ANNUAL REPORT 1984

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COLUMBIA GAS
System

The Columbia Gas System is in the business of finding, producing, purchasing, transmitting, storing and delivering natural gas to individuals, businesses and industry. At every phase our operations are conducted so our customers and investors both realize maximum benefit from our operating efficiencies and timely actions in their behalf.

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HIGHLIGHTS

	1984	1983
Per Share Data ($)		
Earnings from Continuing Operations	**4.22**	4.94
Earnings on Common Stock	**3.53**	4.41
Dividends	**3.18**	3.02
Book Value	**41.22**	41.16
Earnings From Continuing Operations ($000)		
Gas Distribution	**54,839**	21,188
Gas Transmission	**79,192**	102,716
Oil and Gas	**63,279**	68,474
Other	**(31,874)**	(7,677)
Total	**165,436**	184,701
Financial Data ($000)		
Operating Revenues	**4,593,382**	5,075,085
Capital Expenditures	**272,009**	210,941
Total Assets	**5,200,536**	5,238,355
Capitalization	**3,107,709**	3,148,709
Operating Statistics (million cubic feet)		
Gas Sales	**782,859**	876,299
Transportation Volumes	**423,427**	262,798
Total Throughput	**1,206,286**	1,139,097

JOHN H. CROOM
Chairman, President and
Chief Executive Officer

The primary focus of Columbia Gas System activity in 1984 was on rebuilding load on our pipelines by making our natural gas supplies more competitive in a changing marketplace. Our present condition of having too much gas under contract, some at too high a price, had a negative impact on both financial results and operations.

EARNINGS—The 1984 earnings on common stock of $3.53 per share, in comparison to $4.41 per share in 1983, mirrored in large measure decisions which resolved several long-standing problems.

The individual factors which produce the System's earnings are reported in detail beginning on page 6, together with other System activities of note. Recognizing the separate but related operations of the System's affiliates, the year's report is divided into distinct operating segments: distribution, transmission, oil and gas, and other operations.

INDUSTRY CONDITIONS—Our industry has been changing rapidly since passage of the Natural Gas Policy Act of 1978 (NGPA), and the pace of change accelerated during 1984.

The NGPA was intended to overcome the gas supply shortages of the 1970's by permitting wellhead prices to rise in order to stimulate drilling. Congress assumed when it passed the measure that prices of competing oil products, which had risen steadily in the early 1970's, would continue upward and that energy demand would remain strong.

Although available natural gas supplies improved dramatically, the NGPA assumptions on oil prices and energy demand proved to be wrong. Oil prices have since fallen, in many markets going below gas prices being pushed upward by NGPA forces. Energy demand weakened under the impact of recession and increased conservation.

Under these conditions, long established natural gas industry supply practices are changing. Traditionally, pipelines have dealt with producers to purchase gas for delivery and resale to distribution companies. This resale is without markup on the price of gas; the pipelines' income is generated by the transportation service. Now, end users and distribution companies are making direct purchases from producers at an accelerating rate and asking the transmission pipelines only for transportation services. Left with producer contracts signed to meet expected market obligations, pipelines are aggressively seeking other outlets wherever they can find them. Distribution companies are reaching for customers, notably industrial users, beyond their traditional service area, while seeking to lower their gas costs in the face of aggressive oil and electric competition. The long-range role of the pipelines in providing such services as storage for winter peak demand is uncertain as a "spot" market for gas develops. Federal and state regulatory agencies are working to adapt their policies to these changing conditions and in a departure from historic practice are encouraging competition to bring about lower consumer costs.

COLUMBIA'S SITUATION—In this new highly competitive marketplace, where does Columbia find itself? To be quite blunt, we find ourselves with an oversupply of high-priced natural gas to which we are committed and a shrunken market.

There are reasons for this situation, of course. In response to the supply shortages of the mid-seventies, the NGPA provided higher incentives to producers which resulted in accelerated drilling and increased deliverability, largely from existing reserves. Columbia's principal transmission subsidiary contracted with producers for natural gas at these incentive prices to meet the needs projected by its customers. These customer estimates historically had been reliable but those provided in the late seventies and early eighties were overstated for several reasons. The same rising price of gas that attracted new supplies spurred all classes of consumers to institute additional conservation measures to reduce their usage. Of particular impact on Columbia were the major structural changes which occurred in our service area in the energy intensive industries such as steel, glass and automotive, as they faced increasing competition. Sales to these industries dropped markedly in the recent recession years as many older and less efficient plants closed permanently and others invested in equipment and production practices using less energy. Columbia's sales to the industrial sector were further depressed as falling oil prices encouraged many industrial customers with oil burning capability to switch from natural gas.

As prices rose and markets deteriorated, some of the transmission subsidiary's utility customers challenged its supply acquisition practices under a provision of the NGPA in proceedings before the Federal Energy Regulatory Commission (FERC), which must approve the subsidiary's rates. These utilities held that our purchasing practices did not give adequate consideration to the marketability of the natural gas; that we had agreed to pay too much and therefore our rates are too high. They seek refunds or other compensation in a proceeding before the FERC.

We believe that Columbia's acquisition policies and practices have been and are prudent and that our legal position is sound. However, continued hearings and litigation, which could extend over a period of years, are a great drain at a time when primary attention must be focused on serious market problems. We are therefore in discussions with the utility customers in an effort to reach a settlement of the matter.

Any such settlement would require us to renegotiate existing producer contracts to make our prices more competitive in the marketplace—competitive both with alternate fuels and with natural gas from other sources. To that end we are in discussions with producers to secure more realistic prices and volumes. In 1983, we exercised certain contract provisions to reduce the level of prices and volumes in some contracts, actions which were challenged in court by twelve southwestern producers. Through negotiations, agreements have been reached which settle six of the lawsuits, but the broader contract problems of price and volume persist.

Management has under study several alternative plans to resolve the System problems referred to above. Such plans under consideration would involve substantial charges against System assets and have a material adverse effect on future System earnings. However, the amount of such charges and the accounting periods to which they may relate cannot be determined at this time.

It should be emphasized, however, that each of these plans is designed to insure Columbia's long-term future by restoring its competitive position in the marketplace.

DIVIDEND ACTION—Columbia's common stock dividend had been increased in the first quarter for 22 years before 1985. When the Board of Directors met on January 18, 1985, it judged that a dividend increase was not appropriate in view of the unsettled supply problems of the System's primary transmission subsidiary. The dividend was maintained at 79.5 cents a common share, making for an indicated annual dividend rate of $3.18 per share, the same as the 1984 rate. The amount of future quarterly dividends will depend on the resolution of our supply problems and on the earnings level in general.

COMPETITIVE ACTIONS—System operating companies have put in force a variety of programs to address our marketing problems. These have enabled us to regain pipeline load in the current competitive marketplace.

Columbia has been a leader in offering innovative programs to transport natural gas which distributors and large industrial users purchase directly from producers. In some cases the volumes transported must be purchased from our producer suppliers so that those volumes will be credited against our contracted amounts. Other natural gas can be purchased from any source. The flexibility of Columbia's voluntary programs resulted in a steady increase through 1984 in the volume of Columbia's transportation business through both transmission and distribution lines.

The success of the transportation programs in maintaining load to industrial users on our System prevents the shifting of costs to other classes of customers, and maintains the revenue stream of our distribution companies. As a result of these programs, volumes delivered to industrial customers in 1984 increased for the first time in five years.

Under current industry conditions, transportation for others will be a significant part of Columbia's business. Columbia is primarily in the pipeline business and should be able to earn a satisfactory return on its pipeline assets whether it is selling natural gas bought for resale or simply supplying transportation services.

Columbia is actively opposing any legislation providing that pipelines must furnish transportation service. Mandatory carriage, as it is called, would threaten the overall service reliability of the industry. It would require restrictive regulation and would, we believe, be contrary to the desire of most distribution companies to rely on Columbia for long-term supply assurance.

Through its transportation programs, contract renegotiations and other means, our transmission unit has achieved significant reductions in its financial exposure under contracts to accept delivery of natural gas or pay for it anyway—so-called take-or-pay contracts. The renegotiations also resulted in lower prices under some contracts. Details of the renegotiations are reported on page 14.

Operating costs have a direct impact on the price of our product and thus our ability to compete. While Columbia has always tried to maintain a "tight ship" posture, conscious efforts at cost containment throughout the System are resulting in additional reductions in costs and improvements in operating efficiency.

1984 HIGHLIGHTS—Although 1984 ranks as less than a banner year for Columbia, several events merit mention beyond inclusion in the operating and financial report that follows on page 6.

- Sale of the System's West Virginia retail subsidiary was completed in June, separating from the System a unit with a long history of losses in an unrealistic regulatory climate.

• Application was made to the Securities and Exchange Commission for formation of Columbia Natural Resources, Inc., a new subsidiary that will become the operator of all natural resource properties that are now part of two of the System's Appalachian companies. Creation of a separate unit to develop natural gas and oil properties in nine eastern and midwestern states reflects our increased emphasis on exploration and production activities. Structuring operations along functional lines will strengthen all companies involved by allowing their managements and personnel to concentrate on their own areas of expertise.

• The earnings of our affiliated distribution companies in 1984 showed the results of strong efforts made to revitalize the retail markets.

• Columbia's distribution companies have successfully put into effect a number of programs to help low-income families pay winter heating bills. Current natural gas rates are much above their pre-NGPA levels, and this situation in recent winters has made it difficult for families on tight budgets to pay winter gas bills. Columbia's efforts augment various government aid programs and, in some instances, utilize funds not recoverable in rates.

THE YEAR AHEAD—Primary management attention in 1985 will be on resolution of the issues related to contracts with producers and the FERC proceedings on gas acquisition policies. Developments in these matters will be reported promptly.

Capital expenditures are currently projected to increase about 14% in 1985 to $310 million from the $272 million expended in 1984, a reduced amount from that projected a year ago. Almost all of the increase will be devoted to an expansion of gas and oil exploration and development, with expenditures expected to be as follows (1984 outlays in brackets): gas and oil $126 million ($92 million); transmission $100 million ($96 million); distribution $79 million ($77 million); and other $5 ($7 million).

Programs of our transmission and distribution companies to encourage gas transportation business have been extended into 1985. This area of activity is expected to expand further at least until we are able to bring the price of gas bought for resale down to market levels.

RESOURCES FOR THE FUTURE—Looking beyond the immediate, and certainly serious, problems we must settle, the Columbia System has solid qualities upon which to plan for growth.

• Natural gas is a preferred fuel that offers major advantages and efficiencies in many applications and for which abundant potential sources exist.

• The System has in place an efficient, well-maintained pipeline network reaching to large residential, commercial and industrial markets, with the ability to draw upon all major producing areas.

• Columbia's lease holdings in the U.S. and Canada are among the most extensive of any natural gas company, providing broad opportunities for building and marketing gas and oil production.

• Columbia is managed and operated by men and women experienced in the energy industry and dedicated to growth through quality service. Through various plans Columbia employees own 14% of Columbia's common stock and constitute the largest single stockholder group.

• Planning throughout the System is being strengthened to achieve optimum utilization of Columbia's resources and address the changes that are occurring in our industry and economy. Our planning is directed to managing change in an orderly manner and to being prepared to deal with the unexpected.

MANAGEMENT DEVELOPMENTS—W. F. Laird, chairman and chief executive officer of the System, retired as an active employee on August 1, 1984, after 33 years with Columbia, the last four as chief executive officer. He continues as a member of the Columbia board.

On December 19, 1984, Dr. Sherwood L. Fawcett, chairman of the Board of Trustees and retired chief executive officer of the Battelle Memorial Institute, Columbus, Ohio, was elected to the Board of Directors. Dr. Fawcett retired in December 1984 after 16 years as the chief executive officer of Battelle, which is the world's largest nonprofit independent research organization. His election increased the Columbia board to 16 members.

On February 20, 1985, James T. Connors was elected Secretary of the Corporation.

The support of stockholders and employees is of major importance as plans move forward to reposition the Columbia System competitively in the energy industry. With such support and success in the plans we have made, the year 1985 can be a turning point in the course of Columbia's progress.

JH Croom

John H. Croom
Chairman, President and
Chief Executive Officer

February 20, 1985

CONSOLIDATED EARNINGS

ADJUSTED EARNINGS—Adjusted 1984 earnings were up 2% over 1983 and 8% over 1982 as improved earnings from the distribution segment offset lower earnings from the transmission and oil and gas segments. Oil and gas production increased substantially in 1984, however, 1983 earnings included a $23.6 million gain applicable to 1982 as a result of a favorable U.S. Supreme Court decision related to pipeline production pricing. On a per share basis, the earnings improvement was not sufficient to overcome the effect of increases in the average number of common shares outstanding.

REVENUES—Retail gas operating revenues and sales volumes for 1983 and 1982 include sales of the West Virginia distribution subsidiary which was sold in 1984. The former subsidiary is now a wholesale customer.

Total gas operating revenues declined in 1984 as average sales rates moderated (decreased less than one percent) and direct sales volumes to industrial customers continued their downward trend. During 1984, the effect of fuel switching lessened considerably, but due to price competition, industrial customers significantly increased their direct purchases from producers. Conservation has become less of a factor on residential and commercial sales which remain greatly influenced by weather and customer growth. However, some large volume commercial customers are taking advantage of the special marketing programs and transportation services offered by the System's companies. Wholesale sales volumes continued to decline as unaffiliated distributors experienced similar market conditions. In addition, some of these customers increased their purchases from competing pipeline suppliers and directly from producers.

Other operating revenues rose sharply in 1984 reflecting the success

EARNINGS SUMMARY

	1984		1983		1982	
	Earnings ($ Mil.)	**Per Share ($)**	Earnings ($ Mil.)	Per Share ($)	Earnings ($ Mil.)	Per Share ($)
Earnings on Common Stock	**138.6**	**3.53**	164.8	4.41	180.1	5.10
Discontinued Operations[a]	**26.9**	**.69**	2.6	.07	2.7	.07
Extraordinary Charge[b]	**—**	**—**	17.3	.46	—	—
Earnings from Continuing Operations	**165.5**	**4.22**	184.7	4.94	182.8	5.17
Nonrecurring Items[c]	**32.6**	**.83**	9.7	.26	—	—
Adjusted Earnings	**198.1**	**5.05**	194.4	5.20	182.8	5.17

[a] Reflects decision to cease coal mining operations (see Note 2*).
[b] Loss on sale of unprofitable distribution subsidiary (see Note 4*).
[c] Nonrecurring Items (see Note 3*):

1983—Impairment reserves of $9.7 million ($0.26 per share) established to reflect investments in the Alaskan Natural Gas Transportation System and Northern Border Study Group at estimated realizable value.

1984—Fourth quarter adjustment of $2.6 million ($0.07 per share) to the impairment reserve for the Alaskan Natural Gas Transportation System reflecting decision to withdraw from the partnership.

1984—Provision for loss of $30 million ($0.76 per share) reflecting synthetic gas agreements finalized in the first quarter.

*Notes to Consolidated Financial Statements of the System's effort to promote special marketing and transportation programs. The contribution to earnings was significant to the distribution segment as total deliveries to industrial customers increased for the first time in five years. Propane and oil revenues, which were depressed in 1983, also improved in 1984.

Other income increased significantly due primarily to an improved liquidity position which resulted in greater income from temporary cash investments.

TOTAL REVENUES AND THROUGHPUT	1984	1983	1982
Gas Operating Revenues ($000):			
Residential	**1,278,745**	1,357,686	1,256,348
Commercial	**617,593**	646,394	594,316
Industrial	**592,084**	841,891	938,120
Wholesale	**1,843,234**	2,032,807	2,074,838
Other	**15,248**	16,878	17,370
Total Gas Operating Revenues	**4,346,904**	4,895,656	4,880,992
Other Operating Revenues	**246,478**	179,429	178,014
Other Income	**51,793**	26,964	36,746
Total Revenues	**4,645,175**	5,102,049	5,095,752
Sales (Million Cubic Feet):			
Residential	**188,471**	207,225	230,325
Commercial	**97,042**	104,606	115,678
Industrial	**108,124**	151,034	202,591
Wholesale	**384,967**	409,070	502,382
Other	**4,255**	4,364	4,821
Total Sales	**782,859**	876,299	1,055,797
Total Transportation Volumes	**423,427**	262,798	198,004
Total Throughput	**1,206,286**	1,139,097	1,253,801

EXPENSES—Gas purchased costs continued to decline reflecting the lower sales requirements. Average rates, which had been climbing steadily, reflected a slight decrease in 1984. Other products purchased were down substantially, due largely to lower feedstock requirements related to the cutback in synthetic gas operations effective with the second quarter of 1984.

Depreciation and depletion expense increased 24% in 1984 reflecting greater depletion expense related to higher oil and gas production, coupled with the effect of downward adjustments of $24.9 million applicable to 1982 recorded in 1983 related to a U.S. Supreme Court decision allowing pipelines to charge higher rates for their cost-of-service production. Depletion expense in 1982 was affected by a lower depletion rate resulting from the initial inclusion of certain Appalachian reserves.

Interest and related charges were down 17% from 1983 due primarily to the cash generated in the first quarter as a result of colder weather and general rate increases, which practically eliminated the need for short-term borrowings. Interest charges in 1983 and 1982 were influenced by increased borrowings under the revolving credit agreement and the effect of new debentures issued in mid-1982. Both 1984 and 1983 reflected lower levels of interest capitalized.

