COLUMBIA GAS SYSTEM ANNUAL REPORT 1985

COMPETITIVE ACTIONS / REALISTIC PLANS

"The Columbia Gas System, through its subsidiaries, is active in pursuing opportunities in all segments of the natural gas industry and in related resource development.

"Exemplified by Columbia's three-star symbol, these separately managed companies work to benefit: System stockholders—through competitive return on their investment; customers—through efficient, safe, reliable service; and employees—through challenging and rewarding careers."

Cover

Efficient operations enable Columbia's pipelines to provide competitively priced transportation service. The Eagle, Pennsylvania compressor station, where Harold Pennypacker is checking equipment, moves gas to eastern New York and Pennsylvania markets.

Contents

Summary

The Columbia Gas System, Inc. and Subsidiaries

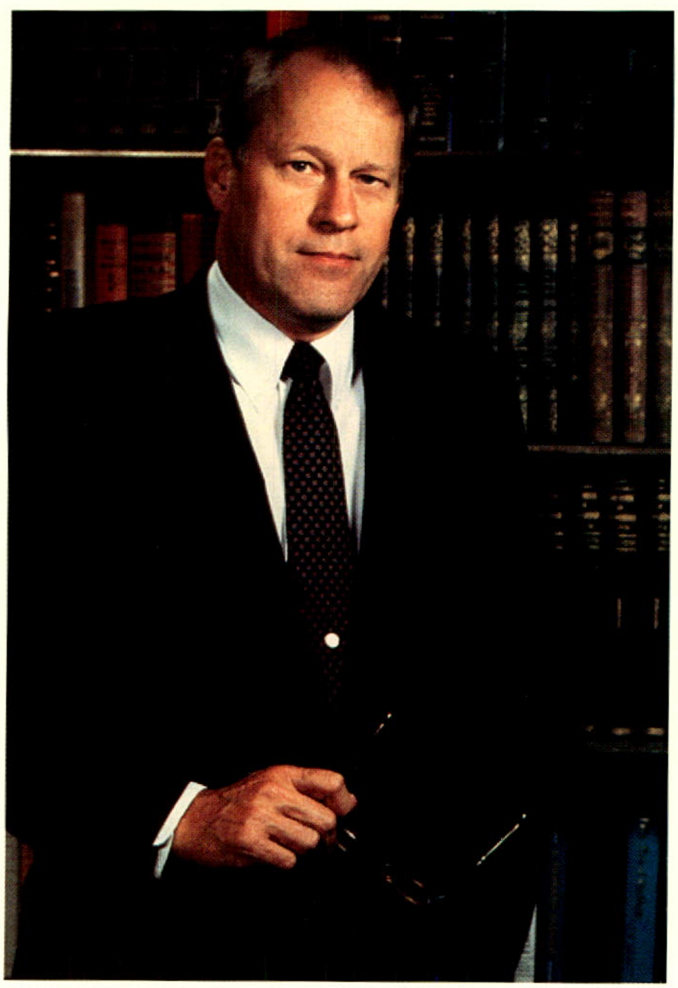
	1985	*1984*	*1983*
Income Statement Data ($000)			
Operating Revenues	**4,052,542**	4,593,382	5,075,085
Net Income (Loss)	**(93,832)**	152,892	173,735
Earnings (Loss) from Continuing Operations:			
Gas Transmission	**(218,714)**	79,192	102,716
Gas Distribution	**62,790**	54,839	21,188
Oil and Gas	**46,507**	63,279	68,474
Other	**2,409**	(31,874)	(7,677)
Total	**(107,008)**	165,436	184,701
Per Share Data ($)			
Earnings (Loss) from Continuing Operations	**(2.67)**	4.22	4.94
Earnings (Loss) on Common Stock	**(2.67)**	3.53	4.41
Dividends	**3.18**	3.18	3.02
Book Value	**35.10**	41.22	41.16
Market Price:			
High	**40.00**	37.50	35.50
Low	**26.75**	27.00	27.88
Close	**39.50**	34.00	35.25
Common Stock Data			
Average Common Shares Outstanding (000)	**40,134**	39,227	37,401
Average Daily Shares Traded	**107,426**	58,403	56,358
Operating Statistics (million cubic feet)			
Gas Sales	**695,017**	782,859	876,299
Transportation Volumes	**511,148**	423,427	262,798
Total Throughput	**1,206,165**	1,206,286	1,139,097
Balance Sheet and Other Data ($000)			
Capital Expenditures	**219,968**	272,009	210,941
Total Assets	**5,835,166**	5,200,536	5,238,355
Capitalization	**3,202,258**	3,107,709	3,148,709

TO THE STOCKHOLDERS

1985 should be remembered as the turnaround year for the Columbia Gas System—the year in which we moved boldly to settle crippling problems and then gathered strength for the competitive tests of the marketplace.

Columbia began 1985 burdened with contracts to buy more gas than its markets wanted and at prices well above competitive levels. This situation impacted all segments of the Corporation and undermined investor confidence in Columbia stock. By aggressive actions, by year-end we had:

- stabilized shrinking markets by settling a prolonged and disruptive rate dispute with distribution companies supplied by the System's principal transmission unit;
- bargained innovatively with producers to cut gas costs to competitive levels by amending contracts which were not market sensitive;
- led the industry in supporting regulatory efforts to adapt pipeline industry operations to the realities of a changing natural gas industry;
- launched a strategic planning process geared to capitalizing on these new realities; and
- by so doing rebuilt investor confidence. Security analysts saluted Columbia's constructive initiative, and in January the Corporation's improving situation prompted three major rating agencies to upgrade our debt securities.



Settling the Past—The actions taken to restore our ability to compete in a dramatically changed environment imposed unprecedented costs on the System.

The rate settlement agreement reached early in the year subjected the System's principal pipeline subsidiary to a potential pre-tax loss of approximately $1 billion over the two-year settlement period. This projection required the Corporation to record a nonrecurring pre-tax charge of $400 million for gas costs incurred before the settlement. As detailed in

John H. Croom
Chairman, President and
Chief Executive Officer

the financial review beginning on page 8, operating results for the full year could not fully offset such a charge, so the Corporation recorded a loss for the year.

To producers holding contracts for unmarketable gas, the System's principal transmission subsidiary offered payments totaling $800 million in exchange for amendments which would reduce prices to competitive levels and to keep them there, while also lowering volumetric purchase obligations. The proposition benefits both parties by relieving the transmission subsidiary of contract obligations many times the payments offered, while helping assure producers a continuing market for their gas. The gas cost reductions achieved by this program will partially offset the losses incurred under the settlement agreement with the distribution companies.

To date contract amendments have been negotiated with producers accounting for more than 80 percent of the high cost gas contracts and have already reduced gas purchase costs to more competitive levels. The transmission company expects to complete the program early in 1986. We believe the high level of agreement with producers demonstrates the soundness of the program.

Financial Strength—Sound financial planning has enabled the System to maintain stability while dealing with the high costs of the customer and producer agreements. Programs to provide financial flexibility and control operating costs have been aggressively implemented.

This financial strength has made it possible to continue providing stockholders with a regular quarterly dividend without any reduction that might have been expected in light of the problems being faced. In 1985 , the Board of Directors approved common stock dividends of 79.5 cents a share for each of the quarters, an annual rate of $3.18, the same paid in 1984. On January 15, 1986, a dividend of 79.5 cents a share was approved for the first quarter of 1986.

Common stock dividends have been paid regularly for more than 39 years, and the System fully expects to have sufficient financial capacity to continue the common stock and preferred stock dividends at their current levels. The amount of future dividends will be reviewed quarterly by the Board in light of future earnings levels.

Early in 1986, the improved financial position of the System which resulted from the corrective actions prompted the major security rating agencies to upgrade their evaluations of Columbia debt securities, preferred stock and commercial paper, reversing in part actions taken late in 1984 and early in 1985 in response to the System's difficulties at that time.

The New Gas Industry—As Columbia struggled to set its own house in order, the entire industry was galvanized in 1985 by proposals from the Federal Energy Regulatory Commission for sweeping changes in the way the industry operates.

The FERC proposal sought to bring order to the chaotic market conditions that had developed from a combination of ample supply, depressed markets and rigid producer/pipeline contracts. These conditions have disrupted normal buyer-seller relations among producers, pipelines and distributors and brought about a welter of marketing and transportation programs to accommodate the new relationships.

The FERC described the proposal, most of which was adopted as an official order in October, as an effort to adjust "those aspects of our current regulations that now appear to hinder the development of competition in those areas where competition will better protect the public interest than will traditional utility regulation rules."

To encourage competition, the FERC order seeks to provide practically unlimited access to interstate pipeline transportation for all those who want to ship gas—producers, distributors, or end-users. For pipelines, it sets up procedures which permit them to more easily enter new markets. The commission postponed until mid-1986 consideration of a proposed change in the apportionment of gas costs among consumers.

The complex order offers both opportunities and risks to pipelines and those using their services. It has been legally challenged by many parties and the ultimate outcome of these challenges is uncertain.

Because of its unique agreements with distribution customers and producer-suppliers, the System's transmission subsidiaries—first among major interstate pipelines—judged that operating according to the FERC order would create new opportunities for business growth in both sales and transportation. Accordingly, they announced in December that they were accepting the basic terms of the order.

The new FERC rules also benefit the System's distribution companies by providing access to more sources of gas at a time when state regulatory agencies are urging utilities to develop a greater diversity of supply.

Distribution companies confront the possibility that these liberalized transportation rules may enable industrial customers to bypass them and take delivery directly from transmission lines, but Columbia's distribution units are developing transportation services to retain these industrial markets.

Until overall industry response to the new FERC order becomes clearer later in 1986, the precise competitive conditions that will exist in the industry remain unclear. What is certain, nonetheless, is that the gas industry has entered a new era of intense competition, one in which previous regulated business patterns have been, to a large degree, discarded and in which initiative and the type of flexibility we have gained are rewarded.

Strategic Planning—Both initiative and flexibility are key elements in the strategic planning process undertaken throughout the System in 1985. The new process builds upon earlier planning patterns, but is geared to the new competitive conditions that we face. In summary, strategic planning identifies opportunities and threats and prepares us to deal with both of them.

The process involves a detailed analysis of the assets and liabilities of each System subsidiary, the business environment in which they operate, and competitive threats and business opportunities. It precisely defines the mission of each System unit, establishes broad objectives and sets forth measurable goals to achieve those objectives.

Strategic planning is a continuing process, and we estimate that several years will be required to refine it. We have made a positive beginning, however, and management is gratified at the reception given by employees throughout the organization to this orderly approach to furthering the System's growth.

For the parent corporation, the mission is defined as follows:

"The Columbia Gas System, through its subsidiaries, is active in pursuing opportunities in all segments of the natural gas industry and in related resource development.

"Exemplified by Columbia's three-star symbol, these separately managed companies work to benefit: System stockholders—through competitive return on their investment; customers—through efficient, safe, reliable service; and employees—through challenging and rewarding careers."

Elsewhere in this Annual Report, the mission statements of certain Columbia units are reported by executives responsible for carrying them out.

In pursuit of its mission, the Columbia Gas System has laid out these broad corporate objectives:

1. Meet stockholders' expectations as to total return.
2. Have access to capital markets at reasonable costs at all times.
3. Provide for efficient management of and planned growth in stockholders' equity.
4. Assure orderly succession at all levels of

System management and enhance employee performance.

The precise goals to attain these objectives will be adjusted and evaluated regularly. Pursuit of these objectives will help to assure that the System is structured and positioned for maximum effectiveness in the new industry climate.

Resources for the Future—As the Columbia System enters what we confidently believe will be a period of capital appreciation for stockholders, it is appropriate to restate the strengths of the System itemized in the previous Annual Report.

• 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 large residential, commercial and industrial markets, and 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.

• The System is managed and operated by 10,800 employees experienced in the energy industry and dedicated to growth through quality service. Through various plans Columbia employees own 15% of Columbia's common stock and constitute the largest single stockholder group.

Management Changes—Dr. William E. Lavery, president of Virginia Polytechnic Institute and State University, was elected a director of The Columbia Gas System, Inc., on December 18, 1985. Dr. Lavery has been an official of the Blacksburg, Virginia school since 1966 and its president since January 1975. Before coming to VPI, he served on the staff of the Federal Extension Service and had been a high school teacher. Dr. Lavery brings to the Columbia Board the perspective of the academic community and broad experience as an administrator.

My letter to stockholders in the previous Annual Report concluded by saying that 1985 could be a turning point for Columbia. As this report chronicles, 1985 indeed was a turning point and for this accomplishment both stockholders and employees can be justifiably proud. We begin 1986 and the new era with confidence and the realization that a stronger, more flexible and more purposeful Columbia organization is at work. The goals and objectives we have laid out will challenge us and we can expect vigorous competition in all areas of activity. We are ready for the challenge and the competition.

JH Croom

John H. Croom
Chairman, President and
Chief Executive Officer

February 19, 1986

GAS TRANSMISSION

Columbia Gas Transmission Corporation (Transmission) sells at wholesale and transports natural gas to affiliated and unaffiliated distribution companies through its 18,800 mile pipeline network serving parts of nine mid-Atlantic and midwest states and the District of Columbia. Transmission also operates storage facilities which are among the most extensive in the nation and is the System's principal purchaser of natural gas from producers in the Southwest, Midcontinent and Appalachian areas. A major part of Transmission's southwest gas supply is delivered by Columbia Gulf Transmission Company (Gulf) through its 4,200 mile pipeline network stretching from offshore Louisiana to Kentucky. Gulf also has ownership interests in the Ozark Transmission System and Trailblazer Pipeline System which deliver gas for Transmission from other areas. An intrastate pipeline network of nearly 600 miles in Virginia is operated by Commonwealth Gas Pipeline Corporation. Columbia LNG Corporation has an interest in an idle liquefied natural gas plant in Cove Point, Maryland.

($ In thousands)	***1985***	*1984*	*1983*
Revenues	**3,205,000**	3,447,000	4,059,000
Operating Income (Loss)	**(326,000)***	224,000	304,000
Assets	**3,630,000**	3,045,000	2,823,000
Depreciation	**137,000**	121,000	121,000

**Includes a nonrecurring charge of $400.0 million.*

GAS DISTRIBUTION

Columbia's seven natural gas distribution subsidiaries serve more than 1.7 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Maryland, New York and Kentucky. In addition, these subsidiaries are actively involved in transporting gas for industrial and large commercial users who purchase gas directly from other sources. A distribution line network of more than 27,000 miles reaches principal communities such as Columbus, Lorain, Parma, Springfield and Toledo, Ohio; New Castle, York and a part of Pittsburgh, Pennsylvania; Binghamton, New York; Cumberland and Hagerstown, Maryland; Staunton and Portsmouth, Virginia; and Ashland, Frankfort and Lexington, Kentucky.

($ In thousands)	***1985***	*1984*	*1983*
Revenues	**2,153,000**	2,460,000	2,785,000
Operating Income	**136,000**	129,000	83,000
Assets	**1,519,000**	1,315,000	1,786,000
Depreciation	**38,000**	30,000	35,000

OIL AND GAS

At the present time, five subsidiaries conduct Columbia's exploration and production programs throughout the United States and Canada.

Midwest and eastern operations, conducted by Transmission, range throughout the Appalachian and Michigan Basins. The Inland Gas Company, Inc. also produces natural gas to serve industrial customers in the Ashland, Kentucky area. A new subsidiary, Columbia Natural Resources, Inc., has been activated and following necessary regulatory approvals, will carry on all of the System's exploration and production activities in the Appalachian and Michigan Basins.

Southwest and western operations are conducted by Columbia Gas Development Corporation and range from the offshore areas extending from the Gulf Coast of Texas and Louisiana through the Williston Basin in North Dakota.

The operations of Columbia Gas Development of Canada Ltd. extend from the Arctic Islands and Northwest territories through western mainland provinces to offshore areas of the Atlantic Provinces.

($ In thousands)	**1985**	*1984*	*1983*
Revenues	**254,000**	292,000	248,000
Operating Income	**101,000**	134,000	154,000
Assets	**767,000**	837,000	864,000
Depreciation and Depletion	**85,000**	92,000	38,000

OTHER

Columbia Hydrocarbon Corporation recovers propane, butanes and natural gasoline from heavier hydrocarbons derived from Appalachian Basin natural gas production and 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 and also operates an appliance merchandising program.

Columbia LNG Corporation sells synthetic gas produced at its Green Springs, Ohio plant. This plant is expected to cease operations at the end of March 1986 as feedstock purchase and sales contracts expire.

Columbia Coal Gasification Corporation owns 650 million tons of Appalachian coal reserves, some of which are now leased to others for development.

($ In thousands)	**1985**	*1984*	*1983*
Revenues	**146,000**	249,000	464,000
Operating Income	**7,000**	(55,000)*	(5,000)
Assets	**89,000**	96,000	126,000
Depreciation and Depletion	**4,000**	6,000	8,000

**Includes nonrecurring charge of $57.7 million.*

CONSOLIDATED EARNINGS

Adjusted Earnings — Adjusted 1985 earnings were below 1984 and 1983 earnings by 55% and 54%, respectively, reflecting the following segment results:

• The transmission segment recorded a loss in 1985 attributable to the System's principal transmission subsidiary. In accordance with a settlement agreement with its customers, the subsidiary reduced its sales rate, effective April 1, 1985, to a level below its prevailing average cost of gas. The segment's 1984 earnings were down 23% from 1983 due primarily to lower sales volumes resulting from price competition and the inability to recover certain operating expenses.

• Earnings of the distribution segment were up 14% over 1984 earnings which had more than doubled the 1983 results. The improvement over 1984 was due largely to general rate filings placed into effect since the latter part of 1984, and the reduction of certain expenses, particularly uncollectible accounts. The substantial improvement in 1984 earnings reflected the general rate filings placed into effect since the latter part of 1983.

