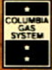

COLUMBIA GAS SYSTEM ANNUAL REPORT 1986

Columbia Gas—
expanding
into new
markets,
honing the
competitive
forces.

THE COMPANY

"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

Welder completes another link in the stretch of 30-inch diameter pipeline installed in West Virginia in 1986. The project increased materially the capacity of Columbia's interstate network to move gas to growing eastern markets.

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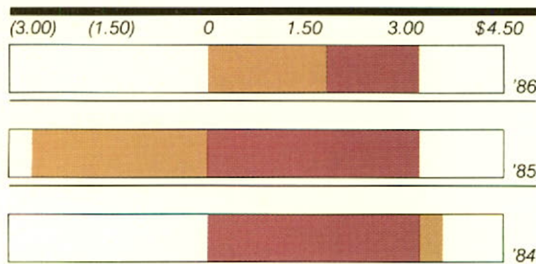
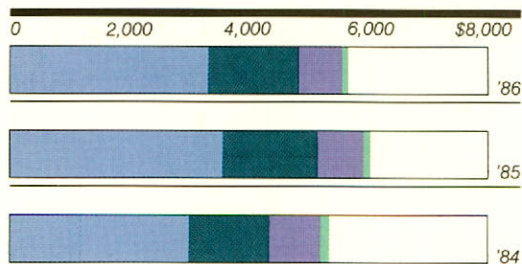
HIGHLIGHTS

The Columbia Gas System, Inc. and Subsidiaries	***1986***	*1985*	*1984*
Income Statement Data ($000)			
Operating Revenues	**3,369,578**	4,060,919	4,603,122
Net Income (Loss)	**86,847**	(93,832)	152,892
Earnings (Loss) from Continuing Operations before Extraordinary Charges:			
Gas Transmission	**19,703**	(218,714)	79,192
Gas Distribution	**75,264**	62,790	54,839
Oil and Gas	**(6,497)**	46,507	63,279
Other	**(578)**	2,409	(31,874)
Total	**87,892**	(107,008)	165,436
Per Share Data ($)			
Earnings (Loss) from Continuing Operations before Extraordinary Charges	**2.12**	(2.67)	4.22
Earnings (Loss) on Common Stock	**1.82**	(2.67)	3.53
Dividends	**3.18**	3.18	3.18
Book Value	**34.06**	35.10	41.22
Market Price:			
High	**46.00**	40.00	37.50
Low	**34.75**	26.75	27.00
Close	**45.25**	39.50	34.00
Common Stock Data			
Average Common Shares Outstanding (000)	**41,436**	40,134	39,227
Average Daily Shares Traded	**104,828**	116,005	58,403
Operating Statistics (million cubic feet)			
Gas Sales	**606,460**	695,017	782,859
Transportation Volumes	**541,497**	511,148	423,427
Total Throughput	**1,147,957**	1,206,165	1,206,286
Balance Sheet and Other Data ($000)			
Capital Expenditures	**232,283**	219,968	272,009
Total Assets	**5,590,161**	5,835,166	5,200,536
Capitalization	**2,942,170**	3,202,258	3,107,709

EARNINGS AND DIVIDENDS PER SHARE OF COMMON STOCK
(In Dollars)



ASSETS BY SEGMENT
(In Millions of Dollars)



HOWARD ROSS LIBRARY OF MANAGEMENT
MAR 26 1987
McGILL UNIVERSITY

John H. Croom, Chairman, President and Chief Executive Officer

LETTER TO STOCKHOLDERS

Building on its 1985 accomplishments, Columbia focused primary attention in 1986 on programs designed to open new markets and mobilize more competitive strength. The producer contract renegotiations and market-stabilizing rate settlement we had achieved uniquely positioned Columbia to prosper in a changing gas industry.

New market-sensitive producer contracts enabled the System's interstate pipelines to lead the industry in working under a new competition-oriented regulatory philosophy embodied in Federal Energy Regulatory Commission (FERC) Order 436. When our two interstate pipelines began operating under the Order in March 1986, they became the first major pipelines to offer transportation service on a first-come, first-served basis to any shipper. This bold move brought a flood of transportation orders, as well as general acclaim for our willingness to pioneer.

This combination of market-responsive contracts, stable markets and open transportation has enabled the whole System to undertake an array of marketing activities that are timely and respond to new business patterns in today's gas industry.

EARNINGS REBOUND

The System's 1986 earnings improvement and the financial community's reaction to Columbia's progress provide the best evidence of the effectiveness of the 1985 accomplishments.

Earnings on common stock for the year, before extraordinary charges, totaled $87.9 million, or $2.12 per share, in comparison to the 1985 loss of $107 million, or $2.67 per share. The 1986 financial

results are discussed in detail beginning on page 16.

The System's improving financial strength enabled directors to maintain the dividend rate of $3.18 per share for 1986 despite the heavy costs of programs to solve Columbia's past problems. A dividend of $0.795 per share was paid in the first quarter of 1987, consistent with the 1986 rate. Common stock dividends have been paid regularly for more than 40 years.

The price of Columbia common stock increased from its 1985 low of $26.75 per share to its 1986 closing price of $45.25 per share. The strong market enabled the Corporation to successfully sell 1¼ million shares of common stock in September, 1986.

CORPORATE OBJECTIVES

A principal objective of the corporation is to earn a competitive return for its investors. The immediate goal is to earn no less than the current annual dividend rate of $3.18 per share and to improve earnings sufficiently to permit increases consistent with a long-term payout policy averaging 55-60 percent of earnings.

The strategic plans of the individual operating units establish performance targets that are sufficiently aggressive to make possible the earnings necessary to attain that objective. The System's strategic planning process began its second annual cycle during 1986 with clear indications that the concept is working productively throughout the organization.

Another vital corporate objective—access to capital at reasonable costs at all times—calls for continuing improvement in our financial strength. Progress toward that goal was achieved early in 1986 when three major rating agencies upgraded the rating of Columbia's debentures, preferred stock and commercial paper. The improvement in Columbia's commercial paper rating allowed us to regain access to that market and reduce the cost of short-term borrowings. All of Columbia's securities are rated investment grade by the major rating agencies.

The vitality of the System requires that capable executives and managers be in place and suitable replacements available. Our planning process in 1986 extended our management development and succession planning program into all levels of management. This process will continue to receive close attention so that talented employees can be identified and given the opportunity for career advancement.

Much effort is made to involve all employees in the planning process, and we found in 1986 an increasing tendency among employees to ask "Are we doing this the right way? Is there a better way to do it?" The questioning spirit has never been completely absent from Columbia, but in the competitive climate which pervades the gas industry, every activity must be monitored with a critical eye. We are looking for the better way, but we are not making changes simply for the sake of change.

THE CHANGING INDUSTRY

All segments of the industry have been struggling to deal with a chaotic market brought about by a combination of ample supply, depressed demand, and rigid producer/pipeline contracts. This mixture has, in just a few years, disrupted and changed traditional

industry business relations that had prevailed for decades. The tangle of marketing and transportation arrangements devised to deal with changing relations led the FERC to issue its Order 436 in an effort to "level the playing field."

As a result of its problem-solving programs, Columbia was well positioned by the start of 1986 to operate successfully under Order 436. Few other major pipelines were so situated, although by now several have accepted the order. Under legal challenge to its Order, the FERC is still considering rules to guide and govern the industry in today's competitive climate.

The industry's difficulties have been compounded by depressed petroleum prices which have intensified market competition and virtually throttled any economic incentive to explore for new reserves of oil and natural gas.

COMPETITIVE STRENGTHS

We believe that market-sensitive producer contracts form the nucleus of a competitive supply available to Columbia for extending sales and transportation business into new areas.

Based on this contract flexibility, Columbia Gas Transmission Corporation (Transmission) is seeking FERC approval for new sales and transportation rates which, when effective on April 1, 1987, would make Transmission one of the most competitive pipelines serving the Eastern Seaboard.