INCOME TAXES—Income taxes, as detailed on the Statements of Consolidated Taxes, decreased in 1984 due primarily to a reduction in pre-tax book income. In 1983, the increase was due to greater pre-tax book income and lower investment tax credits reflecting lower construction activity.

OVERVIEW—Columbia's distribution subsidiaries serve more than 1,700,000 residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Maryland, New York and Kentucky. As these companies move into an environment in which they are more influenced by market forces, emphasis is being placed on aggressiveness and innovation in all areas of distribution operations, particularly in marketing programs, gas transportation services, rate activities, supply procurement and cost reduction.

1984 HIGHLIGHTS—Actions already taken helped produce these positive results in 1984:

- Earnings from distribution operations more than doubled over 1983.
- Success in expanding transportation services offset the continued decline in industrial sales volumes. As a result, the volume of gas delivered to industrial customers in 1984 increased for the first time in five years.
- The sale of the System's unprofitable retail subsidiary in West Virginia was completed in June, ending the drain on earnings resulting from an unrealistic regulatory climate spanning many years.
- Marketing efforts resulted in a net gain of approximately 7,000 residential and 2,000 commercial customers. This growth, coupled with conversions of existing customers to heating added approximately 9,100 residential heating and 1,000 commercial heating customers.
- Stabilized gas rates attained in mid-1983 continued throughout 1984 marking the end of a long period of rapidly escalating gas prices.

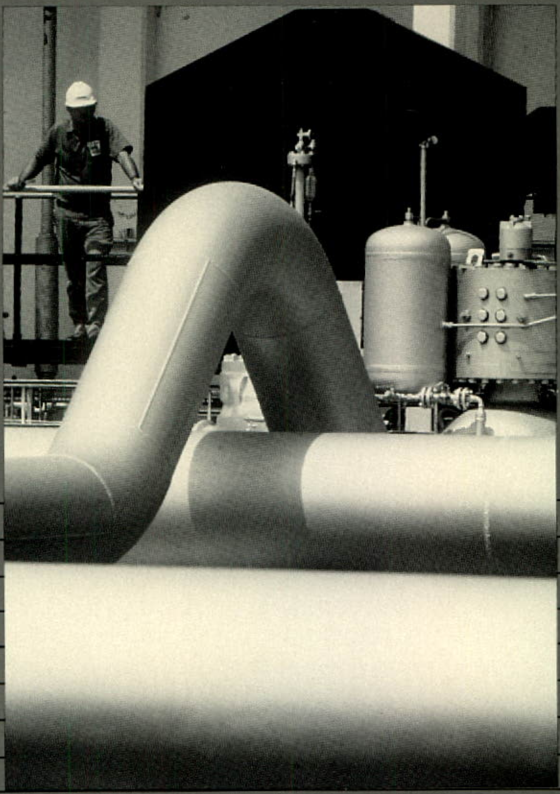
MARKET CONDITIONS AND COMPETITION—With price the driving force in today's marketplace the System's distribution companies face problems in many markets in which their rates are not competitive.

The gas distribution companies compete for sales at the industrial burner tip with other fuels, particularly No. 6 fuel oil, and many industrial customers are equipped to switch between gas and oil with little effort. Electricity also offers competition for melting, annealing and other industrial energy processes. In residential and commercial markets, the electric heat pump has provided aggressive competition. With its low installed cost, electric resistance heat has made inroads in some areas in the starter home market. Electricity also competes strongly for water heating, cooking and clothes drying applications. Recently, competition has also come from other gas suppliers as pipelines and distribution companies are reaching for customers, especially industrial customers, beyond their traditional service area.

Energy prices in Columbia's market area change often and vary widely. Although Columbia's average retail rates only rose 2.5% in 1984, they remain at a level which encourages gas suppliers with lower prices to compete for gas sales in a number of locations. Oil prices are currently dropping as free market forces reduce OPEC's power and supply continues to exceed demand. Electric rates are going up in areas where electric companies must recover large investments in nuclear power plants; but in other areas, electric rates are down as a result of lower oil and coal prices and, in some cases, excess capacity.

OUTLOOK—To meet the challenges of today's price-competitive market, the System's distribution companies are adopting the following strategies for 1985.

- Develop innovative gas transportation services to industrial and other customers, thereby preventing the loss of industrial business and a potential shift of costs to other classes of customers. Transportation activity is expected to represent approximately 40 percent of industrial business in the next few years.
- Expand purchases of lower priced gas to achieve more competitive gas rates.
- Secure greater rate flexibility from state utility commissions by demonstrating that innovative rate-making is necessary to hold rates down, maintain adequate rates of return and to be indifferent as to whether the gas



Columbia's transmission and distribution companies deliver natural gas to large parts of eight populous industrial states and the District of Columbia.

RETAIL AND WHOLESALE SERVICE AREAS

Columbia Retail
Columbia Wholesale
Pipeline Network

delivered is a direct sale or a transportation arrangement.

• Implement a 1985 marketing plan which:

—positions natural gas as the "energy of choice";

—exploits the existing potential to convert buildings to gas heat;

—promotes high-efficiency gas appliances in the residential and commercial markets;

—promotes the "Blue Flame" home program to emphasize the ultimate in home energy conservation and efficiency;

—promotes the use of gas furnaces in conjunction with electric air conditioners to challenge the electric heat pump;

—improves industrial marketing by increasing our knowledge of industrial trends and processes.

• Continue to support research on the gas-fired heat pump;

• Advocate legislation to provide energy assistance funds for low-income families, so that costs of uncollectible bills do not increase rates for paying customers.

The success of these and other programs could result in a continuance of the turnaround which began in 1983.

RESULTS OF OPERATIONS

Gas Distribution ($000)	Revenues	Operating Income	Earnings from Continuing Operations
1984	2,459,600	129,200	54,800
1983	2,785,500	83,300	21,200
1982	2,715,400	49,900	6,100

FINANCIAL REVIEW

Revenues, operating income and earnings for the years 1983 and 1982 include the following amounts for the West Virginia subsidiary which was sold during 1984: revenues were $288.1 million in 1983 and $281.3 million in 1982; operating losses were $7.0 million and $13.3 million, respectively; and the adverse impact on earnings was $7.2 million and $10.8 million, respectively. The loss related to the sale of this subsidiary was recorded in the fourth quarter of 1983 as an extraordinary charge, including a provision for estimated 1984 operating losses. In the following analysis, explanations are provided which eliminate the effects of the West Virginia company.

Operating income rose substantially for the second straight year indicating a trend toward more acceptable levels of return on investment as results of the overall marketing effort more than offset the continued downward trend in sales volumes. Operating income for 1984 was up 43% over the previous year and 1983 operating income exceeded the depressed level of 1982 by 43%. The following factors influenced the results obtained in the two years:

• Sales revenues for 1984 were down 3% as volumes declined 6% and offset an increase in average sales rates of less than 3%. In 1983, sales rates rose 21%, more than offsetting a 16% volume decline.

• Increased transportation volumes in 1984 and 1983 mitigated the effect of lower industrial sales volumes which dropped 21% in 1984 and 26% in 1983.

• General rate filings placed into effect since the latter part of 1982 allowed the recovery of increased costs and allowed such recovery on lower sales volumes.

• The provision for uncollectible accounts increased 62% over 1983 due primarily to regulatory restrictions precluding the recovery of a portion of gas utility bills from low-income families.

• Increases in other operating costs were held down by cost reduction programs and lower rates of inflation.

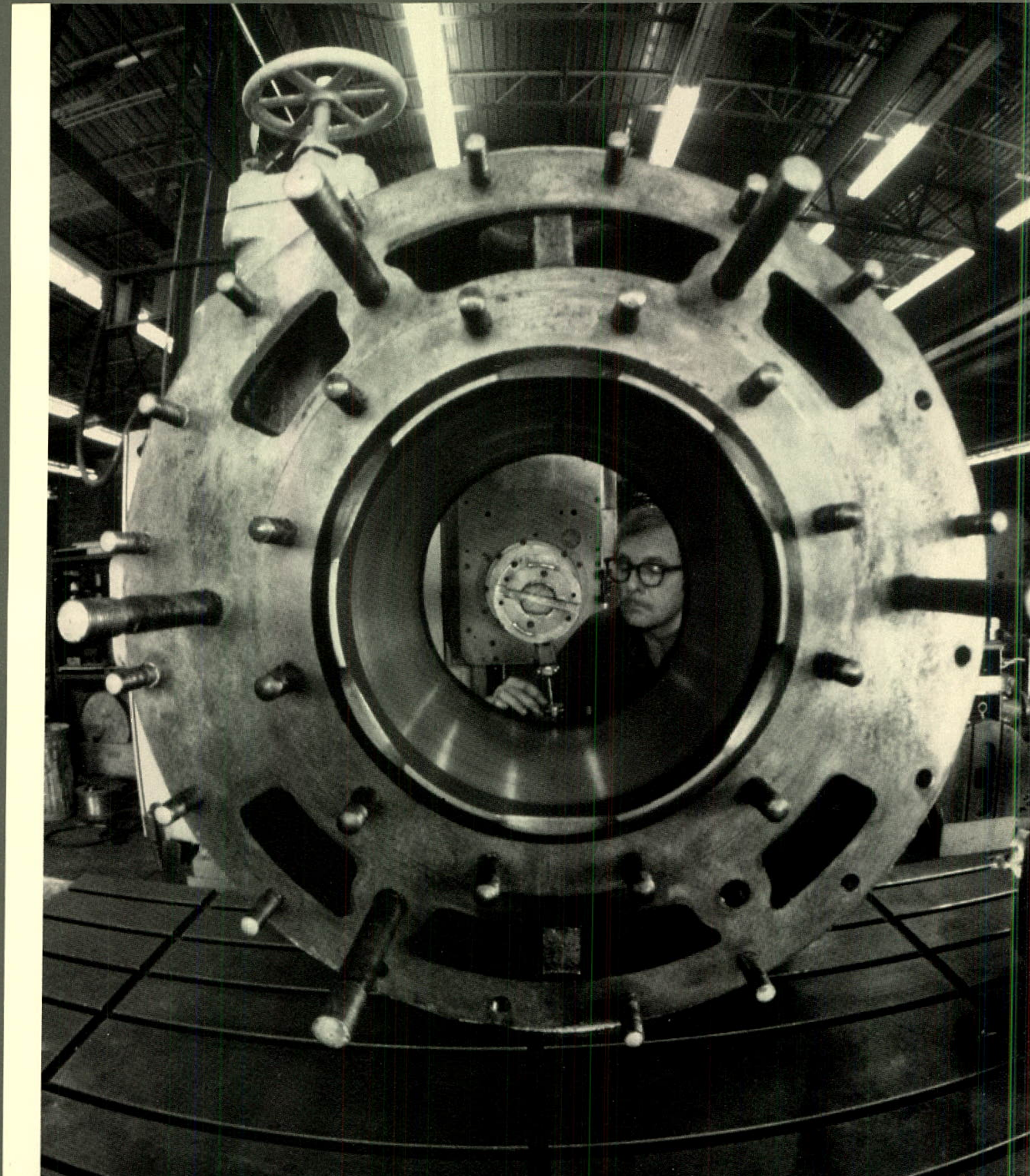
The relatively low operating income in 1982 resulted from a combination of warm weather and the full impact of the recession.

Capital expenditures for 1985 are primarily for replacement of facilities and are currently estimated at $79.2 million. For the three year period 1984-82, capital expenditures totaled $76.6 million, $70.2 million and $69.1 million, respectively.

Columbia's distribution subsidiaries have received approval from the state utility commissions for general rate increases of approximately $55 million annually during 1984. Additional increases of approximately $44 million annually were pending at the end of the year.

Pipelines are built with operating safety and dependability as the first considerations, whether through rugged mountain country or crowded city streets.

Maintenance of massive pipeline facilities calls upon the skills of experienced technicians.



OVERVIEW—Columbia Gas Transmission Corporation (Transmission) sells natural gas at wholesale to affiliated and unaffiliated distribution companies through its pipeline network serving large parts of eight mid-Atlantic and Midwest states and the District of Columbia. In addition, Transmission operates almost all of the System's storage facilities and is the principal purchaser of natural gas from producers in the Southwest, midcontinent and Appalachian areas. A part of Transmission's southwest gas supply is delivered by Columbia Gulf Transmission Company (Gulf) through its pipeline network from Louisiana to Kentucky. Gulf also has varying ownership interests in the Ozark Transmission System and Trailblazer Pipeline System which deliver gas for Transmission from other areas. An intrastate pipeline in Virginia is operated by Commonwealth Gas Pipeline Corporation. Columbia LNG Corporation has an interest in a liquefied natural gas plant located in Cove Point, Maryland. The plant is currently idle as more fully described in Note 9D of Notes to Consolidated Financial Statements.

Despite burdens to purchase excessive volumes of gas, much of it at a high cost, Transmission's focus in 1984 was on building pipeline load through marketing and transportation programs. To lift these burdens, Transmission must resolve its two most serious problems; the proceedings before the Federal Energy Regulatory Commission (FERC) in which some of Transmission's customers blamed their sales losses on Transmission's gas acquisition policies and practices, and producer contracts calling for purchases of gas at volumes and prices that are unrealistic in Transmission's current competitive market.

COMPETITION—Transmission and other pipelines are experiencing a significant transformation in the way they serve their market areas. Traditionally, pipeline companies have bought gas at regulated prices under long-term supply contracts based on customer estimates of future requirements. Now, price conscious distributors are buying much of their supply directly from producers under short-term arrangements at the lowest available price. Even distributors' end users are buying gas directly from producers and competing pipelines or switching to less costly alternate fuels. Both of these developments are making the prediction of market requirements more difficult. Competition among pipelines has been encouraged by the FERC through approval of various marketing programs. In this competitive environment, however, pipeline companies continue to be hindered by lengthy regulatory proceedings and restrictions to obtain FERC approval for transportation and marketing programs. Aware of these problems, the FERC has begun a reappraisal of its policies related to rate treatment for transportation transactions, competition and protection of core markets, and issues related to mandated carriage.

To meet competition, transportation for others is becoming a significant activity for Transmission, and it has demonstrated its ability and willingness to provide transportation voluntarily. Columbia is actively opposing legislation that would mandate pipelines to provide transportation on demand. Mandatory carriage would threaten the service reliability of the industry by requiring restrictive regulation. It would also be contrary to the desire of most distribution companies to rely on Columbia for long-term supply assurance.

MARKET CONDITIONS—In 1979, Transmission was able to meet its customers' full requirements for the first time since 1972 ending a long period of curtailments and customer growth restrictions. Based on indications of pent-up demand for natural gas and expanding supplies following passage of the Natural Gas Policy Act of 1978 (NGPA), Transmission's customers submitted optimistic estimates of future needs and Transmission conducted its gas acquisition programs accordingly. Customer purchases in recent years, however, have not reached the levels contained in the estimates. Unfavorable and unpredictable economic events such as a long recession (particularly severe in Columbia's marketing area), dramatic structural changes in some major industries, high inflation, dropping oil prices and increased consumer conservation depressed sales volumes significantly. At the same time, wellhead prices continued to rise under NGPA provisions, exerting additional downward pressure on sales. A shrinking market meant that Transmission's operating costs per unit increased, making for still higher rates.

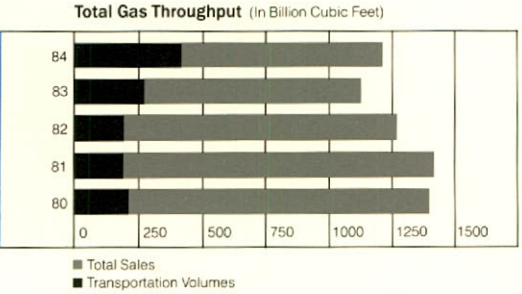
These events led to the two most serious problems faced by Transmission today:

• Faced with climbing gas costs and shrinking markets, some customers challenged Transmission's gas acquisition policies and practices in a purchased gas adjustment (PGA) proceeding before the FERC. The FERC has issued a series of procedural orders unfavorable to Transmission as more fully described in Note 5A of Notes to Consolidated Financial Statements.

• As a result of a growing supply imbalance following the warm 1982-83 winter, Transmission limited purchases from producers and took related actions to limit prices. Some of the resulting producer contract disputes, particularly as related to take-or-pay provisions and the limited prices paid for gas, resulted in litigation as more fully described in Note 9B.

PRODUCER NEGOTIATIONS—Through 1984, Transmission has successfully renegotiated a number of contracts with southwest producers including six of the producers who filed court actions. Such settlements have established price and volume levels closer to current market conditions and resolved past take-or-pay obligations and other issues. Additional settlements are expected in 1985.

Total Gas Throughput (In Billion Cubic Feet)



Transmission has successfully negotiated lower prices for much of the higher cost gas it buys from producers in the Appalachian Basin. The renegotiations also eliminated price escalators and provided for annual price redetermination.

As a result of these settlements, as well as take-or-pay relief obtained through its marketing and transportation programs, Transmission has achieved a substantial reduction in its potential take-or-pay exposure which is now estimated at $800 million through 1984, and an additional $320 million for 1985. However, due to uncertain market conditions, certain payments related to such settlements and other payments which may be required to be made to producers may not be recoverable through rates (See Note 9B).

