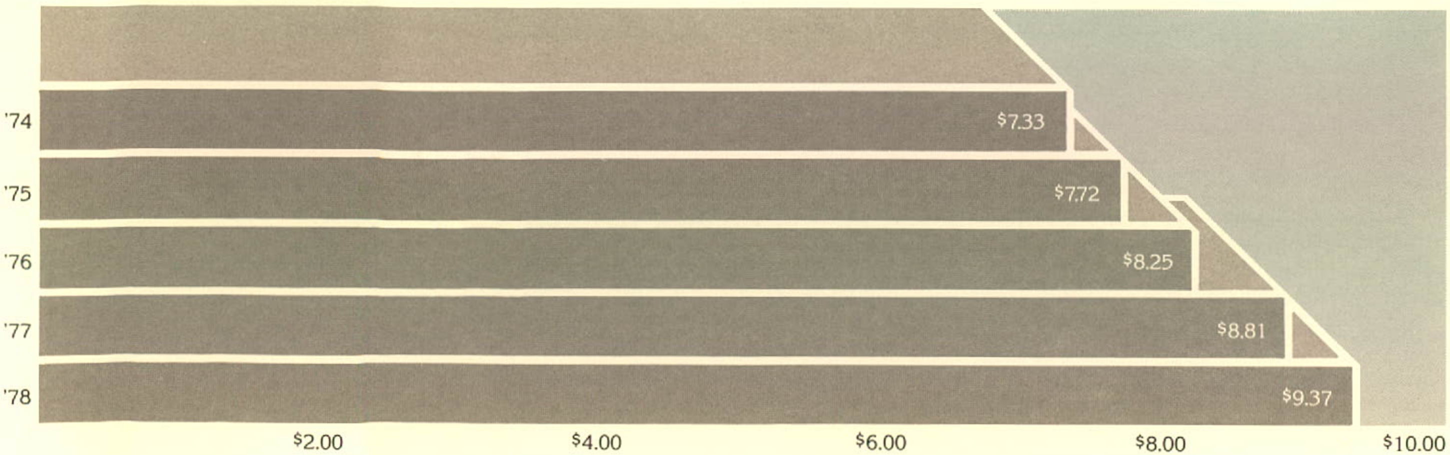


*Reflects three-for-one share split.

Return on Average Common Shareholders' Equity



*Shareholders' Equity per Common Share



*Reflects three-for-one share split.

To Our Shareholders

In a year of unsettling developments in the energy field abroad and varying regulatory decisions on this continent, your Company performed satisfactorily in an immediate sense and particularly well in building for the future. For the eighth year in succession, net income, dividends, operating revenues, cash flow and net income per common share reached record high levels. Net income increased five percent to $44,938,000, operating revenues were up eight percent to $843,902,000, and total common dividends were 69 cents per share, six percent higher than in 1977.

Although the gains were modest, they were achieved despite negative factors relating to regulatory procedures. On September 15, 1977 the Company applied to the National Energy Board for an increased rate of return and for compensation for losses on the Canadian - U.S. dollar exchange rate. By the end of 1978, only one of the three phases of the rate case had been heard and thus the financial relief sought by the Company was not obtained in the year under review.

A display of bold architecture, the Westcoast Transmission Building in Vancouver, British Columbia, is the Head Office of the Company.

A significant development in the Company's affairs in 1978 was the international agreement between Canada and the United States and supporting legislation in both countries which finally and conclusively approved the Alaska Highway natural gas pipeline. Westcoast and The Alberta Gas Trunk Line Ltd. each hold a 50 percent interest in Foothills Pipe Lines (Yukon) Ltd. which is responsible for the Canadian section of the pipeline. One measure of the importance of this multi-billion dollar project is that it has taken your Company 21 years to reach its present status and this single enterprise will triple the size of Westcoast within four to five years in terms of assets administered, equity investment and volume of energy handled.

Westcoast and its Canadian and American associates in the Alaska Highway gas pipeline — again in concert and in the same spirit of entrepreneurship — initiated another major venture during the year. It is an oil pipeline which would carry Alaska crude oil to the midwest United States in the same Alaska Highway corridor as the natural gas pipeline. The parent company for the portion of this project in Canada is Foothills Oil Pipe Line Ltd., in which Westcoast again has a 50-50 interest with The Alberta Gas Trunk Line Ltd.

This is an era of rare opportunity for enterprise, particularly in the energy field. External forces, notably the Organization of Petroleum Exporting Countries (OPEC) and, more recently, the political upheaval in Iran, have been responsible for very substantial increases in the cost of energy and disruption of the traditional pattern of energy flow. This has created grave problems for our industry, but it has also opened exciting new avenues of opportunity.

Capital is abundant in today's industrial society. Westcoast has a particular expertise and unique experience in its field of endeavor. It is your Company's determined policy to take advantage of these two circumstances by intently seeking out new opportunities and not merely waiting for them to materialize.

However, one can never overlook the constant presence of the political administration when contemplating or undertaking major industrial projects. The three tiers of government, each in its own sphere of jurisdiction and yet all in co-ordination, must establish and hold to wise ground rules within which business and industry can function successfully. Excessive taxation and other retardants to a fair and reasonable profit will inevitably interfere with the exploitation of opportunities that would benefit the total Canadian economy.

The year's activities, and particularly the Foothills' gas and oil pipeline projects and applications to regulatory authorities, have drawn heavily on the skills of Westcoast people at all levels. The resourceful and dedicated manner in which all employees have responded is gratefully acknowledged by the Board of Directors.

On behalf of the Board of Directors,

E. C. Phillips
President and Chief Executive Officer

John Anderson
Executive Vice President and
Chief Operating Officer

Vancouver, Canada
March 14, 1979

Annual Review

Financial Results and Planning

Improvement was achieved in all key financial results for the eighth consecutive year. Operating revenues increased eight percent to $843,902,000, net income was up five percent to $44,938,000 and dividends were 69 cents per common share, an increase of six percent. Cash flow was up five percent to $85,805,000 and net income per common share of $1.21 was two percent higher.

The increase in operating revenues was attributable to a rise in domestic prices, effective March 1, 1978, and increased revenues on export sales which are priced in U.S. dollars.

Net income increased despite the negative impact of the depressed Canadian dollar which resulted in losses of approximately $2 million on exchange in servicing the company's U.S. debt, compared to a loss in 1977 of $1.3 million. This additional loss which was not recoverable by the Company was, however, offset to a significant extent by higher income from the return on rate base realized in 1978 due to increased investment in Westcoast's expanded facilities.

Earnings Trend Upward

With the level of capital expenditures for Westcoast and its subsidiaries in 1978 exceeding $137 million and with capital spending of approximately $140 million expected in 1979, continued increases in earnings from the pipeline system seem secure. Expenditures on the Foothills pipeline project to transport Alaska gas to the United States are mounting as this project advances. The Company's expenditures on the project will total approximately $45 million to $50 million by the end of 1979. The combination of capital expenditures on the Westcoast system and commitments to the Foothills project will result in an external financing requirement of over $100 million in 1979. The Company anticipates obtaining these funds through a large Canadian financing in mid-1979.

On completion of the Foothills gas pipeline project in the winter of 1984-85 the Company will have a substantial investment in the system. The present plan is to raise the required funds largely in the Canadian market through a combination of bonds, debentures and preferred shares.

Higher Rate Sought

In the area of financial planning, one of the major objectives of the Company's current rate application to the National Energy Board is to achieve an increase in the return on equity to 14.75 percent. The return on equity realized in 1978 was 14 percent. Hearings on the Company's rate application, which encompasses rates, tolls, tariffs and cost of service including income taxes, depreciation and rate of return, reconvened in February 1979.

Cost-of-Service Contract

The Company continued to operate under a cost-of-service contract with the British Columbia Petroleum Corporation during 1978. As an agency of the B.C. government, the BCPC purchases all natural gas produced in the province. The purchase takes place at the wellhead and the gas is immediately resold to the Company. The Company then gathers, processes, transports and sells the gas to B.C. distributors and to Northwest Pipeline Corporation in the U.S. Additional supplies of gas are purchased from producers in the Yukon Territory, the Northwest Territories and Alberta to supplement the supply of B.C. gas. The Company gathers and processes the territories' gas while the Alberta gas, which requires no processing, is transported from the Alberta-B.C. border through Company-owned facilities. After receiving the sales revenue each month, the Company retains a sum of money equal to the costs incurred in operating its facilities. These costs include operating, maintenance and administrative expenses as well as depreciation and taxes, including income taxes. The Company also retains at present an amount equal to 11 percent on its rate base, this percentage being subject to periodic negotiation with the BCPC. The Company pays producers in the Yukon, Northwest Territories and Alberta directly for gas purchases. The remainder of the sales revenue is remitted to the BCPC as payment for gas produced in B.C. The arrangement is termed a cost-of-service contract. Income from subsidiary operations referred to on page 13 is in no way involved in the contract.

The rate of return on rate base was 11 percent for the fiscal year ended December 31, 1978 which resulted in a return on equity invested in the pipeline system of 14 percent.

Gas Sales

The gas sales picture during the year under review was marked by contradictions. While total sales were 344 billion cubic feet (Bcf), which is 7 percent below the 1977 figure of 370 Bcf, two all-time sales records were established during the year.

Furthermore, although the volume of gas sales was lower in total, gas sales revenue increased by 9.5 percent, as a result of an increase in the domestic price of gas and the lower value of the Canadian dollar which increased the average export price of gas which is set at $2.16 (U.S.) per thousand cubic feet (Mcf).

The reduction in sales volume was due primarily to intense competition from excess residual oils entering the Pacific Northwest region of the United States, which is Westcoast's traditional export market.

Notwithstanding this reduction, a record average daily sales of 1,301 million cubic feet (MMcf) was recorded for December, an increase of 47 MMcf over the previous high average day sales for December 1977. In addition, sales of 1,369 MMcf on November 21, 1978, exceeded the previous single day record of 1,320 MMcf recorded on December 4, 1977.

Throughout the year customers purchased an average of 944 MMcf per day, compared with 1,012 MMcfd in 1977. Exports to the United States accounted for 61 percent of 1978 total shipments, which compares with 64 percent in the previous year.

Despite a strong market beginning in November 1978, for the first time sales opportunities were lost on several peak days in November and December due to insufficient mainline capacity and, to a lesser degree, inadequate gas supply.

Market Pattern Shifts

Although two of the Company's three major customers in Canada increased their purchases, this was heavily offset by the downturn in annual sales to the U.S. The marketing pattern in the U.S. Pacific Northwest shifted dramatically during the year. The demand for gas in the residential and commercial sectors continued to grow strongly, however, the industrial market experienced a large erosion in sales. A large quantity of surplus residual oil with high sulphur content is finding its way into this market from California where pollution control standards restrict its use. This residual oil, a by-product of the refining of Alaska crude, is under-pricing natural gas by a considerable margin. As a result, many of the large forest products operations have opted for residual oil. Because it is the standard practice of transmission companies to utilize the large industrial load to level their gas sales throughout the year, the loss of sales disrupted the Company's sales pattern. Historically, the load pattern was fairly steady, however, in 1978 high peak days in the winter and very low volumes in the summer were experienced, that is the swings were more marked. Even though the Company's export customer was able to negotiate some special off-line sales of gas to southern California, they were far from sufficient to compensate for the loss of industrial sales in the Pacific Northwest.