Columbia's distribution companies have been diversifying their supply sources so as to lower gas costs to residential, commercial and industrial customers. For large industrial users, the distribution companies have developed economical transportation rates which have made it possible for industries to purchase low-cost gas directly from producers for delivery by the distribution company. In this way, gas loads that could have been lost to oil have been retained.

The many programs under way to expand markets are reported in detail in a section beginning on page 10.

SUPPLY DEVELOPMENT ISSUES

As we enter 1987, two major gas supply issues overhang the industry.

There is no question that abundant proven and potential gas reserves await the full resumption of drilling activity. The nation can have ample supplies, but the current "bubble" of excess deliverable supplies could well be depleted in another year or two at the current level of demand. The industry could even experience localized delivery problems on extremely cold days as early as next winter unless development of new reserves resumes shortly.

The first issue flows from the new patterns that have developed for buying and selling gas. Pipelines were once the sole aggregators of supplies, buying from producers and selling to distributors and occasionally to industry. Many categories of customers are now purchasing directly from producers and then seeking only transportation service from pipelines. The traditional merchant function of the pipeline has been diminished.

At issue is whether a pipeline's merchant *responsibility* has also been diminished. For example, a distribution company may plan to acquire 40 percent of its gas directly from a producer and the balance from its traditional pipeline supplier, but then only be able to obtain 20 percent from the producer during a severe winter. In that event a serious question arises as to the pipeline's responsibility for supplying the balance. No regulatory policy has said whether it must contract for gas just to be a back-up source. The problem can assume many forms, and political complexities, depending on the nature of the customer and the number of parties involved. In some areas, school systems are buying some or all of their gas directly from producers, but who is responsible for providing back-up?

We believe that pipelines have proven themselves to be the most efficient aggregators of supply. They draw from many sources, have the capacity to store gas for peak needs, and provide economies of scale. However, with the existing uncertainty as to the extent of their future supply responsibilities, pipelines are naturally reluctant to make purchase commitments to producers. Lacking such commitments, producers in turn have little incentive to invest in drilling to develop new reserves.

The issue of merchant responsibility involves both gas companies and the regulatory agencies, which must ultimately approve the rates that start drill bits turning. Discussions of the issue are going on throughout the industry, and we are confident that a workable solution will be found.

Columbia has proposed several actions of the type we feel are needed to break the stalemate. In a recent rate filing with the FERC, Transmission is seeking to establish a seasonal entitlement for each distribution company it serves, a specific volume of gas for which Transmission would be the source but beyond which it would have no obligation. With its specific obligations thus established, Transmission would not be compelled to invest in reserves beyond

those needed to meet its customers' seasonal requirements.

Transmission has also proposed that pipelines willing to maintain a merchant function be compensated for the risks assumed in providing such gas supply service —"a merchant fee."

Already there are indications that regulatory agencies are now becoming as concerned about supply reliability as they have been about costs. As this concern becomes evident, distribution companies are beginning to consider the longer term contracts that send encouraging market signals to producers.

The other supply issue is the depressed level of prices and its impact on drilling activity and development of new reserves. With much gas exploration tied to the amount of oil exploration under way in this country, the gas supply issue is hostage in substantial degree to the actions of the Organization of Petroleum Exporting Countries (OPEC) and other external forces that drive U.S. oil and gas prices. A number of alternatives, such as a fee on imported oil, have been proposed to boost domestic prices and so stimulate drilling activity. We believe that an effective oil import fee is not politically achievable and that attention being devoted to the issue can be more usefully directed to working out other measures which would stimulate increased drilling activity.

Despite the uncertainty, there have been indications in the early weeks of 1987 that the decline in drilling has at least hit bottom. A slight increase in the number of active drilling rigs provides encouragement that the amount of exploration will increase somewhat during the year.

1987 AND BEYOND

Despite these unresolved issues, we remain confident for the future. As we have stated in previous stockholder reports:

• Natural gas is the 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, with the ability to draw upon most major gas 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 developing and marketing gas and oil production.

• By a substantial margin, Transmission's reserves under contract are the largest of any of its competitors.

• The size and scope of the Columbia System provides the financial stability and resources that allow its operating companies a greater range of functional flexibility than they might have as independent entities.

• Columbia maintains a strong, internal research organization which, in combination with the broad range of studies conducted by the Gas Research Institute, generates the fresh concepts essential to progress and profitability.

• The System is managed and operated by 10,600 employees experienced in the energy industry and dedicated to growth through quality service. Through various plans Columbia employees own 12 percent of Columbia's common stock and constitute the largest single stockholder group.

MANAGEMENT CHANGES

Warren W. Clute, Jr., a member of the Board of Directors since 1962, retired as a director on October 31, 1986, having reached mandatory retirement age. Mr. Clute is a former Chairman of the Board of Watkins Salt Company and of the Glen Bank and Trust Company, both of Watkins Glen, New York. The counsel and advice he provided to the Columbia System for almost a quarter century will be missed.

* * *

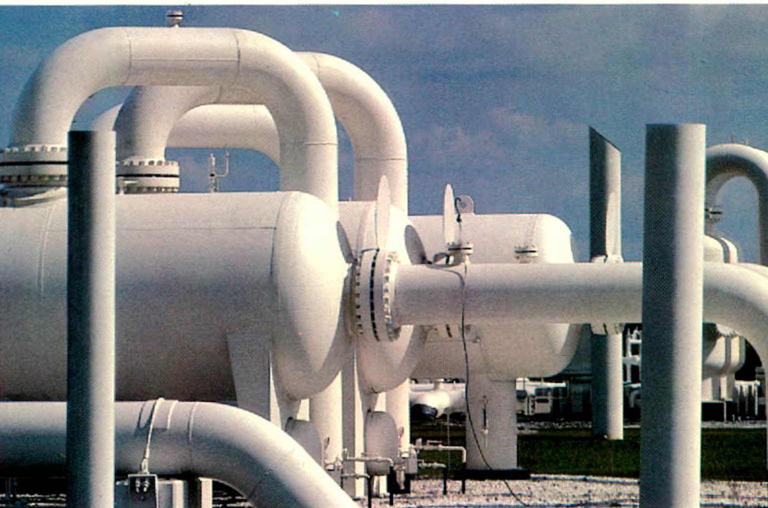
On September 30, 1986, we observed the 60th anniversary of the formation of the parent firm, first known as The Columbia Gas & Electric Corporation. As even its first name suggests, Columbia has passed through a number of transformations over more than six decades. It has not only survived but gained strength from each experience. Those of us privileged to be part of the Columbia family today owe much to the stockholders and employees who have sustained the System through many changes. We know that Columbia is prepared for tomorrow's changes and challenges in substantial measure because of them.

John H. Croom
Chairman, President and
Chief Executive Officer

February 18, 1987

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 ten mid-Atlantic and Midwest states and the District of Columbia. Transmission also operates extensive storage facilities and is the System's principal purchaser of natural gas from producers in the Southwestern, Midcontinental and Appalachian areas. A major part of Transmission's southwest gas supply is delivered by Columbia Gulf Transmission Company (Gulf) through its 4,300 mile pipeline network stretching from offshore Louisiana to Kentucky. Gulf also transports gas for unaffiliated customers and 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.



GAS DISTRIBUTION

The Corporation has seven distribution subsidiaries which provide natural gas service to 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 network of more than 29,000 miles of pipe reaches the principal communities of 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.

OIL AND GAS

The System holds varying interests amounting to 3.6 million net acres throughout the United States and Canada. Domestic oil and gas operations are focused in the Appalachian and Michigan Basins, the Williston Basin, the Powder River Basin and the Gulf Coast areas of Texas and Louisiana. Domestic offshore holdings include varying interests in Federal blocks, most of which are located in the West Cameron, Vermillion, Eugene Island and Ship Shoal area.