OUTLOOK—In a report to the FERC at the end of the third quarter, Transmission indicated that for the contract year which runs from November 1984 through October 1985, it will experience further reductions in demand while the level of available supply increases resulting in a substantial excess gas supply. Accordingly, Transmission is expanding its efforts to balance supply and demand through marketing, transportation and other programs.

Transmission is seeking to settle the FERC proceedings (Note 5A) and producer contract problems (Note 9B) in a way that will improve its supply situation and lower gas prices to a competitive level. Such settlements will require a substantial financial commitment.

With the lifting of Federal price controls on January 1, 1985, on a substantial portion of U.S. natural gas reserves, Transmission believed that because of price escalation clauses in producer contracts, its customers could be faced with a fly-up in gas costs. However, the effect of the additional decontrol on Transmission's rates are expected to be minimized by:

• Success in renegotiating contracts.

• Transmission's notification to 111 producers exercising price redetermination provisions in 170 gas purchase contracts effective January 1, 1985, reducing the price paid under those contracts.

• Transmission's implementation of a new pricing structure for Appalachian Basin purchases effective January 1, 1985, reducing the price it will pay for certain categories of gas.

FINANCIAL REVIEW

The significant decline in 1984 results reflected the following factors:

• Sales volumes continued to decline and were down 11% from 1983 and 26% from depressed 1982 levels.

• Average sales rates, which had been escalating rapidly, dropped almost 4% in 1984 due to lower gas costs.

• Some operating costs were not recovered because of a rate formula in effect through October 31, 1984, which assigned 75% of fixed costs to the commodity rate. As sales volumes continued to drop below rate design levels established in the previous general rate case (effective January 1, 1983), a portion of fixed costs were not recovered. In addition, a decision in late 1983 to defer a general rate filing precluded recovery of operating expenses above the cost-of-service levels established in the previous rate case.

Earnings on common stock in 1984 were also reduced by an adjustment of $2.6 million ($0.07 per share) to the impairment reserve for the Alaskan Natural Gas Transportation System (ANGTS) made following a decision to withdraw from the partnership. The impairment reserve was first established in 1983.

Operating income for 1983 increased 4% over 1982 because a 21% increase in average sales rates more than offset a 17% decline in sales volumes. These results show the effect of higher sales rates permitted in a general rate increase put into effect January 1, 1983, to recover increased operating expenses over lower sales volumes. As part of the same rate case, a method of deferring gas purchased costs was adopted which permitted the matching of gas purchased costs with revenues, thereby eliminating the financial effects of unaccounted for gas. As in 1984, sales volumes declined because end users increasingly bought lower priced gas available from other pipelines and through special marketing and transportation programs.

Earnings on common stock for 1983 reflected a $27.9 million decrease in investment credits as construction expenditures fell from $313.9 million in 1982 to $61.0 million in 1983 and the recording of the impairment reserves for the investments in ANGTS and the related Northern Border Study Group.

Operating income for 1982 was impacted by factors similar to 1983 as a general rate increase effective January 1, 1982 more than offset a decline in sales volumes which were adversely impacted by warm weather in addition to price competition. Earnings on common stock for 1982 benefited from a $12.3 million increase in investment credits related to pipeline projects of unconsolidated affiliates.

Capital expenditures for 1985 are currently estimated at $100.1 million as compared to $96.2 million for 1984, $61.0 million in 1983 and $313.9 million in 1982. For the most part, capital expenditures since 1983 have only been made to maintain transmission facilities.

RESULTS OF OPERATIONS

Gas Transmission ($000)	Revenues	Operating Income	Earnings from Continuing Operations
1984	3,447,500	224,100	79,200
1983	4,058,700	304,200	102,700
1982	3,991,000	292,700	145,200

In order to meet competition from other pipelines and alternative fuels, Transmission and Gulf filed new rate schedules which became effective November 1, 1984, subject to FERC approval. The new rate schedules did not increase revenues but instituted a change in the cost allocation—rate design methodology to shift certain fixed costs from the commodity rate to the demand charge. In addition, the filed cost-of-service included a representative level of transportation volumes which allow the companies to retain all transportation revenues. In order to make rates more competitive, Transmission and Gulf omitted from the same filing increased operating expenses and other cost-of-service items. This action reduced the return on equity to below normally acceptable levels.

In a related action, Transmission has filed with the FERC for reduced rates to become effective March 1, 1985. The semi-annual purchased gas adjustment filing, which will reduce average rates charged to distributors by almost $0.12 per Mcf, reflects actual and projected reductions in the cost of Transmission's gas purchases. The projected lower gas purchase costs were partially offset in the filing by the net effect of $37.5 million in surcharges primarily reflecting retroactive costs paid to producers for gathering and other production related costs.

Transmission has also filed with the FERC for authorization to accept Eastern Shore Natural Gas Co. as a new wholesale customer. The utility serves customers on the Eastern Shore of Maryland and lower Delaware. The utility's current supplier was unable to supply enough natural gas to meet growing requirements.

As previously reported, Transmission is faced with uncertain market conditions related to excess supply and its high cost of gas which could preclude the recovery of substantial costs normally recoverable through rates (see Note 9B of Notes to Consolidated Financial Statements for additional information). As a result, Transmission has intensified discussions with its customers and with producers to achieve a settlement beneficial to all parties. Management also has under study various other alternatives to resolve System problems. Such approaches would involve substantial charges against System assets and have a material adverse effect on future earnings. However, the financial effect on future accounting periods cannot be determined at this time.

It should be emphasized, however, that each of these plans is designed to insure Columbia's long-term future by restoring its competitive position in the marketplace.

OVERVIEW—Four subsidiaries conduct Columbia's exploration and production programs throughout the United States and Canada.

Midwest and eastern operations, conducted by Columbia Gas Transmission Corporation, range throughout the Appalachian and Michigan Basins and northeast to Vermont. The Inland Gas Company, Inc. also produces natural gas to serve nearby industrial customers in the Ashland, Kentucky area. Columbia has an application before the Securities and Exchange Commission to form a new exploration and production subsidiary to carry on these activities.

Southwest and western operations are conducted by Columbia Gas Development Corporation and range throughout the Gulf of Mexico and basins extending from the Gulf Coast of Texas and Louisiana through the Powder River Basin of Wyoming and Williston Basin in North Dakota.

Canadian operations extend from the Arctic Islands and Northwest territories through western mainland provinces to offshore areas of the east.

Columbia's domestic natural gas production during 1984 was limited by the market's inability to take contracted production. Certain of Columbia wells in the Appalachian area were shut-in for up to six months, while in the southwest, production was held close to contract volumes through participation in Columbia's Special Marketing Program. Canadian natural gas production was also limited because of market conditions. The large Kotaneelee Field was shut-in for the entire year, awaiting development of either Canadian or U.S. markets.

Oil was produced at full levels with all of the production successfully marketed but at reduced prices toward year end. Full production is expected in 1985 with favorable market prices.

Columbia is committed to a long-term expansion of its reserve base. Accordingly, during the past two years, funds for exploration have been substantially increased. Exploration and drilling operations were expanded in 1984 over 1983 with a slightly lower drilling cost profile. Exploration prospect generation increased in both the U.S. and Canada which was accomplished by increasing staff, and joint venture activity. Acreage acquisition programs begun in the southwest and Canada in 1983 continued.

As a result of such activity, the rate of decline in proved reserves has been arrested and should turn around in the future. In 1984, after producing 2.5 million barrels of oil and other liquids and 81.6 billion cubic feet of natural gas, reserves increased by 4.1 percent for oil and decreased by 5.4 percent for natural gas.

The primary exploration strategy is to participate in the maximum number of wells with available funds. This is done by participating in exploration programs with other companies whenever possible. As a result, Columbia will be participating in most of the proven basins east of the Rocky Mountains. In Canada, participation follows a similar pattern. Columbia's offshore activities continue in the Gulf of Mexico, the Arctic Islands and eastern Canada. Ownership participation in most onshore programs is between 30-50 percent, while offshore participation is smaller, usually not more than 25 pecent.

Internal generation of drilling prospects has greatly increased during the past two years and has been largely responsible for the broader participation and risk-spreading. Consequently, the prospect portfolio contains a range of opportunities from low-risk, moderate return to high-risk, high return. Columbia intends for all of its exploration programs to follow this same strategy in the forseeable future.

MIDWEST AND EASTERN OPERATIONS—Significant programs include:

Southwest Virginia: Columbia is part of a joint venture to develop approximately 590,000 acres in Scott and Wise Counties where proved and potential reserves of natural gas are estimated to be 123 billion cubic feet. In 1984, 45 wells were completed, bringing total wells completed to 87. Columbia has an 11.65 percent interest in the project and first call on all gas.

Bass Island: The Bass Island Trend in Chautaugua County, New York has proved to be the most prolific oil-producing area discovered in the Appalachian Basin in two decades. Columbia had an interest in 40 oil and gas wells completed in the Trend in 1984 and, by year-end, along with its

Columbia's lease holdings in the U.S. and Canada are among the most extensive of any natural gas company, providing broad opportunities for building and marketing gas and oil production.

partners, had completed 55 wells. Additional wells are in progress or scheduled in 1985.

Wayne/Lincoln Counties, West Virginia: A total of five oil wells were completed during 1984 in Wayne and Lincoln Counties, West Virginia, with average proved reserves of 20,000 barrels per well. Ten more wells are scheduled for the area in 1985.

Vermont: An exploratory well drilled by Columbia and partners in the Eastern Overthrust in Franklin County, Vermont, was plugged and abandoned due to drilling difficulties at a depth of 6,969 feet. Since the well did not reach its planned depth, further drilling in the area will be considered.

Eastern Overthrust: Four of eight exploratory wells drilled in 1984 were productive for a 50 percent success ratio. All were located in the Eastern Overthrust in Grant, Pendleton and Randolph Counties, West Virginia. Further drilling to measure the reserves discovered will be started in 1985.

SOUTHWEST AND WESTERN OPERATIONS—**Williston Basin:** During the year, development of the West Indian Hills Field in North Dakota continued with ten additional wells completed. Production from 13 wells at year-end was averaging 3,500 gross barrels per day. Columbia is a major operator in the field with a 51 percent working interest. In a joint exploration program Columbia acquired about 4,000 acres during the year and now controls about 47,000 net acres in the Williston Basin.

Midcontinent: Columbia entered a joint venture in 1984 with Citation Oil and Gas Corp. to participate in a two-year exploration program with expenditures limited to $30 million net exposure to Columbia. Drilling began in the latter part of 1984, and seven wells were spudded before year-end. Two oil discoveries have been made in the drilling program and development of reserves surrounding those wells has begun. Prospects under the program have been delineated in Louisiana, south and central Texas and in Oklahoma. It is expected that 50 wells will be drilled under the program in 1985.

Gulf of Mexico: Columbia currently holds an interest in 79,800 acres in 67 Federal offshore blocks and participated in the offshore drilling of seven exploratory wells, five development wells, and in the installation of two new platforms. In addition, twenty development wells were put on production in early 1984.

Columbia participated in setting a 24 slot platform in 650 feet of water in the East Breaks area, offshore Texas. During the year, four development wells were drilled. Drilling will continue into 1986 when initial production is scheduled to begin at a daily net rate of 30 Mmcf of gas. Columbia holds a 12.5 percent working interest in this block.

Results from a wildcat at Eugene Island 286, in which Columbia has a 30% interest, located offshore Louisiana, indicated discovery of significant shallow gas reserves. Evaluation of deeper zones in this well will be conducted in 1985.

Bidding with partners, Columbia was awarded two offshore Louisiana leases in the March 1984 Federal sale.

CANADIAN OPERATIONS—Columbia added further in 1984 to reserves of both oil and gas. Oil and other liquid reserves at year-end totalled 4.3 million barrels, compared to 3.6 million barrels the year before. Gas reserves increased to 151 billion cubic feet from 147 billion cubic feet. These data do not include projected reserves for the Hibernia, Hebron, Nautilus and South Mara discoveries off Canada's East Coast.

Columbia participated in a total of 58 exploratory wells in Canada in 1984 of which 16 were oil discoveries and 4 were gas discoveries.

Mainland Operations: Mainland exploratory activity was expanded from Alberta into Saskatchewan and Manitoba. In all programs the emphasis in the exploration effort is on shallow oil prospects.

In Saskatchewan emphasis was placed on early stages of exploration comprising prospect generation, acquisition of lands and geophysical surveys. Limited exploratory drilling resulted in a discovery in close proximity to the Moosomin pool, reported last year. Possibly the most significant 1984 discovery was made at nearby Walpole, where seismic information indicates three square miles of prospective lands. This discovery was the first well drilled in a joint venture program in which Columbia is the operator and has a 50% working interest in 32,000 acres. An aggressive exploratory drilling program is planned in Saskatchewan during 1985.

Columbia participated in 69 development wells of which 54 were successful oil wells and 4 were successful gas wells. A major feature of Columbia's development program was the establishment of a pressure maintenance (waterflood) recovery program for an oil pool in the Genesee area in which Columbia's net participation is 21%. If the oil pool reservoir responds as anticipated, the resultant net increase in Columbia's proven oil reserves will be in excess of 500,000 barrels.

Canadian export permits have been obtained for the Kotaneelee gas field in the Yukon where Columbia has a 22% interest and is the operator. This gas was originally contracted to companies which could not obtain U.S. import authorizations because the gas could not be priced competitively. Columbia is negotiating with a U.S. gas buyer which would use the Kotaneelee gas as a source of boiler fuel for an enhanced oil recovery project in the western United States. This sale could commence in 1986 at rates up to 50 million cubic feet per day. Short-term U.S. sales which would provide an earlier start-up date for Kotaneelee are being considered.

Hibernia: Exploration and delineation drilling continued during 1984 in the Hibernia block off Canada's East Coast. The ninth delineation well for the Hibernia Field, Hibernia C-96, tested oil from four zones at a combined rate of 5,200 barrels per day and determined an easterly extension of the productive Hibernia sands. An exploratory well, the South Mara, C-13 well established the presence of productive Avalon sands, approximately 10 miles east of the C-96 well and 16 miles northwest of the Hebron I-13 discovery well of 1981. A second exploratory well, the Mara M-54, was drilling at year-end.

The operator, Mobil Oil Canada Ltd., plans to submit to the Canadian government a development plan for the Hibernia Field in 1985. It is anticipated that all government approvals will be received by January 1, 1986. The earliest likely production date is 1990. Columbia's 5.47% interest in the Hibernia block could be reduced under the Canadianization elements of the National Energy program.

RESULTS OF OPERATIONS

Oil & Gas Operations ($000)	Revenues	Operating Income	Earnings from Continuing Operations
1984	292,300	133,900	63,300
1983	247,900	153,600	68,500
1982	199,700	83,400	33,000

FINANCIAL REVIEW

Operating income for 1984 was down due to the effect of a 1983 Supreme Court decision which improved 1983 results. The decision permitted natural gas pipeline companies to charge the same rates for cost-of-service gas they produce as charged by independent producers. Application of the decision commencing January 1, 1982, included the recording of $44.7 million of operating income applicable to 1982. Of this amount, $19.8 million impacted 1983 revenues. The addition of these gas reserves lowered the U.S. cost center depletion rate, also improving operating income. Excluding the effect of the adjustment applicable to 1982, operating income for 1983 would have been $108.9 million.

Operating income for 1984 was up 23% over adjusted 1983 operating income. The improvement reflects increased production of oil and gas partially offset by the effect of lower prices. Natural gas production was up 27 Bcf (48.0%) mostly due to increased production in the Appalachian area. The average U.S. sales price per Mcf was $2.69 in 1984 as compared to $3.03 in 1983 and $2.41 in 1982. The increases over 1982 reflect the court decision; however, due to the difficulties experienced in the marketplace, a price ceiling well below NGPA allowed prices was established for the affected production as well as for other production. Oil production was up 26% partially offset by lower prices reflecting the softening of worldwide oil prices.

Operating income in 1983 was also helped by increased gas production at the higher prices. Oil production and oil prices were both lower than in 1982. Operating income for 1982 was improved by higher NGPA prices for gas production and a lower depletion rate in the U.S. cost center reflecting the initial inclusion of certain Appalachian reserves.

Capital expenditures for 1985 are currently estimated at $125.6 million compared to $92.1 million in 1984, $72.4 million in 1983 and $143.5 million in 1982. The 1985 estimate includes outlays of $62.4 million in the Southwest and Rocky Mountain regions, $20.5 million in the Appalachian Basin and $42.7 million in Canada.

Commonwealth Propane provides the advantages of gas service to more than 34,000 customers in Virginia, and Columbia Hydrocarbon serves several thousand more in other areas beyond the gas mains.

PROPANE OPERATIONS—Columbia Hydrocarbon Corporation recovers propane, butanes and natural gasoline from heavier hydrocarbons derived from Appalachian Basin natural gas production. The butanes and natural gasoline are marketed for use in the production of chemicals and gasoline. Additionally, Columbia Hydrocarbon offers propane service to more than 2,400 residential, commercial, industrial, wholesale and motor fuel customers.

Commonwealth Propane, Inc. sells propane at wholesale and retail to more than 34,000 customers in Virginia. It also operates an aggressive appliance merchandising program. Commonwealth operates in a territory with good growth potential and it has added approximately 1,000 customers each of the past three years.