Most industry authorities believe the gas-oil market imbalance in the Pacific Northwest is a relatively short term problem which should be resolved within two years.

Domestic Price Increased

Effective March 1, 1978, the price of gas to Westcoast's Canadian customers was increased by 21 cents per Mcf. This raised the price to Westcoast's largest Canadian customer to $1.22 Mcf. The increase was implemented by order of the British Columbia Energy Commission and had no bearing on Company earnings which are determined by a return on investment in pipeline facilities.

The price for gas exported to the U.S., which is set by the National Energy Board, remained at $2.16 per Mcf in U.S. currency throughout the year. After adjustments to take into account the variances in currency and heating values, the average price to the Company's U.S. customer was $2.53 per Mcf in Canadian funds. The B.C. Petroleum Corporation and out-of-province producers received the full benefit of the premium on the higher U.S. dollar.

Sales Trend Mixed

The Company's sales in 1978 to its largest Canadian customer, B.C. Hydro and Power Authority, were 80 Bcf, an increase of 1.8 percent over 1977. As in other recent years, Hydro did not use gas in its Burrard thermal generating plant, however, it began deliveries to a major new industrial customer, a cement plant in Delta, south of Vancouver.

Inland Natural Gas Co. Ltd. purchased 42.2 Bcf, which was 2.6 percent more than in the previous year. This increase was partially the result of an arrangement under which Inland sold gas by displacement to Columbia Natural Gas Ltd. which distributes in the Kootenay area of southeastern B.C. The arrangement provides for Columbia to receive its gas from an Alberta supplier and the latter receives an equivalent volume of gas, which Inland has purchased from Westcoast, at a point down line where Inland interconnects with the Alberta supplier.

Sales to Pacific Northern Gas Ltd., the Company's third major Canadian customer, totalled 9.3 Bcf, a 4.4 percent decrease over the previous year. This was due primarily to flood conditions which broke the PNG mainline in several places in November and, to a lesser degree, a four-month strike by that company's employees.

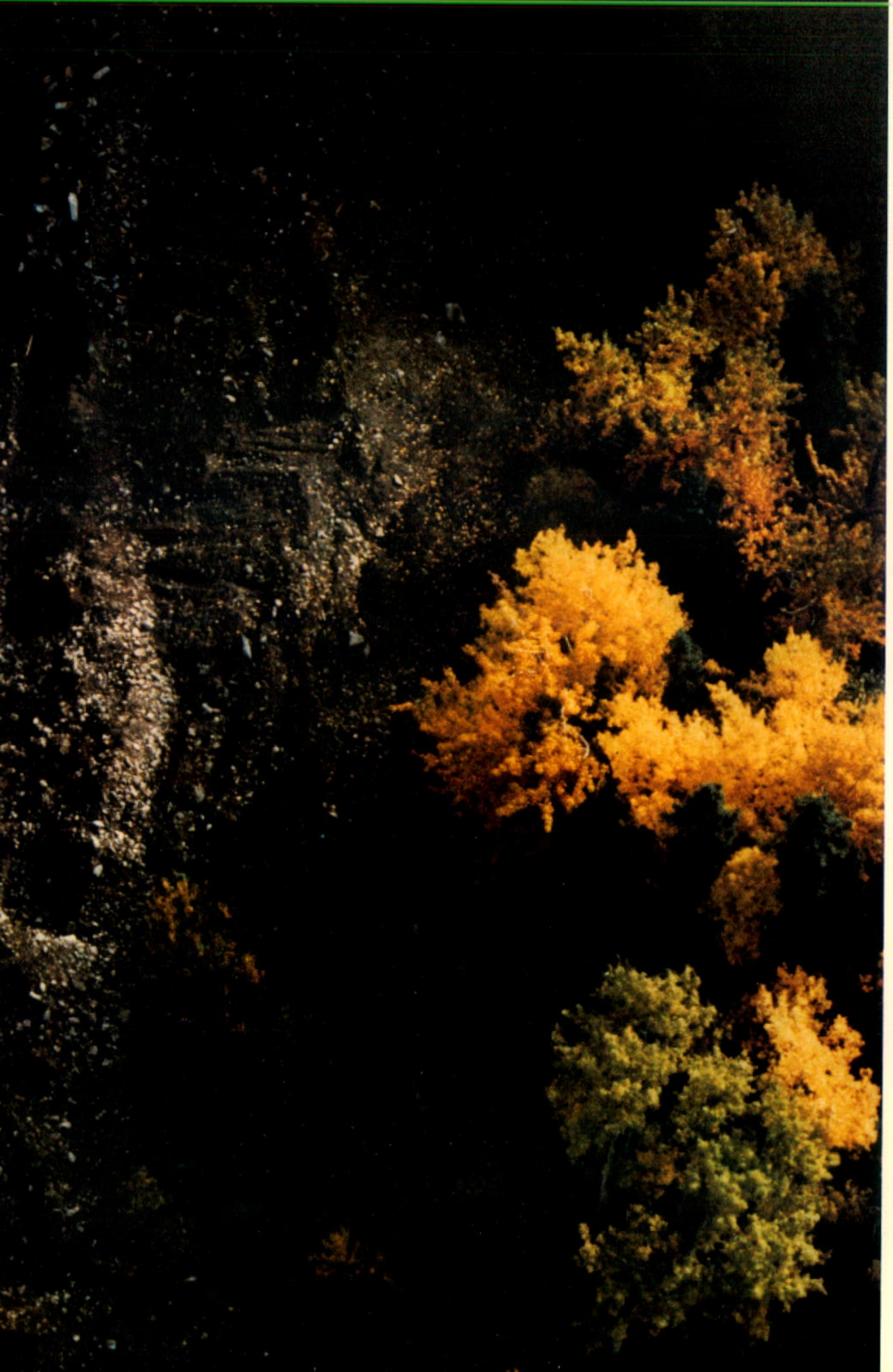
Deliveries to the Company's export customer, Northwest Pipeline Corporation, were 210 Bcf, a decrease of 12 percent. However, from a favourable point of view, because of an improved gas supply position, the Company was better able to service Northwest during periods of high demand than at any time within the past five years. There were still numerous days when the BCPC could not provide sufficient gas to meet the U.S. customer's full demand, but overall the Company's ability to supply improved appreciably.

Improvements in supply resulted from gas purchases outside the province, notably contracts signed with Pan-Alberta Gas Ltd. for up to 200 million cubic feet a day of Alberta gas, extending to October 31, 1989 at the Company's option, and greatly expanded exploration and development activity within B.C. in the past few years.

Gas Supply

The availability of gas in the Company's supply areas continued to improve dur-

Helicopter view of a segment of 20-inch pipe of the Grizzly Valley pipeline gathering system under construction. Other segments range from 8 to 24 inches. The project was completed in 1978 at a cost of $47 million.



ing the year to the point where insufficient capacity in the Company's mainline transmission system is impinging upon its ability to meet gas demand on peak days. This became apparent during the 1978-79 peak demand season. In anticipation of reaching this capacity limitation, the Company had applied in 1978 to complete looping of the mainline transmission system from Chetwynd to the U.S. border. The application for some 111.5 miles of 36-inch loop was denied by the National Energy Board primarily because of the marketing difficulties which the Company was experiencing in the Pacific Northwest region of the United States.

In the light of the Company's 1978-79 winter experience, rejection of the looping application was an unfortunate decision which cost the provincial treasury approximately $2 million in lost revenue through the BCPC and resulted in an additional loss of about $1 million to B.C. gas producers. After careful review of its 1978 application, the Company selected those sections of the mainline where looping is more critical in terms of anticipated market growth, fuel conservation and the security of supply provided by two parallel pipelines. Two new applications to proceed with construction of these particular pipeline sections have now been filed with the NEB and the details are reported under "Operations and Construction."

Shortage Corrected

The supply shortage of the last five years has been largely corrected. The nominated contract demands of Canadian customers were met in full. Shortages which did occur due to pipeline capacity constraints, inadequate gas supply or operating problems were borne entirely by the export customer.

As background to the supply picture, as of January 1, 1978 the remaining pipeline gas reserves of Westcoast's supply area — not including back-up gas from Pan-Alberta Gas Ltd. in Alberta — were 7.3 trillion cubic feet (Tcf), of which approximately 5.7 Tcf were contracted. About 93 percent of these reserves were located in northeastern British Columbia. Natural gas reserves at the end of 1978 are expected to show an increase over the corresponding figures at the end of 1977.

Consensus within the industry is that at least another nine to 15 trillion cubic feet of natural gas will be found in B.C. in addition to existing proven reserves. This does not include the potential of the B.C. portion of the "deep basin" described later in this section.

New Fields Tapped

Additional supplies were obtained in 1978 from the connection of several new fields, notably the Grizzly and adjacent fields. Completion of the Grizzly pipeline in the fall initially brought another 35 million cubic feet per day (MMcfd) into the mainline. This will increase by 150 MMcfd when construction of the Pine River processing plant is completed in late 1979, with ultimate deliveries reaching about 200 MMcfd in 1980. Other new fields connected and their potential supply volumes were: Silver-Dahl, 62 MMcfd; Clarke Lake South, 32 MMcfd; Red Creek, 10 MMcfd; and Monias, 22 MMcfd.

A contract has been negotiated with Columbia Gas Development of Canada

Limited and others to supply an initial volume of 35 MMcfd from the Kotaneelee area of the Yukon near the producing Pointed Mountain field located in the Northwest Territories. It is a "best efforts" contract which means that the gas is available for Westcoast to purchase when B.C. gas is not available to meet market demand, but there is no stipulated volume of gas which the Company must buy annually.

Initial steps have been taken to tap another important gas supply source, the Junior-Sierra area east of Fort Nelson. Application to build a 83-mile connecting pipeline was made in August 1978 to the National Energy Board and the hearing will begin April 18, 1979. A decision is required by July 1979 at the latest if the project is to proceed in an orderly manner and enter service as scheduled in 1980, delivering about 160 MMcfd. The Junior-Sierra fields' ultimate production is expected to be up to 270 MMcfd.

A number of major gas fields in the Company's supply area have been producing for 15 years or more. Because of decreasing reservoir pressure they are now delivering declining gas volumes. As of October 7, 1978, all gas production was suspended from Amoco Canada's Beaver River field due to water intrusion, which was not unexpected since the intrusion was first detected in 1973 and had gradually worsened since that time.

"Deep Basin" Testing

Since the first discovery of gas in the Alberta Wapiti basin in January 1976, this area has attracted wide attention. Drilling in the basin extends over an area some 70 miles in length and 55 miles in width, straddling the border between British Columbia and Alberta. Some twenty wells will be drilled in 1979 to prove up reserves in the basin's British Columbia portion, which is adjacent to the Elmworth area of Alberta. The Elmworth area lies immediately northeast of the Grizzly field which began production in December 1978. Recent well-publicized studies predict that huge volumes of gas are to be found in the Mesozoic Sands of the "deep basin", an area which extends for 400 miles parallel to the Rocky Mountains and is up to 80 miles wide where it crosses the Alberta - British Columbia border. Westcoast is in a prime position to transport reserves which are established in the B.C. portion of the basin.