• Earnings of the oil and gas segment were down 27% compared to 1984 and 32% compared to 1983. The 1985 decrease resulted from declines in oil and gas prices and lower gas production. The segment's 1984 earnings were 8% below 1983's primarily due to the effect of a1983 U.S. Supreme Court decision related to the pricing of gas produced by natural gas pipelines which resulted in a $23.6 million gain applicable to 1982.

• Earnings related to other operations were $2.4 million after losses of $1.9 million in 1984 and $7.7 million in 1983. The 1985 results reflect the elimination of losses related to synthetic gas operations and of other unprofitable operations.

	1985		*1984*		*1983*	
Earnings Summary	***Earnings ($ Mil.)***	***Per Share ($)***	*Earnings ($ Mil.)*	*Per Share ($)*	*Earnings ($ Mil.)*	*Per Share ($)*
Earnings (Loss) on Common Stock	**(107.0)**	**(2.67)**	138.6	3.53	164.8	4.41
Discontinued Operations[a]	**—**	**—**	26.9	.69	2.6	.07
Extraordinary Charge[b]	**—**	**—**	—	—	17.3	.46
Earnings (Loss) from Continuing Operations	**(107.0)**	**(2.67)**	165.5	4.22	184.7	4.94
Nonrecurring Items[c]	**196.0**	**4.89**	32.6	.83	9.7	.26
Adjusted Earnings	**89.0**	**2.22**	198.1	5.05	194.4	5.20

(a) Reflects decision to cease coal mining operations (see Note 5).*
(b) Loss on sale of unprofitable distribution subsidiary (see Note 6).*
(c) Nonrecurring Items (see Notes 3 and 4):*

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

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.

1985—The first quarter reserve of $207 million ($5.16 per share) represents a substantial portion of unrecovered gas costs applicable to gas purchased prior to April 1, 1985. Under terms of a settlement between Columbia Gas Transmission Corporation and its wholesale customers, such costs can only be collected under specific conditions. Therefore, the agreement did not give adequate assurance that all or a substantial portion of these costs will be recovered.

1985—The fourth quarter adjustments which increased earnings $11 million ($0.27 per share) as a result of discontinued application of Statement of Financial Accounting Standards No. 71.

**Notes to Consolidated Financial Statements*

Revenues — Total operating revenues declined in 1985 because of lower average sales rates for substantially all forms of energy sold and reduced sales volumes. Warmer weather, price competition and other economic factors caused the decline in sales. The expansion of transportation services resulted in a significant increase in other operating revenues.

Total Revenues and Throughput	**1985**	*1984*	*1983*
Gas Operating Revenues ($000):			
Residential	**1,210,623**	1,278,745	1,357,686
Commercial	**566,608**	617,593	646,394
Industrial	**383,177**	592,084	841,891
Wholesale	**1,566,005**	1,843,234	2,032,807
Other	**12,195**	15,248	16,878
Total Gas Operating Revenues	**3,738,608**	4,346,904	4,895,656
Other Operating Revenues	**313,934**	246,478	179,429
Other Income	**89,288**	51,280	26,451
Total Revenues	**4,141,830**	4,644,662	5,101,536
Sales (Million Cubic Feet):			
Residential	**181,354**	188,471	207,225
Commercial	**91,579**	97,042	104,606
Industrial	**73,252**	108,124	151,034
Wholesale	**344,594**	384,967	409,070
Other	**4,238**	4,255	4,364
Total Sales	**695,017**	782,859	876,299
Total Transportation Volumes	**511,148**	423,427	262,798
Total Throughput	**1,206,165**	1,206,286	1,139,097

Total revenues decreased in 1984 as competition from other gas suppliers led to reduced wholesale and retail sales of gas. Partially offsetting this sales loss was a significant increase in transportation revenues, higher income from temporary cash investments and improved revenue from propane and company owned oil and gas production.

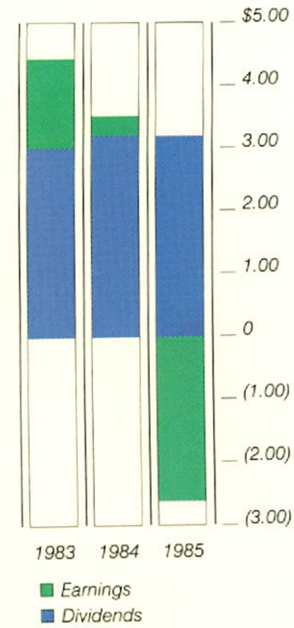
Expenses — Gas purchased costs continued to decline in 1985 due to lower sales volumes as well as lower unit costs. Costs of other products for resale declined in 1985 and in 1984 due to the cutback in synthetic gas operations.

Operation and maintenance expenses increased modestly in 1985 and 1984 due to lower levels of inflation and the effect of System programs designed to control costs.

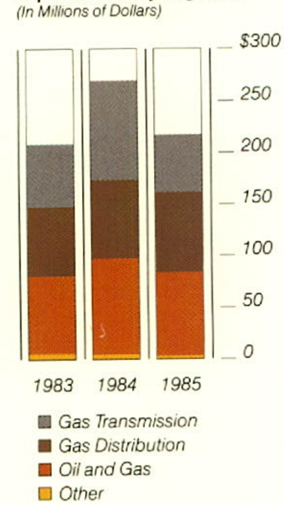
Interest and related charges increased over 1984 due to increased borrowings necessitated by major steps taken to resolve customer and gas supply problems of the System's principal transmission subsidiary. Cash generated in the first quarter of 1984 practically eliminated the need for short-term borrowings in 1984.

Income Taxes — Income taxes, as detailed on the Statements of Consolidated Taxes, decreased in 1985 due primarily to the pre-tax nonrecurring charge of $400 million establishing a reserve for unrecovered gas costs reflecting terms of a wholesale rate settlement. 1984 income taxes decreased due to a reduction in pre-tax income.

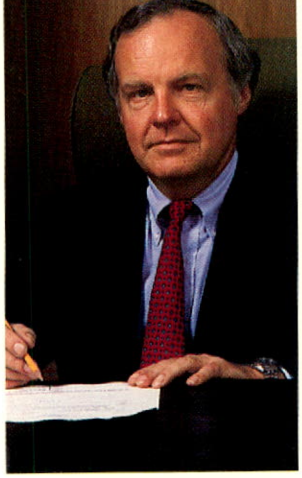
Earnings and Dividends per Share of Common Stock
(In Dollars)



Summary of Gross Capital Expenditures by Segment
(In Millions of Dollars)



GAS TRANSMISSION OPERATIONS



A Transmission Unit Mission Statement

"To provide reliable gas service at competitive prices, seek new markets and revenue sources, ensure flexibility to respond to market and supply changes and achieve an adequate return for shareholders, while continuing commitment to safety and employee relations."

John D. Daly
Chairman, Columbia Gas Transmission Corporation

Review of Operations

1985: An Historic Year—For the System's principal transmission subsidiary, Columbia Gas Transmission Corporation (Transmission), 1985 was a critical year which saw the resolution of serious problems which threatened its viability: contracts to purchase excessive supplies of high-priced natural gas and a shrunken market. By the end of the year, Transmission was able to announce that steps had been taken which will enable it to be competitive, recapture markets and attach new customers.

To resolve Transmission's problems, two major steps had to be taken. First, Transmission needed to resolve the proceedings before the Federal Energy Regulatory Commission (FERC) in which some of Transmission's customers had charged that Transmission's gas acquisition policies and practices were abusive. Second, it also had to renegotiate producer contracts calling for purchases of gas at volumes and prices that were unrealistic in its competitive market.

As Transmission grappled with these issues, the FERC in 1985 proposed a sweeping revision of natural gas pipeline regulation. The proposal became reality on October 9, 1985, when the FERC issued an order (Order 436) that has the potential to change the way all segments of the gas industry conduct business, as well as reshaping both Federal and state regulation.

Customer Settlement Agreement—In the first quarter of 1985, Transmission reached a settlement with its customers and other parties which resolved more than 20 dockets pending before the FERC. The agreement, although costly, was needed to avoid further market erosion which could have resulted from lengthy hearings and litigation.

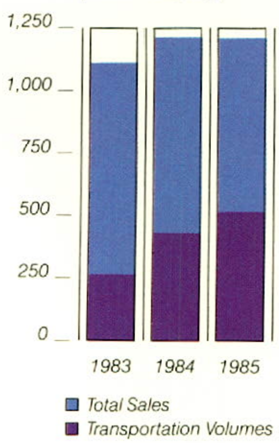
Under terms of the settlement agreement (approved by the FERC on June 25, 1985), Transmission lowered its commodity rate significantly, to a level below its prevailing average cost of gas. Transmission also effectively agreed not to increase its commodity rate over the two-year settlement period commencing April 1, 1985. Transmission will not have any refund obligation relating to gas acquisition practices for the period March 1982 through March 1987, and its refund obligation related to FERC orders covering the period between March 1981 and February 1982, which have been remanded to the FERC by a U.S. Court of Appeals, is limited to $1 million.

Columbia's transmission companies offer competitively-priced transportation service to major markets in nine states and the District of Columbia.

Transmission, along with its affiliate Columbia Gulf Transmission Company (Gulf), agreed to offer transportation services within capacity limits and within the framework of Order 436 to enable customers to purchase available low-cost spot market supplies, and agreed not to file a general rate increase to be effective before April 1987.

For their part, the customers agreed to make every effort to purchase volumes of gas sufficient for Transmission to avoid having to make prepayments under take-or-pay provisions in producer contracts. They also agreed to allow Transmission the opportunity to collect up to $600 million of deferred costs relating to gas purchased prior to April 1, 1985, under conditions described in Note 2A of Notes to Consolidated Financial Statements.

Total Gas Throughput
(In Billion Cubic Feet)



When the agreement with customers was announced, management estimated that the total cost of the settlement, including write-offs and operating losses, could reach $1 billion for the two-year settlement period should Transmission fail to renegotiate certain high-cost gas contracts.

Producer Contract Modifications—In mid-1985, Transmission announced that it was offering cash payments totaling $800 million to certain high-cost producers in exchange for major modifications in the terms of their contracts. The modifications would reduce prices to market levels, allow periodic price redetermination, and lower take-or-pay levels. Transmission proposed to pay producers in three installments: 20% in December 1985; 40% in December 1986; and 40% in December 1987.

At year-end, Transmission had successfully modified its agreements with producers representing approximately 80% of the Southwest and Rocky Mountain high-cost gas. Additional details related to the plan are discussed in Note 12B of Notes to Consolidated Financial Statements.

The contract modifications materially reduce the projected loss of the two-year customer settlement period, and enable Transmission to return to a competitive position.

A New Way of Doing Business—The Natural Gas Policy Act of 1978 (NGPA), which had stimulated development of new natural gas reserves by allowing prices to rise, helped push gas prices up as oil prices fell in the early 1980's, causing large industrial gas loads to switch to alternative fuels. Transmission and others attempted to arrest this trend by offering to provide transportation if industries could buy less costly gas directly from other sources. Similar services were also offered to distribution companies under limited conditions. As these transportation programs evolved, competition in the gas industry increased. Many special transportation programs were authorized by the FERC until the U.S. Court of Appeals found the eligibility criteria for participating in these programs to be unduly discriminatory against large numbers of customers.

This court action was followed by sweeping changes which have been embodied in FERC Order 436. Although the new rules have met with criticism from all segments of the industry, Transmission and its affiliate, Gulf, have accepted Order 436 because of the unique customer settlement and contract modifications secured in 1985. This acceptance will permit Transmission to offer open-access transportation services under the new nondiscriminatory guidelines established by the FERC.

Order 436 is seen as an effort by the FERC to utilize competitive structures rather than traditional regulatory practices to guide the production, transmission and distribution of natural gas. The order should stimulate direct dealings between producers and consumers, while ensuring the timely and accurate transmission of market signals between the wellhead and the burner tip.

As an open-access transporter, Transmission will be able to utilize new rules established by Order 436 which simplify the procedure by which participating pipelines may offer services—including sales, transportation and storage—in new markets.

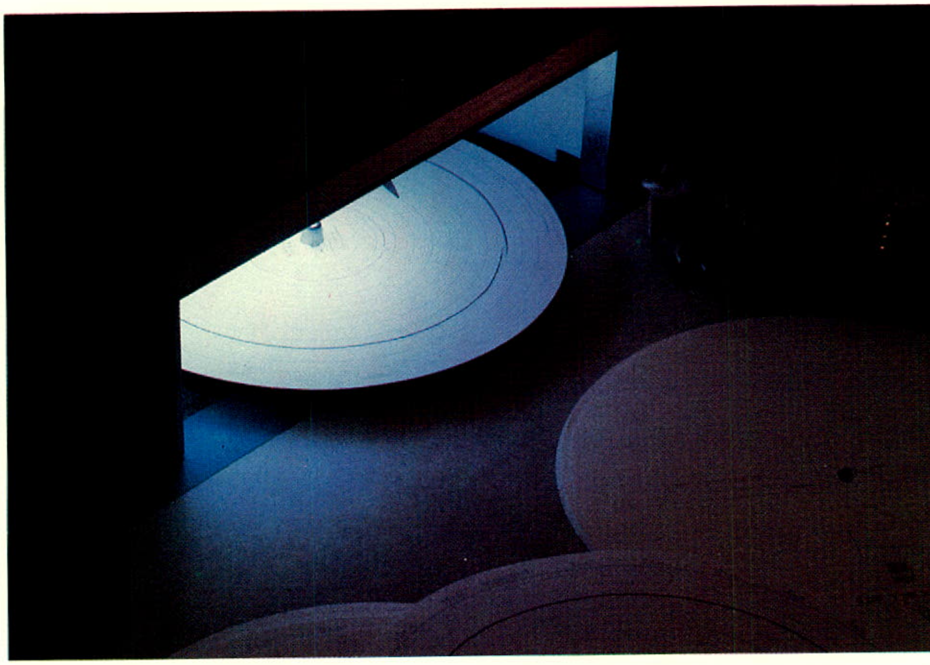
Order 436 has been widely challenged by producers, pipelines and others, and its fate is uncertain. Columbia has supported the concepts embodied in the order since they were first proposed by the FERC and believes that, whatever the fate of this particular order, the movement toward regulations allowing increased market competition cannot be reversed. As a result of the actions taken in 1985, Columbia transmission companies are positioned to function effectively and to seek new business opportunities in the new industry climate.

Financial Review

Transmission Operations ($ In thousands)	**1985**	*1984*	*1983*
Unaffiliated Revenues	**1,653,600**	1,904,000	1,979,400
Intersegment Revenues	**1,551,900**	1,543,500	2,079,300
Total Revenues	**3,205,500**	3,447,500	4,058,700
Operating Income	**(326,400)**	224,100	304,200

Nonrecurring Charge—Under the terms of the settlement agreement between Transmission and its customers (as more fully described in Note 2A of Notes to Consolidated Financial Statements), Transmission did not receive adequate assurance that it could recover in future revenues certain deferred costs for gas purchased prior to April 1, 1985. Accordingly, Transmission established a $400 million reserve for such costs in the first quarter of 1985.

With billions of cubic feet of gas moving through Columbia's lines daily, accurate records are essential. This device in Columbia's Houston office reads meter records automatically.



Operating Income—Operating income before the nonrecurring charge was $73.6 million in 1985 compared with $224.1 million in 1984 and $304.2 million in 1983. The significant reduction in operating income was due largely to:

- Operating losses incurred by Transmission in the last nine months of 1985 resulting from the lowering of its commodity rate below its cost associated with the purchasing of gas under the terms of the customer settlement agreement. Such operating losses were moderated by Transmission's producer contract modifications which are more fully described in Note 12B of Notes to the Consolidated Financial Statements.
- Decreased sales, partially offset by transportation services. The impact of the lower sales was further mitigated by an improved rate design which permitted greater cost recovery through demand rather than commodity rates.
- The $13.6 million cost of a voluntary severance program offered by Transmission to reduce future labor and benefit costs. Approximately 200 employees participated in the program.
- The recording of a $7.0 million upward depreciation adjustment related to the liquefied natural gas facility.