SYNTHETIC GAS OPERATIONS—Columbia LNG Corporation sells synthetic gas (SNG) produced at its Green Springs, Ohio plant to some of Transmission's wholesale customers. The gas is delivered by Transmission. The current status of SNG operations is more fully described in Note 3B of Notes to Consolidated Financial Statements.

COAL MINING OPERATIONS—Because of a depressed market for coal and high production costs, the West Virginia mine jointly owned by Columbia Coal Gasification Corporation and an Exxon affiliate was shut down in July 1983. Based on recent market studies, a decision was made to sell Columbia's interest in the mine and discontinue coal mining operations (See Note 2 of Notes to Consolidated Financial Statements for additional information).

RESULTS OF OPERATIONS

Other Operations ($000)	Revenues	Operating Income	Earnings from Continuing Operations
1984	248,800	(54,800)	(31,900)
1983	464,400	(4,600)	(7,700)
1982	457,600	(1,700)	(1,400)

OTHER COAL INVESTMENTS—Writedown and eventual sale of its interest in the mine facilities will not affect Columbia's 50% ownership of the 200 million tons of coal reserves dedicated to the Columbia-Exxon venture. In addition to these coal reserves, approximately 550 million tons of low-sulphur coal are owned. It is management's intent to maintain its royalty interest in these coal reserves some of which are now leased to others for development.

FINANCIAL REVIEW
The reduction in 1984 revenues was caused by lower synthetic gas sales of $240.9 million partially offset by a $21.4 million increase in sales of propane, butanes and natural gasoline. Synthetic gas sales were down as a result of the amended feedstock and sales agreements negotiated in the first quarter of 1984. Sales of propane, butanes and natural gasoline increased due largely to customer growth, the improved economy and availability of product, which is recovered from Appalachian gas production. Operating income for 1984 reflects a $57.7 million non-recurring charge in the first quarter of 1984 related to the expected operating losses during the initial eighteen-month period of the amended SNG agreements. The effect on earnings was $30.0 million or $0.76 per share. The loss was partially offset by income contributions from increased sales of propane and other hydrocarbons.

During 1983 and 1982, over 80% of the revenues were generated by sales of synthetic gas although the earnings contribution was negligible due to the declining investment base of the synthetic gas facility. Revenues and earnings in 1983 reflected reduced sales of propane and other hydrocarbons. Propane sales were depressed by the economy, warm weather, customer conversions to natural gas by affiliated distribution companies and lower requirements for agricultural use due to bad weather in the growing season.

Capital expenditures for 1985 are currently estimated at $5.2 million compared to $7.2 million for 1984, $6.4 million in 1983 and $14.0 million in 1982.

During 1984, the Corporation maintained a liquidity position adequate to satisfy demands for funds. Demands for funds relate mostly to capital expenditures, payment of gas purchase costs including take-or-pay and other contested gas costs related to prior periods, debt service requirements and dividends on common and preferred stock. Net cash from operations of $330.5 million was adequate to meet these demands in addition to allowing a significant reduction in short-term borrowings by year-end.

Capital expenditures for 1984, originally estimated at $330 million, totaled $272 million. Reductions occurred in exploration and development activities, storage facilities and the expansion of transmission facilities.

Working capital requirements, which largely relate to gas storage inventory and deferred gas purchased costs, were financed with commercial paper under confirmed lines of credit with commercial banks. Cash generated in the first quarter and the additional infusion of equity capital through the dividend reinvestment and tax reduction employee stock ownership plans mitigated short-term requirements during 1984. The average daily outstanding short-term debt was only $26.3 million in 1984 compared to $320.5 in 1983 and $249.6 in 1982. The bank lines of credit totaled $525 million at December 31, 1984. No short-term borrowings were outstanding at year-end.

Capital expenditures for 1985 are estimated at $310 million. As in 1984, the projects included in the program will be under constant review and will be revised to meet changing conditions.

Present estimates of internally generated funds are sufficient to meet known demands for funds in 1985, including the 1985 capital expenditures program. To the extent that additional funds are required, the Corporation expects to be able to meet such demands. As to the financing of working capital requirements, the Corporation will utilize its existing bank credit lines and/or issue commercial paper to finance deferred gas purchased costs and gas storage inventory.

Resolution of the matters discussed in Notes 5A and 9B would increase the System's cash requirements to the extent that payments to producers exceed the amounts recoverable in rates and/or refunds be required for past purchased gas adjustment periods. The amount of such additional cash requirements cannot be determined at the present time; however, management believes that the System has sufficient financial capacity to meet such demands. In addition to its traditional financing sources, such as bank loans, debentures, preferred stock and common stock, the System has considerable potential for asset-based financing and has considerable flexibility to reduce its capital expenditure program. Three major rating agencies, citing continued uncertainty with respect to the above matters, recently reduced their rating of the Corporation's debentures and preferred stock from A2/A6 to A3/A7 and one agency reduced its rating of Columbia's commercial paper from P-1 to P-2. These changes should not affect the Corporation's ability to raise new capital but could increase the cost of issuing such securities.

INFLATION

Reference is made to Note C of Supplementary Financial Information related to the effects of inflation on the Corporation.

COMMON STOCK PRICES AND DIVIDENDS

The common stock of The Columbia Gas System, Inc. is listed on the New York Stock Exchange, Philadelphia Stock Exchange and Toronto Stock Exchange under the symbol CG. At December 31, 1984, there were 122,362 shareholders of record.

Dividends paid and the price range of the Corporation's common stock by quarters of the last two years are provided below.

Quarter Ended	High	Market Price Low	Close	Quarterly Dividends Paid
	$	$	$	¢
1984				
December 31	**35**	**29⅞**	**34**	**79.5**
September 30	**33½**	**27**	**31⅛**	**79.5**
June 30	**37**	**31⅜**	**33¼**	**79.5**
March 31	**37½**	**33**	**36¾**	**79.5**
1983				
December 31	35½	31⅜	35¼	75.5
September 30	33½	29½	33	75.5
June 30	32½	28⅜	31¾	75.5
March 31	31¼	27⅞	30	75.5

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COMPARATIVE GAS OPERATIONS DATA

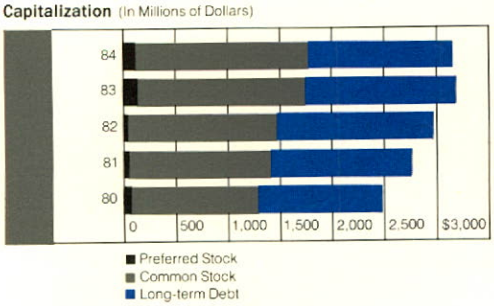
	1984*	1983	1982	1981	1980
Gas Operating Revenues (in thousands)					
Residential	**$1,278,745**	$1,357,686	$1,256,348	$ 997,741	$ 896,541
Commercial	**617,593**	646,394	594,316	448,179	385,723
Industrial	**592,084**	841,891	938,120	951,720	814,198
Wholesale	**1,843,234**	2,032,807	2,074,838	1,804,515	1,465,339
Other	**15,248**	16,878	17,370	14,578	6,673
Total gas operating revenues	**$4,346,904**	$4,895,656	$4,880,992	$4,216,733	$3,568,474
Sales (million cu. ft.)					
Residential	**188,471**	207,225	230,325	237,486	244,336
Commercial	**97,042**	104,606	115,678	114,481	112,962
Industrial	**108,124**	151,034	202,591	269,772	267,611
Wholesale	**384,967**	409,070	502,382	578,521	544,695
Other	**4,255**	4,364	4,821	4,289	2,705
Total sales	**782,859**	876,299	1,055,797	1,204,549	1,172,309
Transportation gas volumes	**423,427**	262,798	198,004	196,403	214,745
Total throughput	**1,206,286**	1,139,097	1,253,801	1,400,952	1,387,054
Gas Available for Sale (million cu. ft.)					
Total gas purchased	**705,070**	758,739	1,004,117	1,107,619	1,063,351
Total gas produced (natural and synthetic)	**125,462**	115,921	138,547	169,888	156,698
Exchange gas—net	**(1,558)**	(2,252)	(4,091)	1,601	(5,601)
Gas withdrawn from (delivered to) storage	**(1,879)**	46,062	(38,571)	(5,519)	(1,044)
Other—net	**(44,236)**	(42,171)	(44,205)	(69,040)	(41,095)
Total gas available for sale	**782,859**	876,299	1,055,797	1,204,549	1,172,309
Customers at Year-End					
Residential	**1,564,460**	1,744,883	1,744,178	1,746,774	1,738,815
Commercial	**138,663**	154,063	153,132	152,332	150,057
Industrial	**2,280**	2,450	2,546	2,546	2,473
Wholesale	**75**	86	86	85	86
Other	**48**	55	62	65	67
Total customers at year-end	**1,705,526**	1,901,537	1,900,004	1,901,802	1,891,498
Average Usage Per Customer (thousand cu. ft.)					
Residential	**120.5**	118.8	125.7	135.3	143.8
Commercial	**699.8**	679.0	719.9	756.5	780.4
Degree Days	**5,410**	5,381	5,271	5,474	5,683
Variation from normal (%)	**0.1**	0.3	(1.7)	2.1	5.3

*Wholesale data includes the operations of a distribution company, sold in June 1984, for the entire year.

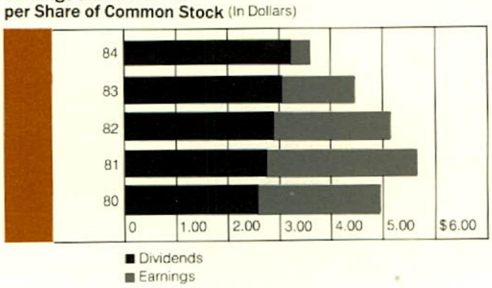
SELECTED FINANCIAL DATA

(Dollars in thousands except per share amounts)	**1984**	1983	1982	1981	1980
Income Statement Data ($)					
Total revenues	**4,645,175**	5,102,049	5,095,752	4,465,985	3,741,597
Products purchased	**3,099,319**	3,586,139	3,720,871	3,145,012	2,546,400
Earnings on common stock before discontinued operations and extraordinary charge	**165,436**	184,701	182,736	196,277	167,329
Earnings on common stock	**138,564**	164,754	180,063	194,085	168,160
Per Share Data					
Earnings per common share ($):					
Before discontinued operations and extraordinary charge	**4.22**	4.94	5.17	5.67	4.90
Earnings on common stock	**3.53**	4.41	5.10	5.61	4.93
Dividends:					
Per share ($)	**3.18**	3.02	2.86	2.70	2.56
Payout ratio (%)	**90.1**	68.5	56.1	48.1	51.9
Average common shares (000)	**39,227**	37,401	35,328	34,597	34,142
Balance Sheet Data ($)					
Capitalization:					
Common stock equity	**1,634,225**	1,598,634	1,458,326	1,357,635	1,241,386
Preferred stock	**50,000**	50,000	—	—	—
Redeemable preferred stock	**75,000**	80,000	35,000	40,000	45,000
Long-term debt	**1,348,484**	1,420,075	1,468,894	1,324,025	1,211,847
Total capitalization	**3,107,709**	3,148,709	2,962,220	2,721,660	2,498,233
Total assets	**5,200,536**	5,238,355	5,155,190	4,643,259	3,947,247
Other Financial Data					
Capitalization ratio (%):					
Common stock equity	**52.6**	50.8	49.2	49.9	49.7
Preferred stock	**4.0**	4.1	1.2	1.5	1.8
Long-term debt	**43.4**	45.1	49.6	48.6	48.5
Capital expenditures ($)	**272,009**	210,941	584,057	592,002	445,201
Net cash from operations ($)	**330,542**	133,063	257,339	396,187	310,818
Book value per common share ($)	**41.22**	41.16	40.73	38.90	36.14
Return on average common equity before discontinued operations and extraordinary charge (%)	**10.2**	12.1	13.0	15.1	14.0
Average cost of long-term debt at year-end (%)	**9.2**	9.5	9.5	9.5	8.6

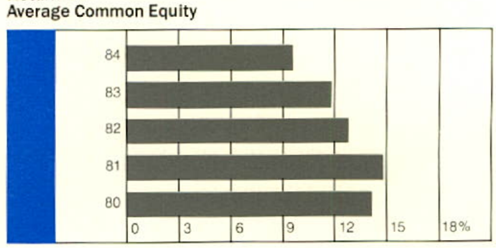
Capitalization (In Millions of Dollars)



Earnings and Dividends per Share of Common Stock (In Dollars)



Return on Average Common Equity



MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL STATEMENTS

The accompanying consolidated financial statements and related notes have been prepared by the Corporation based on generally accepted accounting principles, and are considered by management to present fairly and consistently the Corporation's financial position and results of operations subject to the outcome of certain matters discussed in the accompanying Auditors' Report. The integrity and objectivity of the data in these financial statements, including estimates and judgments relating to matters not concluded by year-end, are the responsibility of management as is all other information included in the Annual Report, unless otherwise indicated.

To meet its responsibilities with respect to financial information, management maintains an accounting system and related controls to reasonably assure the integrity of financial records and the protection of assets. The effectiveness of this system is enhanced by the selection and training of qualified personnel, an organizational structure that provides an appropriate division of responsibility, a strong budgetary control system, and a comprehensive program of internal audits designed to reasonably assure the adequacy of internal controls and implementation of company policies and procedures. The internal audit staff is under the direction of the Vice President and General Auditor who reports directly to the Chairman of the Board.

An audit committee assists the Board of Directors in its oversight role and is composed of seven directors who are not officers or employees of the Corporation. The audit committee meets periodically with the Vice President and General Auditor to review his work and to monitor the discharge of his responsibilities. The audit committee also meets periodically with the Corporation's independent public accountants, who have free access to the audit committee of the board, to discuss internal accounting controls, auditing and financial reporting matters.

AUDITORS' REPORT

Arthur Andersen & Co.
1345 Avenue of the Americas
New York, New York 10105

To the Stockholders of The Columbia Gas System, Inc.:

We have examined the consolidated balance sheets of The Columbia Gas System, Inc. (a Delaware corporation) and subsidiaries as of December 31, 1984 and 1983 and the related statements of consolidated income, taxes, common stock equity and changes in financial position for each of the three years in the period ended December 31, 1984. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As discussed in Note 9B of the accompanying notes to consolidated financial statements, market conditions could limit the recovery by Columbia Gas Transmission Corporation of substantial gas costs normally recoverable through revenues under Federal Energy Regulatory Commission (FERC) regulations. The December 31, 1984 consolidated balance sheet includes approximately $323 million of such costs pending future recovery through rates. Further, additional payments related to any future settlements with producers concerning past take-or-pay obligations, related litigation and other obligations due producers for past costs have not been recorded at December 31, 1984, since they cannot be presently estimated, but such additional payments could be substantial. The amount of costs determined to be nonrecoverable, if any, will depend upon, among other things, Columbia Gas Transmission Corporation's participation in special marketing programs, negotiations with producers to limit prices paid and other economic and regulatory factors. Consequently, the amount of nonrecoverable costs, if any, cannot be determined at this time.

In addition, as discussed in Note 5A of the accompanying notes to consolidated financial statements, the FERC is reviewing Columbia Gas Transmission Corporation's gas acquisition policies and practices followed during the period subsequent to February 1982, to determine whether such policies and practices constitute an "abuse" under the Natural Gas Policy Act. If an unfavorable ruling is ultimately issued by the FERC, significant refunds could be required. The ultimate outcome of these proceedings cannot be determined at this time.

In our previous report dated February 7, 1984, our opinion on the above-mentioned 1983 and 1982 consolidated financial statements was unqualified; however, in view of the uncertainties referred to above, our present opinion on such consolidated financial statements, as expressed herein, is different from that expressed in our previous report.

In our opinion, subject to the effect of such adjustments, if any, as might have been required had the outcome of the matters discussed in the preceding paragraphs been known, the consolidated financial statements referred to above present fairly the financial position of The Columbia Gas System, Inc. and subsidiaries as of December 31, 1984 and 1983, and the results of their operations and changes in financial position for each of the three years in the period ended December 31, 1984, in conformity with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen + Co.