Discoveries at Record Level

Drilling activity and successful gas-oil well completions reached record levels in British Columbia during the year, portending substantial additions to gas reserves in Westcoast's main supply area. The record activity is continuing into 1979 and more than 80 rigs were working in the province at the winter drilling peak.

A total of 379 wells were drilled in British Columbia in 1978 resulting in 176 gas wells and 74 oil wells. The comparative figures for 1977 are 303 wells drilled, resulting in 156 gas wells and 31 oil wells. Of the total wells drilled in 1978, a large proportion were exploratory wells, which are wells drilled with the objective of finding new gas and oil pools. Exploratory wells drilled during 1978 totalled 198, of which 90 were gas discoveries and 13 were oil discoveries. Comparable figures for 1977 were 93 exploratory wells, 28 gas discoveries, and 6 oil discoveries.

Gas Reserves Projected

The preceding statistics strongly support the calculated ultimate gas potential in northeastern B.C. Notwithstanding the industry consensus of total gas reserves to be found in B.C., which were mentioned earlier, the Company has extended these estimates using accepted industry formulas. Based on the historical annual growth rate of approximately 490 Bcf, it is assumed that during the 20-year period from 1978 to 1997 total initial reserves will reach 19 trillion cubic feet. Generally, a number of factors, including the exciting new "deep basin" discoveries, lead your Company to believe the ultimate potential is in the order of 20 to 30 trillion cubic feet. This overall projection of gas reserves assures your Company a continuing supply well into the future.

Government Revenues Soar

Indicative of the sustained high level of interest in B.C.'s gas and oil potential, seven land sales which were held in 1978 brought the provincial government all-time record revenues of $176.9 million. These bonus payments were $51.4 million more than in 1977 and four times the $43.2 million received in 1976. Of significance, the majority of the lands purchased were, as in other recent years, exploratory acreage in the form of large petroleum and natural gas permits.

Regulatory Proceedings

The National Energy Board conducted two major hearings in 1978 to determine Canadian oil and natural gas supply and demand levels. Its findings regarding gas were announced on February 28, 1979. They are of critical importance to the industry which believes that an appreciable quantity of available gas is surplus to Canadian long term needs and consequently that increased exports are justified. At this time your Company is reviewing the implications of the report in relation to its own future export plans and the pre-building of the southern portion of the Alaska Highway gas pipeline.

The Board's recommendations following the oil hearings were that the present level of light and medium crude exports be maintained.

Alberta Assesses Reserves

Early in 1979 the Alberta Energy Resources Conservation Board will conduct public hearings which also will have an important bearing on future gas exports from that province. The two-phase hearings will determine the ultimate reserves of gas and co-products in Alberta and the amount of gas which is surplus to the province's needs. These hearings also are significant in relation to Phase I of the Alaska Highway gas pipeline project.

Export Study Recommended

The B.C. Energy Commission conducted hearings in June 1978 on natural gas and oil prices, and its recommendations included the following: that the wholesale price for gas remain unchanged until the National Energy Board has reached a decision regarding Westcoast's rate increase application, which is presently before the Board; that the price for "old" and "new" gas remain at 78 cents and $1.03 per Mcf respectively; and that the province of British Columbia undertake a detailed study of the export market for gas as soon as possible, and assure that future additional exports of gas are surplus to B.C.'s requirements.

Rate Hearings Resumed

Prolonged hearings on the Company's application to the National Energy Board for a rate increase resumed in Ottawa on February 6, 1979. The application was filed with the Board September 15, 1977, and hearings on the first of three phases began February 28, 1978, and concluded May 24, 1978.

This phase dealt with income taxes and depreciation. The Company sought to change its accounting practice in collecting taxes from a "flow-through" basis to a "normalized" basis and to include "normalized" taxes in its cost-of-service. It also sought to increase its depreciation rates and to begin collecting "catch-up" taxes. In simple terms, the change in accounting practice would permit the Company to begin collecting current taxes from the current customers rather than deferring their collection from future customers who would thus bear the double burden of past and present income taxes. Increased depreciation rates would permit earlier recovery of invested capital; and collection of "catch-up" taxes would enable the Company to begin recovering income taxes which had been deferred for the past 21 years.

The Board's decision on Phase I, rendered May 24, 1978, was favourable to Westcoast although it would not increase net profit in any way. It provided for the collection of taxes on a "normalized" basis and also for the collection of "catch-up" taxes. The combined impact of these two items would have increased the Company's cash flow by some $60 million in the first year after the Board's rate decisions were implemented. While not altering depreciation rates significantly, the Phase I decision did permit the Company to recover that portion of its invested capital which was allocated to its export business by the time the export licence terminated in 1989.

First Decision Appealed

Although hearings on Phase II of the application had begun, the decision on Phase I was challenged by a number of intervenors, including the Attorney General of B.C., the B.C. Petroleum Corporation, B.C. Hydro and Power Authority, and some gas consumers from the private industry sector. The Board agreed to review the decision and did so on July 26. The review decision was rendered December 7, 1978. It reaffirmed the original finding in favour of "normalized" accounting, rejected the concept of "catch-up" income taxes and deferred a ruling on more rapid recovery of capital through depreciation changes from the export business until later in the hearings. As a consequence of the review, when the Board's final decisions are implemented the Company's cash flow will be increased by some $40 million in the first year after charging the new rates, rather than $60 million. Again this NEB review decision did not alter Westcoast's net income.

Final Decision Nearing

In the current Phase II of the hearings, the Board will consider the rate of return on utility investment which Westcoast should be allowed, rate base and cost-of-service items. Subsequently, in the final phase, rates, tolls and tariffs proposed for Westcoast's domestic customers will be studied.

It is expected the Board's final decisions will be made in time for implementation by mid-1979.

Operations and Construction

Important additions to the transmission gathering system and supporting facilities were made in 1978. Actual capital expenditures were more than $108 million and the value of capital projects of $115 million scheduled for 1979 indicates a vigorous extension of expansion activities.

Major capital expenditures were centered on large new transmission and processing units, and the minor capital program was concerned chiefly with improvements to, and upgrading the technology of existing facilities.

Expenditures in 1978 would have been considerably higher if the mainline looping project had been approved by the National Energy Board and construction proceeded with as planned in the last half of the year.

Two major gathering pipelines, the Grizzly Valley and Silver-Dahl, were completed and placed in service and construction of a large new processing plant was begun. Completion on schedule of the 101-mile Grizzly line at a cost of $47 million and of the 95-mile Silver-Dahl line at a cost of $14 million were important achievements, because the start of construction was delayed in both cases.

Two smaller gathering systems were completed, tapping the Red Creek and South Clarke Lake fields and the Monias field line was purchased. These three small systems total some 38 miles of pipeline.

Environmental Decision

The Pine River plant near Chetwynd, which will be the Company's third large processing plant, is scheduled for completion in November, at which time residue gas deliveries from Grizzly to the mainline will rise sharply. Originally it was planned to build the processing plant in the Pine River valley. However, for environmental reasons and at considerable extra cost, the Company was required to change the location to a high plateau overlooking the valley. The cost of the plant, one of the largest and most technically advanced in western Canada, was increased by $5 million to accommodate this move. The total cost is now estimated at $90 million.

Westcoast's processing capacity will be increased by 15 percent with completion of the plant, a significant figure in terms of security of natural gas supply for sale in B.C. From Grizzly's sour gas the plant will recover 1,100 tons per day of elemental sulphur, which will go into block storage for sale by the B.C. Petroleum Corporation.

Construction workers have completed about 50 percent of the process area, including buildings and vessels, and only piping remains to be installed. Most of the equipment has been installed in the utility area and the sulphur recovery plant. In the processing and sulphur extraction units both hydrogen sulphide and carbon dioxide, which are referred to in the industry as "acid gases", are removed. Some 99 percent of the hydrogen sulphide will be converted into elemental sulphur and the carbon dioxide is released. The natural gas then is dried and fed into the mainline as residue or sales gas.

The plant as a whole is now 30 percent complete. Some units will start up in August 1979 and the plant is expected to be fully operational as scheduled by November 1, 1979.

New Loop Applications

The National Energy Board denial of the Company's application to complete looping of the southern section of the mainline with 111.5 miles of large diameter pipe was disappointing. The added capacity would have saved 6.7 Bcf annually in gas which is taken from the line as fuel gas, a sizeable volume in terms of conservation and sufficient to supply 52,000 B.C. homes their total annual gas needs. The added capacity is needed, as well, to fill peak gas demands, as discussed in the gas supply section of this report.

To help meet these and other pressing circumstances, a new application filed December 15, 1978 seeks approval to loop 20.2 miles in the Coquihalla Pass, northeast of Hope, prior to construction of a new, major provincial highway through this narrow canyon. The Company hopes for an early decision which would enable construction of this loop with 36-inch pipe in 1979 at an estimated cost of $19.8 million.

Westcoast also applied to the Board in late February 1979 to loop nine sections of the mainline totalling 53.9 miles with 36-inch pipe. This looping will provide some of the added capacity needed to meet peak customer requirements, reduce compressor fuel useage and provide backup service in the event the flow through the existing 30-inch mainline is interrupted. The sections are located between Compressor Station No. 1 at Taylor in the north and Kingsvale at the north end of Coquihalla Pass. Cost will be $42.4 million and no date has been set for an NEB hearing. Given early approval, the Company would also install this loop in 1979.

New Capital Spending

New capital programs in 1979 for the Westcoast utility system are estimated at $115 million.

The minor capital program includes $14.8 million to replace sections of the original 30-inch mainline system with heavy wall pipe because of population encroachment, as required under construction and operating standards adopted by the NEB. The encroachment has occurred near Chetwynd; Quesnel; 100-Mile House; and near Sardis in the eastern Fraser Valley.

Among major works scheduled for 1980 is the $34 million Junior-Sierra pipeline, for which application was made to the NEB in August 1978. This was originally a project for the winter of 1978-79 but the necessary NEB hearing was not scheduled in time. Even with a decision early this year, construction cannot commence in this muskeg area until after freeze-up in January 1980. The hearing is scheduled to commence April 18, 1979.

Industrial Relations

Management-employee relations were excellent throughout the year.

One-year agreements were successfully concluded with the three trade unions which have contracts with Westcoast.

The Company's employees totalled 638 as of December 31, 1978, compared to 573 a year earlier. A significant and unplanned increase in employees was the force of 21 extra men hired and trained to staff certain compressor stations. This was required to maximize compressor capacity that would not have been necessary had the 1978 looping application been approved. Additional personnel were required to operate the Company's expanded transmission and processing facilities and for preparatory work in connection with the Alaska Highway gas pipeline.

Westcoast Innovation

An innovative program to protect sections of 30-inch mainline pipe from rock damage was carried out at four locations in the Fraser Valley, east of Vancouver, in the summer of 1978. Fast-setting polyurethane foam was used by work crews for both construction and maintenance jobs on four sections of the line to pad the ditch under the pipe, protect the pipe from rock fill dumped into the trench and to erect water erosion barriers. It is believed to be the first application of this technique in Canada. In preliminary tests, 150 to 200-pound boulders which were dropped on pipe sprayed with the foam failed to penetrate the protective polyurethane, leaving both coating and pipe intact. The operation established that foam can be applied more rapidly, with less manpower and hence is less costly than traditional sand and light fill when the latter has to be hauled any appreciable distance. The Company is considering use of the foam at other locations where pipe may be vulnerable to rock fill damage and where runoff water on slopes exposes the pipe to rolling rocks.