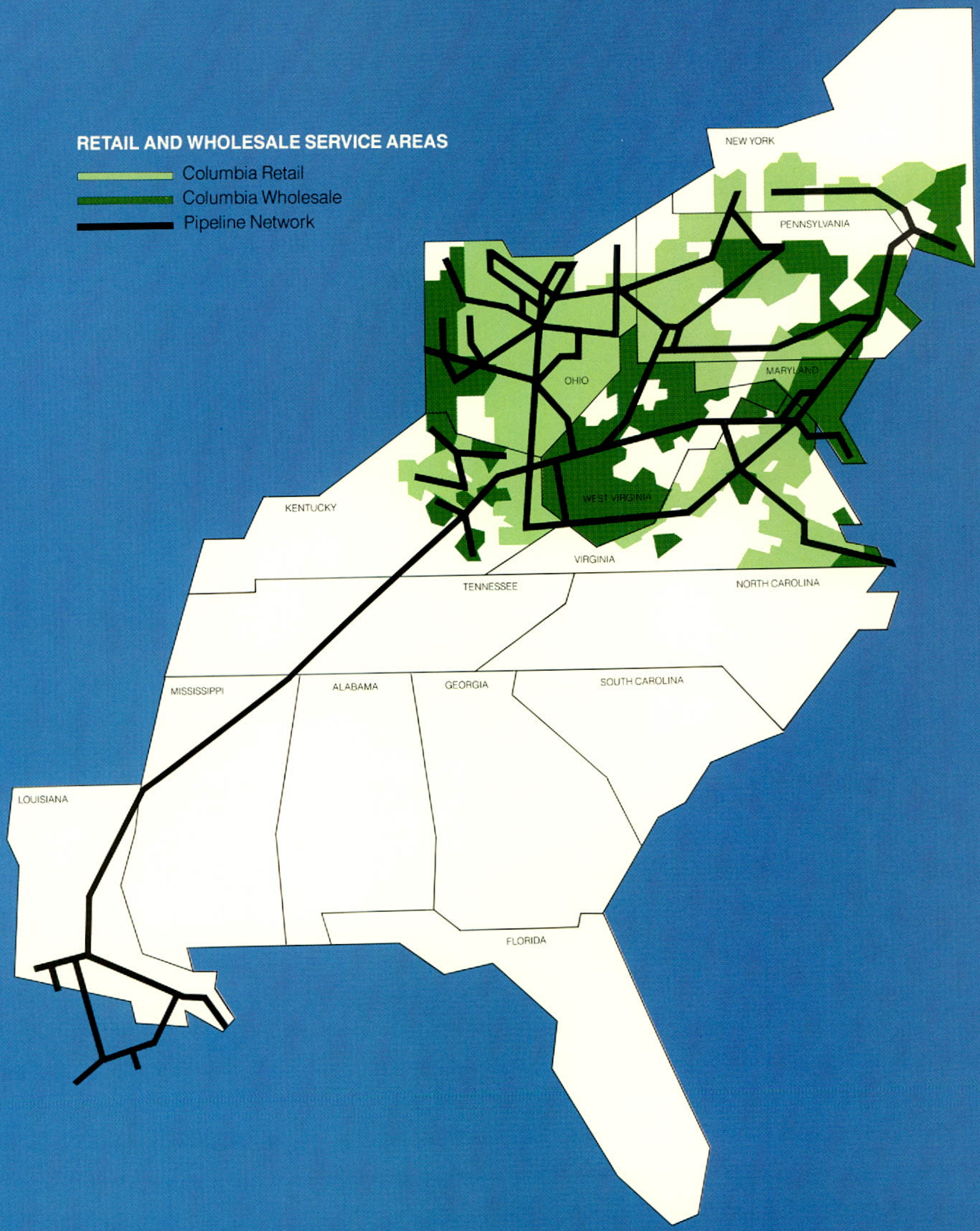
Volumes—The decline in sales volumes moderated in 1985. Sales volumes were down 4% from 1984 and 20% from 1983 due to warmer weather for the year and increased purchases made by wholesale customers and their end-users directly from producers and other suppliers. 1985 volumes also reflected sales to a new wholesale customer serving the Eastern Shore of Maryland and lower Delaware.

Transportation volumes were up 22% over 1984 and more than doubled the 236.2 Bcf transported by the transmission companies in 1983. The increase in volumes transported improved utilization of facilities by 5% over 1984 and 8% over 1983.

Revenues—Revenues were down 7% from 1984 and 21% from 1983 primarily because of the 11.5% reduction in Transmission's commodity rate effective April 1, 1985 coupled with the erosion of sales, partially offset by higher transportation revenues. Unlike sales revenues, transportation revenues do not include the cost of gas sold.

Financial Outlook—The measures taken by Transmission during 1985 should produce improved results in 1986. Financial results in 1986 will be influenced by:

- Modified producer contracts.
- The agreement by customers to make "every effort" to purchase volumes of gas sufficient for Transmission to avoid making take-or-pay payments under producer contracts.
- Competitive opportunities offered by FERC Order 436.


RETAIL AND WHOLESALE SERVICE AREAS
Columbia Retail
Columbia Wholesale
Pipeline Network
NEW YORK
PENNSYLVANIA
OHIO
MARYLAND
WEST VIRGINIA
KENTUCKY
VIRGINIA
TENNESSEE
NORTH CAROLINA
MISSISSIPPI
ALABAMA
GEORGIA
SOUTH CAROLINA
LOUISIANA
FLORIDA

GAS DISTRIBUTION OPERATIONS

A Distribution Segment Mission Statement

"To market gas energy and related services in response to customer needs at competitive prices in a manner that assures a strong corporate financial position, while continuing the commitment to its employees."

Marvin E. White
Chairman, Columbia Gas Distribution Companies

Review of Operations

1985 Highlights—In 1985, the distribution companies successfully operated in a highly competitive environment by:

- Decreasing their cost of purchased gas.
- Expanding transportation services for end-users electing to purchase gas directly from other sources.
- Increasing flexibility for following a least-cost supply strategy.
- Conducting aggressive marketing programs.

Market Conditions—Market conditions for the distribution companies continue to be characterized by intense competition from other fuels and other gas suppliers as well. To date, the distribution companies have largely met the competitive challenges by offering responsive new services, such as transportation of user-owned gas.

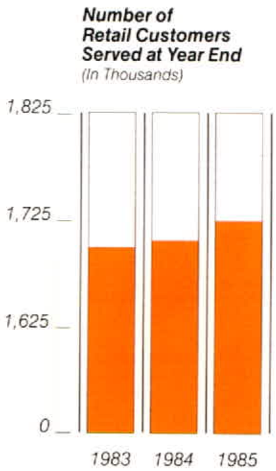
The FERC's open-access transportation rules under Order 436 are likely to further affect market conditions at the state level. On one hand, the new rule should enable distribution companies greater access to new gas supplies and thus enable them to achieve more competitive gas costs. On the other hand, the new rules may also enable current large-volume customers to bypass the distribution company in favor of direct service from the transmission company. State utility commission reaction to the FERC rules will be a major area of interest in 1986.

Columbia's distribution companies are dealing with these new competitive conditions in a relatively mature market area. Except in Virginia, population and employment growth has been small in absolute terms and below the U.S. average. Comparatively low housing starts and the already high level of gas usage among homeowners and businesses suggest limited overall market growth potential.

The industrial base of the area has been concentrated in heavy industries which have been affected both by imports and overall economic conditions. However, plans of Toyota to build a new auto assembly plant on Columbia's lines in Kentucky, with probable satellite industrial activity, have provided encouragement for a degree of industrial revival. Columbia now supplies a large Honda assembly plant in Ohio, which may undergo expansion in the near future. The availability of highly skilled employees, knowledgeable of industrial trends and processes, should enable the distribution companies to take advantage of similar opportunities and will be a significant sales tool to counter pipeline bypass.

Columbia Gas distribution companies now serve more than 1,700,000 meters and have active promotions underway to add more.

Efforts to build retail markets are furthered by utilization research conducted by Columbia's Research Department. Development of innovative energy-efficient appliances, end-use equipment and industrial processes contributes to the maintenance of a competitive edge. Advanced technology highlights include a gas heat pump for residential and commercial markets being developed in association with the Gas Research Institute, and a unique high-



efficiency home and water heater developed by Columbia which has been licensed for manufacture by Mor-Flo Industries under the name Polaris Comfort System. Columbia is participating with other utilities in research of improved gas-fired techniques for paper drying and scrap metal processing. Other research work is directed to reducing operating costs.

The distribution companies will continue their aggressive marketing programs to compete in suburban areas as the trend from congested urban to suburban areas is expected to continue. Where possible, they will cooperate with affiliated propane companies to hold markets until distribution lines can be constructed.

Outlook—In an increasingly competitive marketplace, the distribution companies bring these strengths to bear:

- Access to a large and stable market.
- Availability of ample, competitively priced gas supplies.
- An established marketing organization.
- Efficient cost-effective operations.
- Market-responsive transportation services.

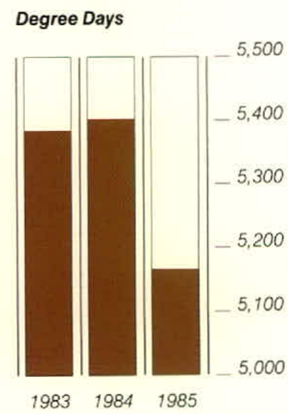
Financial Review

Gas Distribution ($ In thousands)	**1985**	*1984*	*1983*
Unaffiliated Revenues	**2,149,000**	2,458,700	2,784,900
Intersegment Revenues	**3,800**	900	600
Total Revenues	**2,152,800**	2,459,600	2,785,500
Operating Income	**135,700**	129,200	83,300

Results for 1983 include $288.1 million of revenues and an operating loss of $7.0 million for a subsidiary which was sold in 1984. The results of this subsidiary have been eliminated in the following analysis.

Revenues—Total revenues from distribution operations declined in 1985 by 12% from 1984 and 14% from 1983. This decline in revenues is primarily the result of lower sales rates which the gas distribution companies have been able to accomplish by reducing their cost of gas and by a continuing shift in the nature of the service provided to many large end-users. As lower priced spot market gas has become available over the last several years, the distribution companies have offered transportation services which permit large users to purchase gas directly from alternate suppliers for transportation by the distribution companies. This results in lower revenues for the distribution companies, but lower expenses as well, since the cost of gas is borne directly by the user. Consequently, the operating income effect of providing transportation versus sales services is approximately the same.

Combining the volumes of gas sold and transported produced a total throughput decline of 5% from 1984 and 11% from 1983. These declines reflect weather which was slightly warmer in 1985 than in each of the prior two years and a lower level of industrial activity. In the residential and commercial classes, the distribution companies experienced a net gain of 18,000 new customers in 1985 on top of a net gain of 9,000 in 1984. Sales to these new customers have generally offset the effect of lower per customer usage which results from continued conservation and improvements in equipment efficiencies.

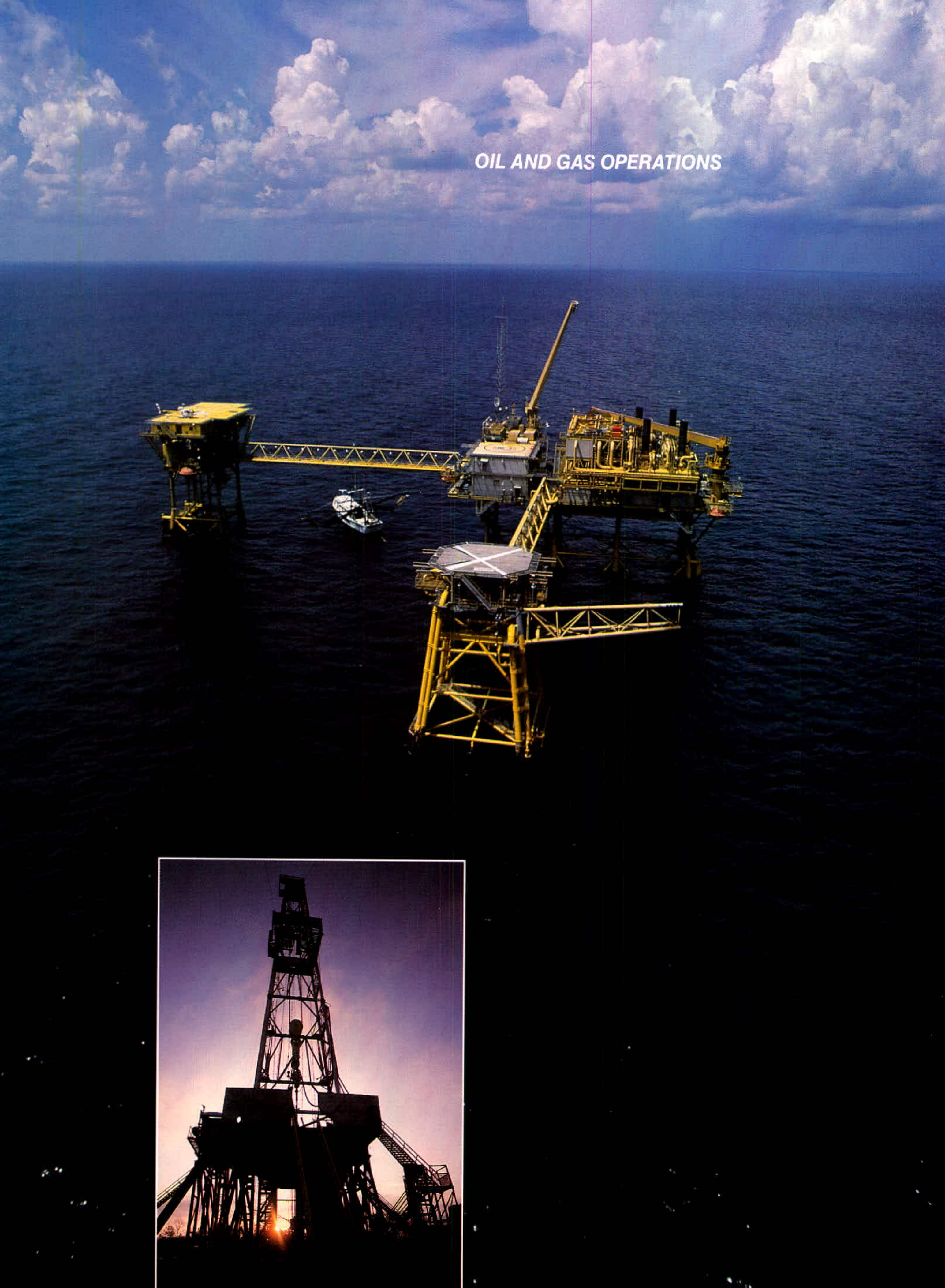


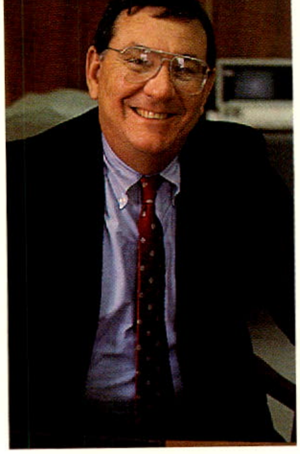
Operating Income—Operating income for the distribution subsidiaries rose 5% over 1984 and 50% over 1983. This trend is the combined result of general rate increases which have been placed into effect and the positive impact of cost containment programs.

Financial Outlook—The distribution companies' marketing programs are expected to continue this segment's ability to maintain throughput at approximately the 1985 level in 1986. Operating income from the segment is expected to be approximately the same as in 1985. The primary factor which may affect this outlook is the extent to which oil prices continue to fall, providing competitive pressure for dual fuel industrial customers to switch to oil from natural gas.

Natural gas heats more than 97 percent of the homes served by Columbia distribution companies. Realtors find that gas-heated homes sell more readily than those using other energy sources.

OIL AND GAS OPERATIONS





A Production Company Mission Statement

"To find and develop, or otherwise acquire, produce and market economic accumulations of oil and gas consistent with the objectives, goals and strategies of The Columbia Gas System, Inc."

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

Review of Operations

1985: Overview—The System's oil and gas activities were adversely impacted in 1985 by lower prices for oil and gas and the excess gas supply problem.

Domestic gas production declined 6% as sales to unaffiliated customers were not sufficient to overcome Transmission's reduced purchases. Capital expenditures, which were originally estimated at $125.6 million, were reduced 38% primarily due to the deferral of certain projects which became less profitable with dropping oil and gas prices.

Functional operations of the exploration and production efforts in the Appalachian area were structurally moved from Transmission and The Inland Gas Company, Inc. into a new company. The new company, Columbia Natural Resources, Inc., subject to approvals from the Securities and Exchange Commission and the Federal Energy Regulatory Commission, will continue to operate throughout the Appalachian and Michigan Basins.

In Canada, the government significantly revised the Dominion's energy policy, eliminating measures which had been counter-productive to Columbia's efforts there.

System Lease Holdings—The System has one of the largest lease holdings among major gas companies, with total net acreage exceeding 4.5 million. Of this amount, 1.5 million represents developed acreage.

Domestic onshore lease holdings at year-end amounted to 3.2 million, of which 98% is located in the Appalachian area. The remainder of the onshore acreage is concentrated mostly in the Powder River Basin, the Williston Basin and Gulf Coast Salt Basin.

Domestic offshore holdings include varying interests in Federal offshore blocks consisting of 74,000 net acres, most of which are located in the West Cameron, Vermillion, Eugene Island and Ship Shoal blocks.

Canadian holdings total 1.3 million net acres including a 5.47% interest in the 307,051 gross acres in the block encompassing the Hibernia, Hebron, Nautilus and Mara structures offshore Newfoundland.

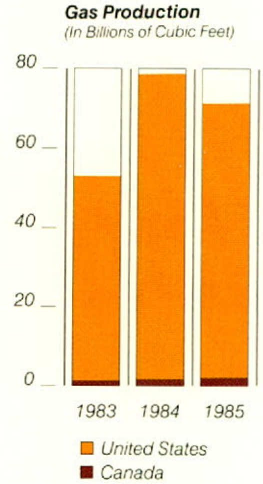
Reserves—Domestic gas reserves of 751.4 Bcf at December 31, 1985, remained essentially the same as in 1984. Domestic oil reserves of 8.4 million barrels were down 18% from 1984.

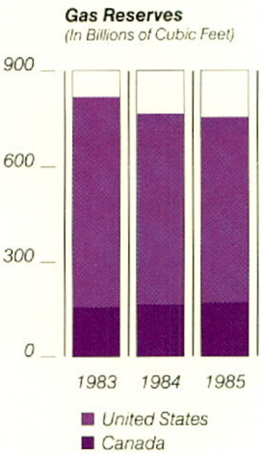
Canadian gas reserves totaled 154.4 Bcf, a slight increase over the previous year. Canadian oil reserves of 6.0 million barrels were up 41% reflecting drilling and development in Alberta and Saskatchewan, but excluding any offshore reserves such as Hibernia.

Columbia's efforts to find and produce gas and oil extend from the Gulf of Mexico to the frontier areas of Canada.

The pre-tax net present value of proved System reserves, using a 10% discount factor as required by rules established by the Financial Accounting Standards Board, amounted to $1,008 million at December 31, 1985, compared to $1,088 million at year-end 1984. Lower oil and gas prices at the end of 1985 principally caused the decline in discounted future cash flows.