February 6, 1985

STATEMENTS OF CONSOLIDATED INCOME

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	1984	1983	1982
Revenues			
Operating revenues			
Gas	**$4,346,904**	$4,895,656	$4,880,992
Other	**246,478**	179,429	178,014
Other income (Note 11)	**51,793**	26,964	36,746
Total revenues	**4,645,175**	5,102,049	5,095,752
Expenses			
Products purchased			
Natural gas	**2,887,581**	3,178,495	3,314,976
Other	**211,738**	407,644	405,895
Operation	**493,896**	478,340	447,981
Maintenance	**78,405**	79,318	84,711
Depreciation and depletion	**251,019**	203,111	216,284
Other taxes	**198,144**	210,046	194,907
Interest and related charges (Note 12)	**139,387**	167,628	154,814
Write-down of Alaskan pipeline investment (Note 3)	**4,844**	18,194	—
Loss on synthetic gas operations (Note 3)	**57,700**	—	—
Total expenses	**4,322,714**	4,742,776	4,819,568
Income from Continuing Operations before Income Taxes	**322,461**	359,273	276,184
Income taxes	**142,697**	165,591	88,973
Income from Continuing Operations	**179,764**	193,682	187,211
Discontinued coal mining operations (Note 2)			
Loss from operations	**3,172**	2,652	2,673
Estimated loss on disposal	**23,700**	—	—
Income before Extraordinary Charge	**152,892**	191,030	184,538
Extraordinary charge (Note 4)	**—**	17,295	—
Net Income	**152,892**	173,735	184,538
Preferred stock dividend	**14,328**	8,981	4,475
Earnings on Common Stock (Notes 5A and 9B)	**$ 138,564**	$ 164,754	$ 180,063
Earnings Per Share of Common Stock			
(based on average shares outstanding)			
Earnings from continuing operations	**$4.22**	$4.94	$5.17
Discontinued operations	**.69**	.07	.07
Earnings before extraordinary charge	**3.53**	4.87	5.10
Extraordinary charge	**—**	.46	—
Earnings on common stock	**$3.53**	$4.41	$5.10
Dividends Per Share of Common Stock	**$3.18**	$3.02	$2.86
Average Common Shares Outstanding (thousands)	**39,227**	37,401	35,328

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

CONSOLIDATED BALANCE SHEETS

The Columbia Gas System, Inc. and Subsidiaries

Assets

As of December 31 (in thousands)	1984	1983
Property, Plant and Equipment		
Gas utility and other plant, at original cost	**$4,615,731**	$4,558,782
Accumulated depreciation and depletion	**(2,071,037)**	(1,925,697)
	2,544,694	2,633,085
Oil and gas producing properties, full cost method		
United States cost center	**977,090**	958,749
Canadian cost center ($52,500,000 and $57,185,000 respectively, not being amortized) (Note 1D)	**179,874**	162,649
Accumulated depletion	**(415,631)**	(363,887)
	741,333	757,511
Net property, plant and equipment	**3,286,027**	3,390,596
Investments and Other Assets		
Gas supply prepayments and advances	**150,869**	56,424
Investments in unconsolidated affiliates	**42,231**	49,061
Investment in subsidiary sold (Note 4)	**—**	58,634
Net assets of discontinued coal segment (Note 2)	**11,138**	—
Other	**65,349**	27,906
Total investments and other assets	**269,587**	192,025
Current Assets		
Cash and temporary cash investments	**56,370**	29,330
Accounts receivable		
Customers (less allowance for doubtful accounts of $9,355,000 and $11,731,000, respectively)	**378,583**	546,505
Other	**105,240**	128,181
Accrued utility revenue	**101,226**	174,701
Income tax refunds	**—**	17,232
Gas inventory	**428,343**	325,785
Other inventories—at average cost	**41,800**	52,745
Deferred purchased gas costs	**310,571**	172,528
Prepayments	**65,012**	69,176
Other	**80,371**	75,474
Total current assets	**1,567,516**	1,591,657
Deferred Charges	**77,406**	64,077
Total Assets	**$5,200,536**	$5,238,355

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Capitalization and Liabilities

As of December 31 (in thousands)	1984	1983
Common Stock Equity		
Common stock	**$ 396,419**	$ 388,382
Additional paid in capital	**243,674**	226,221
Retained earnings	**1,005,305**	991,088
Accumulated foreign currency translation adjustment	**(11,173)**	(7,057)
Total common stock equity	**1,634,225**	1,598,634
Preferred Stock (Note 6)	**50,000**	50,000
Redeemable Preferred Stock (Note 6)	**75,000**	80,000
Long-Term Debt and Capitalized Lease Obligations (Note 8)	**1,348,484**	1,420,075
Total capitalization	**3,107,709**	3,148,709
Current Liabilities		
Commercial paper	**—**	253,300
Current maturities of long-term debt and preferred stock	**73,088**	31,891
Accounts and drafts payable	**497,491**	612,166
Accrued taxes	**85,980**	89,223
Accrued interest	**34,212**	33,183
Estimated rate refunds	**25,028**	51,904
Deferred income taxes	**183,802**	192,281
Estimated supplier obligations	**267,242**	—
Other	**174,757**	108,849
Total current liabilities	**1,341,600**	1,372,797
Deferred Credits		
Deferred income taxes, noncurrent	**613,296**	578,062
Deferred investment tax credits	**50,919**	48,001
Other	**87,012**	90,786
Total deferred credits	**751,227**	716,849
Commitments and Contingencies (Notes 5 and 9)		
Total Capitalization and Liabilities	**$5,200,536**	$5,238,355

CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	1984	1983	1982
Cash From Operations			
Income from continuing operations	**$179,764**	$193,682	$187,211
Items not requiring (providing) cash:			
Depreciation and depletion	**252,557**	204,021	216,925
Deferred income taxes, noncurrent and investment credits	**62,280**	72,629	93,969
Other—net	**(1,353)**	574	(10,786)
Accrued loss on synthetic gas operations	**33,239**	—	—
Write-down of Alaskan pipeline investment	**4,844**	18,194	—
Net change in working capital (increase) (Note 13)	**(59,303)**	(235,547)	(125,233)
Cash from continuing operations	**472,028**	253,553	362,086
Dividends	**(138,671)**	(120,497)	(105,152)
Net cash from continuing operations	**333,357**	133,056	256,934
Discontinued operations	**(2,815)**	7	405
Net cash from operations	**330,542**	133,063	257,339
Capital Investment Activities			
Capital expenditures	**(272,009)**	(210,941)	(584,057)
Gas supply prepayments and advances	**(62,226)**	(11,091)	(3,445)
Recovery of gas supply advances	**27,493**	33,415	22,302
Sale of subsidiary	**30,187**	—	—
Other—net	**614**	(23,064)	125,632
Net capital investment activities	**(275,941)**	(211,681)	(439,568)
External Financing Activities			
Retirement of preferred stock	**(5,000)**	(5,000)	(5,000)
Retirement of long-term debt	**(48,051)**	(91,396)	(72,330)
Issuance of common stock	**25,490**	89,854	27,571
Issuance of preferred stock	**—**	100,000	—
Debentures	**—**	—	100,000
Revolving credit agreement	**—**	—	120,000
Total external financing activities	**(27,561)**	93,458	170,241
Increase in Cash and Temporary Cash Investments	**$ 27,040**	$ 14,840	$(11,988)

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

STATEMENTS OF CONSOLIDATED COMMON STOCK EQUITY

The Columbia Gas System, Inc. and Subsidiaries

	Common Stock*				
	Shares Outstanding	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Foreign Currency Translation Adjustment
Balance at December 31, 1981 (in thousands)	34,898	$348,981	$148,140	$860,514	$ —
Beginning balance of cumulative translation adjustments					(4,463)
Net Income				184,538	
Dividends:					
Common ($2.86 per share)				(100,677)	
Preferred:					
10.96% Series B				(4,475)	
Common stock issued:					
Dividend reinvestment plan	659	6,592	13,625	(66)	
Tax reduction employee stock ownership plan	249	2,485	4,869		
Other			57		(1,794)
Balance at December 31, 1982	35,806	358,058	166,691	939,834	(6,257)
Net Income				173,735	
Dividends:					
Common ($3.02 per share)				(111,516)	
Preferred:					
10.96% Series B				(4,065)	
10.24% Series C				(2,603)	
Adjustable rate Series D (Note 6)				(2,313)	
Common stock issued:					
Exchange of common stock for debentures	2,000	20,000	38,353	(221)	
Dividend reinvestment plan	723	7,234	14,930	(8)	
Tax reduction employee stock ownership plan	309	3,090	6,247		
Discount on issuance of preferred stock				(1,755)	
Other					(800)
Balance at December 31, 1983	38,838	388,382	226,221	991,088	(7,057)
Net Income				152,892	
Dividends:					
Common ($3.18 per share)				(124,343)	
Preferred:					
10.96% Series B				(3,516)	
10.24% Series C				(5,120)	
Adjustable rate Series D (Note 6)				(5,692)	
Common stock issued:					
Dividend reinvestment plan	737	7,365	16,172	(4)	
Tax reduction employee stock ownership plan	67	672	1,281		
Other					(4,116)
Balance at December 31, 1984**	39,642	$396,419	$243,674	$1,005,305	$(11,173)

*50,000,000 shares authorized—$10 par value.

**$715,400,000 of retained earnings is not available for cash dividends at December 31, 1984, under the terms of the indentures securing the Corporation's outstanding debentures. In addition, restrictions on payment of cash dividends are also imposed by the Certificate of Incorporation as long as any preferred stock is outstanding. However, the provisions contained in the indentures are presently more restrictive than those contained in the Certificate of Incorporation.

STATEMENTS OF CONSOLIDATED TAXES

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	1984	1983	1982
Income Taxes			
Currently payable			
Federal	**$ 95,919**	$ (10,888)	$ 25,646
State	**7,269**	2,618	4,950
Investment credits*	**(14,151)**	(15,859)	(53,742)
Total currently payable	**89,037**	(24,129)	(23,146)
Deferred			
Federal	**43,309**	172,557	92,983
State	**3,775**	10,523	5,802
Foreign	**1,789**	1,860	784
Total deferred	**48,873**	184,940	99,569
Deferred investment credits, net	**2,918**	3,325	5,527
Provision for employee stock ownership plan	**1,869**	1,455	7,023
Income taxes included in income from continuing operations	**142,697**	165,591	88,973
Federal income taxes—discontinued operations:			
Current	**(3,059)**	(4,561)	(4,935)
Deferred	**(19,832)**	2,292	2,585
Deferred federal income taxes—extraordinary charge	**—**	(3,131)	—
Total income taxes	**119,806**	160,191	86,623
Other Taxes			
Property	**50,044**	52,041	45,994
Gross receipts	**114,619**	131,314	120,861
Payroll	**20,051**	18,512	17,055
Other	**13,430**	8,179	10,997
Other taxes included in income from continuing operations	**198,144**	210,046	194,907
Other taxes—discontinued operations	**153**	290	365
Total other taxes	**198,297**	210,336	195,272
Total Tax Expense	**$318,103**	$370,527	$281,895

*Includes Employee Stock Ownership Plan investment credits of $1,869,000, $1,455,000, and $7,023,000, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Year Ended December 31 (in thousands)	**1984**		1983		1982	
Computation of Income Taxes Total income taxes are different than the amount which would be computed by applying the statutory Federal income tax rate to book income before income tax. The major reasons for this difference are as follows:						
Book income before income taxes (including before tax loss associated with discontinued operations and extraordinary charge)*	**$272,700**		$333,926		$271,161	
Tax expense at statutory Federal income tax rate	**$125,442**	46.0%	$153,606	46.0%	$124,734	46.0%
Increases (reductions) in taxes resulting from—						
State income taxes, net of Federal income tax benefit	**5,767**	2.1	6,878	2.1	5,500	2.0
Investment credits not deferred and amortization of credits deferred in prior years	**(9,364)**	(3.4)	(11,079)	(3.3)	(41,192)	(15.1)
Depreciation expense for accounting purposes over amounts claimed for income tax purposes	**4,356**	1.5	6,812	2.0	4,148	1.5
Extraordinary charge taxed at less than statutory rate	**—**	—	6,265	1.9	—	—
Other	**(6,395)**	(2.3)	(2,291)	(0.7)	(6,567)	(2.4)
Total Income Taxes	**$119,806**	43.9%	$160,191	48.0%	$ 86,623	32.0%

*Includes income from foreign operations of $5,058,000, $5,123,000, and $8,833,000 respectively.

Deferred Income Taxes Deferred income taxes result from timing differences in the recognition of revenues and expenses for tax and accounting purposes. The source of these differences and tax effect of each is as follows:			
Acquisition, exploration and development costs	**$ (12,922)**	$ 33,694	$ 48,055
Depreciation expense	**34,790**	45,306	44,382
Deferred purchased gas costs	**10,253**	67,989	(1,195)
Estimated rate refunds	**12,186**	12,045	(388)
Unbilled utility revenue	**(15,640)**	20,227	3,622
Other	**374**	4,840	7,678
Total Deferred Income Taxes	**$ 29,041**	$184,101*	$102,154

*Includes benefits associated with the extraordinary charge.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Principles of Consolidation. The Consolidated Financial Statements include the accounts of the Corporation and all subsidiaries, except for the investment in one distribution subsidiary at December 31, 1983, which was in the process of being sold. The net assets of this subsidiary were included in the investment account at net realizable value.

The equity method of accounting is used for investments in affiliates where ownership is 50% or less. Such investments (which are not material) are reported under Investments and Other Assets in the Consolidated Balance Sheets, and the equity in earnings of such unconsolidated affiliates, before income taxes and excluding investment tax credits, is reported under Other Income in the Statements of Consolidated Income.

All appropriate intercompany accounts and transactions have been eliminated. Certain reclassifications and restatements have been made to the 1983 and 1982 financial statements to conform to the 1984 presentation.

B. Property, Plant and Equipment, and Related Depreciation. Property, plant and equipment (principally utility plant) is stated at original cost. The cost of utility plant includes an allowance for funds used during construction (AFUDC). Interest during construction (IDC) is capitalized in connection with certain non-rate regulated projects. Improvements and replacements of retirement units are capitalized at cost. When units of utility property are retired, the accumulated provision for depreciation is charged with the cost of the units and the cost of removal, net of salvage. Maintenance, repairs and minor replacements of property are charged to expense.

For financial reporting purposes, the Corporation's subsidiaries provide for depreciation on a composite straight-line basis. The annual depreciation rates were as follows:

Year ended December 31, (%)	**1984**	1983	1982
Transmission Property	**4.0**	4.0	4.0
Distribution Property	**2.9**	3.1	2.9
Other Property	**7.4**	7.2	7.6

C. Capitalization of Interest and Other Funds. AFUDC is capitalized in accordance with regulatory rules and is defined in the applicable Uniform System of Accounts as the net cost, during the period of construction, of borrowed funds used and a reasonable rate upon other funds when so used. IDC is capitalized by the unregulated subsidiaries in accordance with Statement of Financial Accounting Standards No. 34 issued by the Financial Accounting Standards Board (FASB). Capitalized interest is recorded as a reduction to interest expense and the allowance for other funds is recorded as other income. The before tax rates for AFUDC and IDC were as follows:

Year ended December 31, (%)	**1984**	1983	1982
Allowance for funds used during construction	**12.75**	9.75	12.25
Interest during construction	**9.90**	9.60	9.90

D. Accounting for Oil and Gas Producing Properties. The Corporation's subsidiaries engaged in exploring for and developing reserves of hydrocarbons follow the full cost method of accounting. Under this method of accounting, all productive and nonproductive costs directly identified with acquisition, exploration and development activities are capitalized in country-wide cost centers. Costs are accumulated by each cost center to the extent they do not exceed the estimated present value of the cost center's oil and gas revenues, plus the value of unproved properties reduced by estimated future operating expenses and development costs. Should costs exceed future net revenues, such excess would be charged to current expense. Gains or losses on the sale or other disposition of oil and gas properties are normally recorded as adjustments to capitalized costs.

Capitalized costs for certain unevaluated properties are excluded from amortization pending determination of proved reserves related to such properties and/or valuation attributable to the properties. Such properties are subject to periodic assessment (at least annually) and any impairment below cost is included in costs being amortized. The following table summarizes, by period incurred, net unevaluated costs capitalized in the Canadian cost center which have been excluded from amortization:

($000)	**1984**	1983	1982	Prior Years	Total
Acquisition costs	**—**	—	—	300	300
Exploration costs	**5,900**	6,900	2,200	30,000	45,000
Interest capitalized	**3,800**	2,100	4,100	3,900	13,900
Subtotal	**9,700**	9,000	6,300	34,200	59,200
Less translation adjustments	**3,100**	200	3,400	—	6,700
Total	**6,600**	8,800	2,900	34,200	52,500

Columbia owns varying interests in 9.7 million gross acres (1.4 million net) offshore Labrador and Newfoundland and 0.7 million gross acres (111,000 net) offshore Prince Edward Island. Net costs (initially incurred in 1972) excluded from depletion amounted to $46.6 million at December 31, 1984. (Reference is made to Page 19 of the foregoing report to stockholders for additional information.)

Columbia also owns varying interests in 6.5 million gross acres (520,000 net) in the Arctic Islands and Northwest Territories. Net costs (initially incurred in 1971) excluded from depletion were $5.9 million at December 31, 1984. Management estimates that development of gas reserves attributable to these properties will occur in the early 1990's.

E. Gas Inventory. Current inventory is carried at cost on a last-in, first-out basis (LIFO). Under present regulatory practice, liquidation of LIFO layers would not affect income since the effect would be deferred and reflected in future customer rates through purchased gas adjustments.

F. Income Taxes and Investment Tax Credits. The Corporation's subsidiaries follow interperiod tax allocation with respect to timing differences in the recognition of revenues and expenses for tax accounting purposes except when regulatory commissions do not recognize interperiod tax allocation for rate purposes. The cumulative amount of income tax timing differences for which deferred income taxes have not been provided was approximately $211,000,000 at December 31, 1984. In accordance with an approved rate order, the estimated future tax liabilities associated with $67,000,000 of the above amount are being recovered over a period ending in 1989.

Investment tax credits are being recorded in income currently except for credits of the gas distribution subsidiaries, which are being deferred and amortized generally over the life of the related property to conform with regulatory policy.

Reference is made to the Statements of Consolidated Taxes for the components of and additional information related to taxes.