Canadian oil and gas operations extend from the Arctic Islands and Northwest territories through western mainland provinces to offshore areas of the Atlantic Provinces. Canadian holdings include a 5.47% interest in over 256,000 gross acres in the block encompassing the Hibernia, Hebron, Nautilus and Mara structures offshore Newfoundland.

OTHER

A fractionation plant recovers propane, butanes and natural gasoline from heavier hydrocarbons derived from Appalachian Basin natural gas production. The butanes and natural gasoline are marketed for use in the production of chemicals and gasoline and the propane is sold to 2,400 customers principally in Ohio and Kentucky.

In Virginia, propane is purchased and resold at wholesale and retail to more than 34,000 customers.

System-owned coal reserves in the Appalachian area exceed 650 million tons. Some reserves are leased to others for development.

GAS TRANSMISSION

Wholesale Customers		Storage Facilities	
Unaffiliated	73	No. of Wells	3,747
Affiliated	9	Acreage (000)	773
Total	82	Capacity (Bcf)	697
Total Throughput (Bcf)	1,063	1986 Capital Expenditures ($000)	60,700

GAS DISTRIBUTION

Retail Customers		Total Throughput (Bcf)	414
Residential	1,598,099	1986 Capital Expenditures ($000)	101,000
Commercial	147,493		
Industrial and Other	2,195		
Total	1,747,787		

OIL AND GAS

Net Acreage (000)		Net Gas Productive Wells	6,198
Developed	1,442	Net Oil Productive Wells	385
Undeveloped	2,156	Oil and Gas Production	
Proved Reserves		Natural Gas (Bcf)	68
Natural Gas (Bcf)	884	Oil (000 Bbls.)	2,170
Oil (000 Bbls.)	12,699	1986 Capital Expenditures ($000)	66,800

OTHER OPERATIONS

Coal Reserves (Million Tons)	650	Gallons Sold (000)	
1986 Capital Expenditures ($000)	3,800	Propane	64,054
Propane Customers	42,629	Butanes	19,376
		Natural Gasolines	9,365

THE NEW ENVIRONMENT

Almost overnight the key word in the natural gas business has changed from regulation to competition. Pipelines, distributors and producers all are seeking new territories and new methods for marketing their gas sales and transportation services. Brokers and other entrepreneurs have set up shop to compete for business.

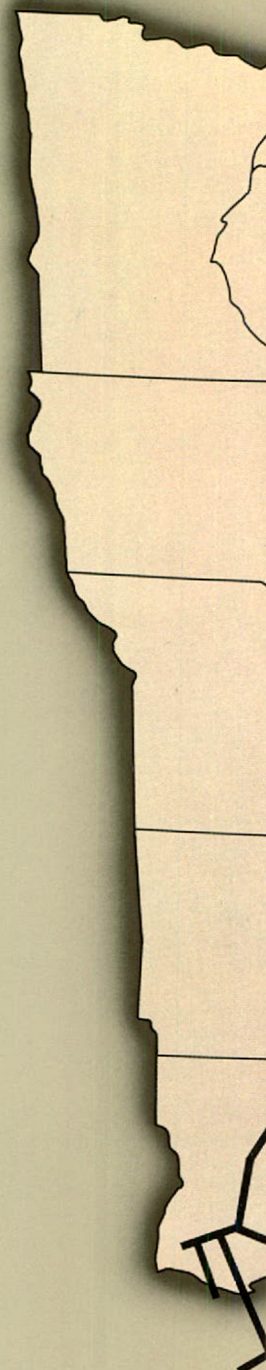
The driving force for change has been an excess of supply over demand, a condition that the industry had not experienced for decades. With this imbalance, coupled with the FERC's policies promoting competition, classic economic forces have opened new business channels around established buying and selling patterns.

The new environment presents Columbia with business opportunities as well as challenges in both its historic and non-historic market areas. System units have responded forcefully to capitalize on the opportunities and respond to the challenges.

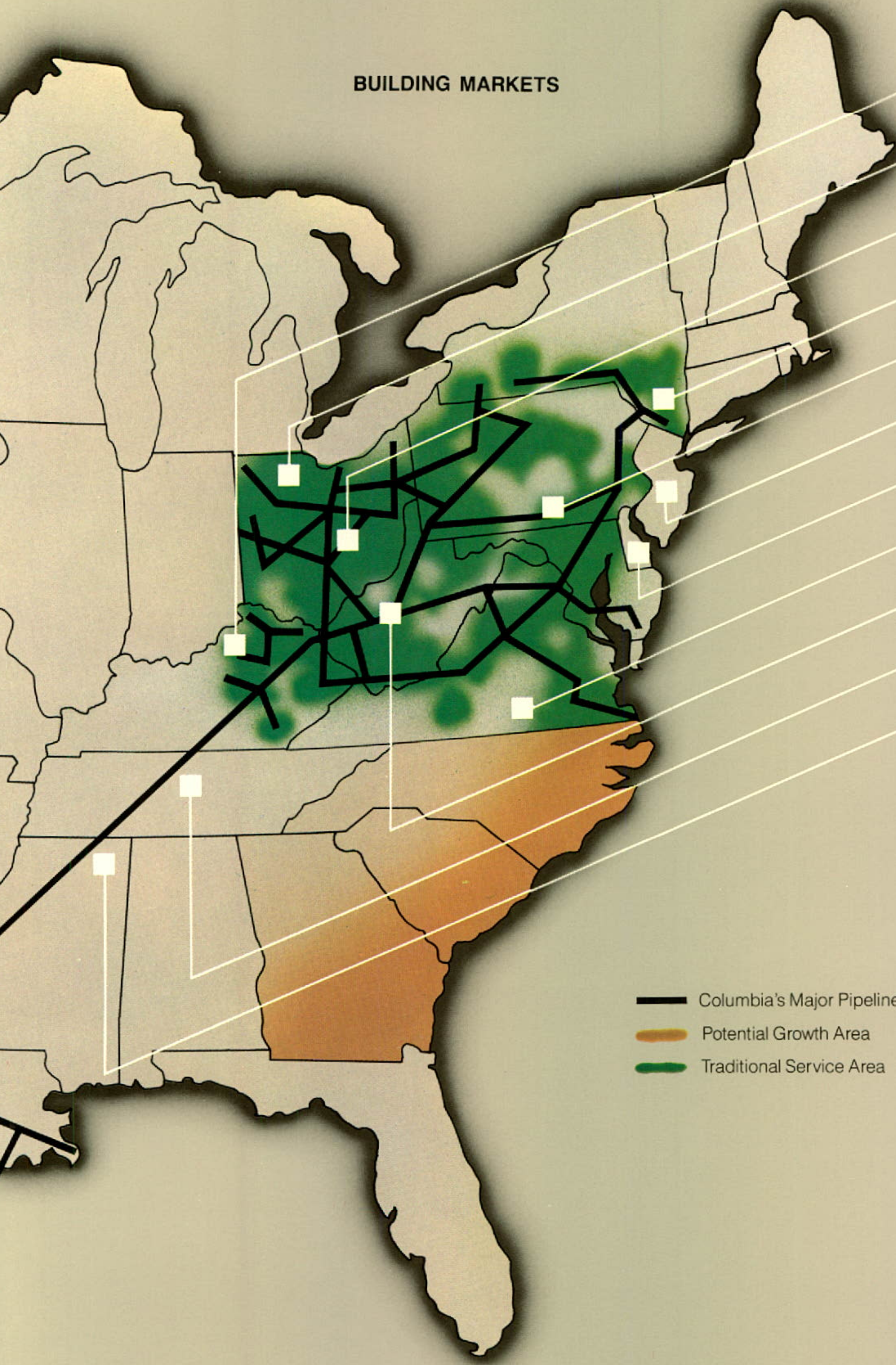
THE RESOURCES AVAILABLE

Columbia's operating companies bring to the competitive arena an impressive arsenal of resources:

- The market-sensitive producer contracts—the industry's most flexible—renegotiated in 1985 by Columbia Gas Transmission Corporation (Transmission) assure that the price of a major portion of the System's gas supply can be quickly adjusted to reflect current market conditions and thus remain competitive.
- The System's two interstate transmission companies were the first major industry units to accept the open-access transportation guidelines set up in the FERC's Order 436 and so have gained valuable operating experience in this new regulatory environment.
- The wholesale rates proposed by Transmission to take effect during 1987 and thereafter, reflecting its successful efforts to reduce gas costs, will be among the most competitive in the industry and will enable Transmission to offer a long-term competitive merchant function.
- The System's pipeline network is backed up by the strongest gas reserve position of any interstate system serving the Eastern Seaboard.
- The efficiencies and capacities of the Columbia System enable it to offer sales and transportation service at competitive costs, while its interconnections with other major pipeline networks provide a flexibility few other pipelines can offer.