Engineering

A high level of activity was maintained throughout the year by the Engineering Group, its work ranging from the design of new gathering pipelines and a large process plant to on-site work on the B.C. section of the Alaska Highway gas pipeline. Engineering plans for the Company's next major gathering pipeline, the Junior-Sierra project, were completed during the year. Delivery of machinery and other major components for the Pine River process plant are progressing well, indicating the completion target of November 1979 will be met.

Looping Needed

While there is a growing need to complete looping of the whole southern section of the Company's 30-inch mainline with 36-inch pipe, the need is becoming critical in some sections, such as the Coquihalla Pass. The provincial government's plans to construct a four-lane highway through this narrow, 20-mile pass are well advanced. The roadway would be directly on top of the Company's pipeline for several thousand feet, pointing up the necessity to install the 36-inch pipe before highway construction commences. It would be extremely difficult and expensive to install the line beneath the paved highway and its heavy rock foundations. This developing situation is under engineering scrutiny and close liaison is being maintained with the Department of Highways while the Company's application to loop this section is considered by the NEB.

Energy Conservation

As a continuing program, new power-recovery turbines which hold the prospect of substantial energy savings are being installed in the Company's processing plants. One unit is to be placed in service in the Fort Nelson plant in 1979 and it is expected that several more will be installed at this location. They also will be employed in the Pine River process plant, now under construction. The first unit was designed and manufactured in B.C. The units being installed at Pine River will come from Switzerland. The Engineering Group will compare their performance to determine which will better serve the Company's fuel conservation goals.

Environmental Work

Personnel from virtually all sectors of Westcoast were involved to varying degrees in preparations for the Foothills gas pipeline. The basic design of the northeast B.C. segment was complete at year-end and 77 miles of field location surveys were finalized. It is expected that by spring field location surveys will have been completed on 270 miles of the route, from the Alberta boundary northwestward to Toad River. Detailed engineering will proceed through 1979 with the objective that all engineering activity on the 439-mile B.C. section be completed by mid-1980.

Several man-years already have been devoted to environmental and socio-economic studies related to the Alaska Highway gas pipeline by Westcoast staff and outside consultants. They assessed the pipeline's impact, particularly during the construction phase, on residents, wildlife, the terrain and forest, and the economy.

Subsidiary Companies

Westcoast Petroleum Ltd.

Westcoast Petroleum Ltd. reported net income available to common shareholders of $7,731,000 or $1.23 per common share in 1978, as against $6,618,000 or $1.10 per common share in the previous year.

The Company holds 3,750,050 or 60 percent of the Westcoast Petroleum common shares outstanding.

Revenue from oil and gas sales increased 41 percent while pipeline revenue declined seven percent. The increase in oil and gas revenue was due to increases in both prices and production. Oil production was up 25 percent; gas sales rose 17 percent despite a soft market.

Westcoast Petroleum participated in the drilling of 112 exploration and development wells in 1978, 49 resulting in gas well completions and 28 in oil well completions. Its interests include a total of 8,249,090 gross acres (2,304,571 net acres) of prospective oil and gas lands in western Canada, the Northwest Territories and the Arctic islands.

Pacific Northern Gas Ltd.

Pacific Northern Gas Ltd. reported net earnings available to common shares of $1,012,000 or 64 cents per common share, compared with $1,097,000 or 69 cents per share in 1977. Total sales revenue increased to $15,850,000 from $13,739,000, although sales volume declined to 9.07 Bcf from 9.47 Bcf in 1977. Flood conditions which broke the PNG line and a four-month strike by its employees, resulting in lower sales to some large industrial customers, were responsible for the lower earnings.

The Company's application to the B.C. Energy Commission for an increase in rates began in Prince Rupert on February 28. PNG seeks the increase to attain a 15½ percent return on equity and to recover increased operating costs.

PNG distributes in west-central B.C. Westcoast owns 45 percent of the common shares and all of the voting shares.

Saratoga Processing Company Limited

Saratoga Processing Company Limited had net income in 1978 of $329,000 or 66 cents per common share, which compares with $322,000 or 64 cents per common share a year earlier.

Saratoga owns and operates a gas gathering and processing system and a sulphur extraction plant in southwestern Alberta. Its processing facility, which has a capacity of 52 MMcfd of raw gas, treats Westcoast gas and other gas for sale in southeastern B.C. and the U.S.

The Company owns 25 percent of Saratoga's common shares, including all of the voting shares.

Northern Pipelines

The Foothills Alaska Highway natural gas pipeline project continued to gain momentum throughout 1978. In Ottawa, Washington, D.C., Calgary, Vancouver, Salt Lake City and other North American cities legislative and corporate decisions were made and activities undertaken to expedite preparations. There also was activity along the 4,786-mile right-of-way of the pipeline which will move Alaska gas across Canada to California and the midwest states centered about Illinois, including field work on geotechnical, environmental, socio-economic and line location surveys.

Cost Estimates Revised

Your Company has a 50 percent interest in Foothills Pipe Lines (Yukon) Ltd., the parent company of the five companies which will build different segments of the 2,027-miles of the pipeline in Canada. Westcoast will have responsibility for construction and operation of the 439-mile B.C. segment through one of the five companies, namely Foothills Pipe Lines (North B.C.) Ltd. The Alberta Gas Trunk Line Company Limited of Calgary (AGTL) owns the other 50 percent of the parent Foothills (Yukon).

The present cost estimate for the Canadian and United States sections of the project is $10.7 billion including $4.3 billion for the Canadian portion and $1.3 billion for the B.C. section. The project estimates are presently being revised upward to reflect increased costs attributable principally to the delay in construction and the start of gas flow to the 1984-85 heating season.

The previous timetable for the start of gas flow required that the U.S. Congress set the price to be paid for gas at the Alaska wellhead by passage of the U.S. National Energy Act early in 1978. The Act, in fact, was signed by President Carter on December 9, 1978. This delay fostered further delays in the U.S. regulatory system regarding financial and technical aspects of the pipeline in the U.S. Consequently the project timing has been pushed back approximately one year.

Financing Plans Take Shape

A particularly positive aspect of President Carter's energy bill was the fixing of the price of gas at the Alaska wellhead and establishment of a mechanism for "rolled in" or "average" pricing of the Alaska gas to customers in the lower 48 mainland states. This virtually assures the marketability of Alaska gas and will expedite negotiations for gas purchase contracts and pipeline transportation tariffs, which will proceed during 1979.

Both the National Energy Board (NEB) in Canada and the Federal Energy Regulatory Commission (FERC) in the U.S. released discussion drafts in late 1978 respecting the incentive rates of return for the pipeline. This unique concept of financial regulation provides incentives for successful project management. The Company believes these proposed incentives, when finalized, will be of significant assistance in financing and operating the pipeline.

Backed by the legislative support of the Canadian and U.S. governments and the burgeoning market for natural gas in the U.S., these developments provide a sound basis for private financing of the project. The shaping of financing plans continued on a project basis in consultation with financial advisors and potential investors.

Phased Construction

The feasibility of two-phase construction (pre-building of the pipeline's southern segment) will be determined this year following the NEB report in February 1979 to Cabinet on the results of its natural gas supply/demand hearings. The NEB has found that certain volumes of gas are surplus to Canadian requirements and are available for export. Pan-Alberta Gas Ltd., a subsidiary of AGTL, has completed its hearing before the Alberta Energy Resources Conservation Board for an export permit, and shortly will make the companion application to the NEB for a license for short-term gas export sales for the Phase I pipeline.

The present timetable for gas flow through the Phase I southern pipeline is November 1980 for the western leg to California, and November 1981 for the eastern leg to Illinois. However, these dates are currently being reassessed by Foothills (Yukon).

Pipe Negotiations Underway

Another positive step, in the interim, is the approval given to Foothills (Yukon) by the Northern Pipeline Agency (NPA) and the Canadian government to begin negotiations with The Steel Company of Canada Ltd. and Interprovincial Steel and Pipe Co. Ltd. for the purchase of 1.5 million tons of pipe for the Canadian section.

Westcoast, for its part, continues to work closely with AGTL, the Foothills group of companies and the NPA in planning and engineering for the start of construction in northern B.C., which is scheduled to begin in the winter of 1980-81. At this time the field construction will consist of right-of-way clearing and other preparatory work required prior to actual pipe laying operations.

Oil Pipeline Proposed

What was a year ago a concept under study has now become a formal project proposal designed to transport Alaska crude oil to the U.S. midwest and to some states along the 49th parallel via a companion oil pipeline to the Canadian portion of the Alaska Highway gas pipeline. The sponsors of Foothills Oil Pipe Line Ltd., which would build the Canadian section, are Westcoast and AGTL who again share a 50-50 interest. Foothills' U.S. associate in the venture is Northwest Energy Company (Northwest) of Salt Lake City, which will be responsible for the American facilities including a proposed oil port at Skagway and pipeline in the Alaska panhandle. The White Pass and Yukon Corporation Limited is associated with Foothills and Northwest in the western leg of the pipeline.

Northwest made application in early December 1978 to the U.S. Secretary of the Interior for authorization to construct facilities in Alaska. Foothills' application to the National Energy Board regarding the Canadian portion will be filed in the spring of 1979.

Existing Lines Utilized

The proposal is to move oil by tanker from Valdez, the southern terminus of the Alyeska oil pipeline, south to Skagway, in the Alaska panhandle, where storage facilities would be built. A 710-mile, 34-inch diameter pipeline would move the crude from Skagway across the Alaska panhandle, via the White Pass rail and road route into the Yukon, then through the Alaska Highway gas pipeline corridor in the Yukon and northeastern B.C. to Keg River, Alberta. Existing pipelines with idle capacity would transport the oil to Edmonton, where the existing Interprovincial Pipe Line Limited system which also has unused capacity would carry it to markets in the midwest U.S.

Estimated cost of both the Canadian and U.S. segments is approximately $1 billion in Canadian funds in 1978 dollars. Initial deliveries would be about 500,000 barrels per day, expandable to 750,000 barrels per day.

Advantages Favour Foothills

The advantages of the Valdez, Skagway, Keg River, Edmonton route are compelling. In contrast to competing proposals, it would require a shorter tanker haul and utilize a remote port in Alaska far removed from areas of heavy population, and would have less overall impact upon the environment. One competitor envisions Kitimat, B.C. as an oil port or terminal; another would use Port Angeles, Wash. Federal cabinet ministers have repeatedly stated that Canada has no desire nor need for a new oil port on the west coast, and the proposal utilizing Port Angeles is strongly opposed by environmentalists and others. The Company and its partners are confident that the U.S. Government and the NEB will be impressed by the Foothills oil pipeline project for the same logical reasons which led to selection of the Alaska Highway gas pipeline route.

In addition, Skagway would provide the west coast of North American with a port of entry for offshore oil from the Middle East and southeast Asia, as required. Lighter crude from offshore better meets the requirements of many north-central U.S. refineries than heavier Alaska crude. Canadian oil exports have supplied many of these refineries in the past but shipments are diminishing because the oil is needed in the Canadian domestic market.

Carrying offshore crude with Alaska crude would not only lower the unit transportation cost for both types of oil, but would also extend the economic life of the pipeline if Alaska production tapers off.