G. Estimated Rate Refunds. Certain rate regulated subsidiaries are allowed to collect revenues which are subject to final determination in rate proceedings. In connection with such revenues, estimated rate refund liabilities are recorded which reflect management's current judgement of the ultimate outcome of pending regulatory proceedings. Provisions are not made when the amount of the estimated refund cannot reasonably be determined.

H. Deferred Purchased Gas Costs. The Corporation's rate regulated subsidiaries defer differences between gas purchased costs and the recovery of such costs in revenues, and adjust future billings for such deferrals on a basis consistent with applicable tariff provisions.

I. Accrued Utility Revenues. The Corporation's rate regulated subsidiaries bill customers on a monthly cycle billing basis. Revenues are recorded on the accrual basis including an estimate for gas delivered but unbilled at the end of each accounting period.

J. Pension Costs and Other Postretirement Benefits. The Corporation has trusteed, noncontributory pension plans which, with certain minor exceptions, cover all regular employees, 21 years of age and over. The System's policy is to fund pension costs accrued, including amortization of any unfunded actuarial accrued liability. Pension costs amounted to $31,600,000 in 1984, $31,500,000 in 1983, and $29,400,000 in 1982. The following table compares accumulated benefits and assets of the plans in accordance with disclosure requirements established by the FASB.

At December 31, ($000)	**1984**	1983
Actuarial present value of accumulated benefits:		
Vested	**398,900**	382,400
Nonvested	**8,200**	8,000
Total	**407,100**	390,400
Net assets available for benefits	**456,100**	444,600

The average assumed rate of return used in determining the actuarial present value of accumulated benefits was 9.0% as of December 31, 1984 and 8.5% as of December 31, 1983. The rate is based on rates used by the Pension Benefit Guaranty Corporation in determining the value of plan benefits under terminated pension plans.

The above total of actuarial present value of accumulated benefits reflects pay levels and past years of service accumulated through the valuation date, consistent with requirements of the FASB. Furthermore, plan assets available are also at a specific point in time. This approach does not take into consideration expected future service, increased pay levels and other actuarial assumptions.

In determining the actuarial present value of accumulated benefits under the Plan's annual valuation, benefits are generally based upon a final pay formula utilizing the last five years of service and are integrated with Social Security benefits. This valuation also utilizes a trendline value of Plan assets. This methodology, which uses a 7% investment rate assumption, produced an unfunded actuarial liability of approximately $27 million at December 31, 1984. Future pay increases, changes in Social Security benefits, growth in assets using a rate of return assumption of 7%, and amortization of unfunded actuarial liability are recognized in determining annual pension costs.

In addition to providing pension benefits, the Corporation's subsidiaries provide certain medical care and life insurance benefits which cover substantially all active employees upon their retirement. The medical care benefits for retirees are expensed as paid. Life insurance benefits are funded based on normal cost and the amortization of an accrued unfunded actuarial liability. The cost of providing these benefits was $5,650,000 in 1984, $5,111,000 in 1983 and $4,360,000 in 1982.

2. DISCONTINUED OPERATIONS

Production in the Wayne County, West Virginia, coal mine, owned jointly by a subsidiary of the Corporation and a subsidiary of Exxon Company USA, was suspended in July 1983 because of the continuing depressed market for coal. Management had believed that the mine could be reopened with certain operating modifications to make the price of coal competitive. However, recent market studies indicated no near term prospects for resumption of production. Consequently, the decision was made in the fourth quarter of 1984 to discontinue mining operations and to dispose of the net assets related to Columbia's interest in the mine. Accordingly, the accompanying Consolidated Financial Statements have been reclassified to display separately the discontinued operation.

The loss on disposal of $20,000,000, which is net of income tax benefits of $17,037,000, adjusted the investment in the coal mine to its estimated net realizable value. In addition, a provision of $3,700,000 which is net of income tax benefits of $3,152,000 was recorded reflecting estimated costs related to the disposal of the mine. Revenues from mining operations were $3,285,000 in 1983 and $11,585,000 in 1982. Losses from operations are net of income taxes of $2,702,000, $2,269,000, and $2,350,000 for 1984, 1983, and 1982, respectively.

3. NONRECURRING ITEMS

A. Alaskan Pipeline Investment. The projected completion date for the Alaskan Natural Gas Transportation System (ANGTS) was extended beyond 1989 because of economic conditions. Since completion of the pipeline, as planned, had become uncertain, an impairment reserve of $16.5 million was recorded in the fourth quarter of 1983. At the same time, a related investment in the Northern Border Pipeline Study Group of $1.7 million was also impaired.

In the fourth quarter of 1984, the remaining investment of $4.8 million was impaired following management's decision to withdraw from the partnership.

B. Synthetic Gas Operations. At December 31, 1983, negotiations were in progress between Dome Petroleum Ltd. (Dome) and Columbia LNG Corporation (LNG) concerning the continuation of the feedstock agreement between the two companies after March 31, 1984. During the first quarter of 1984, an amended agreement was reached with Dome for the continued purchase of feedstock by LNG at a substantially reduced price and volume and agreements were reached with customers for the purchase of the synthetic gas from LNG. However, near-term market conditions necessitate a sales price not sufficient to recover fully the cost of feedstock and related processing. Accordingly, an after-tax nonrecurring charge of $30 million ($0.76 per share) was recorded in the first quarter of 1984 reflecting the terms of the final agreements and projected sales rates for the initial 18-month period commencing April 1, 1984. Upon the expiration of the 18-month period, the agreement between LNG and Dome can be continued for up to three and one-half years depending on Dome's ability to sell feedstock to LNG at a price which will permit LNG to produce synthetic gas and sell it at a price which is competitive in LNG's market area without incurring any additional losses.

4. EXTRAORDINARY CHARGE

The extraordinary charge, recorded in the fourth quarter of 1983, resulted from the Corporation's agreement to sell the common stock and installment promissory notes of its wholly owned subsidiary, Columbia Gas of West Virginia, Inc., to Allegheny and Western Energy Corporation. The extraordinary charge of $17,295,000 represents the net loss sustained upon the sale of the investment in the subsidiary of $20,426,000 offset by $3,131,000 of estimated income tax benefits. The sale of the subsidiary was completed on June 21, 1984.

5. REGULATORY MATTERS

A. Wholesale Purchased Gas Adjustment Filings. A ruling issued December 30, 1982, by a Federal Energy Regulatory Commission (FERC) administrative law judge faulted Columbia Gas Transmission Corporation's (Transmission) gas purchasing and cutback policies and recommended Transmission not be permitted to pass through to its customers a portion of the increased cost of purchased gas.

In an order issued in January and affirmed in March 1984, the FERC overturned the law judge's conclusion that during the period March 1, 1981, through February 1982, Transmission's cutback policies and practices were imprudent. In addition, the FERC broadened its definition of what constitutes "abuse" under Section 601(C)(2) of the Natural Gas Policy Act (NGPA) to include circumstances where a pipeline's gas acquisition or cutback policies and practices evidence a reckless disregard of its fundamental duty to provide service at the lowest, reasonable rate and where such disregard has a significant adverse impact on its customers and consumers. The Commission found that Transmission's gas acquisition policies and practices evidenced such reckless disregard by not giving adequate consideration to marketability during the period referred to above and such policies constitute imprudence under the Natural Gas Act; however, the FERC found no evidence that such acquisition policies had a significant adverse impact on Transmission's customers and therefore concluded that such acquisition practices did not constitute an "abuse" under the NGPA and did not order refunds. Transmission and other parties filed petitions for review of the order which are pending before the U.S. Circuit Court of Appeals for the D.C. Circuit. Briefs were filed with the Court during the second week of October 1984.

During March 1984, the FERC began its review of Transmission's gas acquisition policies and practices for all purchased gas adjustment (PGA) periods subsequent to February 1982. In June 1984, the Presiding Judge issued a procedural order which precluded Transmission from undertaking discovery and submitting evidence with respect to its gas acquisition policies and practices which were in effect prior to March 1982, but impacted on subsequent PGA periods. An appeal was filed with the full Commission, but was denied. Moreover, in July 1984, Transmission filed a motion with the FERC to reopen the record in the prior PGA case to allow it to offer evidence on its gas purchasing policies and practices in light of the FERC's adoption of a new definition of "abuse" without prior notice, in its January 1984 order. This motion was also denied and it is apparent that Transmission may ultimately be denied a chance to fully litigate the question of its gas acquisition policies and practices under the new definition of "abuse" before the FERC in the subsequent PGA proceedings.

Management continues to believe that its gas acquisition practices have been prudent and not abusive; however, as a result of the unfavorable procedural rulings referred to above, the final FERC or Court disposition of these proceedings is uncertain at this time. Consequently, Management cannot state that the ultimate resolution will not result in a material adverse effect on Transmission's financial position and the Corporation's consolidated financial position. Discussions with Transmission's customers and other parties are continuing in an attempt to produce a basis for possible settlement. In view of the potential for settlement, the administrative law judge agreed to extend the procedural dates in the current FERC proceedings.

B. Income Tax Allowance in Wholesale Rates. In June 1983, the FERC issued an order which confirmed existing FERC policy that statutory income tax rates should be used to compute cost-of-service in determining wholesale rates. The order found that the income tax allowance in rates collected by the corporation's jurisdictional wholesale subsidiaries since December 15, 1975, was just and reasonable. An application for rehearing requested by an opposing intervenor was denied by the FERC, whereupon the opposing intervenor filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit. Briefing and oral argument have been completed and in the opinion of Management, the favorable decision of the FERC will be upheld by the Court.

6. PREFERRED STOCK

As of December 31, 1984, the Corporation had authorized 10,000,000 shares of preferred stock, $50.00 par value, and had outstanding 600,000 shares of 10.96% redeemable Series B Preferred Stock and 1,000,000 shares of 10.24% redeemable Series C Preferred Stock. The Series B and C preferred shares are redeemable at the option of the Corporation and through mandatory sinking fund requirements. The Corporation also had outstanding 1,000,000 shares of Adjustable Rate Series D Preferred Stock. Series D shares are redeemable only at the option of the Corporation.

The Series B Preferred Stock is subject to a mandatory sinking fund of 100,000 shares ($5,000,000) per year, resulting in a maximum aggregate cash requirement of $25,000,000 over the next five years. Shares are redeemable for the sinking fund at a price of $50.00 per share, or otherwise at the optional redemption price of $55.32 on or before May 31, 1985, and $53.95 thereafter.

The Series C Preferred Stock is subject to a mandatory sinking fund of 100,000 shares ($5,000,000) per year beginning on May 31, 1989. Shares are redeemable for the sinking fund at a price of $50.00 per share or otherwise at the optional redemption price of $55.12 on or before May 31, 1988, $53.42 from June 1, 1988 to May 31, 1993, inclusive and $51.71 thereafter.

The Series D Preferred Stock can be redeemed on at least 30 days' notice through July 31, 1993, at the option of the Corporation, in whole or in part, at a redemption price of $51.50 per share, and thereafter at $50.00. For each quarterly dividend period, the dividend rate is determined in advance of such period, at 110 basis points below the highest of the three-month U.S. Treasury bill rate, the U.S. Treasury ten-year constant maturity rate or the U.S. Treasury twenty-year constant maturity rate. Such rate cannot be less than 7½% or more than 13½% per annum. The rates used for each quarterly period were as follows:

Quarter Ended (%)	**1984**	1983
November	**11.65**	10.625
August	**12.30**	10.625
May	**10.75**	—
February	**10.90**	—

Dividends for all series outstanding are cumulative, and if four quarterly dividends remain unpaid, the holders of the preferred stock have the right to elect a majority of the Board of Directors. In addition, for the protection of the preferred stockholders, the Corporation's Certificate of Incorporation limits the ability of the Corporation to create a class of stock equal to or higher in preference than the preferred stock.

7. LEASES

On January 1, 1983, the Corporation's regulated subsidiaries commenced capitalizing new lease obligations in accordance with FASB Statement No. 71. The non-rate regulated subsidiaries (whose lease obligations are not material) commenced capitalizing financing leases at the same time. Payments made in connection with non-capitalized leases initiated prior to January 1, 1983, and operating leases are charged to expense or clearing accounts which are substantially charged to expense, as incurred. Such amounts were $42,600,000 in 1984, $46,000,000 in 1983 and $45,900,000 in 1982.

Minimum rental commitments under these leases are as follows:

($000)	
1985	19,600
1986	12,800
1987	9,700
1988	8,000
1989	5,700
After 1989	85,600

8. LONG-TERM DEBT AND CAPITALIZED LEASE OBLIGATIONS

The outstanding long-term debt and capitalized lease obligations of the Corporation and its subsidiaries are as follows:

At December 31, (in thousands)	1984	1983
The Columbia Gas System, Inc.		
Debentures—		
5⅛% Series due 1985	$ —	$ 9,039
5⅛% Series due June 1986	9,070	9,980
4½% Series due June 1987	8,333	9,250
4⅝% Series due August 1987	5,903	7,400
4⅜% Series due November 1987	10,050	11,100
4⅜% Series due January 1988	8,375	9,250
4⅝% Series due May 1989	20,166	21,702
4⅝% Series due October 1989	16,200	17,600
9⅝% Series due November 1989	30,000	37,500
4⅝% Series due May 1990	17,571	18,992
4⅞% Series due October 1990	17,600	19,000
6¼% Series due October 1991	19,000	20,400
6⅝% Series due October 1992	12,750	13,625
7¼% Series due May 1993	27,250	29,000
7% Series due October 1993	21,800	23,200
9% Series due October 1994	29,000	30,750
8¾% Series due April 1995	24,600	26,000
9⅛% Series due October 1995	30,750	32,500
10⅛% Series due November 1995	46,800	51,500
8⅜% Series due March 1996	48,688	51,338
9⅛% Series due May 1996	51,500	56,148
8¼% Series due September 1996	39,000	41,091
7½% Series due March 1997	34,250	35,971
7½% Series due June 1997	41,042	43,199
15⅜% Series due June 1997	100,000	100,000
7½% Series due October 1997	41,100	43,200
7½% Series due May 1998	36,000	37,693
10¼% Series due May 1999	70,000	75,000
9⅞% Series due June 1999	30,200	31,527
11¾% Series due October 1999	87,500	92,900
12¾% Series due August 2000	93,750	100,000
	1,028,248	1,105,855
Unamortized debt discount, less premium	(6,427)	(7,109)
	1,021,821	1,098,746
Revolving credit agreement[a]	300,000	300,000
Miscellaneous debt of subsidiary companies	8,949	10,585
Capitalized lease obligations	17,714	10,744
Total long-term debt and capitalized lease obligations	$1,348,484	$1,420,075

[a] Under the terms of the agreement with nine major commercial banks, a $300 million commitment is available to the Corporation on a revolving basis through July 31, 1988, with any borrowings outstanding at the end of that period being repayable in sixteen equal quarterly installments from November 1, 1988 to August 1, 1992. The Corporation pays a fee equal to ⅜% per annum on the unused portion of the facility through July 31, 1988, and the amount borrowed may be prepaid and reborrowed at any time in whole or in part. All borrowings under this agreement are subordinate to the corporation's debentures. The notes bear interest according to various rate options (based on the prime rate, bank certificates of deposit, and/or the London InterBank Offered Rate) to be selected by the Corporation for varying time periods.

The aggregate maturities of long-term debt and capitalized lease obligations, for the five years ending December 31, 1989, are as follows:

1985	$ 68,088,000*
1986	85,413,000**
1987	93,676,000***
1988	85,229,000
1989	100,192,000

*Excludes prepayments of $19,147,000
**Excludes prepayments of $975,000
***Excludes prepayments of $97,000

The Corporation has from time to time satisfied sinking fund requirements through open market purchases. In addition, during 1983 the Corporation exchanged common stock for debentures to satisfy future sinking fund requirements.

9. COMMITMENTS AND OTHER CONTINGENCIES

A. Capital Expenditures. Capital expenditures for 1985 are estimated at $310 million. Reference is made to the foregoing report for additional information related to capital expenditures.

B. Uncertainties Related to Market Conditions. Transmission is faced with uncertain market conditions related to the selling price for gas, the continuing excess of deliverability over demand and recently intensified competition for Transmission's market from other supply sources. These market uncertainties could limit Transmission's ability to recover substantial costs normally recoverable through rates under current FERC regulations.

As a result of certain actions taken by Transmission in 1983, limiting purchases from producers and taking actions to limit prices, twelve southwest producers filed court actions against Transmission, and other court challenges may still be forthcoming. Through December 31, 1984, Transmission had successfully renegotiated a number of contracts with Appalachian and southwest producers including six of the producers who filed court actions. Such settlements have resulted in resolution of past take-or-pay obligations, reductions in future take-or-pay levels, reduced prices and other considerations. Although Transmission increased its purchases from affected producers to minimum contract volumes on December 1, 1983, the continued decline in demand during 1984 made it necessary to severely prorate purchases from producers resulting in additional take-or-pay exposure. A precise calculation of such take-or-pay exposure is not possible since this would require estimates of future deliveries, deliverability of individual wells and many other factors. Management believes that after giving consideration to settlement agreements, as well as take-or-pay relief related to transportation programs, a reasonable estimate of such potential exposure is $800 million through December 31, 1984 and an additional $320 million for 1985. Management continues to believe that its actions were appropriate and equitable under its contracts. Although progress is being made toward additional settlements, Management cannot determine the ultimate outcome of such negotiations and/or litigation at this time.