System Drilling Program—During 1985, the System's oil and gas subsidiaries participated in 121 exploration wells and 185 development wells. The success rate for exploratory drilling was 39%, while development drilling had a success rate of 82%.





The System's exploration and development strategy continues to be one of participation 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% while offshore participation is smaller, usually not more than 25%.

Internal generation of drilling prospects has greatly increased during the past three 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 foreseeable future.

Midwest and Eastern Drilling Operations—In 1985, two joint venture programs resulted in the drilling of fifty wells in the Devonian Shale and Mississippian Berea in Virginia, West Virginia and Kentucky. These programs have a high success rate and an average well generally proves up 500 million cubic feet of gas.

Columbia is continuing exploration and development efforts in the Eastern Overthrust area of Grant and Pendelton Counties, West Virginia. Columbia has completed five Oriskany joint venture wells with average reserves of 2.6 Bcf per well. An additional five wells are scheduled in 1986.

Southwest and Western Drilling Operations—Based on earlier success, exploration and development activity continued in the Williston Basin resulting in several new prospects during 1985. The existence of multiple reservoirs, better than average success rates and the success achieved in the Indian Hills Field in North Dakota, make this an important exploration area. Participation in six exploratory wells in 1985 resulted in one oil discovery and two wells production testing at year end.

Oil prospects continued to be generated during 1985 in the Minnelusa sand trend along the eastern flank of the Powder River Basin. A 16,000 foot exploratory well was drilling at the end of the year. Eight to ten wells are planned for 1986 in the trend.

Geological and geophysical work continued in the Anadarko and Permian Basins and during 1985, six prospects were assembled for drilling in 1986.

A joint venture with Citation Oil and Gas Corp. was announced in 1984 to participate in a two-year exploration program. Prospects were delineated in Louisiana, south and central Texas and in Oklahoma. During the year, 42 wells were drilled, resulting in 12 discoveries which are being tested and evaluated. The venture will be continued in 1986, with drilling concentrated in North Dakota, Oklahoma and Texas.

Offshore Louisiana, substantial new gas reserves were added on Eugene Island 286. Development drilling is expected to begin early in 1986 with production commencing by year-end.

Canadian Drilling Operations—Mainland activity in 1985 was concentrated in Alberta and Saskatchewan. Emphasis continued to be placed on shallow prospects less than 6,000 feet deep.

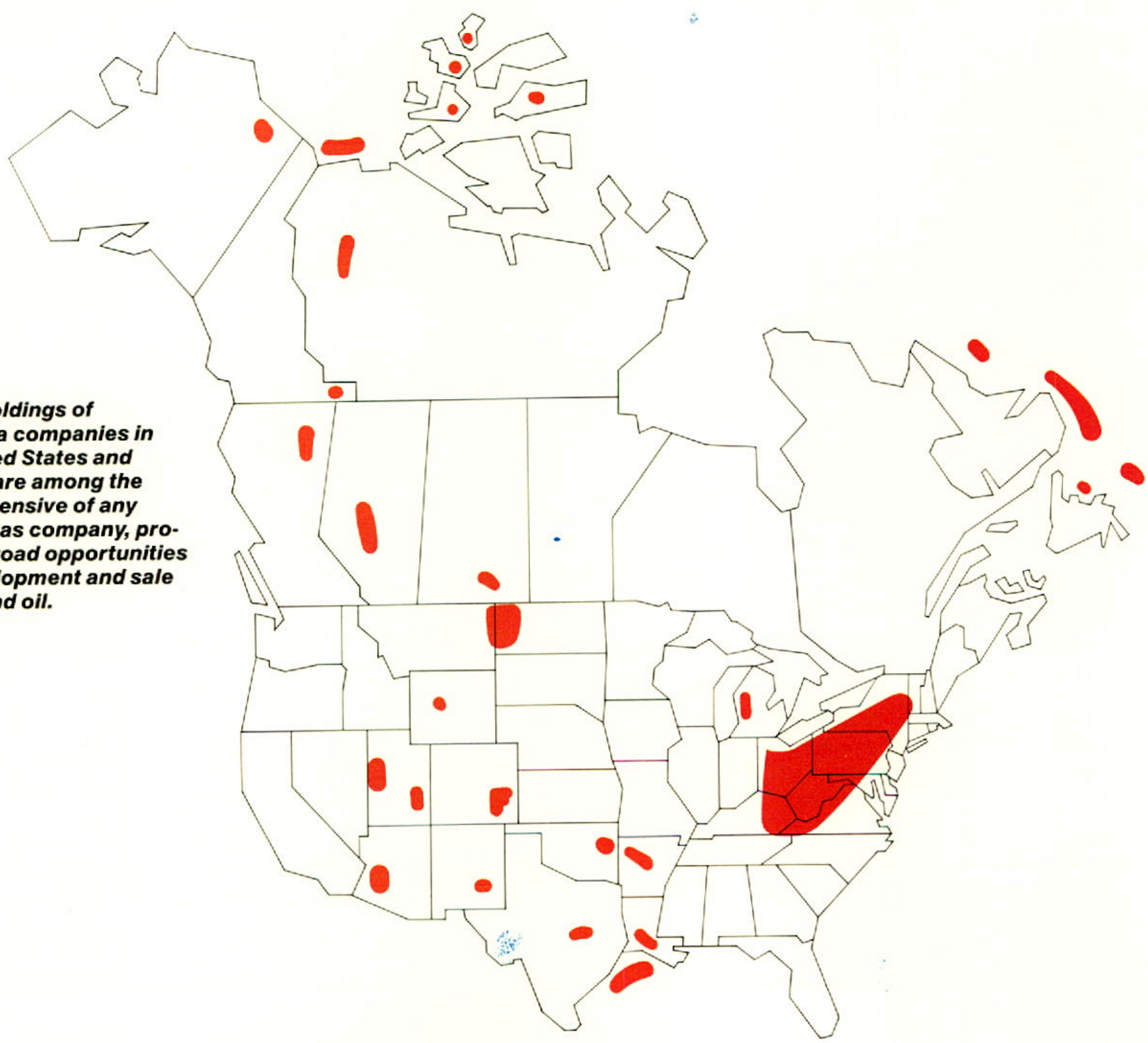
In Alberta, discovery of a new oil pool resulted in an eastward extension of the Highvale Field. In Northern Alberta, geophysical surveys and follow-up drilling indicate discoveries at Valhalla and Red Earth.

In southeast Saskatchewan, two new oil pools were discovered and another discovery at Eyehill in southwest Saskatchewan resulted in a five-well oil pool. These fields are expected to develop from 80 thousand to 250 thousand barrels per well.

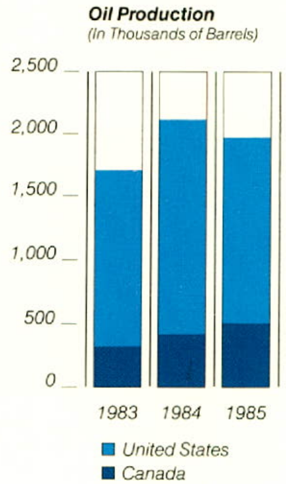
Offshore exploration continued in 1985 with the drilling of two wells on the Hibernia Block off Canada's east coast. The first well, drilled five miles southeast of the Hibernia Field, found two productive zones. One of the zones is present in the Hibernia Field and in two other wells located three miles and six miles to the east, respectively. The second well, drilled on the Mercury Prospect located twelve miles northwest of the Hibernia field, was dry.

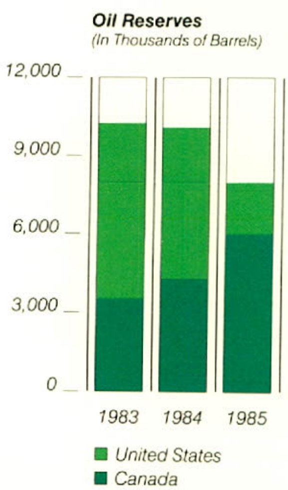
The Hibernia project continues to move ahead. Mobil Oil Canada, Ltd., the operator, on behalf of the partners has filed an application with the Federal and provincial governments requesting approval to proceed with development plans for the field. It is expected that governmental approvals for the 150,000 barrel per day gravity base system will be received by the end of March 1986. Production is expected to commence in 1992.

The Canadian government moved in 1985 to significantly revise its energy policies in terms supportive of gas and oil production activities. In a key action, an accord between the Federal government and the Western producing provinces deregulated the price of crude oil and introduced the phase-out of oil and gas revenue taxes on oil and gas production in the provinces. By a subsequent agreement, the Federal government and the gas producing provinces established a market oriented pricing policy which will expand domestic and export sales opportunities. The Canadian government also proposed legislation, that is now awaiting final action, which would eliminate a provision reserving to the government a 25% interest in certain development projects and otherwise encourage production activity. In Alberta, the government has decreased provincial royalties, increasing the incentive for oil and gas production.



Lease holdings of Columbia companies in the United States and Canada are among the most extensive of any natural gas company, providing broad opportunities for development and sale of gas and oil.





Outlook—While the current outlook for prices of oil and gas is somewhat clouded, the System remains committed to the profitable expansion of its reserve base. Therefore, the basic strategy for 1986 exploration and development programs is to:

- Maximize cash flow from producing reserves.
- Explore proven trends to maintain reserves over the short-term and to increase reserves over the long-term.
- Explore opportunities to acquire additional reserves through the purchase of proved oil and gas fields not fully developed.
- Intensify marketing efforts to take advantage of opportunities available under FERC Order 436.

The 1986 drilling program contemplates participation in 180 exploratory wells and 230 development wells. The oil and gas subsidiaries will be looking for opportunities in most proven basins east of the Rocky Mountains. Offshore activities will continue in the Gulf of Mexico and offshore Atlantic provinces.

Financial Review

Oil and Gas Operations ($ In thousands)	***1985***	*1984*	*1983*
Unaffiliated Revenues	**156,200**	98,800	96,500
Intersegment Revenues	**97,700**	193,500	151,400
Total Revenues	**253,900**	292,300	247,900
Operating Income	**100,900**	133,900	153,600

Revenues—Total revenues in 1985 decreased 13% compared with 1984 due to lower oil and gas prices and a 5% decline in natural gas production. Intersegment revenues decreased substantially, reflecting Transmission's reduced purchases. The decrease was partially offset by increased sales through special marketing programs to unaffiliated customers. Compared to 1983, total revenues increased slightly as gas production rose by 41% and oil production by 30%. These gains were offset by the lower oil and gas prices prevailing in 1985. In addition, 1983 revenues were improved by a $19.8 million adjustment applicable to 1982, reflecting a 1983 U.S. Supreme Court decision which frees natural gas pipeline companies from cost-of-service regulation with respect to their own production, thereby permitting them to charge the same rates as independent producers.

Operating Income—The 25% decrease in operating income compared to 1984 reflected the effects of lower revenues, slightly higher depletion rates and increases in other expenses. 1985 operating income was down 34% in comparison with 1983. 1983's operating income was improved by two special adjustments which resulted from the U.S. Supreme Court's decision on natural gas pricing: (1) the $19.8 million revenue impact discussed above; and (2) a $24.9 million depletion expense reduction caused by the addition of significant volumes of low-cost gas reserves into the U.S. cost center.

Financial Outlook—1986 operating income will be adversely affected should oil and gas prices continue to decline. Emphasis in 1986 will be placed on maximizing cash flow from production and taking advantage of opportunities to improve the reserve base.

OTHER OPERATIONS

Propane sales reach consumers beyond the gas mains and are supplied from strategically-located storage plants.

Review of Operations

Propane Operations—A very versatile fuel, propane is the predominant member of the LP-gas family which ranks fourth in supplying the nation's energy needs. The propane market has grown steadily since 1982, serving primarily suburban and rural areas beyond natural gas mains. The suburban growth trend is expected to continue with Columbia's propane subsidiaries establishing and holding markets for their affiliated natural gas distribution companies. Propane markets expect strong competition from the electric utilities.

Price competition among other distributors is also expected to be intense as a result of large marketers absorbing smaller distributors and thereby achieving operating efficiencies which reduce operating costs. To remain competitive, Columbia's propane companies must continue to reduce overhead costs and develop innovative market building programs.

Columbia Hydrocarbon Corporation operates a fractionation plant located in Siloam, Kentucky, to recover propane, butanes and natural gasoline from local natural gas production. As a result, sales volumes of these products are greatly influenced by the level of Appalachian natural gas production. All butanes and natural gasoline are sold to a nearby chemical company. Sales to distributors represent over 50% of propane sales volumes, but potential growth is limited by the cost of deliveries from the plant to the customers' bulk terminals. The industrial, commercial and other large volume markets, which represent approximately 40% of sales volumes, are greatly influenced by the availability of natural gas and competition from oil, electric and other propane distributors.

Commonwealth Propane, Inc. has a strong position in the propane industry in Virginia, reflecting both aggressive marketing and acquisition programs. Both these tactics will be continued in order to improve earnings and offset the downward trend related to propane sales for tobacco curing. As a result of present and anticipated population growth, emphasis will be on securing suburban markets which can be converted to natural gas as distribution lines can be extended. Commonwealth Propane has a well balanced customer mix of 27% residential sales; 45% industrial, commercial and other large volume sales; 14% agricultural sales and 14% wholesale customers and spot market sales. Commonwealth Propane is also a major marketer of gas appliances in Virginia.

Synthetic Gas Operations—Columbia LNG Corporation will discontinue the production of synthetic gas at its Green Springs, Ohio plant on March 31,1986, as more fully described in Note 4C of Notes to Consolidated Financial Statements.

Coal Mining Operations—Efforts to sell or lease Columbia's interest in the West Virginia mine jointly owned with an Exxon affiliate are continuing. Mining operations were discontinued in 1984 as more fully described in Note 5 of Notes to Consolidated Financial Statements.

Other Coal Investments—The discontinuance of coal mining operations did not affect Columbia Coal Gasification Corporation's 50% ownership of the 200 million tons of coal reserves dedicated to the Columbia-Exxon venture. In addition, approximately 550 million tons of other low-sulphur coal reserves, are owned. Columbia intends to maintain its royalty interest in most of these coal reserves, some of which are now leased to others for development. As opportunities develop, certain small blocks will be offered for sale with Columbia retaining overriding royalties.

Financial Review

Other Operations ($ In thousands)	**1985**	*1984*	*1983*
Unaffiliated Revenues	**99,700**	145,100	229,600
Intersegment Revenues	**46,400**	103,700	234,800
Total Revenues	**146,100**	248,800	464,400
Operating Income	**7,400**	(54,800)	(4,600)

Revenues—During 1983, over 80% of the revenues in this segment were generated by sales of synthetic gas. The earnings contribution was negligible, however, due to the declining investment base of the synthetic gas facility. Synthetic gas revenues were down $95.7 million in 1985 from 1984 and $240.9 million in 1984 from 1983, reflecting amended feedstock and sales contracts in both years. These revenues will end in 1986 because the synthetic gas facility will cease operations after the first quarter.

Propane revenues were down in 1985 due largely to lower agricultural and spot market sales.

Operating Income—The operating income improvement in 1985 reflects the culmination of several years' efforts to terminate losses associated with synthetic gas and the other unprofitable operations.

Operating income generated by the propane companies was down in 1985 due to the lower sales of propane and the reduced prices for other hydrocarbons. 1984 operating income from these companies increased over 1983 due to availability of product from increased Appalachian production and the improved economy. Operating income was depressed in 1983 by the economy, warm weather and the conversion of customers to natural gas by the affiliated Ohio distribution company. All three years reflect customer growth in the Virginia market.

The operating loss in 1984 includes a $57.7 million nonrecurring charge related to synthetic gas operations as more fully discussed in Note 4C of Notes to Consolidated Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

The resolution of Transmission's customer and producer problems discussed earlier in this report introduced unusually high demands on the Corporation's liquidity during 1985 and required changes in the Corporation's traditional means of obtaining long and short-term financing. Demands for funds relate primarily to capital expenditures, payment of gas purchase costs (including take-or-pay and other gas costs related to prior periods and payments made in connection with producer contract modification), debt service requirements and dividends on common and preferred stock. Net cash from operations was negative in 1985 ($58.7 million) necessitating considerable external financing to meet the Corporation's liquidity requirements. Net external financing activities amounted to $519.8 million in 1985. In 1984 and 1983 net external financing activities were negative, reflecting an excess of net cash from operations over the demand for funds in those years.

The $400 million nonrecurring charge recorded in March 1985 to reflect estimated unrecoverable deferred gas purchase costs temporarily eliminated the Corporation's ability to issue debentures and preferred stock because of earnings tests included in the Corporation's Indenture and Certificate of Incorporation. In addition, downgradings by the major rating agencies of the Corporation's commercial paper in April 1985 necessitated that the Corporation seek alternative sources of short-term borrowings for working capital requirements.

In July 1985, the Corporation entered into a $500 million Credit Agreement with thirteen banks, led by Morgan Guaranty Trust Company of New York as agent. At year end, $400 million was borrowed under the Credit Agreement. The proceeds of the loans are used by the Corporation to finance the seasonal gas inventory and other short-term financing requirements of its subsidiaries. The Credit Agreement converted $500 million of confirmed lines of credit previously maintained with many of the same bank lenders to a committed revolving credit facility. The Credit Agreement has an initial termination date of July 25, 1986 but may be extended every six months, at the option of the banks, for additional twelve-month periods. In February 1986, the banks agreed to extend the termination date to January 1987.

The Corporation also had $18 million of additional bank lines of credit at year end 1985, all of which were drawn down in the form of short-term borrowings at year end. These loans, as well as the amounts outstanding under the Credit Agreement, will be repaid with normal seasonal cash receipts early in 1986.