Tanker traffic down the west coast would be reduced. Existing pipelines in Alberta would be more fully utilized, generating added revenue for the pipelines as well as for governments at both the provincial and federal level.

Large Cost Savings

Construction costs would be reduced by following the right-of-way of the White Pass and Yukon railway. Of particular importance, the Foothills oil line could be constructed between Phases I and II of the Alaska Highway gas pipeline if the pre-build is authorized.

Regardless of the timing, substantial savings would be realized for both projects since the gas and oil routes would parallel each other for some 400 miles through the Alaska Highway transportation/energy corridor. Both could use much of the same infrastructure, including roads, housing, communications, construction camp sites, supply centres and compressor station locations.

Consistent with Foothills' sensitivity to environmental considerations, there is the considerable advantage of avoiding virgin territory by using a route which already has been established as a transportation and energy corridor.

This compelling feature applies in three instances — the railroad route through the White Pass, the Alaska Highway corridor, and the existing pipeline system in Alberta.

Early Decision Expected

President Carter's energy bill established procedures which will greatly expedite selection of an approved route. The Secretary of the Interior is required to establish a schedule which will permit other federal agencies in the U.S. to review applications for the oil line and submit their recommendations to the Secretary who, in turn, will forward these comments and recommendations together with his own recommendations to the President. Within 45 days the President is required to decide which, if any, of the proposals should be approved, although the legislation provides him with a limited time extension if he deems it necessary. The U.S. administration has established a review schedule which sets a target date of December 6, 1979 for the Presidential decision. The Canadian decision will follow hearings before the NEB and timing of this procedure is expected to harmonize with the schedule established in the U.S.

Consolidated Balance Sheet

December 31, 1978 and 1977

Assets

	1978	1977
	(in thousands)	
Plant, property and equipment — at cost (Note 1)	$1,070,259	$ 932,821
Less accumulated depreciation and depletion	284,143	254,218
	786,116	678,603
Current assets:		
Temporary cash investments	15,819	18,652
Deposits with trustees	4,833	4,830
Accounts receivable	109,387	91,990
Materials and supplies — at cost	5,134	4,681
Line pack gas — at cost	4,656	4,356
Prepayments	720	874
	140,549	125,383
Deferred charges:		
Debt discount, premium and expense	6,599	4,955
Abandoned pipeline	764	1,145
Capital stock expense	704	941
Northern pipeline projects (Note 2)	24,444	10,014
Other	1,800	1,725
	34,311	18,780
Excess of cost of investment in subsidiary over book value at date of acquisition	362	523
	$ 961,338	$ 823,289

(See accompanying accounting policies and notes.)

WESTCOAST TRANSMISSION COMPANY LIMITED
(Incorporated under the laws of Canada)

Shareholders' Equity

	1978	1977
	(in thousands)	
Capital stock (Note 3):		
Authorized		
5,000,000 preferred shares without nominal or par value		
75,000,000 common shares without nominal or par value		
Issued		
800,000 $4.25 cumulative redeemable preferred shares series A	$ 40,000	$ 40,000
34,662,834 common shares (1977 — 33,651,045 common shares)	175,762	166,299
	215,762	206,299
Contributed surplus	1,280	470
Retained earnings	147,604	129,718
	364,646	336,487

Liabilities

	1978	1977
Long term debt (Note 6)	376,393	310,456
Deferred income taxes	25,697	20,012
Current liabilities:		
Bank indebtedness	14,201	2,258
Accounts payable	105,804	84,383
Sundry taxes	2,637	2,382
Interest on debt	7,013	4,784
Long term debt due within one year	12,008	12,489
	141,663	106,296
Minority interest in subsidiary companies:		
Preferred shares	11,175	13,903
Common shares	41,764	36,135
	52,939	50,038
	$ 961,338	$ 823,289

On behalf of the Board:

E. Phillips

Director

John Anderson

Director

Consolidated Statement of Operations

For the years ended December 31, 1978 and 1977

	1978	1977
	(in thousands)	
Operating revenues:		
Gas and by-product sales	$832,749	$768,699
Other	11,153	11,465
	843,902	780,164
Operating revenue deductions:		
Cost of gas sold	660,213	607,576
Operation and maintenance	56,364	52,865
Depreciation and depletion	30,189	29,052
Taxes — other than income taxes	17,799	15,693
	764,565	705,186
Operating income	79,337	74,978
Other income:		
Allowance for funds used during construction	4,305	751
Investment and other income	2,523	3,881
	86,165	79,610
Income deductions:		
Interest on long term debt	29,032	26,864
Debt discount, premium and expense	516	534
Other interest and amortization	1,260	463
	30,808	27,861
Income before minority interest and income taxes	55,357	51,749
Minority interest	4,100	3,932
Income before income taxes	51,257	47,817
Income taxes:		
Current	634	317
Deferred	5,685	4,650
	6,319	4,967
Net income	44,938	42,850
Provision for dividends on preferred shares	3,400	3,400
Net income applicable to common shares	$ 41,538	$ 39,450
Per common share — weighted average (Note 3)	$1.21	$1.19
— fully diluted (Note 3)	$1.17	$1.13
Dividends per common share (Note 3)	$.690	$.653

(See accompanying accounting policies and notes.)

Consolidated Statement of Retained Earnings

For the years ended December 31, 1978 and 1977

	1978	1977
	(in thousands)	
Unappropriated retained earnings:		
Balance, beginning of year	$101,718	$ 91,942
Net income	44,938	42,850
	146,656	134,792
Deduct dividends paid:		
Preferred shares	3,400	3,400
Common shares	23,652	21,674
	27,052	25,074
	119,604	109,718
Transferred to appropriated retained earnings	8,000	8,000
Balance, end of year	111,604	101,718
Appropriated retained earnings (Note 4):		
Reserve for redemption of preferred shares		
Balance, beginning of year	28,000	20,000
Transferred from unappropriated retained earnings	8,000	8,000
Balance, end of year	36,000	28,000
Retained earnings, end of year	$147,604	$129,718

Consolidated Statement of Contributed Surplus

For the years ended December 31, 1978 and 1977

	1978	1977
	(in thousands)	
Balance, beginning of year	$ 470	$ 370
Contributions in aid of construction	810	100
Balance, end of year	$ 1,280	$ 470

(See accompanying accounting policies and notes.)

Consolidated Statement of Changes in Financial Position

For the years ended December 31, 1978 and 1977

	1978	1977
	(in thousands)	
Funds derived from:		
Operations —		
Net income	$ 44,938	$ 42,850
Add items not involving a flow of funds:		
Minority interest	4,100	3,932
Deferred income taxes	5,685	4,650
Depreciation, depletion and amortization	30,566	29,453
Debt discount, premium and expense	516	534
	85,805	81,419
Common shares issued	9,463	9,738
Additional long term debt (net of financing costs)	92,830	19,647
Conversion of Westcoast Petroleum Ltd. preferred shares	—	15,000
Other	685	—
	$188,783	$125,804
Funds used for:		
Additions to plant, property and equipment	$137,219	$ 50,540
Long term debt retirement (net of exchange)	19,809	16,758
Long term debt converted to common shares	9,254	9,724
Dividends	27,052	25,074
Dividends paid by subsidiaries to minority interests	469	469
Investment in Westcoast Petroleum Ltd.	751	21,296
Northern pipeline projects	14,430	5,699
Other	—	317
Working capital decrease	(20,201)	(4,073)
	$188,783	$125,804
Changes in working capital components:		
Temporary cash investments	$ (2,833)	$ (6,065)
Deposits with trustees	3	(723)
Accounts receivable	17,397	32,679
Materials and supplies	453	(205)
Line pack gas	300	1,714
Prepayments	(154)	(475)
Bank indebtedness	(11,943)	(602)
Accounts payable	(21,421)	(35,651)
Sundry taxes	(255)	(298)
Interest on debt	(2,229)	(336)
Long term debt due within one year	481	5,889
Working capital decrease	$ (20,201)	$ (4,073)

(See accompanying accounting policies and notes.)

Consolidated Statement of Long Term Debt December 31, 1978 and 1977

			1978		1977	
		Due Date	United States Dollars	Canadian Dollars	United States Dollars	Canadian Dollars
				(in thousands)		
Westcoast Transmission Company Limited	First Mortgage Pipe Line Bonds					
	6% Series C	1980	$ 490	$ 527	$ 750	$ 807
	5¾% Series D	1984		18,109		21,107
	5¾% Series E	1984		6,615		7,677
	7% Series F	1988	38,950	41,972	43,032	46,370
	8% Series G	1991		82,300		86,150
	Less purchased in advance of repayment requirements			(4,009)		(4,177)
	9¾% Series H	1996	50,000	49,229	50,000	49,229
	Debentures					
	7½% Convertible, First Series (Note 6)	1991		3,174		4,282
	8½% Debentures, 1993 Series	1993		47,836		50,000
	Less purchased in advance of repayment requirements			(943)		—
	9⅞ Debentures, 1998 Series	1998		75,000		—
	Subordinate Debentures					
	5½% Series A	1988	15,345	15,274	15,984	15,910
	Less purchased in advance of repayment requirements		(1,426)	(1,420)	(925)	(921)
	5½% Series B	1988	2,325	2,228	2,418	2,317
	Less purchased in advance of repayment requirements		(52)	(50)	(12)	(11)
	5½% Series C	1988	2,335	2,244	11,042	10,614
	Less purchased in advance of repayment requirements		(115)	(111)	—	—
Gas Trunk Line of British Columbia Ltd.	First Mortgage Sinking Fund Bonds					
	6% Series A	1979	420	427	896	912
	Subordinated Debentures					
	6% Series A	1981		1,280		1,410
	Less purchased in advance of repayment requirements			(5)		(9)
Westcoast Transmission Housing Ltd.	Housing Mortgages, 7%	1993		52		68
Vancal Properties Ltd.	7½% Secured Notes	1994	4,120	4,420	4,249	4,559
Westcoast Petroleum Ltd.	Term Bank Loan	1980		1,892		1,992
	Sinking Fund Debentures 10%, First Series	1993		20,000		—
	Subordinate Debentures					
	6½% Series A	1981		2,449		3,070
Saratoga Processing Company Limited	First Mortgage Sinking Fund Bonds					
	6¼% Series A	1979	250	256	650	667
	Subordinated Debentures					
	6% Series A	1981		700		750
	Less purchased in advance of repayment requirements			(11)		(14)
	8½% Promissory Note	1981		100		140
Pacific Northern Gas Ltd.	First Mortgage Pipe Line Bonds					
	7¾% Series A	1988	9,713	10,441	10,638	11,435
	9¼% Series B (Note 6)	1991	2,405	2,425	2,590	2,611
	Debentures					
	11½% 1975 Series	1980		6,000		6,000
				388,401		322,945
	Deduct long term debt due within one year			12,008		12,489
				$376,393		$310,456

(See accompanying accounting policies and notes.)