Settlement payments made to producers related to take-or-pay obligations involve either (1) prepayments which are recoverable through future deliveries or refunds from producers, or (2) one-time buy-out payments. The one-time buy-out payments have been deferred on the balance sheet pending future recovery through rates. In addition, other retroactive payments and obligations to producers for such matters as limited prices paid for gas previously taken, gathering and compression obligations, well requalifications, etc., have been recorded and deferred. As of December 31, 1984, deferred costs pending future recovery through rates approximated $323 million. Potential exposure related to future settlements with producers, the outcome of litigation and additional obligations due producers cannot be estimated at this time but could be substantial.

As previously indicated, uncertain market conditions could limit the recovery of the costs referred to above, which could have a material adverse effect on Transmission's financial position and on the Corporation's consolidated financial position. However, the amount of nonrecoverable costs, if any, will depend upon, among other things, Transmission's participation in special marketing programs, negotiations with producers to limit prices paid by Transmission and other economic and regulatory factors. Consequently, management cannot presently determine the ultimate outcome of this matter.

C. Liquefied Natural Gas Pricing. On June 18, 1982, the U.S. Court of Appeals (D.C.) vacated the Economic Regulatory Administration's (ERA) Opinion and Order No. 11 issued on December 29, 1979, approving applications filed by Columbia LNG Corporation (Columbia LNG) and others to adjust the base price for imported liquefied natural gas from $1.15/MMBtu to $1.94/MMBtu. The case was remanded for consideration as to whether or not affected customers were entitled to a refund for gas delivered between January and April, 1980. On May 29, 1984, the ERA issued its Opinion and Order No. 11-A, concluding that refunds were not in the public interest. Petitions for review of Opinion and Order No. 11-A have been filed with the U.S. Court of Appeals (D.C.). At December 31, 1984, the potential refund liability, including carrying charges, amounted to approximately $37 million; however, in the opinion of management, no refunds will be ordered in this case.

D. Cove Point LNG Terminal. Deliveries of liquefied natural gas to Columbia LNG were terminated in April, 1980, due to the failure of the Algerian government to approve a price agreement reached in 1979 between the Algerian national company producing the liquefied natural gas and the company from whom Columbia LNG was purchasing the gas. In orders issued during 1984, the FERC concluded that June 1, 1980, was the appropriate date for implementation of the minimum bill provision of Columbia LNG's FERC tariff. The accompanying consolidated financial statements reflect the June 1, 1980, date consistent with the FERC orders. The minimum bill provision specifically allows recovery of operation and maintenance expenses, taxes, and debt service.

The co-owner of the Cove Point facility filed with FERC in November, 1982, for approval to abandon its interest in the facility and to recover the remaining investment over a period of years. As a result of this filing, FERC issued a show cause order on August 1, 1983, requesting Columbia LNG to supply information showing why its interest in the facility should not be abandoned. In its response, Columbia LNG argued that abandonment is inappropriate because of the potential need for future additions to gas supplies. To date, FERC has taken no action on either the co-owner's application or Columbia LNG's response to the show cause order.

In management's opinion, the investment in the Cove Point terminal of approximately $166 million will be recovered through the resumption of deliveries or other appropriate rate recovery. Of this amount, approximately $4.4 million annually is being recovered through the minimum bill provision.

10. SHORT-TERM BORROWINGS AND COMPENSATING BALANCES

The short-term financing requirements of the Corporation and its subsidiaries are typically met through the sale by the Corporation of commercial paper. The commercial paper is sold through dealers at prevailing market rates of interest in maturities normally ranging from one to seven months.

The commercial paper is supported by confirmed bank lines of credit. Compensation for the credit lines is either by a fee paid to the participating banks or through the maintenance of minimum cash balances. There are no restrictions on the withdrawal of these balances.

Year Ended December 31, (in thousands)	**1984**	1983	1982
Commercial paper			
Maximum outstanding	**$303,500**	$489,800	$493,100
Minimum outstanding	**—**	204,800	—
Daily average	**26,300**	320,500	249,600
Interest rates	**8.8%-10.1%**	8.1%-10.8%	8.1%-15.8%
Weighted daily average rate	**9.6%**	9.1%	11.3%
Weighted average rate at year-end	**—**	9.6%	8.8%
Weighted average maturity at year-end (days)	**—**	23.4	29.4
Credit lines at year-end	**$525,000**	$525,000	$550,000
Less outstanding commercial paper	**—**	253,300	452,800
Unused credit lines	**525,000**	271,700	97,200
Approximate compensating balances at year-end	**$ 2,870**	$ 5,500	$ 7,700

11. OTHER INCOME

Year Ended December 31, (in thousands)	**1984**	1983	1982
Interest income	**$ 38,793**	$ 13,948	$ 28,246
Income from equity investments	**9,928**	8,869	5,976
Allowance for other funds used during construction	**330**	—	—
Miscellaneous	**2,742**	4,147	2,524
Total	**$ 51,793**	$ 26,964	$ 36,746

12. INTEREST AND RELATED CHARGES

Year Ended December 31, (in thousands)	1984	1983	1982
Interest on long-term debt	**$138,903**	$139,532	$136,776
Interest on short-term debt	**2,555**	29,111	28,063
Other interest charges	**4,817**	3,369	10,028
Allowance for borrowed funds used and interest during construction	**(6,888)**	(4,384)	(20,053)
Total	**$139,387**	$167,628	$154,814

13. CHANGES IN COMPONENTS OF WORKING CAPITAL

(excludes cash, current maturities of long-term debt and preferred stock)

Year Ended December 31 (in thousands)	1984	1983	1982
Accounts receivable	**$190,863**	$(160,589)	$ 62,894
Accrued utility revenue	**73,475**	(64,719)	(109,982)
Income tax refunds	**17,232**	47,706	(32,703)
Gas inventory	**(102,558)**	138,184	(152,310)
Deferred purchased gas costs	**(138,043)**	(98,673)	48,185
Commercial paper	**(253,300)**	(199,510)	138,780
Accounts and drafts payable	**(114,675)**	(24,650)	53,300
Accrued taxes	**(3,243)**	9,676	(1,331)
Estimated rate refunds	**(26,876)**	(33,580)	(34,662)
Estimated supplier obligations	**267,242**	—	—
Deferred income taxes	**(8,479)**	99,252	11,127
Miscellaneous	**77,149**	13,516	(45,683)
Change in working capital	**(21,213)**	(273,387)	(62,385)
Non-cash items	**(38,090)**	37,840	(62,848)
Net change in working capital	**$ (59,303)**	$(235,547)	$(125,233)

14. BUSINESS SEGMENT INFORMATION

The information shown in the following tables is provided for the Corporation's segments for three calendar years, 1984, 1983, and 1982. The elements of revenues and expenses for each segment include intersegment sales and expenses of affiliated subsidiaries, which are eliminated to compute the Consolidated amount. Affiliated sales are accounted for at the prevailing market or regulated prices. Operating income is calculated by considering revenues and expenses directly associated with each segment in accordance with Statement of Financial Accounting Standards No. 14 issued by the FASB. Identifiable assets are those assets used in the operations of each segment.

Earnings from continuing operations include the allocation of certain revenues and expenses which are reported as Corporate and Unallocated. The basis for allocation or assignment to a specific segment is dependent on the nature of the item. Income or loss attributable to equity investments are assigned to specific segments. Corporate revenues, interest expense and preferred stock dividends are allocated in proportion to capital employed by identifiable segments. The provision for income taxes before credits is allocated based on pre-tax income of identifiable segments, reduced by assignable investment tax credits. Earnings from Continuing Operations were derived by excluding the net income effects of discontinued operations and extraordinary charge from Earnings on Common Stock.

Identifiable assets related to other operations include the net assets of coal mining operations discontinued in 1984. Such amounts were $11.1 million in 1984, $54.9 million in 1983 and $55.1 million in 1982. Identifiable assets related to gas distribution operations include $179.7 million in 1983 and $151.1 million in 1982 for a subsidiary which was disposed of in June 1984.

1984 ($000)	Gas Transmission	Gas Distribution	Oil and Gas	Other	Adjustments and Eliminations	Corporate and Unallocated	Consolidated
Revenues from unaffiliated sources	1,903,983	2,458,641	98,844	145,120	(1,873)	40,460[a]	4,645,175
Intersegment revenues	1,543,491	910	193,458	103,653	(1,841,512)	—	—
Total revenues	3,447,474	2,459,551	292,302	248,773	(1,843,385)	40,460	4,645,175
Operating income	224,120	129,182	133,871	(54,836)	(1,873)	(108,003)[b]	322,461
Earnings from continuing operations	79,192	54,839	63,279	(31,874)	—	—	165,436
Depreciation and depletion	120,677	30,495	92,397	5,762	—	1,688	251,019
Identifiable assets	3,045,212	1,315,493	836,704	96,468	(234,182)	140,841[c]	5,200,536

[a] Corporate revenues 30,532
Income from equity investments 9,928
40,460

[b] Income from equity investments 9,928
Corporate revenues & expenses, net 26,300
Interest and related charges (139,387)
Write-down of Alaskan pipeline investment (4,844)
(108,003)

[c] Corporate assets 98,610
Investments in unconsolidated affiliates 42,231
140,841

1983 ($000)	Gas Transmission	Gas Distribution	Oil and Gas	Other	Adjustments and Eliminations	Corporate and Unallocated	Consolidated
Revenues from unaffiliated sources	1,979,421	2,784,890	96,517	229,535	—	11,686[a]	5,102,049
Intersegment revenues	2,079,301	560	151,399	234,827	(2,466,087)	—	—
Total revenues	4,058,722	2,785,450	247,916	464,362	(2,466,087)	11,686	5,102,049
Operating income	304,235	83,324	153,559	(4,642)	(423)	(176,780)[b]	359,273
Earnings from continuing operations	102,716	21,188	68,474	(7,677)	—	—	184,701
Depreciation and depletion	121,483	34,982	37,705	8,322	—	619	203,111
Identifiable assets	2,822,512	1,785,706	863,889	125,522	(447,306)	88,032[c]	5,238,355

[a] Corporate revenues 2,817
Income from equity investments 8,869
11,686

[b] Income from equity investments 8,869
Corporate revenues & expenses, net 173
Interest and related charges (167,628)
Write-down of Alaskan pipeline investment (18,194)
(176,780)

[c] Corporate assets 38,971
Investments in unconsolidated affiliates 49,061
88,032

1982 ($000)	Gas Transmission	Gas Distribution	Oil and Gas	Other	Adjustments and Eliminations	Corporate and Unallocated	Consolidated
Revenues from unaffiliated sources	2,001,211	2,714,859	96,966	230,213	42,616	9,887[a]	5,095,752
Intersegment revenues	1,989,773	580	102,729	227,369	(2,320,451)	—	—
Total revenues	3,990,984	2,715,439	199,695	457,582	(2,277,835)	9,887	5,095,752
Operating income	292,717	49,920	83,352	(1,659)	(922)	(147,224)[b]	276,184
Earnings from continuing operations	145,175	6,052	32,957	(1,448)	—	—	182,736
Depreciation and depletion	105,641	31,908	70,599	7,545	—	591	216,284
Identifiable assets	2,869,423	1,472,115	818,748	131,712	(255,572)	118,764[c]	5,155,190

[a] Corporate revenues 3,918
Income from equity investments 5,969
9,887

[b] Income from equity investments 5,969
Corporate revenues & expenses, net 1,621
Interest and related charges (154,814)
(147,224)

[c] Corporate assets 49,564
Investments in unconsolidated affiliates 69,200
118,764

The following pages contain unaudited, supplementary financial information pertaining to: (A) quarterly financial data, (B) oil and gas producing activities and (C) effects of specific price changes.

A. QUARTERLY FINANCIAL DATA

Comparison of results of operations among quarters during the year may be misleading in obtaining an understanding of the trend of the System's business operations, since gas sales are predominantly influenced by seasonal weather patterns which, in turn, affect earnings and related components of operating revenues and expenses. The total of quarterly amounts may not equal annual earnings per share due to increasing average shares outstanding.

Quarter Ended (in thousands except per share data)	Operating Revenue	Income from Continuing Operations Before Income Taxes	Earnings on Common Stock Before Extra-ordinary Charge	Earnings on Common Stock	Earnings Per Share Before Extra-ordinary Charge	Earnings Per Share
1984						
December 31[1]	**$1,208,351**	**$95,491**	**$24,414**	**$24,414**	**$ .62**	**$ .62**
September 30	**621,533**	**14,920**	**4,330**	**4,330**	**.11**	**.11**
June 30	**784,486**	**43,861**	**20,403**	**20,403**	**.52**	**.52**
March 31[2]	**1,979,012**	**168,189**	**89,417**	**89,417**	**2.30**	**2.30**
1983						
December 31[3]	1,591,936	169,459	85,185	67,890	2.20	1.75
September 30	764,459	15,100	4,542	4,542	.12	.12
June 30[3]	962,427	51,574	25,741	25,741	.70	.70
March 31	1,756,264	123,140	66,581	66,581	1.85	1.85

(1) Includes a decrease in earnings of $23,700,000 related to discontinued mining operations (see Note 2).
(2) Includes a decrease in earnings of $30,000,000 reflecting a nonrecurring charge applicable to synthetic gas operations (see Note 3B).
(3) A June 1983 U.S. Supreme Court decision permitting natural gas pipeline companies to charge the same rates for gas produced as charged by independent producers improved earnings in the second and fourth quarters of 1983 by $15,400,000 and $8,200,000, respectively, applicable to the prior year. In addition, the fourth quarter of 1983 reflects the impairment of the Alaskan pipeline investment and an extraordinary charge relating to the sale of Columbia Gas of West Virginia, Inc.

B. OIL AND GAS PRODUCING ACTIVITIES

Introduction. Reserve information contained in the following tables was supplied by the independent consulting firms of Ralph E. Davis Associates, Inc. for U.S. properties and by John R. Lacey International Ltd. for the Canadian properties.

Certain gas producing assets located in the Appalachian area were subject to cost-of-service ratemaking and excluded from the accompanying tables for periods prior to 1983. As a result of a favorable U.S. Supreme Court decision in June 1983 such gas producing assets and related reserves were transferred to the U.S. full cost pool during 1983.

U.S. reserves are reported as net working interest, while Canadian reserves are working interest reserves, since royalties related to Canadian leases generally provide for payment on a basis other than a percent of production. Gross revenues are reported after deduction of royalty interest payments.

CAPITALIZED COSTS

(in thousands)	United States 1984	1983	1982	Canada 1984	1983	1982	Total 1984	1983	1982
Capitalized Costs at Year End									
Proved properties	**$885,129**	$876,500	$829,185	**$109,977**	$ 92,972	$ 76,372	**$ 995,106**	$ 969,472	$ 905,557
Unproved properties*	**91,961**	82,249	99,840	**69,897**	69,677	57,233	**161,858**	151,926	157,073
Total capitalized costs	**977,090**	958,749	929,025	**179,874**	162,649	133,605	**1,156,964**	1,121,398	1,062,630
Accumulated depletion	**(407,674)**	(358,538)	(339,151)	**(7,957)**	(5,349)	(3,498)	**(415,631)**	(363,887)	(342,649)
Net capitalized costs	**$569,416**	$600,211	$589,874	**$171,917**	$157,300	$130,107	**$ 741,333**	$ 757,511	$ 719,981
Costs Capitalized During Year									
Acquisition	**$ 16,200**	$ 13,911	$ 31,773	**$ 4,226**	$ 791	$ 884	**$ 20,426**	$ 14,702	$ 32,657
Exploration	**23,484**	17,213	25,382	**15,320**	13,974	14,823	**38,804**	31,187	40,205
Development	**25,550**	18,290	61,392	**7,311**	7,871	8,978	**32,861**	26,161	70,370
Costs capitalized	**$ 65,234**	$ 49,414	$118,547	**$ 26,857**	$ 22,636	$ 24,685	**$ 92,091**	$ 72,050	$ 143,232

*Represents expenditures associated with properties on which evaluations have not been completed.

HISTORICAL RESULTS OF OPERATIONS

(in thousands)	United States 1984	1983	1982	Canada 1984	1983	1982	Total 1984	1983	1982
Gross Revenues									
Unaffiliated	**$ 83,526**	$ 84,681	$ 86,160	**$13,896**	$10,982	$7,549	**$ 97,422**	$ 95,663	$ 93,709
Affiliated	**192,563**	151,399[a]	102,729	**—**	—	—	**192,563**	151,399	102,729
Production costs	**41,848**	39,287	30,949	**3,570**	2,193	2,515	**45,418**	41,480	33,464
Depletion	**89,179**	35,581[b]	69,124	**2,965**	1,910	1,304	**92,144**	37,491	70,428
Income tax expense	**66,107**	72,768	38,278	**3,386**	3,164	1,716	**69,493**	75,932	39,994
Results of operations	**$ 78,955**	$ 88,444	$ 50,538	**$ 3,975**	$ 3,715	$2,014	**$82,930**	$ 92,159	$ 52,552

Results of operations for producing activities exclude general corporate overhead and interest expense. Income tax expense is expressed at statutory rates less investment tax credits.

[a]Includes a $19.8 million adjustment recorded in 1983 applicable to 1982 cost-of-service production.