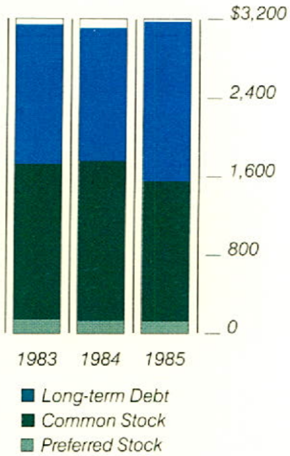
In July 1985, Transmission entered into a $350 million Limited Recourse Loan Agreement (Production Loan) with ten banks led by Bankers Trust Company as agent. The Production Loan, which is secured by Transmission's oil and gas producing properties in Appalachia, is on a revolving basis for the first two years, after which the amounts outstanding will be amortized through 20 quarterly payments. Subject to maintenance of adequate oil and gas reserves, final maturity will be in approximately seven years, although the loan can be prepaid at any time. The Corporation has guaranteed the payments of principal and interest and certain other convenants of Transmission in connection with the loan agreement. Transmission borrowed the initial $150 million available under the loan agreement during the third quarter of 1985. The availability of the additional $200 million is subject to certain conditions relating to the renegotiation of Transmission's Southwest and Rocky Mountain producer contracts. Bank approval of the availability of the additional $200 million is expected in March 1986.

Capital expenditures for 1985 totaled $220 million and are projected to be $310 million for 1986.

It is presently estimated that the Corporation will require approximately $300 million of long-term capital in 1986 primarily to finance the December 1986 installments due certain producers as a result of contract renegotiation. It is expected that $200 million of the above amount will be obtained by drawing down the additional amount available under the Production Loan previously discussed. The additional $100 million is likely to be obtained through the sale of debentures, common stock or a combination thereof. The Corporation anticipates being able to issue debentures and preferred stock under its Indenture and Certificate of Incorporation tests during the second quarter of 1986.

During 1985, the Corporation issued approximately 890,000 shares of its common stock under its Dividend Reinvestment Plan and its Payroll Stock Ownership Plan. Proceeds to the

Capitalization
(In Millions of Dollars)



Corporation were approximately $28.5 million. These plans will continue in 1986. Effective January 1, 1986, dividends reinvested through the Corporation's Dividend Reinvestment Plan are no longer eligible for exclusion from current taxable income as was previously permitted under the Economic Recovery Tax Act of 1981. Some withdrawals from the Dividend Reinvestment Plan are expected as a result of the expiration of this favorable tax treatment.

The Corporation received approval from the holders of its 15 3/8% Debentures, Series Due 1997, to amend the dividend restriction applying to such debenture series, and a 30th Supplemental Indenture was entered into on January 8, 1986. Such supplemental indenture increased the amount of retained earnings available for dividends and other capital stock distributions by approximately $157 million and provided that the Corporation may not redeem such debentures prior to June 1, 1988. As of December 31, 1985, the Corporation had $215 million of retained earnings available for preferred and common stock dividends under the most restrictive supplemental indenture test. The Corporation expects to have sufficient unrestricted retained earnings under the terms of its Indenture to continue the common and preferred stock dividends at their current levels.

In January 1986, the Corporation's debentures, preferred stock and commercial paper were upgraded by Moody's, Standard & Poor's and Duff & Phelps. Moody's upgraded the Corporation's debentures from Baa3 to Baa1, upgraded the Corporation's preferred stock from ba1 to baa2 and upgraded its commercial paper from P-3 to P-2. Standard & Poor's increased the Corporation's debenture rating from BBB– to BBB, its preferred stock rating from BBB– to BBB and its commercial paper rating from A-3 to A-2. Duff & Phelps increased the Corporation's debenture rating from 10 to 9 and increased its preferred stock rating from 12 to 10. These upgradings provide investment grade status for all of the Corporation's rated securities and have permitted the Corporation to regain access to the commercial paper market. Such upgradings are expected to reduce the cost of long and short-term borrowings. The Corporation expects to finance its working capital requirements during the remainder of 1986 through the issuance of its commercial paper.

The Corporation believes that it will have adequate capital resources to meet its liquidity requirements. These resources include (1) the additional $200 million expected to be available under Transmission's Production Loan, (2) sales of its commercial paper and the amounts available under the $500 million Credit Agreement, (3) authorized but unissued shares of capital stock of the Corporation and (4) additional senior debt capacity expected to be available under its Indenture during the second quarter of 1986 and thereafter.

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, 1985, there were 112,973 stockholders 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	*Market Price* High	Low	Close	*Quarterly Dividends Paid*
	$	$	$	¢
1985				
December 31	**40**	**32 1/2**	**39 1/2**	**79.5**
September 30	**34 3/8**	**30**	**32 5/8**	**79.5**
June 30	**32**	**27 1/4**	**32**	**79.5**
March 31	**34**	**26 3/4**	**27 1/2**	**79.5**
1984				
December 31	35	29 7/8	34	79.5
September 30	33 1/2	27	31 1/8	79.5
June 30	37	31 3/8	33 1/4	79.5
March 31	37 1/2	33	36 3/4	79.5

FINANCIAL SECTION

Contents

Comparative Gas Operations Data

The Columbia Gas System, Inc. and Subsidiaries

	1985	*1984**	*1983*	*1982*	*1981*
Gas Operating Revenues (in thousands)					
Residential	**$1,210,623**	$1,278,745	$1,357,686	$1,256,348	$ 997,741
Commercial	**566,608**	617,593	646,394	594,316	448,179
Industrial	**383,177**	592,084	841,891	938,120	951,720
Wholesale	**1,566,005**	1,843,234	2,032,807	2,074,838	1,804,515
Other	**12,195**	15,248	16,878	17,370	14,578
Total gas operating revenues	**$3,738,608**	$4,346,904	$4,895,656	$4,880,992	$4,216,733
Sales (million cu. ft.)					
Residential	**181,354**	188,471	207,225	230,325	237,486
Commercial	**91,579**	97,042	104,606	115,678	114,481
Industrial	**73,252**	108,124	151,034	202,591	269,772
Wholesale	**344,594**	384,967	409,070	502,382	578,521
Other	**4,238**	4,255	4,364	4,821	4,289
Total sales	**695,017**	782,859	876,299	1,055,797	1,204,549
Transportation gas volumes	**511,148**	423,427	262,798	198,004	196,403
Total throughput	**1,206,165**	1,206,286	1,139,097	1,253,801	1,400,952
Sources of Gas Sold (million cu. ft.)					
Total gas purchased	**616,919**	705,070	758,739	1,004,117	1,107,619
Total gas produced (natural and synthetic)	**101,020**	125,462	115,921	138,547	169,888
Exchange gas—net	**(10,346)**	(1,558)	(2,252)	(4,091)	1,601
Gas withdrawn from (delivered to) storage	**44,980**	(1,879)	46,062	(38,571)	(5,519)
Company use and other	**(57,556)**	(44,236)	(42,171)	(44,205)	(69,040)
Total sources of gas sold	**695,017**	782,859	876,299	1,055,797	1,204,549
Customers at Year-End					
Residential	**1,579,279**	1,564,460	1,744,883	1,744,178	1,746,774
Commercial	**141,859**	138,663	154,063	153,132	152,332
Industrial	**2,261**	2,280	2,450	2,546	2,546
Wholesale	**78**	75	86	86	85
Other	**40**	48	55	62	65
Total customers at year-end	**1,723,517**	1,705,526	1,901,537	1,900,004	1,901,802
Average Usage Per Customer (thousand cu. ft.)					
Residential	**114.8**	120.5	118.8	125.7	135.3
Commercial	**645.6**	699.8	679.0	719.9	756.5
Degree Days	**5,167**	5,410	5,381	5,271	5,474
Variation from normal (%)	**(3.9)**	0.1	0.3	(1.7)	2.1

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

Selected Financial Data

The Columbia Gas System, Inc. and Subsidiaries

(Dollars in thousands except per share amounts)	***1985***	*1984*	*1983*	*1982*	*1981*
Income Statement Data ($)					
Total revenues	**4,141,830**	4,644,662	5,101,536	5,095,239	4,465,600
Products purchased	**2,689,686**	3,099,319	3,586,139	3,720,871	3,145,012
Earnings (Loss) on common stock before discontinued operations and extraordinary charge	**(107,008)**	165,436	184,701	182,736	196,277
Earnings (Loss) on common stock	**(107,008)**	138,564	164,754	180,063	194,085
Per Share Data					
Earnings (Loss) per common share ($):					
Before discontinued operations and extraordinary charge	**(2.67)**	4.22	4.94	5.17	5.67
Earnings (Loss) on common stock	**(2.67)**	3.53	4.41	5.10	5.61
Dividends:					
Per share ($)	**3.18**	3.18	3.02	2.86	2.70
Payout ratio (%)	**N/M**	90.1	68.5	56.1	48.1
Average common shares (000)	**40,134**	39,227	37,401	35,328	34,597
Balance Sheet Data ($)					
Capitalization:					
Common stock equity	**1,422,688**	1,634,225	1,598,634	1,458,326	1,357,635
Preferred stock	**50,000**	50,000	50,000	—	—
Redeemable preferred stock	**70,000**	75,000	80,000	35,000	40,000
Long-term debt	**1,659,570**	1,348,484	1,420,075	1,468,894	1,324,025
Total capitalization	**3,202,258**	3,107,709	3,148,709	2,962,220	2,721,660
Total assets	**5,835,166**	5,200,536	5,238,355	5,155,190	4,643,259
Other Financial Data					
Capitalization ratio (%):					
Common stock equity	**44.4**	52.6	50.8	49.2	49.9
Preferred stock	**3.8**	4.0	4.1	1.2	1.5
Long-term debt	**51.8**	43.4	45.1	49.6	48.6
Capital expenditures ($)	**219,968**	272,009	210,941	584,057	592,002
Net cash from operations ($)	**(58,651)**	583,842	332,573	118,559	124,757
Book value per common share ($)	**35.10**	41.22	41.16	40.73	38.90
Return on average common equity before discontinued operations and extraordinary charge (%)	**N/M**	10.2	12.1	13.0	15.1
Average cost of long-term debt at year-end (%)	**9.4**	9.5	9.6	9.4	9.6

N/M = Not Meaningful

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 the matter 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 the 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 system of control, and a comprehensive program of internal audits designed, in total, to provide reasonable assurance regarding 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, 1985 and 1984 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, 1985. 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.

In our report covering the 1984 and 1983 consolidated financial statements of The Columbia Gas System, Inc. and subsidiaries dated February 6, 1985, we expressed an opinion on such consolidated financial statements which was qualified as being subject to the ultimate resolution of significant uncertainties relating to (a) the recovery of certain deferred gas costs and certain payments for gas costs which might have been required to be made applicable to the period prior to December 31, 1984 and (b) the ultimate outcome of the Federal Energy Regulatory Commission (FERC) proceedings reviewing the gas acquisition policies and practices of Columbia Gas Transmission Corporation (Transmission) to determine whether such policies and practices constituted an "abuse" under the Natural Gas Policy Act. As discussed in Note 4A of the accompanying notes to consolidated financial statements, during 1985 Transmission established a reserve of $400 million for deferred gas costs estimated to be nonrecoverable. In addition, as discussed in Note 2A, Transmission and its customers reached an agreement settling the FERC proceedings investigating Transmission's gas acquisition policies and practices. Such settlement does not require a refund obligation by Transmission. Accordingly, our present opinion on the 1984 and 1983 consolidated financial statements, as presented herein, is unqualified with respect to these two matters.

As discussed in Note 12E, Columbia LNG Corporation's liquefied natural gas terminal has not been utilized since 1980, and utilization of the facility in the near-term is not presently anticipated by management. A portion of the investment in the facility is currently being recovered through rates. Although the competitive environment within the gas industry has accelerated and future economic conditions are uncertain, management believes that the remaining investment ($86 million) will be recovered through the resumption of trade, appropriate rate relief, lease of the facility or sale.

In our opinion, subject to the effect on the 1985 consolidated financial statements, of such adjustments, if any, as might have been required had the outcome of the matter discussed in the preceding paragraph 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, 1985 and 1984, and the results of their operations and changes in financial position for each of the three years in the period ended December 31, 1985, in conformity with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen & Co.

February 5, 1986

Statements of Consolidated Income

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	**1985**	*1984*	*1983*
Revenues			
Operating revenues			
Gas	**$3,738,608**	$4,346,904	$4,895,656
Other	**313,934**	246,478	179,429
Other income			
Other (Note 13)	**40,964**	51,280	26,451
Gains on reacquired debt previously deferred (Note 3)	**48,324**	—	—
Total revenues	**4,141,830**	4,644,662	5,101,536
Expenses			
Products purchased			
Natural gas	**2,601,961**	2,887,581	3,178,495
Other	**87,725**	211,738	407,644
Provision for unrecovered gas costs (Note 4A)	**400,000**	—	—
Operation	**519,106**	493,383	477,827
Maintenance	**77,982**	78,405	79,318
Depreciation and depletion	**267,597**	251,019	203,111
Other taxes	**195,030**	198,144	210,046
Interest and related charges (Note 14)	**159,003**	139,387	167,628
Loss on synthetic gas operations (Note 4C)	**—**	57,700	—
Write-down of Alaskan pipeline investment (Note 4B)	**—**	4,844	18,194
Total expenses	**4,308,404**	4,322,201	4,742,263
Income (Loss) from Continuing Operations before Income Taxes	**(166,574)**	322,461	359,273
Income taxes			
Continuing operations	**(110,103)**	142,697	165,591
Discontinued application of SFAS 71 (Note 3)	**37,361**	—	—
Income (Loss) from Continuing Operations	**(93,832)**	179,764	193,682
Discontinued coal mining operations (Note 5)			
Loss from operations	**—**	3,172	2,652
Estimated loss on disposal	**—**	23,700	—
Income (Loss) before Extraordinary Charge	**(93,832)**	152,892	191,030
Extraordinary charge (Note 6)	**—**	—	17,295
Net Income (Loss)	**(93,832)**	152,892	173,735
Preferred stock dividend	**13,176**	14,328	8,981
Earnings (Loss) on Common Stock	**$ (107,008)**	$ 138,564	$ 164,754
Earnings (Loss) Per Share of Common Stock			
(based on average shares outstanding)			
Continuing operations	**$ (2.67)**	$ 4.22	$ 4.94
Discontinued operations	**—**	.69	.07
Before extraordinary charge	**(2.67)**	3.53	4.87
Extraordinary charge	**—**	—	.46
Earnings (loss) on common stock	**$ (2.67)**	$ 3.53	$ 4.41
Dividends Per Share of Common Stock	**$ 3.18**	$ 3.18	$ 3.02
Average Common Shares Outstanding (thousands)	**40,134**	39,227	37,401

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)*	*1985*	*1984*
Property, Plant and Equipment		
Gas utility and other plant, at original cost	**$4,745,957**	$4,615,731
Accumulated depreciation and depletion	**(2,244,318)**	(2,071,037)
	2,501,639	2,544,694
Oil and gas producing properties, full cost method		
United States cost center	**975,146**	977,090
Canadian cost center ($54,000,000 and $52,500,000 respectively, not being amortized) (Note 1D)	**194,187**	179,874
Accumulated depletion	**(452,779)**	(415,631)
	716,554	741,333
Net property, plant and equipment	**3,218,193**	3,286,027
Investments and Other Assets		
Gas supply prepayments and advances (Note 7)	**927,336**	150,869
Unconsolidated affiliates	**37,641**	42,231
Net assets of discontinued coal segment (Note 5)	**12,871**	11,138
Other	**42,705**	65,349
Total investments and other assets	**1,020,553**	269,587
Current Assets		
Cash and temporary cash investments	**58,990**	56,370
Accounts receivable		
Customers (less allowance for doubtful accounts of $5,447,000 and $9,355,000, respectively)	**568,946**	479,809
Other	**79,199**	105,240
Income tax refunds	**129,113**	—
Gas inventory	**284,003**	428,343
Other inventories—at average cost	**46,956**	41,800
Deferred gas purchased costs	**9,558**	6,276
Prepayments	**64,681**	65,012
Other	**131,187**	80,371
Total current assets	**1,372,633**	1,263,221
Deferred Charges		
Gas purchased costs, noncurrent (Note 4A)	**141,164**	321,114
Other	**82,623**	60,587
Total deferred charges	**223,787**	381,701
Total Assets	**$5,835,166**	$5,200,536

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

Capitalization and Liabilities *As of December 31 (in thousands)*	***1985***	*1984*
Common Stock Equity		
Common stock, par value $10 per share—outstanding 40,529,872 and 39,641,839 shares, respectively	**$ 405,299**	$ 396,419
Additional paid in capital	**263,259**	243,674
Retained earnings	**769,321**	1,005,305
Accumulated foreign currency translation adjustment	**(15,191)**	(11,173)
Total common stock equity	**1,422,688**	1,634,225
Preferred Stock (Note 8)	**50,000**	50,000
Redeemable Preferred Stock (Note 8)	**70,000**	75,000
Long-Term Debt and Capitalized Lease Obligations (Note 10)	**1,659,570**	1,348,484
Total capitalization	**3,202,258**	3,107,709
Current Liabilities		
Bank loans	**418,000**	—
Current maturities of long-term debt and preferred stock	**336,132**	73,088
Accounts and drafts payable	**349,514**	497,491
Accrued taxes	**83,221**	85,980
Accrued interest	**41,713**	34,212
Estimated rate refunds	**35,653**	25,028
Deferred income taxes	**164,772**	183,802
Estimated supplier obligations	**244,828**	267,242
Other	**164,700**	174,757
Total current liabilities	**1,838,533**	1,341,600
Deferred Credits		
Income taxes, noncurrent	**679,152**	613,296
Investment tax credits	**54,848**	50,919
Other	**60,375**	87,012
Total deferred credits	**794,375**	751,227
Commitments and Contingencies (Notes 2 and 12)		
Total Capitalization and Liabilities	**$5,835,166**	$5,200,536