BUILDING MARKETS



KENTUCKY—New Toyota plant draws satellite industries.

TOLEDO, OH—Major hospital activates large cogeneration unit.

CAMBRIDGE, OH—Colgate announces plans for manufacturing plant.

NEW YORK—Pipeline capacity to be added for demand growth.

YORK, PA—Cogeneration plant to be largest industrial load in state.

NEW JERSEY—Contract signed to supply large utility company.

DELAWARE—Contract signed to serve state's major utility.

VIRGINIA—System units competing for growing energy markets.

WEST VIRGINIA—Pipeline capacity added to serve growing eastern markets.

NASHVILLE, TN—Transportation service started into nontraditional market.

MISSISSIPPI—Tie-in made to transport gas to Alabama-Tennessee Gas Co.

Cogeneration plant installed in Mercy Hospital, Toledo, Ohio in 1986 uses natural gas to produce most of the hospital's heating, cooling and electricity needs.

• The integrated makeup of the System affords access to a spectrum of gas industry experience reaching from wellhead to burner tip.

EXPANDING WHOLESALE MARKETS

With its strong reserve position and extensive storage facilities, Transmission is one of the few interstate pipelines in the country willing and able to take on new firm sales obligations to distributors. Other pipelines have indicated a reluctance to continue the traditional merchant role, much less expand that role to take on new firm markets. Columbia is well positioned to fill that void and is finding a number of distribution companies interested in a secure and economical source of supply to serve market growth.

New Customers—Contracts were signed in 1986 with two major Eastern Seaboard utilities—Delmarva Power and Light Company, Wilmington, Delaware, and South Jersey Gas Company, Folsom, New Jersey—for sales and transportation service to begin by the end of 1987. Neither company has been a customer of Columbia, so that the transactions represent major extensions of the System's service area. Applications to construct necessary pipeline connections and to initiate service are awaiting regulatory agency approval.

Discussions about possible business connections are being held with other utilities along the Eastern Seaboard, in the Southeast, along the Columbia Gulf pipeline, and elsewhere within and adjacent to Columbia's extensive operating area.

Deliveries that began in 1986 to the utilities serving communities in Tennessee and Alabama demonstrate the System's capabilities to provide service into nontraditional market areas.

Transportation Service—The early acceptance by Columbia's transmission companies of FERC Order 436 had and will continue to have a major impact on those companies, the distribution companies they supply and their customers by providing increased access to low-cost gas. Additionally, the pipelines and their customers, including all Columbia distribution companies, are able to maintain a high level of throughput and consequently more efficient operations.

In 1982, Transmission transported only 88 million dekatherms of gas owned by third parties, less than 10 percent of total throughput. In 1986, out of a total throughput of 913 million dekatherms, 406 million dekatherms were transportation gas, roughly 45 percent.

By the latter months of 1986, Transmission was transporting gas for approximately 1,000 accounts, with expectations that the number will increase. Initially, transportation services were mainly sought by large industrial users and distribution companies. Later came smaller customers, such as schools and hospitals. One commercial account is a fast food chain that is using transported gas to supply its Ohio outlets.

Adding Pipeline Capacity—The transmission companies expended $11.4 million in 1986 to add capacity, and $64.1 million has been budgeted for 1987.

Among the 1986 construction was a significant expansion of capacity on a line passing through West Virginia, to increase Transmission's ability to move gas through to Eastern markets.

Projects planned for 1987 include lines to extend service to Delaware and New Jersey and to add capacity to expand gas service to Orange and Rockland Utilities, Inc. an existing customer in Nyack, N.Y.

Staffing to Market—To help fully realize the market potential, Transmission reorganized its marketing department in 1986 and strategically placed marketing directors to serve both existing customers and acquire nonhistoric markets. These marketing efforts cover both gas sales and transportation services.

As the program evolves, Transmission expects to expand its existing marketing program and work closer with the distribution companies it supplies to reclaim lost loads and attach new customers.

IN THE RETAIL MARKETS

The System's distribution companies compete for energy markets with electric utilities, oil marketers, other gas distributors, gas producers, and nonaffiliated pipelines. In the new business climate, the intensity of competition has been increasing steadily, and Columbia's distribution companies have strengthened existing programs and mobilized new forces in the contest for markets.

Shining the Rust Bowl—A surge of new industrial activity through much of Columbia's retail marketing area is helping erase the "rust bowl" label placed on the nation's industrial heartland when economic recession and industrial restructuring caused many plant closings and cutbacks early in the decade. Columbia has greatly assisted in this revival through its expanded economic development programs and staff. Columbia's economic development personnel work closely with Chambers of Commerce and other groups to stimulate business and industrial activity which brings new jobs and increases gas sales.

In 1986, 43 new manufacturing and distribution facilities were announced for Columbia's retail territory. These will produce additional gas requirements exceeding one billion cubic feet annually, and create more than 4,000 new jobs.

Major among new facilities already under construction is an automotive plant being built by Toyota near Georgetown, Kentucky. Announced in 1985, the plant will be the largest industrial customer supplied by Columbia of Kentucky, requiring roughly a billion cubic feet of gas annually when fully operational in 1990. The plant is expected to employ close to 3,000 people at full capacity. The pipeline which Columbia is building to serve the plant will also extend gas service to areas of the state not previously served with natural gas.

The location of a major plant such as the Toyota facility serves to draw related supplier companies to the area. Among 12 companies that have announced new industrial facilities related to the Toyota plant, 7 will be on Columbia of Kentucky's lines. Continued interest in Columbia's territory is expected from other foreign manufacturers, particularly as Japanese

A compact combination water and space heater developed by Columbia research is being manufactured and marketed under license from Columbia as the "Polaris."

auto suppliers position their facilities to supply their customers such as Toyota in Kentucky and Honda in Ohio, as well as other Midwest auto assembly plants. Columbia's economic development staff has been directly involved in these developments.

At year-end, the Colgate Palmolive Company announced plans to build a detergent plant in Cambridge, Ohio that will require 250 million cubic feet of gas annually. Also a project in which Columbia economic development efforts played a key role, this was the largest plant announced by a domestic company in Columbia's retail territory in 1986.

Holding Industrial Markets—Despite strong competition from other energy marketers, Columbia's distribution companies maintained a high level of deliveries to industrial users in 1986 by their innovative gas transportation service (GTS) program.

The GTS enables customers to purchase currently available low-cost supplies directly from producers while the distribution companies provide a delivery service that keeps the customer on Columbia's lines.

In 1986 GTS volumes represented almost 75 percent of all deliveries to industrial customers in Columbia's retail service area. That was in sharp contrast to only five years ago when transportation volumes accounted for less than 10 percent of industrial gas deliveries. General service customers such as schools, hospitals and restaurants are also utilizing GTS.

In addition to its revenue generating function, the GTS program benefits residential and commercial consumers by broadening the financial base that covers operating costs.

As short-term spot market supplies become higher priced, the distribution companies' gas sales are expected to increase, while GTS volumes decline. Transportation service will continue to account for a notable portion of future deliveries well into the foreseeable future, however.