Accounting Policies December 31, 1978 and 1977

Principles of Consolidation:

The consolidated financial statements include the accounts of the Company and the following subsidiaries:

Westcoast Transmission Company (Alberta) Ltd. (100% owned)
Westcoast Transmission Housing Ltd. (100% owned)
Gas Trunk Line of British Columbia Ltd. (100% owned)
Vancal Properties Ltd. (100% owned)
Saratoga Processing Company Limited (25% owned, including 100% of the voting shares)
Pacific Northern Gas Ltd. (45% owned, including 100% of the voting shares)
Westcoast Petroleum Ltd. (December 31, 1978—57.6% owned, December 31, 1977—57.6% owned)

Cost of Service:

The Company and its utility subsidiaries (Westcoast Transmission Company (Alberta) Ltd., Westcoast Transmission Housing Ltd. and Gas Trunk Line of British Columbia Ltd.) operate under a cost-of-service agreement with the British Columbia Petroleum Corporation. Under this agreement the Company is reimbursed for costs associated with the operation of the utility system including expenses for operating, maintenance, administration, depreciation and taxes including income taxes and receives a return on its utility rate base (primarily the undepreciated portion of the investment in gas plant facilities). The rate of return for each of the years ended December 31, 1978 and December 31, 1977 was 11%.

Regulation:

The Company is subject to the National Energy Board Act and to the jurisdiction of the Board created thereby. That Board regulates accounting matters, export of gas, construction and operation of gas pipelines and rates, tolls and charges of the Company.

Anti-Inflation Guidelines:

For the past three years, the Company has complied with Federal government anti-inflation legislation which imposed controls on dividends, profits and employee compensation. These controls expired at various dates during 1978.

Translation of United States Funds:

The Company's United States funds on deposit with banks and trustees and current liabilities payable in United States funds, with the exception of long term debt due within one year, have been translated to Canadian dollars at the exchange rates prevailing at the end of the fiscal years. Long term debt and capital stock issued in United States funds have been translated at the exchange rates prevailing at the respective dates of issue.

Depreciation and Depletion:

Depreciation is calculated using straight-line rates determined on the economic and physical life of the assets in service at the commencement of the fiscal years. The various rates used by the Company resulted in a composite rate of 3.3% for the year ended December 31, 1978 (for the year ended December 31, 1977 — 3.4%).

Depletion is calculated using the full cost method of accounting wherein all costs related to the acquisition, exploration for and development of oil and gas reserves are capitalized and depleted by a composite unit-of-production method based on total estimated proven reserves.

Capitalization and Maintenance:

Maintenance and repairs are charged to expense accounts when incurred and betterments which extend the useful life of properties are capitalized. Upon retirement or sale of items of property, the original cost of such items is charged against the applicable accumulated depreciation accounts and the net proceeds of disposal are credited to accumulated depreciation.

Allowance for Funds Used During Construction:

An allowance for funds used during construction was charged to plant, property and equipment at a rate of 11% for the year ended December 31, 1978 (for the year ended December 31, 1977 — 10½%).

Income Taxes:

The companies except Westcoast Petroleum Ltd. and Pacific Northern Gas Ltd. provide for income taxes on the taxes payable basis under which no provision is made for income taxes deferred through claiming capital cost and other allowances in excess of amounts recorded in the accounts. Westcoast Petroleum Ltd. accounts for income taxes by the tax allocation basis. Commencing July 1, 1978, Pacific Northern Gas Ltd. adopted the tax allocation basis.

If all the companies had used the tax allocation basis to provide for income taxes, the additional provision for the year would have been $20,600,000 (for the year ended December 31, 1977 — $19,800,000) and the additional accumulated provision to December 31, 1978 would have been $144,900,000 (December 31, 1977 — $124,300,000).

Debt Discount, Premium and Expense:

Debt discount, premium and expense is being amortized over the life of the respective debt issues.

Abandoned Pipeline:

Unrecovered costs of an abandoned gathering pipeline are being amortized over the ten year period ending December 31, 1980.

Capital Stock Expense:

Capital stock expense includes the unamortized portion of issue costs for the preferred shares which is being amortized over the five year period ending December 31, 1979.

Excess of Cost of Investment in Subsidiary:

The excess of the cost of investment in Gas Trunk Line of British Columbia Ltd. over the net book value at date of acquisition is being amortized over the remaining life of the Gas Transportation Contract between the Company and Gas Trunk which expires in December 1981.

Pension Plan:

The Company has a non-contributory pension plan covering substantially all employees and contributes amounts necessary to provide normal retirement income for the participants. The Company contributed and charged to operations $1,115,000 during the year ended December 31, 1978 (during the year ended December 31, 1977 — $1,018,000). Based on an actuarial evaluation dated January 1, 1977, there is no unfunded liability.

Earnings per Common Share:

Fully diluted earnings per common share calculations assume the conversion of the convertible debt and the exercise of share purchase options and warrants. Funds derived from the exercise of options and warrants were assumed to have been invested to produce an annual return of 11% for the year ended December 31, 1978 (for the year ended December 31, 1977 — 10%).

1. Plant, Property and Equipment:

	1978	1977
	(in thousands)	
Westcoast Transmission and Utility Subsidiaries		
Gathering plant	$214,865	$148,295
Products extraction plant	116,733	111,095
Transmission plant	440,490	432,923
Miscellaneous plant and equipment	19,217	17,009
Construction work in progress	47,483	21,538
	838,788	730,860
Westcoast Petroleum Ltd.		
Transmission plant	41,300	40,781
Oil and gas properties	130,577	102,584
	171,877	143,365
Other Subsidiaries		
Gathering plant	5,075	5,073
Products extraction plant	6,416	6,393
Transmission plant	31,721	31,606
Distribution plant	8,313	7,428
Miscellaneous plant and equipment	7,859	7,846
Construction work in progress	210	250
	59,594	58,596
Total Plant, Property and Equipment	1,070,259	932,821
Deduct:		
Accumulated depreciation		
Westcoast Transmission and Utility Subsidiaries	216,860	195,373
Westcoast Petroleum Ltd.	32,048	28,721
Other Subsidiaries	16,190	14,381
	265,098	238,475
Accumulated depletion		
Westcoast Petroleum Ltd.	19,045	15,743
Total Accumulated Depreciation and Depletion	284,143	254,218
	$786,116	$678,603

2. Northern Pipeline Projects:

The Company owns 50% of the outstanding common shares of Foothills Pipe Lines (Yukon) Ltd. which has been given the responsibility by the National Energy Board for coordinating and directing the Canadian portion of the Alaska Highway Pipeline Project. The Canadian portion of the project has as its objectives the transportation of Alaskan natural gas from the Alaska-Yukon border to Monchy, Saskatchewan and Kingsgate, British Columbia at the Canadian-United States border and for preparing and filing an application for the authorization to construct a pipeline, known as the Dempster Link, in the Yukon and Northwest Territories for the transportation of Canadian natural gas from the Mackenzie Delta-Beaufort Basin area to markets in southern Canada.

The Company's ownership in Foothills is recorded as an investment and the advances, which are based on the Company's percentage participation, are recorded as deferred charges.

3. Capital Stock:

(a) Preferred shares:

The Company during the six month periods ending December 31, 1979 and December 31, 1984 will invite tenders from all the holders of the Preferred Shares Series A for the purchase of all such shares at a price equal to $50 per share plus accrued and unpaid preferential dividends and cost of purchase and shall accept all such tenders received by it prior to February 15, 1980 or February 15, 1985 as the case may be.

The Preferred Shares Series A are redeemable after December 31, 1979 at the option of the Company at any time in whole or in part on not less than 30 days notice at varying redemption prices ranging from $54.25 if redeemed on or before December 31, 1980 to $50.50 if redeemed after December 31, 1984.

(b) Common share split:
On May 12, 1978 the authorized number of common shares was increased from 25,000,000 to 75,000,000 by subdividing each issued and unissued common share into three shares. Information pertaining to common shares has been restated to give retroactive effect to this share split.

(c) During 1978 the Company issued:
(i) 132,971 common shares on conversion of 7½% Convertible Debentures, First Series at a conversion rate of $8.33 per share, increasing capital stock by $1,108,000.
(ii) 850,162 common shares on conversion of 5½% Subordinate Debentures, Series C at a conversion rate of $9.96 (U.S.) per share, increasing capital stock by $8,140,000.
(iii) 13,581 common shares on Share Purchase Warrants exercised at a price of $9.44 per share, increasing capital stock by $128,000.
(iv) 15,000 common shares on options exercised by officers at option prices of $5.166 and $6.458 per share, increasing capital stock by $87,000.
(v) 75 common shares on conversion of 25 capital stock shares of Gas Trunk Line of British Columbia Ltd., increasing capital stock by $240.

(d) During 1977 the Company issued:
(i) 228,240 common shares on conversion of 7½% Convertible Debentures, First Series at a conversion rate of $8.33 per share, increasing capital stock by $1,902,000.
(ii) 816,045 common shares on conversion of 5½% Subordinate Debentures, Series C at a conversion rate of $9.96 (U.S.) per share, increasing capital stock by $7,816,000.
(iii) 2,160 common shares on Share Purchase Warrants exercised at a price of $9.44 per share, increasing capital stock by $20,000.
(iv) 51 common shares issued at a price of $3.33 per share were cancelled, decreasing capital stock by $170.

(e) Common share reservations and options are as follows:
(i) Included in the common shares reserved for outstanding options, as set out below are 207,000 common shares optioned to directors and officers (December 31, 1977 — 222,000 common shares).

Expiry date	Option price per share	Number of shares at December 31 1978	1977
July 26, 1980	$5.625	12,000	12,000
Oct. 16, 1983	$5.166	30,000	37,500
July 29, 1984	$6.458	30,000	37,500
April 20, 1986	$7.875	150,000	150,000

(ii) 608,625 common shares are reserved for options which have not yet been allocated (December 31, 1977 — 608,625 common shares).
(iii) 381,033 common shares are reserved for conversion of the 7½% Convertible Debentures, First Series (December 31, 1977 — 513,840 common shares).
(iv) 5,384,259 common shares are reserved for issuance upon the exercising of Share Purchase Warrants which may be exercised at $9.44 per share until May 15, 1981 (December 31, 1977 — 5,397,840 common shares).

4. Appropriated Retained Earnings:

The Company is required to provide for a Retraction Purchase Fund through an appropriation of retained earnings at an annual rate of 20% of the aggregate value of the outstanding preferred shares until July 1, 1979 when the appropriation will amount to 100% of the value of the outstanding shares.

5. Dividend Restriction:

The First Mortgage and the indentures relating to the Company's long term debt and preferred shares contain restrictions as to the declaration or payment of dividends (other than stock dividends) on common shares. Under the most restrictive provision, the amount available for dividends at December 31, 1978 is $62,000,000 (December 31, 1977 — $49,000,000).

6. Long Term Debt:

Long term debt payments required in the five years ending December 31 are:

1979 — $12,008,000
1980 — $29,456,000
1981 — $23,646,000
1982 — $21,549,000
1983 — $21,563,000

7½% Convertible Debentures, First Series are convertible into common shares at $8.33 per share until December 31, 1980.

Pacific Northern's 9¼% First Mortgage Pipe Line Bonds, Series B include detachable warrants to purchase 50,000 Class A common shares of Pacific Northern at $5 per share until maturity.

The translation of long term debt payable in United States funds at the exchange rate prevailing at the end of the fiscal year would increase long term debt including the portion due within one year to $408,504,000 (December 31, 1977 — $333,097,000). If followed, generally accepted accounting principles used in the United States for translation of foreign currencies would reduce net income by $9,950,000 (for the year ended December 31, 1977 — $12,278,000).