Consolidated Statements of Changes in Financial Position

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	**1985**	*1984*	*1983*
Cash From Operations			
Income (loss) from continuing operations	**$(93,832)**	$179,764	$193,682
Items not requiring (providing) cash:			
Depreciation and depletion	**267,597**	252,557	204,021
Deferred income taxes, noncurrent and investment credits	**73,125**	62,280	72,629
Nonrecurring charges—net	**48,038**	38,083	18,194
Amortization of prepayments for producer contract modifications	**42,322**	—	—
Other—net	**483**	(1,353)	574
Net change in working capital (increase) (Note 15)	**(256,030)**	193,997	(36,037)
Cash from continuing operations	**81,703**	725,328	453,063
Dividends	**(140,354)**	(138,671)	(120,497)
Net cash from continuing operations	**(58,651)**	586,657	332,566
Discontinued operations	**—**	(2,815)	7
Net cash from operations	**(58,651)**	583,842	332,573
External Financing Activities			
Retirement of long-term debt and preferred stock	**(76,663)**	(53,051)	(96,396)
Issuance of common stock	**28,465**	25,490	89,854
Issuance of preferred stock	**—**	—	100,000
Production loan	**150,000**	—	—
Increase (decrease) in short-term bank loans and commercial paper	**418,000**	(253,300)	(199,510)
Net external financing activities	**519,802**	(280,861)	(106,052)
Capital Investment Activities			
Capital expenditures	**(219,968)**	(272,009)	(210,941)
Gas supply prepayments and advances—net	**(321,172)**	(34,733)	22,324
Sale of subsidiary	**—**	30,187	—
Net capital investment activities	**(541,140)**	(276,555)	(188,617)
Other—net	**82,609**	614	(23,064)
Increase in Cash and Temporary Cash Investments	**$ 2,620**	$ 27,040	$ 14,840

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

(in thousands)	Common Stock* Shares Outstanding	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Foreign Currency Translation Adjustment
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 8)				(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)	
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 8)				(5,692)	
Common stock issued:					
Dividend reinvestment plan	737	7,365	16,172	(4)	
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)
Net Income (Loss)				(93,832)	
Dividends:					
Common ($3.18 per share)				(127,178)	
Preferred:					
10.96% Series B				(2,968)	
10.24% Series C				(5,120)	
Adjustable rate Series D (Note 8)				(5,088)	
Common stock issued:					
Dividend reinvestment plan	841	8,407	18,516		
Employee stock ownership plan	47	473	1,069		
Other				(1,798)	(4,018)
Balance at December 31, 1985**	**40,530**	**$405,299**	**$263,259**	**$769,321**	**$(15,191)**

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

***$554,351,000 of retained earnings is not available for cash dividends and other capital stock distributions at December 31, 1985.*

Statements of Consolidated Taxes

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	**1985**	1984	1983
Income Taxes			
Currently payable:			
Federal	**$(110,752)**	$95,919	$(10,888)
State	**(9,186)**	7,269	2,618
Investment credits*	**(12,362)**	(14,151)	(15,859)
Total currently payable	**(132,300)**	89,037	(24,129)
Deferred:			
Federal	**51,796**	43,309	172,557
State	**472**	3,775	10,523
Foreign	**1,899**	1,789	1,860
Total deferred	**54,167**	48,873	184,940
Deferred investment credits, net	**3,929**	2,918	3,325
Provision for employee stock ownership plan	**1,462**	1,869	1,455
Income taxes included in income from continuing operations	**(72,742)**	142,697	165,591
Federal income taxes—discontinued operations:			
Current	**—**	(3,059)	(4,561)
Deferred	**—**	(19,832)	2,292
Deferred Federal income taxes—extraordinary charge	**—**	—	(3,131)
Total income taxes	**(72,742)**	119,806	160,191
Other Taxes			
Property	**52,921**	50,044	52,041
Gross receipts	**107,630**	114,619	131,314
Payroll	**21,299**	20,051	18,512
Other	**13,180**	13,430	8,179
Other taxes included in income from continuing operations	**195,030**	198,144	210,046
Other taxes—discontinued operations	**—**	153	290
Total other taxes	**195,030**	198,297	210,336
Total Tax Expense	**$ 122,288**	$318,103	$370,527

Includes Employee Stock Ownership Plan investment credits of $1,462,000, $1,869,000 and $1,455,000, respectively.

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

Year Ended December 31, (in thousands)	1985		1984		1983	
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)*	**$ (166,574)**		$272,700		$333,926	
Tax expense at statutory Federal income tax rate	**$ (76,624)**	**(46.0)%**	$125,442	46.0%	$153,606	46.0%
Increases (reductions) in taxes resulting from—						
State income taxes, net of Federal income tax benefit	**(5,649)**	**(3.4)**	5,767	2.1	6,878	2.1
Investment credits not deferred and amortization of credits deferred in prior years	**(6,971)**	**(4.2)**	(9,364)	(3.4)	(11,079)	(3.3)
Depreciation expense for accounting purposes over amounts claimed for income tax purposes	**7,153**	**4.3**	4,356	1.5	6,812	2.0
Extraordinary charge taxed at less than statutory rate	**—**	**—**	—	—	6,265	1.9
Discontinuing SFAS 71 (Note 3)**	**15,133**	**9.1**	—	—	—	—
Other	**(5,784)**	**(3.5)**	(6,395)	(2.3)	(2,291)	(0.7)
Total Income Taxes	**$ (72,742)**	**(43.7)%**	$119,806	43.9%	$160,191	48.0%

**Includes income from foreign operations of $4,301,000, $5,058,000 and $5,123,000, respectively.*

***Includes $24.4 million of previously unprovided deferred taxes related to depreciation expense claimed for income tax purposes in excess of depreciation recorded for accounting purposes and $(9.3) million related to nontaxable gains on reacquired debt.*

	1985	1984	1983
Deferred Income Taxes Deferred income taxes result from timing differences in 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	**$ 1,460**	$ (12,922)	$ 33,694
Depreciation expense	**52,698**	34,790	45,306
Deferred gas purchased costs	**(48,954)**	10,253	67,989
Estimated rate refunds	**(862)**	12,186	12,045
Unbilled utility revenue	**5,453**	(15,640)	20,227
Gains on reacquired debt	**12,961**	—	—
Loss on synthetic gas operations	**12,565**	(15,287)	—
Other	**18,846**	15,661	4,840
Total Deferred Income Taxes	**$ 54,167**	$ 29,041	$184,101*

**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.

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 recorded as Other Income in the Statements of Consolidated Income.

All appropriate intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to the 1984 and 1983 financial statements to conform to the 1985 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 related to rate regulated subsidiaries 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 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, (%)	***1985***	*1984*	*1983*
Transmission property	**4.4**	4.0	4.0
Distribution property	**3.4**	2.9	3.1
Other property	**8.0**	7.4	7.2

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 in accordance with Statement of Financial Accounting Standards No. 34. 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, (%)	***1985***	*1984*	*1983*
Allowance for funds used during construction	**10.79**	12.75	9.75
Interest during construction	**9.70**	9.90	9.60

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 cost center to the extent they do not exceed the estimated present value of the following: (1) the cost center's future oil and gas revenues; (2) plus the value of unproved properties; and (3) reduced by estimated future operating expenses and development costs. Should costs exceed the estimated present value, the 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 and/or valuation attributable to the properties. The 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:

($ in thousands)	***1985***	*1984*	*1983*	*Prior Years*	*Total*
Acquisition costs	**—**	—	—	300	300
Exploration costs	**3,800**	5,500	6,200	23,200	38,700
Interest capitalized	**3,600**	3,100	1,300	7,000	15,000
Total	**7,400**	8,600	7,500	30,500	54,000

Columbia owns varying interests in 4.0 million gross acres (0.6 million net) offshore Labrador and Newfoundland. Approximately 5.7 million gross acres (0.8 million net) were evaluated and surrendered during 1985 to the Canadian federal government. Net costs (initially incurred in 1972) excluded from depletion amounted to $48.1 million at December 31, 1985. (Reference is made to the foregoing report to stockholders for additional information.)

Columbia also owns varying interests in 5.9 million gross acres (0.5 million net) in the Arctic Islands and Northwest Territories. Net costs (initially incurred in 1971) excluded from depletion were $5.9 million at December 31, 1985. Management estimates that development of gas reserves attributable to these properties will occur in the mid 1990's.

E. Gas Inventory. Current inventory is carried at cost on a last-in, first-out basis (LIFO). Prior to 1985, liquidation of LIFO layers did not affect income since the effect was deferred and reflected in future customer rates through purchased gas adjustments. Due to a settlement agreement between Columbia Gas Transmission Corporation and its customers (as more fully described in Note 2A), a portion of the effect of such liquidation, if any, during the settlement period ending March 31, 1987, may be deferred and reflected in future customer rates. During 1985, 73.5 Bcf of gas inventory was liquidated at an average cost of $3.31 per Mcf. The estimated replacement cost of gas inventory in excess of carrying amounts was $258.8 million at December 31, 1985.

F. Income Taxes and Investment Tax Credits. The Corporation's subsidiaries record income taxes, including provisions to recognize full interperiod tax allocations which arise from timing differences in the recognition of revenues and expenses for income tax and 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 $154.1 million at December 31, 1985 principally related to accelerated depreciation income tax deductions of the Corporation's gas distribution subsidiaries.

Investment tax credits are 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 judgment 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 Gas Purchased 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, except as noted in Note 3.

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. Accounting for Pension Costs and Other Post-retirement 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 $22,800,000 in 1985, $31,600,000 in 1984, and $31,500,000 in 1983. The reduction in 1985 pension expense resulted from a change in several actuarial assumptions, the most significant being an increase in the assumed earnings rate on plan assets from 7% to 8%.

The following table compares accumulated benefits and assets of the plans in accordance with disclosure requirements established by the Financial Accounting Standards Board (FASB).

At December 31, ($ in thousands)	***1985***	*1984*
Actuarial present value of accumulated benefits:		
Vested	**462,700**	398,900
Nonvested	**11,600**	8,200
Total	**474,300**	407,100
Net assets available for benefits	**560,300**	456,100

The average assumed rate of return used in determining the actuarial present value of accumulated benefits was 8.0% as of December 31, 1985 and 9.0% as of December 31, 1984. 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 impact of favorable market conditions on the plan investments improved the value of net assets available for benefits in 1985.

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 valued at a specific point in time. This approach does not consider the participant's expected future service, increased pay levels and the impact of other actuarial assumptions.

However, in determining the actuarial present value of accumulated benefits under the plan's annual valuation, estimated 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 based upon an assumed earnings rate of 8% in 1985. This resulted in a net actuarial surplus of approximately $60 million at December 31, 1985. Future pay increases, changes in Social Security benefits, growth in assets at 8%, amortization of unfunded actuarial liabilities and actuarial gains and/or losses are also recognized in determining annual pension costs.

In December 1985, the FASB issued new standards on employers' accounting and reporting for pensions. Various provisions of the new standards must be adopted in 1986 and 1987 and restatement of the financial statements included herein is not permitted. Preliminary evaluation indicates that the adoption of the new standards should not have a material effect on the Corporation's results of operations and financial position.

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 $5,623,000 in 1985, $5,650,000 in 1984 and $5,111,000 in 1983.

K. Accounting For Leases. The Corporation's gas distribution subsidiaries adhere to Statement of Financial Accounting Standards No. 71 by capitalizing financing leases initiated since January 1, 1983. The other subsidiaries have capitalized financing leases. Capitalized lease costs, included principally in Gas Utility and Other Plant, are amortized ratably over the lease term and charged to depreciation expense. Payments made in connection with operating leases, including certain pre-January 1, 1983 leases which have not been capitalized, are charged to operation and maintenance expenses as incurred. Such amounts were $ 31,400,000 in 1985, $42,600,000 in 1984 and $46,000,000 in 1983.

2. Regulatory Matters

A. Wholesale Rate Settlement. In the first quarter of 1985, Columbia Gas Transmission Corporation (Transmission), whose gas acquisition policies and practices for all purchased gas adjustment periods (PGA) subsequent to February 1982 were under review by the Federal Energy Regulatory Commission (FERC), reached a settlement with its customers and other parties resolving more than 20 dockets pending before the FERC. The complex settlement agreement was approved by the FERC in orders issued on June 14 and June 25, 1985. Petitions for rehearing of the orders have been filed by certain intervenors and are presently pending before the FERC.

The settlement of the FERC proceedings resolves the long-standing protests by certain of Transmission's customers and other parties over Transmission's purchases of high-cost gas. Management, while continuing to believe that

Transmission's gas acquisition practices were prudent, pursued a settlement of the disputes to avoid lengthy litigation and to permit management to devote full attention to changing market conditions.

Under the terms of the settlement agreement, Transmission lowered its commodity rate by 11.5% effective April 1, 1985. Transmission will incur certain refund obligations if it achieves average gas purchased costs below a designated level for the twelve months ended March 31, 1987. Transmission will have no refund obligation relating to gas acquisition policies and practices for the period March 1982 through March 1987. Its refund obligation related to PGA proceedings for the period between March 1981 and February 1982, which have been remanded to the FERC by a U.S. Court of Appeals, is limited to $1 million.

At December 31, 1985, Transmission had deferred certain unrecovered costs related to gas purchased prior to April 1, 1985, pending future rate recovery (as more fully discussed in Note 4A). Under the terms of the settlement agreement, Transmission is permitted to recover up to $600 million of such costs. Recovery is permitted during the settlement period should gas purchased costs be reduced below a specified rate and also over a seven-year period commencing September 1, 1987, subject to a formula which compares Transmission's gas costs to gas costs incurred by Transmission's five major pipeline suppliers.

B. Tax Allowance in Wholesale Rates. In June 1983, the FERC issued an order which confirmed its existing 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 subsidiaries since December 15, 1975, was proper. An opposing party, after exhausting administrative and lower court appeals, has filed a Petition for Writ of Certiorari in the U.S. Supreme Court. The Supreme Court has not as yet ruled on that petition. In the opinion of management, the petition has no merit and the existing FERC policy will continue.

3. Discontinuance of Application of Statement of Financial Accounting Standards No. 71

Statement of Financial Accounting Standards No. 71 (SFAS 71) requires, among other things, accounting and reporting of assets and liabilities consistent with the economic effects of the manner in which regulators establish rate levels. There are certain criteria for application of SFAS 71, which include a requirement for cost-based rates. Transmission's settlement agreement discussed in Note 2A, provides for, among other items, a negotiated commodity rate and the discontinuance of a purchased gas adjustment mechanism for the commodity portion of its gas costs during the primary settlement period. Because of this and the competitive environment in the pipeline industry, together with Transmission's December 1985 acceptance of recently promulgated FERC rules related to open access transportation, management has concluded that it is no longer appropriate to continue application of the financial reporting and accounting requirements of SFAS 71 for its interstate transmission operations. The accounting adjustments which are necessary to reflect the changed economic environment improved 1985 earnings by $11 million ($0.27 per share) as follows:

($ in millions)

Gains on reacquired debt previously deferred and amortized in accordance with rate treatment (net of deferred income taxes of $12.9 million)	35.4
Provision for previously unprovided deferred taxes	(24.4)
Increase in earnings	11.0

The Corporation's gas distribution subsidiaries continue to meet the criteria and to follow the accounting requirements of SFAS 71.

4. Nonrecurring Items

A. Deferred Gas Purchased Costs. At December 31, 1985, Transmission had deferred $541.2 million of unrecovered costs related to gas purchased prior to April 1, 1985. Under the terms of the settlement agreement described in Note 2A, Transmission is permitted to recover such costs under specified conditions. Since in management's opinion, the settlement agreement does not provide adequate assurance that all of these costs will be recoverable in the future, Transmission recorded a pre-tax nonrecurring charge in the first quarter of 1985 of $400 million, establishing a reserve for unrecovered gas purchased costs. In management's opinion, based on current studies, Transmission will be able to recover the unreserved gas purchased costs of $141.2 million during the primary term of the settlement agreement.

B. Alaskan Pipeline Investment. Reserves totaling $18.2 million were recorded in 1983 to reflect impairment of investments in delayed partnership projects to build pipeline systems to bring Alaskan gas to the lower 48 states. The remaining investment of $4.8 million was written off in 1984 following management's decision to withdraw from the partnership.

C. Synthetic Gas Operations. At the end of 1983, negotiations were in progress between Dome Petroleum Ltd. (Dome) and Columbia LNG Corporation (Columbia 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 Columbia LNG at a substantially reduced price and volume and agreements were reached with customers for the purchase of the synthetic gas from Columbia LNG. However, near-term market conditions necessitated a sales price insufficient 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. During 1985, the parties agreed to a continuation of the amended agreements into 1986 on a basis that guaranteed that Columbia LNG would not incur any additional losses. Under the terms of the agreement, Columbia LNG has terminated the supply contract with Dome effective March 31, 1986. No additional losses are anticipated in connection with operations nor with the dismantling of the synthetic gas facility.

5. Discontinued Operations

A decision to discontinue coal mining operations at the Wayne County, West Virginia, coal mine resulted in a provision for loss of $20 million (net of $17 million income tax benefits) recorded in the fourth quarter of 1984. A provision was also recorded for costs related to the disposal of the mine of $3.7 million (net of income tax benefits of $3.2 million). Losses from operations were $3.2 million in 1984 and $2.7 million in 1983 (net of income taxes of $2.7 million and $2.3 million, respectively). Revenues from mining operations were $3.3 million in 1983. Efforts are continuing to dispose of the net assets related to Columbia's interest in the mine.

6. Extraordinary Charge

The extraordinary charge recorded in 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. The extraordinary charge of $17.3 million represents the net loss sustained upon the sale of $20.4 million offset by $3.1 million of income tax benefits. The sale of the subsidiary was completed on June 21, 1984.