Residential Markets Change—Recognizing the changing nature of the residential market, with its increasing emphasis on multi-family apartments, condominiums and retirement complexes, Columbia has undertaken special programs to serve such residents. This emphasis has enabled Columbia distribution units to capture service to about 3,000 of the 4,000 multi-family housing units built in their territory in the past year. This 75 percent market share compares with a national average for gas companies of about a 30 percent market share of multi-family housing.

Success in this special residential market is attributed to the competitive gas rates which Columbia offers compared to electricity, new technologies which have led to more efficient gas appliances and a variety of innovative marketing activities.

Among the new appliances helping in this market are a through-the-wall unit which combines gas space heating with electric air conditioning and compact combination water heater and space heater units. One of these combination units, the Polaris System manufactured by Mor-Flo Company, was developed by Columbia research engineers and is being manufactured and marketed under license from Columbia.

COGENERATION MARKET

Columbia expects to find important marketing growth in the use by industrial and commercial customers of cogeneration plants, those which produce both useful heat and on-site electrical power. The development of improved cogeneration equipment and the relationship of gas and electric rates is helping stimulate use of cogeneration.

To further development of cogeneration systems, Columbia in 1986 formed a separate new subsidiary—TriStar Ventures Corporation—to serve as a source of financial support for cogeneration projects. TriStar will invest in cogeneration projects, supplementing the gas supply acquisition, gas transportation and marketing services available to potential projects from other Columbia units.

In the summer of 1986, a major Toledo, Ohio hospital put into operation a cogeneration plant which supplies most of its heating, cooling and electricity needs for less cost than separate utility services had been. The plant doubled the hospital's use of natural gas, giving it an average load equal to about 1,300 residential customers. Other hospitals are studying similar cogeneration systems.

In York, Pennsylvania, Caterpillar Corporation plans to install a cogeneration system in its manufacturing plant there. It will use about 4.5 billion cubic feet of gas annually and make that installation the largest single industrial gas customer served by Columbia of Pennsylvania. The plant produces engine parts for tractors and other small vehicles, and expects to sell excess electricity to the local utility.

Transmission is working with its distribution company customers and their end-users to develop large-volume cogeneration projects. In Harrisburg, Pennsylvania a facility served by a nonaffiliated utility customer, initiated a cogeneration project using about half a billion cubic feet annually.

VIRGINIA MARKET EXPANSION

The central and eastern counties of Virginia are experiencing steady economic growth and have become a focal point of interest for competing gas marketers.

Through an intrastate transmission unit, Commonwealth Gas Pipeline Corporation, Columbia supplies gas to utilities serving more than 270,000 residential, commercial and industrial consumers in those areas, including consumers in the cities of Richmond, Portsmouth, Norfolk and Fredericksburg. Approximately 55,000 of those customers are served directly by the Commonwealth distribution company, Commonwealth Gas Services.

That company has applied to the State Corporation Commission for authority to serve Henrico County, which borders the city of Richmond and is projected to undergo steady commercial expansion. Another Virginia distributor, Virginia Natural Gas Company, is also seeking authorization to serve Henrico County and through plans for a major pipeline has indicated that it intends to contest for business in other areas of the state.

Columbia has mounted a major effort to demonstrate that it has the resources of supply, experience and facilities to best serve the consumers of the areas involved. The market contest under way in Virginia demonstrates the changing business relationship in progress in the gas industry.

CONSOLIDATED EARNINGS REVIEW

ADJUSTED EARNINGS

Adjusted 1986 earnings increased 37% over 1985 but were 39% below those in 1984. The following discussion briefly describes the results by segment:

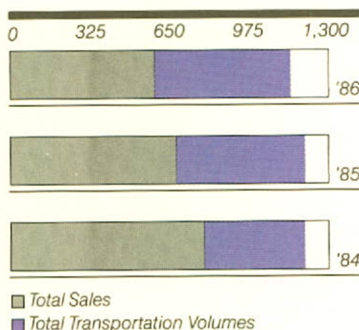
• The 1986 improvement over 1985 was primarily due to the increased sales margins of the System's principal transmission subsidiary, made possible by its success in negotiating lower prices for gas purchased from producers. In accordance with a settlement agreement with its customers, this subsidiary reduced its commodity sales rate 11.5%, for a two-year period effective April 1, 1985, to a level below its then prevailing cost of gas. The effect of this settlement, resulting from customer concerns related to the high cost of gas, accounted for the loss recorded by the segment in 1985. Earnings in 1984 were depressed due, for the most part, to lower sales volumes caused by price competition.

• Earnings of the distribution segment for the years 1984 through 1986 are up substantially over the depressed results of 1983 and 1982. The substantial earnings improvement reflects: (1) the success of transportation programs to offset the effect of lower sales volumes; (2) a strong marketing program; (3) the effect of general rate filings more responsive to the current business environment; (4) reduced operating expenses; and (5) the sale of an unprofitable distribution subsidiary in 1984. Earnings in 1986 were also improved by $16.8 million resulting from court actions related to the recovery of certain previously expensed uncollectible customer accounts.

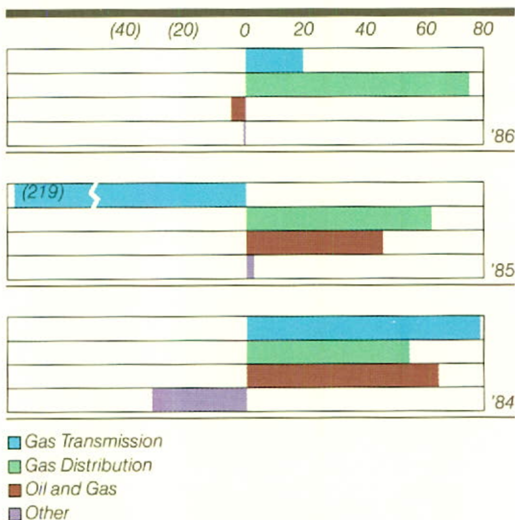
• The oil and gas segment recorded a loss in 1986 following declines in 1985 and 1984. Prices for both oil and gas, which had been dropping gradually since 1983, fell sharply in 1986. The decline in 1986 oil and gas prices resulted in second and fourth quarter charges against earnings aggregating $14.3 million to write-down the carrying value of Canadian oil and gas properties. In addition to the effect of lower prices, each of the three years was adversely impacted by lower gas production reflecting current market conditions.

• Results from other operations continue to be close to a break-even level following the elimination of unprofitable synthetic gas and coal mining operations. Earnings

TOTAL SYSTEM GAS THROUGHPUT
(In Billion Cubic Feet)



EARNINGS BY SEGMENT*
(In Millions of Dollars)



*From Continuing Operations before Extraordinary Charges

from depressed propane operations are offset by taxes and debt service related to the remaining investment in an idle coal mine.

EARNINGS OUTLOOK

Consolidated earnings have been below the $3.18 per share annual dividend that has been paid on common stock for two consecutive years. However, with the resolution of serious past problems, management expects 1987 earnings to be no less than the $3.18 dividend rate.

REVENUES

Total gas operating revenues have been declining since 1983 due to lower average sales rates and sales volumes. The decline in sales volumes is due to warmer than normal weather in 1986 and 1985, price competition and other factors. Other revenues, which increased significantly in 1985 and 1984 due principally to expanding transportation services, were reduced in 1986 by the effect of lower sales volumes and prices of oil, propane and other hydrocarbons.

EXPENSES

Gas purchased costs were down in each of the three years because of lower sales volumes. In addition, unit costs were down significantly in 1986 largely as a result of success in renegotiating contracts with producers. The decline in other products purchased is due primarily to the phasing out of synthetic gas operations, which were terminated at the end of March 1986.