The Company has a line of credit with two Canadian chartered banks to an aggregate limit of $100,000,000. Each bank's commitment under the line of credit will be reviewed annually and interest will be charged at each bank's prime rate.

The Company's First Mortgage Pipe Line Bonds are secured by a specific First Mortgage of substantially all of the Company's fixed assets, its gas purchase contracts, its gas sales contracts and 807,200 common shares of Westcoast Petroleum Ltd. and by a first floating charge on other assets and its undertakings.

7. Remuneration of Directors and Senior Officers of the Company:

The aggregate remuneration paid to directors and senior officers in their capacity as directors or officers for the year ended December 31, 1978 was $641,000 (for the year ended December 31, 1977 — $610,000).

8. Commitments and Contingencies:

(a) The Company has received approval from the National Energy

Board for a major construction project which will cost approximately $85,000,000 and has filed an application with the National Energy Board requesting approval of another construction project that will cost approximately $20,000,000. Of these amounts $32,000,000 has been included in the accounts at December 31, 1978 and an additional $16,000,000 has been committed.

(b) The Company is a party, along with others, to an agreement with the Government of Canada requiring that feasibility studies be completed and applications be made to the National Energy Board on or before July 1, 1979 for the construction of the Dempster Link. In the event of default by the parties to the agreement, the agreement provides for payment of $50,000,000 to the Government of Canada, the obligation for which is joint and several among the parties.

(c) In 1977, the Company filed its first rate application before the National Energy Board and the Board decided to hold hearings in three phases. A decision on Phase I was rendered in May 1978 but was amended in November 1978 as a result of the Board's subsequent review of the initial decision. The amended decision approves a change in certain depreciation rates and the use of normalized accounting for corporate income taxes, but without the recovery of prior years' deferred taxes at this time. The November 1978 order postponed until Phase II any decision on methods for allocating depreciation and income tax expenses to domestic and export sales and affirmed the decision to defer the above changes until the time new tolls are approved by the National Energy Board which will be after the completion of Phase III.

Phase II, which is concerned with cost of service, rate base and rate of return, commenced in July 1978 but was adjourned to allow time for the National Energy Board to review Phase I. Phase II is scheduled to commence in February 1979 and be completed in March 1979. Phase III, which will cover the design of rates and tolls, is scheduled to commence in March 1979 and is anticipated to be completed in April 1979.

9. Selected Quarterly Data (Unaudited) (in thousands):

1978		For the three months ended		
	March 31	June 30	Sept. 30	Dec. 31
Operating revenues	$239,219	$185,705	$158,423	$260,555
Operating revenue deductions	219,414	166,780	139,248	239,123
Operating income	19,805	18,925	19,175	21,432
Other	7,123	6,705	6,559	7,693
Net income before income taxes	12,682	12,220	12,616	13,739
Provision for income taxes	1,549	1,263	1,075	2,432
Net income	11,133	10,957	11,541	11,307
Provision for preferred dividends	850	850	850	850
Net income applicable to common shares	$ 10,283	$ 10,107	$ 10,691	$ 10,457
Per common share:				
Weighted average	$.30	$.30	$.31	$.30
Fully diluted	$.29	$.29	$.30	$.29

1977		For the three months ended		
	March 31	June 30	September 30	December 31
Operating revenues	$180,248	$181,122	$158,485	$260,309
Operating revenue deductions	161,503	162,446	140,396	240,841
Operating income	18,745	18,676	18,089	19,468
Other	7,006	6,590	6,472	7,093
Net income before income taxes	11,739	12,086	11,617	12,375
Provision for income taxes	1,119	1,471	1,256	1,121
Net income	10,620	10,615	10,361	11,254
Provision for preferred dividends	850	850	850	850
Net income applicable to common shares	$ 9,770	$ 9,765	$ 9,511	$ 10,404
Per common share:				
Weighted average	$.30	$.29	$.29	$.31
Fully diluted	$.28	$.28	$.27	$.30

10. Replacement Cost Data (unaudited):

In compliance with the rules of the Securities and Exchange Commission of the United States, the Company has estimated certain replacement cost data with respect to plant investment and related accumulated depreciation, cost of gas sold, and depreciation expense. The results are explained and quantified in the Company's Form 10-K filed with the Commission and show that a significant increase in capital investment would be necessary to replace existing service capacity. The disclosure of this data is to comply with the Commission's rules and does not indicate a change in the Company's replacement policy.

The Company is under the jurisdiction of the National Energy Board of Canada and operates under a cost-of-service agreement with the British Columbia Petroleum Corporation. This agreement allows for the recovery of the Company's cost of service, including the cost of gas sold, depreciation based upon the historical plant cost, and a return on a rate base which includes net plant based upon historical cost. The National Energy Board presently does not recognize replacement cost for accounting purposes or rate determinations.

Auditors' Report

To the Shareholders of
Westcoast Transmission Company Limited:

We have examined the consolidated balance sheet and the consolidated statement of long term debt of Westcoast Transmission Company Limited as at December 31, 1978 and 1977 and the consolidated statements of operations, retained earnings, contributed surplus and changes in financial position for the years then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the company as at December 31, 1978 and 1977 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles applied on a consistent basis during the period.

Vancouver, Canada,
February 2, 1979.

CLARKSON, GORDON & CO.
Chartered Accountants

Concrete and steel rise from ground level at the new Pine River gas processing plant near Chetwynd. The $90 million facility ultimately will process 200 million cubic feet of gas and extract 1,100 tons of sulphur per day.

Management's Discussion of Operations

The Company's Ten Year Review on page 32 presents financial data which provide the basis for the following discussion of operations.

Year ended December 31, 1978

Substantial increases in operating revenue and operating revenue deductions over 1977 resulted from an increase of 17% in the average price of gas sold offset by a decrease of 7% in volumes of gas sold. The net income of the Company, however, was not appreciably affected as the Company's income from utility operations is based on the cost-of-service agreement with the B.C. Petroleum Corporation.

Operating income increased because of an increased average utility rate base (3.2%) and because operating income also increased by $1,955,000 with respect to Westcoast Petroleum Ltd.

Allowance for funds used during construction increased relative to 1977 because of the increase in construction activity.

Investment and other income decreased from 1977 because reduced surplus funds provided less interest income on amounts available for investment.

Interest on long term debt increased over 1977 due to the issuance of 9⅞% debentures on September 1, 1978 and foreign exchange on interest on debt payable in U.S. funds offset by reduced debt due to conversions of certain debt securities and scheduled repayments.

Other interest and amortization increased over 1977 due to interest on increased bank borrowings.

Year ended December 31, 1977

Substantial increases in operating revenue and operating revenue deductions over 1976 resulted from an increase of 28% in average price for gas sold and from an increase of 7% in volumes of gas sold.

Operation and maintenance increased over 1976 as a result of increases in maintenance, insurance and cost of fuel consumed in operations.

Increases in depreciation and depletion over 1976 resulted mainly from increases in depletion charged by Westcoast Petroleum Ltd.

Operating income increased because of an increased average utility rate base (2.5%) and because, effective January 1, 1977, the rate of return on rate base was increased from 10½% to 11%. Operating income also increased by $2,803,000 with respect to Westcoast Petroleum's operations.

Investment and other income increased over 1976 because proceeds from the 9¾%, Series H bond issue provided interest income on amounts available for temporary cash investments. Interest income on temporary cash investments increased income over 1976 by $2,000,000 and foreign exchange on debt repayments reduced income over 1976 by $1,200,000.

Interest on long term debt increased over 1976 due to the issuance of 9¾% Series H bonds and foreign exchange on interest on debt payable in U.S. funds offset by reduced debt due to conversions of certain debt securities and scheduled repayments.

Deferred income taxes, applicable to Westcoast Petroleum Ltd., increased in relation to that company's increased net income before income taxes.

Segmented Statement of Operations

Years ended December 31

	Westcoast Transmission Company Limited and Utility Subsidiaries(a)	Westcoast Petroleum Ltd.	Other Subsidiaries	Consolidated
	(in thousands)			
1978				
Operating revenues	$810,827	$ 25,623	$ 7,452	$843,902
Operating revenue deductions	750,240	11,963	2,362	764,565
Operating income	60,587	13,660	5,090	79,337
Other income	6,125	564	139	6,828
	66,712	14,224	5,229	86,165
Income deductions	27,105	1,393	2,310	30,808
	39,607	12,831	2,919	55,357
Minority interest	—	2,981	1,119	4,100
Income before income taxes	39,607	9,850	1,800	51,257
Income taxes	19	5,100	1,200	6,319
Net income	$ 39,588	$ 4,750	$ 600	$ 44,938
1977				
Operating revenues	$751,602	$ 21,783	$ 6,779	$780,164
Operating revenue deductions	692,749	10,078	2,359	705,186
Operating income	58,853	11,705	4,420	74,978
Other income	4,393	46	193	4,632
	63,246	11,751	4,613	79,610
Income deductions	24,855	483	2,523	27,861
	38,391	11,268	2,090	51,749
Minority interest	—	2,777	1,155	3,932
Income before income taxes	38,391	8,491	935	47,817
Income taxes	35	4,650	282	4,967
Net income	$ 38,356	$ 3,841	$ 653	$ 42,850

(a) Utility subsidiaries are:
Westcoast Transmission Company (Alberta) Ltd.
Westcoast Transmission Housing Ltd.
Gas Trunk Line of British Columbia Ltd.

Corporate Information

Registrars

Common Shares

CANADA TRUST COMPANY — Vancouver, B.C., Calgary, Alta., Regina, Sask., Toronto, Ont., Montreal, P.Q.

CHEMICAL BANK
New York, N.Y.

Preferred Shares

CANADA PERMANENT TRUST COMPANY — Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Bonds

MONTREAL TRUST COMPANY — Vancouver, B.C.

Debentures

Subordinate Debentures:

CITIBANK, N.A. — New York, N.Y.

MONTREAL TRUST COMPANY (co-registrar) — Vancouver, B.C., Calgary, Alta., Toronto, Ont., Montreal, P.Q.

First Series Debentures:

CANADA PERMANENT TRUST COMPANY — Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

1993 and 1998 Series Debentures:

CANADA TRUST COMPANY — Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Auditors

Clarkson, Gordon & Co.
P.O. Box 10101
Pacific Centre
700 West Georgia Street
Vancouver, B.C.

Transfer Agents

Common Shares, Bonds, Subordinate Debentures

MONTREAL TRUST COMPANY — Vancouver, B.C., Calgary, Alta., Toronto, Ont., Montreal, P.Q.

CITIBANK, N.A. — New York, N.Y.
(Series E Bonds are transferable at the Montreal Trust Company branch in Winnipeg, Man., and Common Shares are transferable at the Montreal Trust Company branch in Regina, Sask.)

First Series Debentures

CANADA PERMANENT TRUST COMPANY — Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

1993 and 1998 Series Debentures

CANADA TRUST COMPANY — Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Preferred Shares

CANADA TRUST COMPANY — Vancouver, B.C., Calgary, Alta., Regina, Sask., Winnipeg, Man., Toronto, Ont., Montreal, P.Q.