7. Gas Supply Prepayments and Advances

The following prepayments and advances represent payments and obligations to producers and pipeline suppliers in connection with gas supply:

At December 31, ($ in thousands)	**1985**	*1984*
Gas supply advances	**31,889**	7,440
Gas supply prepayments	**279,549**	143,429
Prepayments for producer contract modifications	**615,898**	—
Total	**927,336**	150,869

A. Gas Supply Advances. Advances have been made to certain producers in return for the right to purchase gas from future exploration and/or development drilling. The advances are repayable under the terms specified in each contract.

B. Gas Supply Prepayments. Prepayments are based upon the take-or-pay provisions of the various producer and pipeline supplier contracts. They are recoupable through future deliveries of gas and/or cash payments.

C. Prepayments for Producer Contract Modifications. Prepayments have been made to certain producers in return for contract modifications as more fully described in Note 12B. The carrying amount represents the unamortized balance of obligations incurred in 1985 including the present value of future payments (see Note 10(c)). The prepayments are being amortized on a volumetric basis over a ten-year period, the primary period of benefit.

8. Preferred Stock

As of December 31, 1985, the Corporation had authorized 10,000,000 shares of preferred stock, $50.00 par value, and had outstanding 500,000 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 which is 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 million) per year, resulting in a maximum aggregate cash requirement of $25 million 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 $53.95.

The Series C Preferred Stock is subject to a mandatory sinking fund of 100,000 shares ($5 million) per year beginning on May 31, 1989, resulting in a maximum aggregate cash requirement of $10 million 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 $55.12 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 7-1/2% or more than 13-1/2% per annum. The rates used for each quarterly period were as follows:

Quarter Ended (%)	***1985***	*1984*	*1983*
November	**9.75**	11.65	10.625
August	**10.45**	12.30	10.625
May	**10.30**	10.75	—
February	**10.70**	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.

9. Long-Term Incentive Plan

In September 1985, the Board of Directors approved a Long-Term Incentive Plan. At December 31, 1985, subject to approval of the Securities and Exchange Commission and of the Corporation's stockholders, a total of 1,500,000 shares of the Corporation's common stock was reserved for issuance under the plan. On December 17, 1985, certain employees were granted Incentive Stock Options, Nonqualified Stock Options, and Nonqualified Stock Options with Stock Appreciation Rights at a unit price of $38.31, $38.30, and $38.30, respectively. On December 17, 1986, 50% of each employee's options will become exercisable and the remaining 50% will become exercisable on December 17, 1987. Employees will have 10 years to exercise the options. Contingent stock awards were also granted, without cost to the recipients, with the restrictions lapsing on December 17, 1987.

Options and Awards Granted and Outstanding At December 31, 1985	*Shares*
Incentive stock options	153,400
Nonqualified stock options	5,550
Nonqualified stock options with stock appreciation rights	6,100
Contingent stock awards	12,950

10. 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)	*1985*	*1984*
The Columbia Gas System, Inc.		
Debentures:		
5 1/8% Series due June 1986	—	9,070
4 1/2% Series due June 1987	**7,500**	8,333
4 5/8% Series due August 1987	**5,903**	5,903
4 3/8% Series due November 1987	**9,000**	10,050
4 3/8% Series due January 1988	**7,500**	8,375
4 5/8% Series due May 1989	**18,500**	20,166
4 5/8% Series due October 1989	**14,800**	16,200
9 5/8% Series due November 1989	**22,500**	30,000
4 5/8% Series due May 1990	**16,200**	17,571
4 7/8% Series due October 1990	**16,200**	17,600
6 1/4% Series due October 1991	**17,600**	19,000
6 5/8% Series due October 1992	**11,875**	12,750
7 1/4% Series due May 1993	**25,500**	27,250
7% Series due October 1993	**20,400**	21,800
9% Series due October 1994	**27,250**	29,000
8 3/4% Series due April 1995	**23,200**	24,600
9 1/8% Series due October 1995	**29,000**	30,750
10 1/8% Series due November 1995	**42,100**	46,800
8 3/8% Series due March 1996	**46,125**	48,688
9 1/8% Series due May 1996	**46,800**	51,500
8 1/4% Series due September 1996	**36,900**	39,000
7 1/2% Series due March 1997	**32,496**	34,250
7 1/2% Series due June 1997	**38,942**	41,042
15 3/8% Series due June 1997	**100,000**	100,000
7 1/2% Series due October 1997	**39,000**	41,100
7 1/2% Series due May 1998	**34,250**	36,000
10 1/4% Series due May 1999	**65,000**	70,000
9 7/8% Series due June 1999	**28,800**	30,200
11 3/4% Series due October 1999	**81,250**	87,500
12 3/4% Series due August 2000	**87,500**	93,750
	952,091	1,028,248
Unamortized debt discount, less premium	**(5,575)**	(6,427)
	946,516	1,021,821
Revolving credit agreement[(a)]	**300,000**	300,000
Subsidiary debt:		
Production loan[(b)]	**150,000**	—
Contract modification obligation[(c)]	**225,718**	—
Other	**7,393**	8,949
Capitalized lease obligations	**29,943**	17,714
Total long-term debt and capitalized lease obligations	**1,659,570**	1,348,484

[(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 1/2% 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.

[(b)]Under the terms of the Limited Recourse Loan Agreement, (Production Loan) Transmission has available up to $350 million on a revolving basis through October 14, 1987, with (subject to maintenance of adequate oil and gas reserves) any borrowings outstanding at the end of that period being repayable in twenty equal quarterly installments from October 15, 1987, to July 15, 1992. Transmission pays a fee equal to the sum of (i) 1/2% per annum on the daily average unused available commitment and (ii) 3/8% per annum on the daily average unavailable commitment (the availability subject to certain conditions, including satisfactory price relief of its high-cost gas with Southwest and Rocky Mountain area producers) to October 15, 1987, and the amount may be prepaid and reborrowed at any time in whole or in part. The notes bear interest according to various rate options (based on the prime rate, bank certificates of deposit, the London InterBank Offered Rate, and/or Fixed Rate Options) to be selected by the company for various time periods.

[(c)]As discussed in Note 12B, the Contract Modification Obligation is a noninterest bearing liability which has been discounted based on an imputed interest rate of 9.5% compounded semi-annually, as follows:

($ in thousands)	*Total Payments*	*Interest Component*	*Principal*
Total Contract Modification Obligation	539,328	65,940	473,388
Less Current Maturities	269,664	21,994	247,670
Long-Term Obligation	269,664	43,946	225,718

The aggregate maturities of long-term debt and capitalized lease obligations, for the five years ending December 31, 1990, are as follows:

($ in thousands)	
1986	331,132*
1987	340,256**
1988	112,902
1989	133,301
1990	118,338

* *Excludes prepayments of $9,456,000*
** *Excludes prepayments of $159,000*

The Corporation has from time to time satisfied sinking fund requirements through open market purchases.

11. Short-Term Borrowings And Compensating Balances

The short-term financing requirements of the Corporation and its subsidiaries are met through the sale by the Corporation of commercial paper and/or through borrowings under bank lines of credit. The commercial paper is sold through dealers at prevailing market rates of interest in maturities normally ranging from one to seven months. The bank loans are at money market rates, ranging from one day to three months. When commercial paper is outstanding, it is supported by unused bank lines of credit. Compensation for the credit lines during 1985 was by a fee paid to the participating banks. In prior years, such compensation was either by fees or through the maintenance of minimum cash balances.

Year Ended December 31, ($ in thousands)	***1985***	*1984*	*1983*
Maximum outstanding:			
Commercial paper	**—**	303,500	489,800
Bank loans	**418,000**	—	—
Minimum outstanding:			
Commercial paper	**—**	—	204,800
Bank loans	**—**	—	—
Daily average outstanding:			
Commercial paper	**—**	26,300	320,500
Bank loans	**86,700**	—	—
Interest rates:			
Commercial paper	**—**	8.8%-10.1%	8.1%-10.8%
Bank loans	**8.9%-9.2%**	—	—
Weighted daily average rate:			
Commercial paper	**—**	9.6%	9.1%
Bank loans	**9.0%**	—	—
Weighted average rate at year-end:			
Commercial paper	**—**	—	9.6%
Bank loans	**9.1%**	—	—
Weighted average maturity at year-end (days):			
Commercial paper	**—**	—	23.4
Bank loans	**26.8**	—	—
Credit lines at year-end	**518,000**	525,000	525,000
Less—outstanding commercial paper/bank loans	**418,000**	—	253,000
Unused credit lines	**100,000**	525,000	272,000
Approximate compensating balances at year-end	**—**	2,870	5,500

12. Other Commitments And Contingencies

A. Capital Expenditures. Capital expenditures for 1986 are estimated at $310 million. Of this amount, $69 million is for transmission operations, $86.6 million for distribution operations, $151 million for oil and gas operations and $3.4 million for other operations.

B. Producer Negotiations and Settlement Plan. 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. In addition, Transmission took actions in 1984 and 1985 to limit the price it would pay and the quantities it would take of higher-priced Appalachian gas resulting in court challenges by four Appalachian producers. To date, Transmission has successfully renegotiated a number of contracts with Appalachian and Southwest producers including eleven of the Southwest producers who filed court actions. Such settlements have resulted in resolution of past take-or-pay obligations and other considerations and in some cases, reductions in future take-or-pay levels and prices. Progress is being made toward additional settlements with producers including some of the producers who filed court actions.

These settlements, for the most part, resolved past disputes but still left Transmission with contracts for volumes and prices in excess of current market requirements and market clearing levels. Therefore, in the second quarter of 1985, Transmission announced a major program offering payments totaling $800 million to 22 Southwest and Rocky Mountain area producers in exchange for the needed contract modifications. Transmission has reached agreement with producers whose contracts cover more than 80% of the volumes of high-cost gas affected by the program. The amendments provide for reduced prices, periodic price redeterminations beginning January 1986 and lower volumes of gas which Transmission must take or pay for. Under the terms of the agreements, Transmission made payments to the producers totaling $122.9 million in December 1985 and expects to make additional payments of $12 million early in 1986. Transmission is obligated to make payments of $269.7 million by December 1, 1986 and another $269.7 million by December 1, 1987. Transmission will be obligated to make additional installment payments up to $125.7 million should the remaining producers agree to participate in the program.

The obligations to make the 1986 and 1987 installment payments are secured by a pledge of Transmission's bonds held by a special purpose subsidiary of the Corporation. The bonds are secured by a mortgage on Transmission's assets. In addition, the Corporation has guaranteed the payment of the 1986 and 1987 installments. Such guarantee is subordinated to the Corporation's debentures and bank loans. Also, in connection with contract modifications, Transmission has agreed to indemnify producers against certain potential liabilities that may be incurred by them as a result of the contract modifications. In management's opinion, these indemnifications will not result in liabilities that will have material adverse affects on the consolidated financial condition of the Corporation and its subsidiaries.

C. Assets Under Lien and Other Guarantees. As a result of the producer contract modifications and Transmission's other financing activities in 1985, substantially all of Transmission's tangible assets, having a book value of approximately $1.3 billion, have been pledged as security under various mortgages and financing agreements.

In connection with such financing, the Corporation has made certain senior guarantees and a subordinated guarantee of the interest and principal of loans related to Transmission's $350 million Production Loan (as more fully described in Note 10).

D. Liquefied Natural Gas Pricing. In 1982, the U.S. Court of Appeals for the D.C. Circuit vacated the Economic Regulatory Administration's (ERA) Opinion and Order No. 11 issued in 1979, approving applications filed by 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. The U.S. Court of Appeals denied a petition for review of the ERA Order in 1985 and Suggestion for Rehearing in January 1986. In the opinion of management, this should terminate the refund issue.

E. Cove Point LNG Terminal. Deliveries of liquefied natural gas to Columbia LNG Corporation's Cove Point LNG terminal were terminated in April 1980 due to 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. Subsequent to the cessation of deliveries, Columbia LNG invoked the minimum bill provision of its tariff, which specifically provides for recovery of operation and maintenance expenses, taxes and debt service.

The co-owner of the Cove Point facility filed with the FERC in November 1982 for approval to abandon its interest in the facility and to recover the remaining investment over a ten-year period. As a result of this filing, the 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. Discussions between the parties regarding the abandonment application are continuing in an effort to resolve this matter.

The minimum bill tariff provides for recovery of a portion of the investment in the Cove Point facility. Although the competitive environment within the gas industry has accelerated and future economic conditions are uncertain, management believes that the remaining investment of $86 million will be recovered through the resumption of trade, appropriate rate relief, lease of the facility, or sale. Utilization of the facility in the near-term is not presently anticipated.

F. Legal Proceedings. The Corporation and its subsidiaries have been named as defendants in various legal proceedings arising from the conduct of their business operations. In the opinion of management, the ultimate disposition of the currently asserted claims will not have a material impact on consolidated financial position or results of operations.

G. Minimum Rental Commitments. Minimum rental commitments for noncancellable operating leases are as follows:

($ in thousands)	
1986	10,900
1987	9,500
1988	8,400
1989	6,500
1990	7,600
After 1990	99,600

13. Other Income

Year Ended December 31 ($ in thousands)	**1985**	*1984*	*1983*
Interest income	**32,149**	38,793	13,948
Income from equity investments	**7,697**	9,928	8,869
Allowance for other funds used during construction	**—**	330	—
Miscellaneous	**1,118**	2,229	3,634
Total	**40,964**	51,280	26,451

14. Interest and Related Charges

Year Ended December 31 ($ in thousands)	**1985**	*1984*	*1983*
Interest on long-term debt	**131,686**	138,903	139,532
Interest on short-term debt	**8,138**	2,555	29,111
Other interest charges	**25,636**	4,817	3,369
Allowance for borrowed funds used and interest during construction	**(6,457)**	(6,888)	(4,384)
Total	**159,003**	139,387	167,628

15. Changes in Components of Working Capital

(excludes cash, bank loans, commercial paper and current maturities of long-term debt and preferred stock)

Year Ended December 31 ($ in thousands)	**1985**	*1984*	*1983*
Accounts receivable	**(63,096)**	264,338	(225,308)
Income tax refunds	**(129,113)**	17,232	47,706
Gas inventory	**144,340**	(102,558)	138,184
Deferred gas purchased costs	**(3,282)**	(138,043)	(98,673)
Accounts and drafts payable	**(147,977)**	(114,675)	(24,650)
Accrued taxes	**(2,759)**	(3,243)	9,676
Estimated rate refunds	**10,625**	(26,876)	(33,580)
Estimated supplier obligations	**(22,414)**	267,242	—
Deferred income taxes	**(19,030)**	(8,479)	99,252
Miscellaneous	**(58,197)**	77,149	13,516
Change in working capital	**(290,903)**	232,087	(73,877)
Non-cash items	**34,873**	(38,090)	37,840
Net change in working capital	**(256,030)**	193,997	(36,037)

16. Business Segment Information

The information shown in the following tables is provided for the Corporation's segments for three calendar years, 1985, 1984 and 1983. 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 is 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, except for the provision for previously unprovided deferred taxes discussed in Note 3, which is assigned to Transmission. Earnings from continuing operations were derived by excluding the net income effects of discontinued operations and extraordinary charges 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 $12.9 million in 1985, $11.1 million in 1984, and $54.9 million in 1983. Identifiable assets related to gas distribution operations include $179.7 million in 1983 for a subsidiary which was disposed of in June 1984.