Operation and maintenance expenses were down 9% in 1986 after modest increases in 1985 and

EARNINGS SUMMARY *($ in millions)*	***1986***	*1985*	*1984*
Earnings (Loss) on Common Stock	**75.3**	(107.0)	138.6
Discontinued Operations	**—**	—	26.9[d]
Extraordinary Charges	**12.6**[a]	—	—
Nonrecurring Items and Adjustments	**33.6**[b]	196.0[c]	32.6[e]
Adjusted Earnings	**121.5**	89.0	198.1
Adjusted Earnings per Share ($)	**2.93**	2.22	5.05

[a] Costs of $8.6 million ($0.21 per share) on refunding of long-term debt and an additional loss of $4.0 million ($0.09 per share) on sale of a distribution subsidiary (Note 5).*

[b] Additional charge of $33.6 million ($0.81 per share) for unrecovered gas purchased costs (Note 3A).*

[c] Charge of $207.0 million ($5.16 per share) to establish a reserve for unrecovered gas purchased costs (Note 3A) less an improvement to earnings of $11.0 million ($0.27 per share) reflecting the discontinuance of the application of Statement of Financial Accounting Standards No. 71 by the interstate transmission subsidiaries (Note 3B*).*

[d] Charge of $26.9 million ($0.69 per share) reflecting the decision to cease coal mining operations (Note 4).*

[e] Provision for loss of $30.0 million ($0.76 per share) related to synthetic gas operations (Note 3C) and an adjustment of $2.6 million ($0.07 per share) to increase the impairment reserve for the Alaskan Natural Gas Transportation System reflecting the decision to withdraw from the partnership.*

**Notes to Consolidated Financial Statements.*

TOTAL REVENUES AND THROUGHPUT	***1986***	*1985*	*1984*
Gas Operating Revenues ($000):			
Residential	**1,115,572**	1,210,623	1,278,745
Commercial	**502,712**	566,608	617,593
Industrial	**223,585**	383,177	592,084
Wholesale	**1,229,090**	1,566,005	1,843,234
Other	**16,088**	12,195	15,248
Total Gas Operating Revenues	**3,087,047**	3,738,608	4,346,904
Transportation Revenues	**192,187**	174,581	92,730
Other Operating Revenues	**90,344**	147,730	163,488
Total Revenues	**3,369,578**	4,060,919	4,603,122
Sales (Million Cubic Feet):			
Residential	**178,750**	181,354	188,471
Commercial	**87,222**	91,579	97,042
Industrial	**47,669**	73,252	108,124
Wholesale	**283,593**	344,594	384,967
Other	**9,226**	4,238	4,255
Total Sales	**606,460**	695,017	782,859
Total Transportation Volumes	**541,497**	511,148	423,427
Total Throughput	**1,147,957**	1,206,165	1,206,286

1984. All periods reflect the effect of System-wide cost containment programs and moderate levels of inflation. Expenses in 1986 were reduced $31.1 million resulting from court actions related to the recovery of certain previously expensed uncollectible accounts. In addition,1986 pension costs were reduced due in part by the adoption of Statement of Financial Accounting Standards No. 87 as more fully described in Note 8 of Notes to Consolidated Financial Statements.

The decrease in 1986 depreciation and depletion is due to lower rates on transmission properties, partially offset by higher rates applicable to distribution properties and the write-down of the carrying value of Canadian oil and gas properties.

INTEREST INCOME AND OTHER, NET

Interest and other income decreased $61.1 million from 1985 due to reduced earnings from temporary cash investments and the recording to income in 1985 of gains on reacquired debt of $48.3 million which previously were deferred and amortized to income in accordance with rate treatment.

INTEREST EXPENSE AND RELATED CHARGES

The increases in interest expense and related charges in both 1986 and 1985 reflect the financial impact of the steps taken in 1985 to solve customer and producer problems of the System's principal transmission subsidiary.

INCOME TAXES

Income taxes, as detailed on the Statements of Consolidated Taxes, increased in 1986 due primarily to an increase in pre-tax book income and the elimination of investment tax credits. In 1985, the decrease was due principally to the pre-tax nonrecurring charge of $400 million related to previously deferred unrecovered gas costs.

EFFECTS OF INFLATION

Because the Corporation's subsidiaries are engaged in capital intensive lines of business, cumulative effects of inflation cause substantially greater investment to replace existing productive capacity. However, such replacements occur gradually and revenues have kept pace in order to recover plant investment.

During periods of high inflation, current operating cost increases are generally not concurrently reflected in increased revenues due to lag effects inherent in the ratemaking process governing the Corporation's regulated subsidiaries. Inflation rates have subsided recently and together with effective cost containment programs have resulted in a better matching of revenues with current operating costs.

The Corporation's unregulated subsidiaries, principally oil and gas producers, are essentially operating in a commodity environment. As such, prices are influenced by relative scarcity (supply and demand) rather than cost. Oil and gas are significant commodities in the determination of inflationary effects. In general, therefore, during periods of declining oil and gas prices, inflation rates tend to stabilize or decline with similar effects on plant investment and operating costs related to production.

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,

QUARTER ENDED	*Market Price*			*Quarterly*
	High	*Low*	*Close*	*Dividends Paid*
	$	**$**	**$**	**¢**
1986				
December 31	**46**	**41¼**	**45¼**	**79.5**
September 30	**43⅝**	**37¾**	**41¾**	**79.5**
June 30	**43¾**	**35¾**	**43¼**	**79.5**
March 31	**41½**	**34¾**	**38¾**	**79.5**
1985				
December 31	40	32½	39½	79.5
September 30	34⅜	30	32⅝	79.5
June 30	32	27¼	32	79.5
March 31	34	26¾	27½	79.5

1986, there were 104,284 stockholders of record. The table on the left shows the dividends paid and the price range of the Corporation's common stock by quarters of the last two years.

LIQUIDITY AND CAPITAL RESOURCES

The year 1986 brought a significant improvement in the Corporation's financial position. During the year, the Corporation accessed the long-term public debt markets for the first time since 1982 and re-entered the commercial paper market for the first time since 1984. In addition, the Corporation successfully sold a 1.25 million share common stock issue at competitive bidding. During the year, $249 million of debentures were retired, $167 million of which had interest rates of 11¾% or higher.

Capital market conditions also improved and the weighted daily average interest rate for commercial paper issued by the Corporation was 6.4%. The Corporation's common stock continued its strong performance in the marketplace, closing the year at $45.25 per share, up from its 1985 year-end closing price of $39.50.

FUNDS FROM OPERATIONS

Cash from continuing operations increased from $81.7 million in 1985 to $574.0 in 1986. The increase is primarily attributable to the turnaround in operating income in the transmission segment.

FUNDS FROM FINANCING

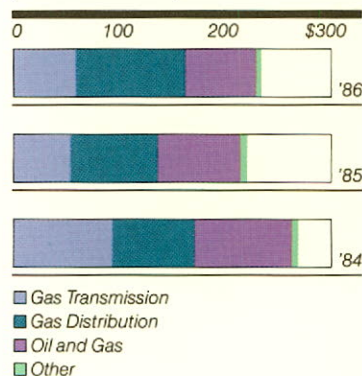
Net external financing requirements decreased from $520 million in 1985 to $58 million in 1986, although total long-term financing increased from $178 million to $356 million because of the substantial amount of debt retired during the year. The decrease in net financing requirements was largely a result of the improvement in cash from operations. For the first time since 1982, the Corporation accessed the public debt markets with a negotiated offering led by Morgan Stanley & Co. Incorporated. In August 1986, the Corporation sold $150 million of 9% Debentures, Series Due 1993 and $100 million of 10¼% Debentures, Series Due 2011. In September 1986, the Corporation sold 1.25 million shares of common stock via a competitive offering that was underwritten by Prudential-Bache Securities. Net proceeds were $51.4 million or $41.207 per share to the Corporation. In addition, approximately 747,000 shares of common stock were issued under the Dividend Reinvestment Plan and the Payroll Stock Ownership Plan. Proceeds to the Corporation were $29.3 million.