[b]Includes a $24.9 million adjustment recorded in 1983 applicable to 1982 cost-of-service production.

OTHER OIL AND GAS PRODUCTION DATA

	United States 1984	1983	1982	Canada 1984	1983	1982
Average sales price per Mcf of gas	**$ 2.69**	$ 3.03[a]	$ 2.41	**$ 1.89**	$ 1.91	$ 1.87
Average sales price per barrel of oil and other liquids	**$27.56**	$29.03	$29.86	**$26.36**	$26.72	$22.23
Production (lifting) cost per dollar of gross revenue	**$ 0.15**	$ 0.18[a]	$ 0.16	**$ 0.26**	$ 0.20	$ 0.33
Depletion rate per dollar of gross revenue	**$ 0.32**	$ 0.28[a]	$ 0.37	**—**	—	—
Depletion rate per equivalent Mcf	**—**	—	—	**$ 0.73**	$ 0.59	$ 0.49

[a]Rates computed exclusive of prior year adjustment applicable to 1982 cost-of-service production.

RESERVE QUANTITY INFORMATION

Proved Reserves	United States		Canada[a]	
	Gas @14.73 psia (MMcf)	Oil and Other Liquids (000 Bbls)	Gas @14.73 psia (MMcf)	Oil and Other Liquids (000 Bbls)
Reserves as of December 31, 1981	350,095	12,839	138,320	1,923
Revisions of previous estimate	162,567[b]	(1,744)	(45)	13
Extensions, discoveries and other additions	21,748	1,432	3,959	1,227
Production	(51,276)	(2,133)	(1,411)	(221)
Reserves as of December 31, 1982	483,134	10,394	140,823	2,942
Revisions of previous estimate	360,291[c]	228	99	4
Extensions, discoveries and other additions	20,279	1,420	7,820	908
Production	(53,559)[d]	(1,700)	(1,525)	(302)
Reserves as of December 31, 1983	810,145	10,342	147,217	3,552
Revisions of previous estimate	20,587	1,171	2,031	419
Extensions, discoveries and other additions	4,151	830	3,535	679
Production	(79,811)	(2,133)	(1,801)	(398)
Reserves as of December 31, 1984	755,072	10,210	150,982	4,252
Proved developed reserves as of December 31				
1982	292,229	7,180	140,711	2,941
1983	629,181	7,113	147,105	3,551
1984	579,473	7,648	150,982	4,252

[a] Gross working interest reserves.
[b] Includes 152 Bcf of proved undeveloped Appalachian reserves added in 1982 as the data necessary to determine reliable estimates of these reserves became available for the first time.
[c] Includes 336 Bcf previously classified as cost-of-service reserves.
[d] Includes 13.1 Bcf previously classified as cost-of-service production.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	United States			Canada			Total		
(in thousands)	**1984**	1983	1982	**1984**	1983	1982	**1984**	1983	1982
Future cash inflows	**$2,415,156**	$2,816,127	$2,040,033	**$381,544**	$372,856	$306,104	**$2,796,700**	$3,188,983	$2,346,137
Future production costs	**(519,418)**	(642,515)	(418,065)	**(57,095)**	(53,741)	(49,501)	**(576,513)**	(696,256)	(467,566)
Future development costs	**(191,041)**	(196,627)	(175,797)	**(3,455)**	(27)	(28)	**(194,496)**	(196,654)	(175,825)
Future income tax expense	**(702,393)**	(820,793)	(560,738)	**(129,411)**	(132,338)	(103,409)	**(831,804)**	(953,131)	(664,147)
Future net cash flows	**1,002,304**	1,156,192	885,433	**191,583**	186,750	153,166	**1,193,887**	1,342,942	1,038,599
Less 10% discount	**436,756**	532,341	384,342	**106,944**	108,234	85,994	**543,700**	640,575	470,336
Standardized measure of discounted future net cash flows	**$ 565,548**	$ 623,851	$ 501,091	**$ 84,639**	$ 78,516	$ 67,172	**$ 650,187**	$ 702,367	$ 568,263

Future cash flows are computed by applying year-end prices of oil and gas to estimated future production of proved oil and gas reserves. Future expenditures (based on year-end costs) represent those costs to be incurred in developing and producing the reserves. The Discounted Future Net Cash Flows are derived by applying a 10% discount factor, as required by the FASB rules, to the Future Net Cash Flows. Management believes that this data does not adequately reflect the current economic value of the oil and gas producing properties or the present value of estimated future cash flows since no economic value is attributed to potential reserves and unproved properties, the use of a 10% discount rate is arbitrary and prices constantly change from year-end levels.

A reconciliation of the changes in discounted cash flows of proved oil and gas reserves, from the beginning to the end of the years ending December 31, 1984, 1983 and 1982 follows:

	United States			Canada			Total		
(in thousands)	**1984**	1983	1982	**1984**	1983	1982	**1984**	1983	1982
Beginning of year	**$623,851**	$501,091	$499,073	**$78,516**	$67,172	$66,875	**$702,367**	$568,263	$565,948
Oil and gas sales, net of production costs	**(234,241)**	(196,793)	(157,940)	**(10,326)**	(8,789)	(5,034)	**(244,567)**	(205,582)	(162,974)
Net changes in prices and production costs	**(64,211)**	(51,046)	(68,253)	**(8,949)**	14,803	(12,562)	**(73,160)**	(36,243)	(80,815)
Extensions, discoveries and other additions, net of related costs	**18,550**	44,530	71,723	**11,805**	10,593	6,359	**30,355**	55,123	78,082
Revisions of previous quantity estimates, net of related costs	**30,228**	479,038	117,098	**3,990**	360	93	**34,218**	479,398	117,191
Accretion of discount	**105,644**	80,045	79,759	**13,414**	11,257	11,317	**119,058**	91,302	91,076
Net change in income taxes	**51,643**	(133,226)	(849)	**(1,465)**	(10,222)	941	**50,178**	(143,448)	92
Other	**34,084**	(99,788)	(39,520)	**(2,346)**	(6,658)	(817)	**31,738**	(106,446)	(40,337)
End of Year	**$565,548**	$623,851	$501,091	**$84,639**	$78,516	$67,172	**$650,187**	$702,367	$568,263

Estimated discounted future net cash flows decreased $52.2 million in 1984. Principal downward changes resulted from: (1) current year production of $244.6 million; and (2) a reduction of $73.2 million, largely due to lower prices. Partially offsetting these decreases were: (1) lower income taxes of $50.2 million; (2) upward revisions of previous quantity estimates, mainly in the southwest area, in the amount of $34.2 million; and (3) discoveries of 7.7 Bcf of gas and 1.5 million barrels of oil and other liquids, which added $30.3 million to future net revenues.

The increased estimated cash flows noted in 1983 were caused mainly by an upward revision of previous estimates of $479.3 million resulting from the inclusion of reserves previously accorded cost of service treatment. New discoveries added $55.1 million. Offsetting these increases were decreases of $385.2 million, the result of 1983 production, higher income taxes, and reduced prices.

Estimated future cash flows changed little in 1982. The value of new discoveries and upward quantity revisions totaling 177 Bcf was offset by current year production, price reductions, and production cost increases.

C. EFFECTS OF SPECIFIC PRICE CHANGES

The following supplementary information is supplied in accordance with the requirements of the FASB and is intended to illustrate the effects of specific price changes on resources used by the Corporation and its subsidiaries (current cost). The computations should be viewed as estimates rather than as a precise measure.

The presentation included herein reconciles earnings on common stock reported in the financial statements to income under the current cost reporting method. Management believes that income adjusted for the effects of specific price changes as required by the FASB is incomplete. Therefore, additional effects occurring as a result of changes in purchasing power, due to debt financing and specific price gains in excess of general inflation, should also be included in the measure of income. These effects are provided in the Statement of Income and the Five Year Comparison as "Income after all adjustments."

STATEMENT OF INCOME ADJUSTED FOR CHANGING PRICES STATED IN TERMS OF SPECIFIC PRICES

Year Ended December 31, 1984 (in thousands of average 1984 dollars)	
Earnings on common stock, as reported	$138,564
Effect on earnings of changing prices on depreciation and depletion expense	(370,206)
Loss after required adjustments	(231,642)
Reduction in purchasing power loss through debt financing	77,127
Excess of increase in general inflation, net of adjustment to recoverable cost ($249,448), over increase in specific prices ($63,215)*	(186,233)
Loss after all adjustments	$(340,748)

*At December 31, 1984, the current cost of property, plant and equipment, net of accumulated depreciation and depletion, approximated $4,251,771,000 at recoverable cost.

METHODS AND ASSUMPTIONS

The current cost amounts reflect the changes in specific prices to the extent that specific prices have increased more or less rapidly than the general rate of inflation. The current cost of property, plant and equipment represents an estimated cost of replacing existing plant assets and was primarily determined by indexing the historical cost of existing plant by the Handy-Whitman Index of Public Utility Construction Costs. Land and oil and gas producing properties were converted using other indices as deemed appropriate. Since the assets are not expected to be replaced precisely in kind, current cost does not necessarily represent the replacement cost of the System's productive capacity.

The change in depreciation expense is the amount necessary to reflect the difference between the indexed depreciation and historical cost depreciation.

The reduction in income due to the effects of general inflation in excess of increases in specific prices represents an unrealized holding loss, principally attributable to oil and gas producing assets.

In accordance with FASB Statement No. 33, no adjustment has been made to income taxes.

FIVE-YEAR COMPARISON OF SELECTED SUPPLEMENTARY FINANCIAL DATA ADJUSTED FOR CHANGING PRICES

Year Ended December 31,

(in thousands of average 1984 dollars except as noted)	**1984**	1983	1982	1981	1980
Historical cost information adjusted for changes in specific prices:					
Income (loss) after required adjustments	**$ (231,642)**	$ (27,214)	$ 30,804	$ (105,768)	$ (166,115)
Income (loss) after required adjustments per common share	**(5.91)**	(.73)	.87	(3.05)	(4.87)
Income (loss) after all adjustments	**(340,748)**	97,261	123,126	153,773	257,185
Income (loss) after all adjustments per common share	**(8.69)**	2.60	3.49	4.45	7.53
Specific price changes of nonmonetary assets compared with changes due to general inflation after adjustment to recoverable cost	**(186,233)**	39,608	15,528	88,084	187,015
Net assets at recoverable cost	**2,557,285**	2,739,265	2,408,115	2,375,182	2,317,227
Reduction in purchasing power loss through debt financing	**77,127**	84,867	76,794	171,458	236,285
General information:					
Cash dividend per common share—					
actual	**$3.18**	$3.02	$2.86	$2.70	$2.56
in average 1984 dollars	**$3.18**	$3.15	$3.08	$3.09	$3.23
Market price per common share at year end—					
actual	**$34**	$35¼	$28⅞	$32⅛	$40¼
in average 1984 dollars	**$33½**	$36⅛	$30¾	$35½	$48½
Average consumer price index	**311.2**	298.4	289.1	272.3	246.8

DIRECTORS AND OFFICERS—PARENT COMPANY

DIRECTORS

Thomas S. Blair[2,4]
Chairman, Blair Strip Steel Company
New Castle, Pennsylvania

Warren W. Clute, Jr.[3,4]
Former Chairman, Glen Bank and Trust Company
Watkins Glen, New York

John P. Cornell
Executive Vice President and Chief Financial Officer

John H. Croom[1]
Chairman, President and Chief Executive Officer

Frank J. Durzo[2,4]
Former Chairman and Chief Executive Officer
Jeffrey Galion, Inc.
Acquired by Dresser Industries, Inc.
Industrial Equipment, Supplies and Services
Columbus, Ohio

Dr. Sherwood L. Fawcett[2,4]
Chairman, Board of Trustees
Battelle Memorial Institute
Columbus, Ohio

J. Robert Fletcher[1,3]
Chairman, J. H. Fletcher & Co.
Manufacturer of Mining Equipment
Huntington, West Virginia

Robert H. Hillenmeyer[2,3]
Chairman, Hillenmeyer Nurseries, Inc.
Lexington, Kentucky

Malcolm T. Hopkins[3,4]
Former Vice Chairman, Chief Financial Officer and Director
St. Regis Corporation
Forest Products, Oil, Gas and Insurance
New York, New York

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Former Chairman of the Board

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President and Chief Executive Officer
E. G. Bowman Co., Inc. Insurance Brokerage Firm
New York, New York

John P. Roche[1,3]
Of Counsel, Reed Smith Shaw & McClay
Attorneys-at-Law
Washington, D.C.

Arch A. Sproul[2,4]
Chairman, Virginia International Co.
Foreign Investments
Staunton, Virginia

OFFICERS

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Chairman, President and Chief Executive Officer

John P. Cornell
Executive Vice President and Chief Financial Officer

James D. Little
Executive Vice President

James T. Connors
Secretary

Stanley C. Kauffman
Treasurer

Alexander P. McCann
Assistant Treasurer and Assistant Secretary

Hart T. Mankin
Assistant Secretary

1. Member of the Executive Committee
2. Member of the Audit Committee
3. Member of the Compensation Committee
4. Member of the Long-Range Planning Committee

(Left to right)

Seated
John W. Partridge
George P. MacNichol, III

Standing
Frank J. Durzo
James D. Little

Seated
John H. Croom
John P. Roche

Standing
Thomas S. Blair
Arch A. Sproul

(Left to right)

Seated
Ernesta G. Procope

Standing
John P. Cornell
Robert H. Hillenmeyer
Malcolm T. Hopkins

Seated
Warren W. Clute, Jr.
Dr. Sherwood L. Fawcett

Standing
W. Frederick Laird
J. Robert Fletcher

COLUMBIA GAS SYSTEM SERVICE CORPORATION

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Chairman, President and Chief Executive Officer

John P. Cornell
Executive Vice President and Chief Financial Officer

James D. Little
Executive Vice President

Daniel L. Bell
Edward A. Callahan
Senior Vice Presidents

James T. Connors
Vice President and Secretary

Stanley C. Kauffman
Vice President and Treasurer

Philip L. Magley
Vice President and General Auditor

Hart T. Mankin
Vice President and General Counsel

Richard A. Casali
John W. F. Faircloth
Robert L. Geiler
Max M. Levy
G. A. Martin
Roger E. McVey
Michael W. O'Donnell
Robert A. Oswald
Bruce Quayle
Robert W. Welch
Vice Presidents

William J. Forsythe
Controller

Alexander P. McCann
Assistant Secretary

Larry J. Bainter
Lawrence J. Doyle
Joseph V. Yandoli
Assistant Treasurers

John F. Litzinger
Kenneth P. Murphy
Mark P. O'Flynn
Assistant Controllers

OPERATING COMPANY EXECUTIVES

Joseph A. Brake
President
Ashland Group Companies

Marvin E. White
Chairman
C. Ronald Tilley
President
Columbia Distribution Companies

John P. Bornman, Jr.
President
Columbia Gas Development Corporation

Spencer S. Chambers
President
Columbia Gas Development of Canada Ltd.

John D. Daly
Chairman
William H. Howard
President
Columbia Gas Transmission Corporation

Charles W. Morrow
President
Columbia Gulf Transmission Company

John E. Towle
President
Columbia LNG Corporation

Paul R. Bigley
Chairman
Commonwealth Group Companies

STOCKHOLDER INFORMATION

Dividend Disbursement and Certificate Inquiries
Stockholder Services Department
The Columbia Gas System, Inc.
20 Montchanin Road
Wilmington, Delaware 19807

Common Stock Listed:
New York Stock Exchange
Philadelphia Stock Exchange
Toronto Stock Exchange

Ticker Symbol: CG

Preferred Stock Listed:
New York Stock Exchange

Dividend Reinvestment Plan
P.O. Box 4020
Wilmington, Delaware 19807

Transfer Agents and Registrars
Harris Trust Company of New York
Corporate Trust Department
110 William Street—9th Floor
New York, New York 10038

The National Victoria and Grey Trust Company
21 King Street East
Toronto, Ontario, Canada M5C 1B3

Trustee and Paying Agent for Debentures
Morgan Guaranty Trust Company of New York
30 West Broadway
New York, New York 10015

Dividend Reinvestment—Columbia offers a Dividend Reinvestment Plan to its common stockholders which provides a convenient and economical method of acquiring additional shares of Columbia common stock through the reinvestment of quarterly cash dividends and optional cash payments. Dividends reinvested through Columbia's Plan qualify for income exclusion for Federal income tax purposes as provided for in The Economic Recovery Tax Act of 1981. The Act provides that through 1985, individuals who are U.S. citizens or resident aliens may claim an aggregate gross income exclusion of reinvested dividends of qualifying corporations of up to $1,500 for married taxpayers filing joint returns and up to $750 for all other individual holders.

Participation is entirely voluntary and, if you elect to enter the Plan, you may discontinue it at any time you wish. A prospectus containing details of the Plan and an authorization card may be obtained from Corporate Secretary.

Additional Information
A supplementary report containing more detailed operating, financial, and statistical data on the Columbia Gas System is prepared each year for stockholders and others interested in such information. A copy of Form 10K filed annually with the Securities and Exchange Commission is also available. A copy of either document may be obtained by writing to: Secretary, The Columbia Gas System, Inc., 20 Montchanin Road, Wilmington, Delaware 19807.

COLUMBIA GAS
System

20 Montchanin Road, Wilmington, Delaware 19807