Stock Exchanges

Listed on the Toronto, Montreal and Vancouver Stock Exchanges in Canada and the New York and Pacific Coast Stock Exchanges in the United States

Stock Symbol — WTC

Offices

1333 West Georgia Street, Vancouver, B.C. V6E 3K9
1212-One Palliser Square, Calgary, Alberta T2G 0P6

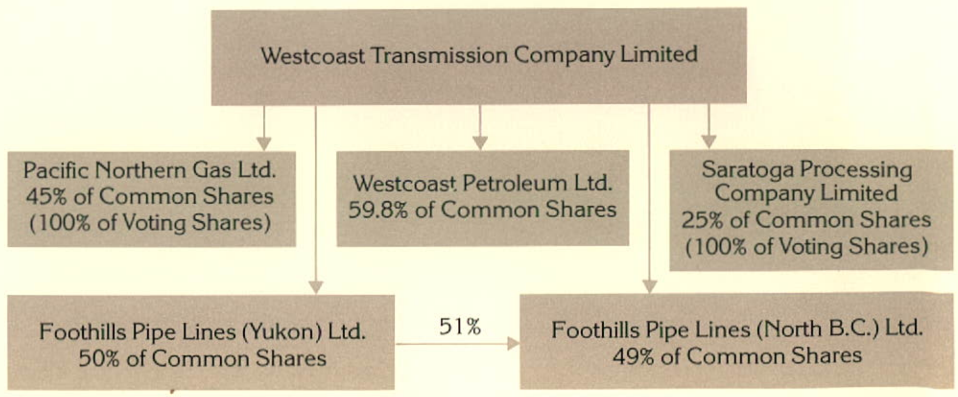
Stock Market Price Ranges Common Shares*

	New York		Toronto	
	Low	High	Low	High
	(U.S. Dollars)		(Canadian Dollars)	
January-March 1978	9⅜	10⅜	10⅜	11¾
April-June 1978	9½	10⅝	10⅞	11⅝
July-September 1978	9¾	11⅛	11	12¾
October-December 1978	8¾	10¼	11	11⅞
January-March 1977	8¾	9⅛	8⅞	9½
April-June 1977	8⅞	10	9⅜	10⅜
July-September 1977	9½	10⅜	10⅛	11
October-December 1977	9½	10⅝	10⅝	11¾

Earnings and Dividends Paid Common Shares*

	1978		1977	
	Earnings	Dividends	Earnings	Dividends
January-March	$0.30	$0.167	$0.30	$0.162
April-June	0.30	0.170	0.29	0.162
July-September	0.31	0.170	0.29	0.162
October-December	0.30	0.183	0.31	0.167
	$1.21	$0.690	$1.19	$0.653

**Reflects three-for-one share split.*



John Anderson

James S. Byrn

Alton J. Green

J. Taylor Kennedy

Edwin C. Phillips

L. Merrill Rasmussen

J. Ernest Richardson

Warren A. Roberts

William H. Tye

Charles N. W. Woodward

Directors

*John Anderson
Executive Vice President and
Chief Operating Officer
Westcoast Transmission Company Limited
Vancouver, British Columbia

†James S. Byrn
President and Chief Executive Officer
Genstar Marine Limited
North Vancouver, British Columbia

*Alton J. Green
Vice President and
Northern Pipelines Co-Ordinator
Westcoast Transmission Company Limited
Vancouver, British Columbia

J. Taylor Kennedy
Director
Canada Cement Lafarge Ltd.
Montreal, Quebec

*Edwin C. Phillips
President and Chief Executive Officer
Westcoast Transmission Company Limited
Vancouver, British Columbia

L. Merrill Rasmussen
President and Chief Executive Officer
Pacific Petroleums Ltd.
Calgary, Alberta

J. Ernest Richardson
Chairman of the Board
MacMillan Bloedel Limited
Vancouver, British Columbia

Warren A. Roberts
Executive Vice President
Phillips Petroleum Company
Bartlesville, Oklahoma

†William H. Tye
Senior Vice President
Pacific Petroleums Ltd.
Calgary, Alberta

†Charles N.W. Woodward
Chairman of the Board
Woodward Stores Limited
Vancouver, British Columbia

Frank M. McMahon
Chairman Emeritus of the Board
Hamilton, Bermuda

Norman R. Whittall
Honorary Director
Vancouver, British Columbia

*Executive Committee Member
†Audit Committee Member

Officers

Edwin C. Phillips
President and Chief Executive Officer

John Anderson
Executive Vice President and
Chief Operating Officer

A. J. Green
Vice President and
Northern Pipelines Co-Ordinator

J.E. Johnson
Vice President, Operations

J.A. Kavanagh
Vice President, Engineering

L.J. Smith
Vice President, Finance and Treasurer

C.D. Williams
Vice President, General Counsel and Secretary

J.E. May
Comptroller

D.O. Hunter
Assistant Treasurer

P.M. Steele
Assistant Secretary

Ten Year Review

(Dollar amounts are in thousands, except per share figures)

Financial*

	Years Ended December 31					
	1978	1977	1976	1975	1974	1973
Operations:						
Operating revenue	$ 843,902	$ 780,164	$ 579,276	$ 416,677	$ 266,600	$ 168,764
Operating income	79,337	74,978	67,930	53,913	49,974	47,093
Financial charges	29,548	27,398	23,945	25,934	27,680	28,062
Income before special items	44,938	42,850	39,459	33,019	26,731	24,001
Special items	—	—	—	—	—	—
Net income	44,938	42,850	39,459	33,019	26,731	24,001
Dividends on preferred shares	3,400	3,400	3,400	3,400	1,559	—
Net income applicable to common shares	41,538	39,450	36,059	29,619	25,172	24,001
Dividends on common shares	23,652	21,674	19,798	17,654	11,275	6,430
Cash flow	85,805	81,419	75,867	55,060	47,161	42,082
Per Common Share:						
Net income — weighted average	1.21	1.19	1.11	.99	.97	.93
— fully diluted	1.17	1.13	1.04	.90	.83	.80
Dividends	.69	.653	.612	.60	.433	.25
Dividend payout ratio	57%	55%	55%	61%	45%	27%
Cash flow	2.49	2.45	2.34	1.84	1.81	1.64
Assets:						
Plant, property and equipment	1,070,259	932,821	882,394	736,752	699,954	653,223
Accumulated depreciation and depletion	284,143	254,218	227,669	167,632	149,212	131,826
Net plant, property and equipment	786,116	678,603	654,725	569,120	550,742	521,397
Net additions to plant	137,438	50,427	36,977	36,798	46,731	35,152
Total assets	961,338	823,289	767,840	675,189	664,999	614,217
Rate Base and Return:**						
Average utility rate base	546,579	529,758	516,738	499,092	493,404	—
Average return on utility rate base	11.0%	11.0%	10.5%	10.0%	9.5%	—
Average return on equity in utility rate base	14.0%	14.5%	14.4%	14.2%	14.2%	—
Capitalization:						
Long term debt	376,393	310,456	317,275	308,037	367,105	386,960
Preferred shareholders' equity	40,000	40,000	40,000	40,000	40,000	—
Common shareholders' equity	324,646	296,487	268,873	247,670	190,668	174,332
— per common share	9.37	8.81	8.25	7.72	7.33	6.78
Return on average common shareholders' equity	13.4%	14.0%	14.0%	13.5%	13.8%	14.5%
Capitalization Ratios:						
Long term debt	50.8%	48.0%	50.7%	51.7%	61.4%	68.9%
Preferred shareholders' equity	5.4%	6.2%	6.4%	6.7%	6.7%	—
Common shareholders' equity	43.8%	45.8%	42.9%	41.6%	31.9%	31.1%

Statistical

	1978	1977	1976	1975	1974	1973
Total gas sales —						
Thousands of cubic meters	9 757 496	10 467 364	9 791 490	10 005 393	10 261 958	11 675 489
Millions of cubic feet	344,449	369,508	345,649	353,200	362,257	412,156
Average daily sales —						
Cubic meters	26 732 869	28 677 710	26 752 727	27 412 029	28 114 928	31 987 627
Thousands of cubic feet	943,696	1,012,351	944,397	967,671	992,484	1,129,194
Peak day sales —						
Cubic meters	38 774 354	37 395 270	32 972 331	33 265 722	33 681 688	36 393 966
Thousands of cubic feet	1,368,772	1,320,089	1,163,955	1,174,312	1,188,996	1,284,742
System sales capacity —						
Cubic meters per day	36 996 159	36 996 159	36 996 159	36 996 159	36 996 159	36 996 159
Thousands of cubic feet per day	1,306,000	1,306,000	1,306,000	1,306,000	1,306,000	1,306,000
Kilometers of transmission pipelines	2 253	2 253	2 214	2 214	2 211	2 211
Miles of transmission pipelines	1,400	1,400	1,376	1,376	1,374	1,374
Kilometers of gathering pipelines	1 935	1 593	1 548	1 395	1 278	1 151
Miles of gathering pipelines	1,203	990	962	867	794	715
Compressor kilowatts	337 966	333 492	333 492	333 492	329 017	285 021
Compressor horsepower	453,220	447,220	447,220	447,220	441,220	382,220
Shares outstanding at year end*	34,662,834	33,651,045	32,604,651	32,089,857	26,020,200	25,727,931
Number of common shareholders	12,496	9,870	9,677	9,768	9,525	10,225
Number of employees	638	573	508	514	519	515

*Financial information has been restated to give retroactive effect to the three-for-one common share split.

**The nature of the Company's utility operations changed significantly in November 1973 at which time it commenced operating on a cost-of-service basis whereby utility operating costs are recovered and the Company receives a return on its utility investment.

1972	1971	Nine Months Ended December 31 1970	Year Ended March 31 1970
$ 139,492	$ 101,575	$ 69,684	$ 92,837
42,810	26,665	16,254	22,415
26,189	24,960	14,597	18,854
21,314	8,416	3,103	5,319
(470)	814	—	—
20,844	9,230	3,103	5,319
—	—	—	—
20,844	9,230	3,103	5,319
5,112	3,368	3,351	3,349
37,931	21,836	12,779	16,845
.82	.46	.15	.26
.76	.46	.15	.26
.20	.167	.167	.167
24%	36%	109%	63%
1.49	1.08	.64	.84
618,071	564,769	461,394	429,486
115,262	100,175	89,839	81,238
502,809	464,594	371,555	348,248
53,302	103,375	31,908	15,152
571,584	533,836	437,154	410,079
—	—	—	—
—	—	—	—
—	—	—	—
371,098	378,712	305,518	257,580
—	—	—	—
156,508	96,459	89,396	89,700
6.09	4.76	4.45	4.46
16.5%	9.9%	3.5%	5.9%
70.3%	79.7%	77.4%	74.2%
—	—	—	—
29.7%	20.3%	22.6%	25.8%

10 443 880	8 148 758	5 591 462	7 333 710
368,679	287,659	197,384	258,887
28 535 171	22 325 341	20 332 562	20 092 342
1,007,319	788,106	717,759	709,279
35 439 119	31 806 244	25 117 701	24 558 396
1,251,035	1,122,791	886,679	866,935
34 871 571	31 217 280	24 475 254	24 475 254
1,231,000	1,102,000	864,000	864,000
2 076	1 934	1 555	1 555
1,290	1,202	966	966
1 147	1 093	914	914
713	679	568	568
284 275	256 312	214 627	214 627
381,220	343,720	287,820	287,820
25,688,829	20,281,023	20,111,451	20,099,451
10,630	10,450	10,585	10,183
502	494	518	526