The Corporation regained access to the commercial paper market with the upgrading of its securities to A-2/P-2 by Standard & Poor's and Moody's in January 1986. Commercial paper is used to fund the Corporation's working capital requirements, primarily gas storage inventory and accounts receivable. Average short-term debt outstanding during 1986 was $165 million. Commercial paper outstanding on December 31, 1986, was $393 million. The commercial paper will be repaid with normal seasonal cash receipts early in 1987. The commercial paper program is supported by a $500 million credit facility and $25 million of additional bank lines of credit.

CAPITAL EXPENDITURES

Capital expenditures in 1986 were $232 million, down from the earlier projection of $310 million. Capital expenditures are projected to be $300 million in 1987. Because of depressed product prices, the capital program for the oil and gas segment will continue at reduced levels. As part of the continued

SUMMARY OF GROSS CAPITAL EXPENDITURES BY SEGMENT
(In Millions of Dollars)



marketing effort of Transmission to attach new loads, capital investments in its pipeline operations will increase by approximately $46 million in 1987. In addition, Transmission, in December 1987, will make the third and final installment payment due certain producers for contract modifications. The payment is estimated to be approximately $280 million.

The Corporation is investigating the purchase of businesses and properties in various segments of the natural gas business. The aggregate which might be incurred by the Corporation with respect to such acquisitions in 1987 is not expected to exceed $200 million. One possible acquisition is in an advanced stage of confidential negotiations, but the parties have not reached an agreement. Any acquisition would be subject to the receipt of required state and Federal regulatory approvals.

REFUNDING

During 1986, $249 million of debentures were retired including approximately $167 million principal amount of high-cost debentures, as shown below:

To minimize refunding costs, a program of partial retirements is being used to take maximum advantage of the mandatory and accelerated sinking fund redemption provisions included in the individual debenture series' indentures. These provisions permit limited periodic redemptions without the payment of premiums. It is presently anticipated that the remaining amounts outstanding of the 15⅜%, 12¾% and 11¾% debentures will be retired in this manner by 1989.

DIVIDENDS

In 1986, the Corporation paid dividends of $3.18 per share on its common stock. As of December 31, 1986, the Corporation had $159 million of retained earnings available for preferred and common stock dividends under the most restrictive covenants of the Corporation's loan agreements.

DEBENTURES *($ in thousands)*	*Retired in 1986*	*Balance Outstanding at 12/31/86*
11¾% Series due October 1999	56,100	31,250
12¾% Series due August 2000	62,375	31,250
15⅜% Series due June 1997	48,226	51,774
	166,701	114,274

Pipeline sections 30 inches in diameter await the construction crew on a West Virginia expansion project.

TAX REFORM ACT OF 1986

Although the Tax Reform Act of 1986 reduces corporate tax rates from 46% to 40% in 1987 and 34% thereafter, it also contains provisions that eliminate investment tax credits and extend the tax depreciation lives of distribution and transmission properties. As a result, it is not expected that the Corporation's future tax payments will be significantly affected by the Tax Reform Act.

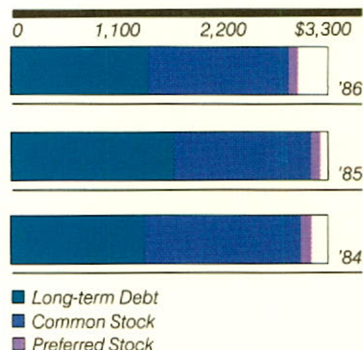
The Corporation's subsidiaries have utilized comprehensive interperiod tax allocation methods to recognize timing differences in the determination of income taxes for financial statement and tax return purposes, except for depreciation differences related to distribution properties acquired prior to 1981, at rates equal to or greater than 46% tax rates. As a result, substantial "excess future tax liabilities" are included in the accompanying December 31, 1986, balance sheet. The Corporation expects that the benefit of the "excess future tax liabilities" related to regulated depreciable properties will be recognized in determining future rates to utility customers over the remaining lives of the related assets. The benefit of similar liabilities associated with nonregulated depreciable properties ultimately will be reflected in future years' income. Timing differences other than those related to depreciable properties generally reverse in one year.

The Financial Accounting Standards Board is currently considering the method of accounting for income taxes that would require the immediate recognition of changes in future tax liabilities rather than recognizing the excess or deficiency as the timing differences reverse. If this proposed standard is implemented, 1987 and future years' tax expense recorded in the financial statements could be subject to material variation as tax rates change.

1987 FINANCING

Long-term financing requirements for 1987 are currently projected to be approximately $250 million. Approximately $105 million is earmarked for the retirement of previously issued debentures. Funding will be provided by selling some portion or a combination of the $200 million remaining on the debenture shelf registration and the remaining 1.75 million shares on the common stock shelf registration. The Corporation had approximately $400 million of bondable credit available under the most restrictive covenant of its Indenture at year-end 1986. This covenant requires that earnings before interest and taxes exceed 2½ times interest on senior debt. At December 31, 1986, Transmission had $175 million outstanding under its $350 million Limited Recourse Loan Agreement (the Production Loan). In January 1987, $100 million of such amount outstanding was repaid leaving $275 million available.

The Corporation believes that it will have adequate capital resources to meet its 1987 liquidity requirements. The resources include (1) the additional $275 million available under the Production Loan; (2) sales of its commercial paper and the amounts available under a $500 million credit facility and a $25 million committed line of credit; (3) authorized but unissued shares of common stock of the Corporation; and (4) senior debt capacity available under its Indenture.



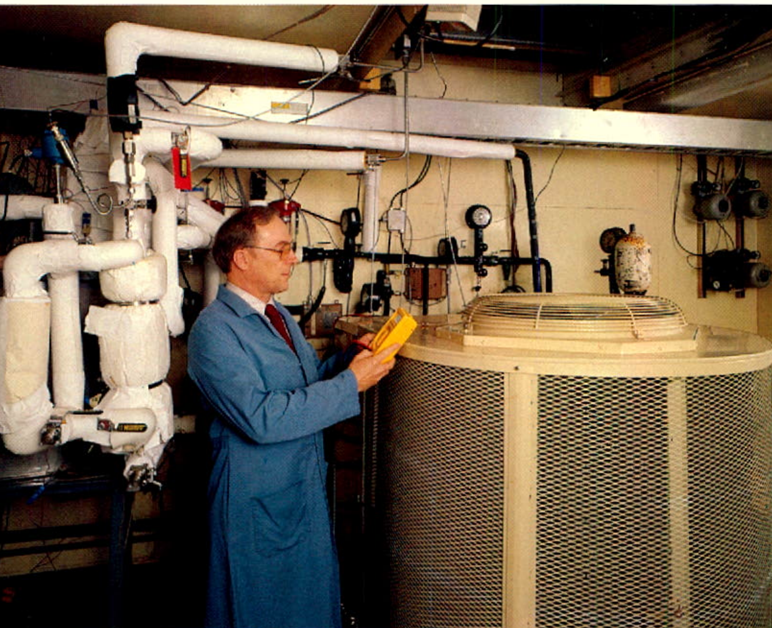
A PIVOTAL YEAR

Aggressive actions taken in 1985 to solve crippling problems with customers and producers set the groundwork for Transmission in 1986 to gain the gas price flexibility and market position necessary for it to play a leading role in the new market-driven business environment.

In 1985, three major events took place:

- Transmission entered into a settlement agreement with its wholesale customers resolving claims concerning Transmission's gas acquisition policies and practices and providing a two-year freeze until April of 1987 of Transmission's commodity sales rate at a level then below its cost of gas in return for its customers' every efforts commitments to purchase gas.
- Transmission instituted a program whereby $800 million was offered to certain high-cost producers in exchange for flexible takes and contract modifications which would reduce gas purchase prices to market levels and allow periodic price redeterminations. By the end of 1986, producers accounting for 94% of the high-cost gas covered by the program, had accepted the offer.
- FERC instituted Order 436 which provided for participation on a voluntary basis in a procedure which fosters sweeping changes in the traditional way pipelines conduct business. Transmission and Gulf were the first major pipeline systems to accept FERC's Order 436.