($ in thousands)		**1985**	1984	1983
Revenues				
Transmission	-Unaffiliated	**1,653,609**	1,903,983	1,979,421
	-Intersegment	**1,551,851**	1,543,491	2,079,301
	Total	**3,205,460**	3,447,474	4,058,722
Distribution	-Unaffiliated	**2,149,049**	2,458,641	2,784,890
	-Intersegment	**3,765**	910	560
	Total	**2,152,814**	2,459,551	2,785,450
Oil and gas	-Unaffiliated	**156,193**	98,844	96,517
	-Intersegment	**97,674**	193,458	151,399
	Total	**253,867**	292,302	247,916
Other	-Unaffiliated	**99,708**	145,120	229,535
	-Intersegment	**46,393**	103,653	234,827
	Total	**146,101**	248,773	464,362
Adjustments and eliminations	-Unaffiliated	**6,194**	(1,873)	—
	-Intersegment	**(1,699,683)**	(1,841,512)	(2,466,087)
	Total	**(1,693,489)**	(1,843,385)	(2,466,087)
Corporate and unallocated	-Unaffiliated	**77,077**[a]	39,947[a]	11,173[a]
	-Intersegment	**—**	—	—
	Total	**77,077**	39,947	11,173
Consolidated	-Unaffiliated	**4,141,830**	4,644,662	5,101,536
	-Intersegment	**—**	—	—
	Total	**4,141,830**	4,644,662	5,101,536
[a]Corporate revenues		**69,380**	30,019	2,304
Income from equity investments		**7,697**	9,928	8,869
Total		**77,077**	39,947	11,173

($ in thousands)	1985	1984	1983
Operating Income			
Transmission	**(326,356)**	224,120	304,235
Distribution	**135,692**	129,182	83,324
Oil and gas	**100,944**	133,871	153,559
Other	**7,363**	(54,836)	(4,642)
Adjustments and eliminations	**(991)**	(1,873)	(423)
Corporate and unallocated	**(83,226)**[b]	(108,003)[b]	(176,780)[b]
Consolidated	**(166,574)**	322,461	359,273
Earnings from Continuing Operations			
Transmission	**(218,714)**	79,192	102,716
Distribution	**62,790**	54,839	21,188
Oil and gas	**46,507**	63,279	68,474
Other	**2,409**	(31,874)	(7,677)
Consolidated	**(107,008)**	165,436	184,701
Depreciation & Depletion			
Transmission	**136,913**	120,677	121,483
Distribution	**38,306**	30,495	34,982
Oil and gas	**84,733**	92,397	37,705
Other	**4,070**	5,762	8,322
Corporate and unallocated	**3,575**	1,688	619
Consolidated	**267,597**	251,019	203,111
Identifiable Assets			
Transmission	**3,630,343**	3,045,212	2,822,512
Distribution	**1,518,995**	1,315,493	1,785,706
Oil and gas	**766,667**	836,704	863,889
Other	**88,574**	96,468	125,522
Adjustments and eliminations	**(322,162)**	(234,182)	(447,306)
Corporate and unallocated	**152,749**[c]	140,841[c]	88,032[c]
Consolidated	**5,835,166**	5,200,536	5,238,355
Capital Expenditures			
Transmission	**55,600**	96,200	61,000
Distribution	**80,900**	76,600	70,200
Oil and Gas	**78,200**	92,100	72,400
Other	**5,300**	7,200	6,400
Total	**220,000**	272,100	210,000
[b]Income from equity investments	**7,697**	9,928	8,869
Corporate revenues and expenses (net)	**68,080**	26,300	173
Interest and related charges	**(159,003)**	(139,387)	(167,628)
Writedown of Alaskan pipeline investment	**—**	(4,844)	(18,194)
Total	**(83,226)**	(108,003)	(176,780)
[c]Corporate assets	**115,108**	98,610	38,971
Investment in unconsolidated affiliates	**37,641**	42,231	49,061
Total	**152,749**	140,841	88,032

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 (Loss) from Continuing Operations Before Income Taxes*	*Earnings (Loss) on Common Stock*	*Earnings (Loss) Per Share*
1985				
December 31[(1)]	**$1,176,419**	**$ 68,892**	**$21,616**	**$ .53**
September 30	**553,960**	**(23,771)**	**(16,007)**	**(.40)**
June 30	**605,891**	**(17,554)**	**(18,923)**	**(.47)**
March 31[(2)]	**1,716,272**	**(194,141)**	**(93,694)**	**(2.36)**
1984				
December 31[(3)]	$1,208,351	$ 95,491	$24,414	$ .62
September 30	621,533	14,920	4,330	.11
June 30	784,486	43,861	20,403	.52
March 31[(4)]	1,979,012	168,189	89,417	2.30

[(1)]Includes an increase in earnings of $11,000,000 related to discontinued application of Statement of Financial Accounting Standards No. 71 (see Note 3).
[(2)]Includes a decrease in earnings of $207,000,000 reflecting a reserve for a portion of unrecovered gas costs applicable to gas purchased prior to April 1, 1985.(see Note 4A).
[(3)]Includes a decrease in earnings of $23,700,000 related to discontinued mining operations (see Note 5).
[(4)]Includes a decrease in earnings of $30,000,000 reflecting a nonrecurring charge applicable to synthetic gas operations (see Note 4C).

B. Oil and Gas Producing Activities

Introduction. Reserve information contained in the following tables for the U.S. properties for 1985 are the System's estimates which are reviewed by the independent consulting firm of Ryder Scott Company Petroleum Engineers. 1984 and 1983 reserve information for U.S. properties was supplied by the independent consulting firm of Ralph E. Davis Associates, Inc. Reserve information for the Canadian properties was supplied by John R. Lacey International Ltd.

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 1985	1984	1983	Canada 1985	1984	1983	Total 1985	1984	1983
Capitalized Costs at Year End									
Proved properties	**885,116**	885,129	876,500	**119,963**	109,977	92,972	**1,005,079**	995,106	969,472
Unproved properties*	**90,030**	91,961	82,249	**74,224**	69,897	69,677	**164,254**	161,858	151,926
Total capitalized costs	**975,146**	977,090	958,749	**194,187**	179,874	162,649	**1,169,333**	1,156,964	1,121,398
Accumulated depletion	**(441,963)**	(407,674)	(358,538)	**(10,816)**	(7,957)	(5,349)	**(452,779)**	(415,631)	(363,887)
Net capitalized costs	**533,183**	569,416	600,211	**183,371**	171,917	157,300	**716,554**	741,333	757,511
Costs Capitalized During Year									
Acquisition	**10,037**	16,200	13,911	**1,864**	4,226	791	**11,901**	20,426	14,702
Exploration	**25,147**	23,484	17,213	**15,127**	15,320	13,974	**40,274**	38,804	31,187
Development	**18,475**	25,550	18,290	**7,120**	7,311	7,871	**25,595**	32,861	26,161
Costs capitalized	**53,659**	65,234	49,414	**24,111**	26,857	22,636	**77,770**	92,091	72,050

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

Historical Results of Operations

($ in thousands)	United States 1985	1984	1983	Canada 1985	1984	1983	Total 1985	1984	1983
Gross revenues									
Unaffiliated	**135,770**	83,526	84,681	**14,535**	13,896	10,982	**150,305**	97,422	95,663
Affiliated	**97,615**	192,563	151,399[a]	**—**	—	—	**97,615**	192,563	151,399
Production costs	**44,194**	41,848	39,287	**3,933**	3,570	2,193	**48,127**	45,418	41,480
Depletion	**80,427**	89,179	35,581[b]	**3,364**	2,965	1,910	**83,791**	92,144	37,491
Income tax expense	**49,237**	66,107	72,768	**3,329**	3,386	3,164	**52,566**	69,493	75,932
Results of operations	**59,527**	78,955	88,444	**3,909**	3,975	3,715	**63,436**	82,930	92,159

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 1985	1984	1983	Canada 1985	1984	1983
Average sales price per Mcf of gas ($)	**2.42**	2.69	3.03[a]	**1.59**	1.89	1.91
Average sales price per barrel of oil and other liquids ($)	**23.42**	27.56	29.03	**23.84**	26.36	26.72
Production (lifting) cost per dollar of gross revenue ($)	**0.19**	0.15	0.18[a]	**0.27**	0.26	0.20
Depletion rate per dollar of gross revenue ($)	**0.35**	0.32	0.28[a]	**—**	—	—
Depletion rate per equivalent Mcf ($)	**—**	—	—	**0.69**	0.73	0.59

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

Reserve Quantity Information

	United States		Canada[a]	
Proved Reserves	*Gas (MMcf)*	*Oil and Other Liquids (000 Bbls)*	*Gas (MMcf)*	*Oil and Other Liquids (000 Bbls)*
Reserves as of December 31, 1982	483,134	10,394	140,823	2,942
Revisions of previous estimate	360,291[b]	228	99	4
Extensions, discoveries and other additions	20,279	1,420	7,820	908
Production	(53,559)[c]	(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
Revisions of previous estimate	59,727	(10)	(88)	353
Extensions, discoveries and other additions	16,583	303	4,186	609
Production	(74,487)	(2,125)	(2,177)	(464)
Improved recovery	—	—	—	1,188
Purchase/(sale) of minerals-in-place	(5,529)	—	1,480	66
Reserves as of December 31, 1985	**751,366**	**8,378**	**154,383**	**6,004**
Proved developed reserves as of December 31				
1983	629,181	7,113	147,105	3,552
1984	579,473	7,648	150,982	4,252
1985	683,797	7,706	154,383	6,004

[a]Gross working interest reserves.
[b]Includes 336 Bcf previously classified as cost-of-service reserves.
[c]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)	***1985***	*1984*	*1983*	***1985***	*1984*	*1983*	***1985***	*1984*	*1983*
Future cash inflows	**2,261,210**	2,415,156	2,816,127	**380,317**	381,544	372,856	**2,641,527**	2,796,700	3,188,983
Future production costs	**(496,945)**	(519,418)	(642,515)	**(70,737)**	(57,095)	(53,741)	**(567,682)**	(576,513)	(696,256)
Future development costs	**(147,939)**	(191,041)	(196,627)	**(4,079)**	(3,455)	(27)	**(152,018)**	(194,496)	(196,654)
Future income tax expense	**(667,495)**	(702,393)	(820,793)	**(120,780)**	(129,411)	(132,338)	**(788,275)**	(831,804)	(953,131)
Future net cash flows	**948,831**	1,002,304	1,156,192	**184,721**	191,583	186,750	**1,133,552**	1,193,887	1,342,942
Less 10% discount	**428,242**	436,756	532,341	**99,920**	106,944	108,234	**528,162**	543,700	640,575
Standardized measure of discounted future net cash flows	**520,589**	565,548	623,851	**84,801**	84,639	78,516	**605,390**	650,187	702,367

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, 1985, 1984 and 1983 follows:

	United States			*Canada*			*Total*		
($ in thousands)	***1985***	*1984*	*1983*	***1985***	1984	1983	***1985***	1984	1983
Beginning of year	**565,548**	623,851	501,091	**84,639**	78,516	67,172	**650,187**	702,367	568,263
Oil and gas sales, net of production costs	**(189,190)**	(234,241)	(196,793)	**(10,602)**	(10,326)	(8,789)	**(199,792)**	(244,567)	(205,582)
Net changes in prices and production costs	**(103,423)**	(64,211)	(51,046)	**(19,363)**	(8,949)	14,803	**(122,786)**	(73,160)	(36,243)
Extensions, discoveries and other additions, net of related costs	**23,899**	18,550	44,530	**15,460**	11,805	10,593	**39,359**	30,355	55,123
Revisions of previous estimates, net of related costs	**151,997**	30,228	479,038	**1,482**	3,990	360	**153,479**	34,218	479,398
Accretion of discount	**94,649**	105,644	80,045	**14,172**	13,414	11,257	**108,821**	119,058	91,302
Net change in income taxes	**33,839**	51,643	(133,226)	**1,740**	(1,465)	(10,222)	**35,579**	50,178	(143,448)
Other	**(56,730)**	34,084	(99,788)	**(2,727)**	(2,346)	(6,658)	**(59,457)**	31,738	(106,446)
End of year	**520,589**	565,548	623,851	**84,801**	84,639	78,516	**605,390**	650,187	702,367

Estimated discounted future net cash flows decreased $44.8 million in 1985. The primary causes of this reduction were: (1) current year production of $199.8 million; (2) a $59.5 million reduction caused principally from changes in production curves from earlier to later periods; and, (3) a decrease of $122.8 million attributable to net changes in gas and oil prices and production costs. Partially offsetting these decreases were: (1) upward revisions of previous quantity estimates valued at $153.5 million including significant reductions in related future development costs; and (2) a $39.4 million increase resulting from discoveries of natural gas (20.8 Bcf) and oil and other liquids (912 thousand barrels).

Estimated discounted future net cash flows decreased $52.2 million in 1984. Principal downward changes resulted from: (1) 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 milion; (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.

C. Effects of Specific Price Changes.

The following supplementary information is presented in accordance with the Statement of Financial Accounting Standards No. 33, as amended by Statement No. 82, 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 precise measures.

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 or losses in relation to general inflation, should also be included in the measure of income. These combined effects are provided in the following tables as "Income (loss) after all adjustments."

Statement of Income Adjusted for Changing Prices

Year Ended December 31, 1985 ($ in thousands of average 1985 dollars)

Earnings (loss) on common stock, as reported	(107,008)
Effect on earnings (loss) of changing prices on depreciation and depletion expense*	(353,992)
Income (loss) after required adjustments	(461,000)
Reduction in purchasing power loss through debt financing	79,820
Excess of increase in general inflation ($388,563), over decrease in specific prices ($52,191)**	(440,754)
Income (loss) after all adjustments	(821,934)

*The provision for specific prices would have been $395,659,000, if this amount had not exceeded the total adjustment to net recoverable cost by $41,667,000.

**At December 31, 1985, the current cost of property, plant and equipment, net of accumulated depreciation and depletion, approximated $8,343,353,000 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.

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

In 1985, the Corporation changed the manner in which transmission assets are treated in the accompanying tables. Adjustments to recoverable cost are made to reflect the economic effects of rate regulation where asset recovery is limited to historical cost. As a consequence of discontinuing application of SFAS No. 71, transmission assets are no longer reduced to historical cost. In prior years, unrealized holding gains or losses were not reflected in "Income (loss) after all adjustments," since adjustments to historical cost offset such gains or losses. The reduction in income in the previous table, of $440.8 million, represents an unrealized holding loss applicable to the current year related to transmission and oil and gas producing assets due to an increase in the measure of general inflation and a reduction in the measurement of the current cost of replacing such assets (losses in terms of constant dollars). In the five-year comparison table, which follows, the cumulative effects of prior year unrealized holding gains related to transmission assets are reflected in the year 1985 under the caption "Net assets at recoverable cost."

Five-Year Comparison of Selected Supplementary Financial Data Adjusted for Changing Prices

Year Ended December 31, ($ in thousands of average 1985 dollars except as noted)	**1985**	*1984*	*1983*	*1982*	*1981*
Historical cost information adjusted for changes in specific prices:					
Income (loss) after required adjustments	**(461,000)**	(239,912)	(28,178)	31,894	(109,465)
Income (loss) after required adjustments per common share	**(11.49)**	(6.12)	(.75)	.90	(3.16)
Income (loss) after all adjustments	**(821,934)**	(352,913)	100,709	127,480	159,147
Income (loss) after all adjustments per common share	**(20.48)**	(9.00)	2.69	3.61	4.60
Specific price changes of nonmonetary assets compared with changes due to general inflation after adjustment to recoverable cost	**(440,754)**	(192,882)	41,012	16,077	91,162
Net assets at recoverable cost	**6,162,853**	2,648,580	2,836,377	2,493,259	2,458,188
Reduction in purchasing power loss through debt financing	**79,820**	79,880	87,875	79,510	177,450
General information:					
Cash dividend per common share— actual	**$3.18**	$3.18	$3.02	$2.86	$2.70
in average 1985 dollars	**$3.18**	$3.29	$3.26	$3.19	$3.19
Market price per common share at year end— actual	**$39½**	$34	$35¼	$28⅞	$32⅛
in average 1985 dollars	**$38⅞**	$34¾	$37½	$31⅞	$36¾
Average consumer price index	**322.2**	311.1	298.4	289.1	272.4

Directors and Officers

The Columbia Gas System, Inc.

Directors

Thomas S. Blair[2,3]
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[3,4]
Former Chairman and Chief Executive Officer
Jeffrey Galion, Inc.
Acquired by Dresser Industries, Inc.
Industrial Equipment, 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[3,4]
Chairman, Hillenmeyer Nurseries, Inc.
Lexington, Kentucky

Malcolm T. Hopkins[2,4]
Former Vice Chairman, Chief Financial Officer and Director
St. Regis Corporation
Forest Products, Oil, Gas and Insurance
New York, New York

W. Frederick Laird[1]
Former Chairman of the Board

Dr. William B. Lavery[2,4]
President
Virginia Polytechnic Institute and State University,
Blacksburg, Virginia

James D. Little
Executive Vice President

George P. MacNichol, III[2,4]
Private Investor; Former Vice President,
Libbey-Owens-Ford Company, Glass and Plastics Business
Toledo, Ohio

Ernesta G. Procope[2,4]
President and Chief Executive Officer
E. G. Bowman Co., Inc. Insurance Brokerage Firm
New York, New York

John P. Roche[1,2]
Of Counsel, Reed Smith Shaw & McClay
Attorneys-at-Law
Washington, D.C.

Arch A. Sproul[3,4]
Former Chairman
Virginia International Co.
Foreign Investments
Staunton, Virginia

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

Officers

John H. Croom
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

Columbia Gas System Service Corporation

John H. Croom
Chairman, President and
Chief Executive Officer

John P. Cornell
Executive Vice President and
Chief Financial Officer

James D. Little
Executive Vice President

Robert A. Oswald
Senior Vice President and Assistant
Chief Financial Officer

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
Bruce Quayle
Robert W. Welch
Vice Presidents

William J. Forsythe
Controller

Alexander P. McCann
Assistant Secretary

Lawrence J. Doyle
Joseph V. Yandoli
Assistant Treasurers

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

Operating Company Executives

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

Donald C. Hubbard
President
Columbia Natural Resources, Inc.
Columbia Coal Gasification Corporation

Charles W. Morrow
President
Columbia Gulf Transmission Company

John E. Towle
President
Columbia Hydrocarbon Corporation
Columbia LNG Corporation
Inland Gas Company, Inc.

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 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

Common Stock Data
The Columbia Gas System, Inc.

Year	*Number of Shares Traded (000)*	*Market Price High $*	*Low $*
1985	29,135	40	26¾
1984	14,624	37½	27
1983	14,191	35½	27⅞
1982	7,414	33⅞	26⅞
1981	6,692	41½	27⅞
1980	10,297	47	33¾
1979	7,126	40¾	25¼
1978	3,642	29½	25⅛
1977	3,890	32¾	28

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.

There are no brokerage commissions or service charges on shares purchased through the Plan. Participation in the Plan may be discontinued at any time, in which case you will receive a stock certificate, or if you prefer, cash for shares credited to your account. Participants will be treated for Federal income tax purposes as having received a cash dividend and will be taxed on the full amount of the dividend utilized to purchase additional shares.

Common stockholders desiring a complete description of the Plan should request a copy of the Prospectus by writing to: Columbia Dividend Reinvestment, Stockholder Services Department, 20 Montchanin Road, Wilmington, Delaware 19807.

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.

Investor Information—Security analysts, investment managers, brokers and others with financial questions should contact J.T. Connors, Vice President for Investor Relations, Columbia Gas System Service Corporation, at Corporate Headquarters or call directly at (302) 429-5363.

Annual Meeting—The Corporation's 1986 Annual Meeting of Stockholders will be held at the Hotel DuPont, Wilmington, Delaware, on May 14, 1986, at 1:00 p.m. Proxy material will be mailed on or about March 20, 1986.

COLUMBIA GAS
System

20 Montchanin Road, Wilmington, Delaware 19807