Research to develop a gas-fired heat pump is being intensely pursued by the Gas Research Institute. Columbia's research laboratory in Columbus, Ohio is a major participant in the effort.



FOCUS ON MARKETING

While its operations and systems were being adjusted to the new business conditions, Transmission focused increased attention in 1986 on the marketing function. It reorganized and expanded its marketing department and is now strategically placing marketing staffs to serve both historic customers and to acquire new markets.

The marketing program is enhanced by Transmission's strong gas reserve position and storage capabilities which make it one of the few pipeline companies willing and able to offer new firm sales commitments to distributors. The transmission companies have also demonstrated the willingness to construct facilities to add capacity and to serve new customers.

The 1986 marketing effort secured many new transportation markets, including gas distribution companies serving communities in Tennessee and Alabama. Agreements were also finalized with two Eastern Seaboard utilities to sup-

plement sales and transportation service presently supplied by a competing pipeline. Applications to construct necessary facilities to initiate service are pending regulatory approval. Additional negotiations with other potential customers are ongoing.

PROPOSED RATES MORE COMPETITIVE

Transmission and Gulf filed for new rates to become effective April 1, 1987, the end of the two-year settlement period. The new rates have been designed to improve Transmission's ability to compete for sales with other interstate pipelines. While the proposed rates allow for the recovery of additional non-gas costs, the commodity rate is expected to be reduced from the present $3.59 per dekatherm to approximately $2.74 per dekatherm, assuming the elimination of minimum commodity bills of pipeline suppliers, as a result of Transmission's lower gas purchased costs. Estimates of lower gas costs, coupled with certain provisions of the customer settlement, indicate a significantly lower commodity sales rate commencing September 1987.

Included in the filing are seasonal entitlements that establish Transmission's maximum sales obligations to wholesale customers. These seasonal entitlements are essential to determine Transmission's long-term merchant function and its gas acquisition strategy of contracting for sufficient supplies of gas to meet customers' future needs, while, at the same time, avoiding take-or-pay liability. The filing also proposes maximum and minimum rates to be charged local distribution companies and end-users for transportation services on either a firm or interruptible basis. These rates include a reservation charge for firm transportation.

On October 30, 1986, the FERC accepted the rate filing, subject to refund. Various parties, challenging certain provisions of the filing, have requested a rehearing of the FERC order. Conferences with customers and other parties are being held in order to reach a settlement.

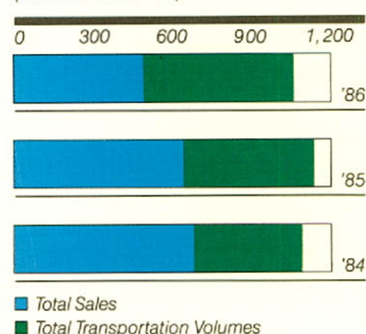
SOME PROBLEMS REMAIN

While Transmission has successfully reduced its past and potential take-or-pay obligations to producers to manageable levels, several of Transmission's pipeline suppliers have not. They have proposed various methods to the FERC under which they would bill their take-or-pay and contract reformation costs directly to their customers in a manner representing a departure from traditional demand-commodity rate treatment. Transmission has vigorously opposed such proposals. The FERC is considering issuing a non-binding policy statement providing for a form of direct billing and pass through by downstream pipelines like Transmission, which would be considered in individual pipeline cases. Management remains of the view that ultimately direct billing will not be permitted.

Concurrently, Transmission has opposed the use of minimum commodity bills in pipeline rates as inhibiting competitive forces and lessening the effectiveness of least-cost purchasing efforts of customers. Minimum bills, which are provisions to recover certain fixed costs when purchases fall below a specified quantity, are being consistently eliminated by the FERC in each rate proceeding as the issue is presented. Management is confident that minimum bills on all pipeline systems ultimately will be eliminated. However, without prompt action, Transmission projects that its April 1, 1987, Purchased Gas Adjustment will include $30.7 million in minimum commodity bill charges for the five-month period ending August 31, 1987, which will result in an increase in its projected commodity sales rate of approximately 15 cents.

More than one year after imple-

TRANSMISSION GAS THROUGHPUT
(In Billion Cubic Feet)



menting Order 436, Transmission and Gulf, along with the FERC and other pipelines, continue to seek workable rules and procedures to implement the Order. Many of the provisions of Order 436 are now under legal challenge.

Great uncertainty exists as to how much Order 436 will change the traditional merchant function of interstate pipelines or what action state regulatory authorities will take to require that distribution companies adopt the more flexible supply arrangements possible under the Order. Management voiced concern over the lack of guidelines defining the merchant role of pipelines because: (1) without adequate sales commitments from customers, pipelines are hesitant to contract for long-term supplies from producers; and (2) the expansion of direct spot market purchases by distributors, because of pressures from state regulators to follow "least cost" purchasing policies, does not send proper market signals to producers. Because of these factors, producers delay drilling for replacement gas supplies, raising the possibility of future shortages.

Recognizing these uncertainties, and the possibility of increased competition from other pipelines accepting Order 436, management believes that Transmission is positioned to compete effectively in the changed business environment. Transportation will continue to play a major role as Transmission pursues its objective of providing customers both sales and transportation services at competitive prices.

A surface marker is the only evidence a pipeline passes under this cornfield. Usually land reverts to its original state along a pipeline right-of-way.

FINANCIAL RESULTS

REVENUES

Total revenues decreased in each of the three years with declining sales volumes being partially offset by higher transportation revenues. Unlike sales revenues, transportation revenues do not include the cost of gas delivered. Total revenues in 1986 and 1985 also reflected the effect of the 11.5% reduction in Transmission's commodity sales rate effective April 1, 1985. The trend of declining revenues is expected to continue due largely to Transmission's successful efforts to reduce its gas purchased costs which will result in a lower commodity sales rate effective April 1, 1987, and thereafter.

VOLUMES

Sales volumes were down 22% in 1986 primarily because of price competition and warmer weather. In addition, a change in the delivery pattern of prepaid sales volumes to affiliated distribution companies resulted in higher than normal intersegment revenues being recorded in 1985 and lower revenues in 1986.

Transportation volumes, excluding short haul volumes, were up 15% over 1985 as gas transported for local distribution companies and their end-users continued to increase significantly, particularly since 1983. Short haul volumes, which represent Gulf's transportation of offshore production for others to onshore delivery systems, decreased 11% to 195 Bcf in 1986.

With the implementation of Order 436, Gulf's mainline pipeline facilities operated at nearly full capacity for most of 1986.

NONRECURRING CHARGES AND ADJUSTMENTS

The settlement agreement between Transmission and its wholesale customers (as more fully described in Note 2A of Notes to Consolidated Financial Statements), did not provide adequate assurance that Transmission could recover from customers previously deferred purchased gas costs. Accordingly, Transmission recorded a charge against operating income of $400 million in 1985 and an additional charge of $65 million in 1986. The additional 1986 charge recognized new estimates of retroactive payments to suppliers and revised projections of the amounts to be recovered from customers.

GAS TRANSMISSION *($ in thousands)*	***1986***	*1985*	*1984*
Unaffiliated Revenues	**1,391,900**	1,653,600	1,904,000
Intersegment Revenues	**1,072,900**	1,551,900	1,543,500
Total Revenues	**2,464,800**	3,205,500	3,447,500
Operating Income	**167,600**	(326,400)	224,100
Depreciation and Depletion	**114,600**	136,900	120,700
Capital Expenditures	**60,700**	55,600	96,200
Identifiable Assets	**3,362,100**	3,630,300	3,045,200

OPERATING INCOME

Operating income before the nonrecurring charges was $232.6 million in 1986, $73.6 million in 1985 and $224.1 million in 1984.

Since April 1, 1985, operating income has been greatly influenced by the terms of the settlement agreement between Transmission and its wholesale customers. The reduced commodity sales rate, which runs for two years, was initially below Transmission's prevailing cost of gas. The sales rate was designed to provide recovery of operating expenses and other costs of $0.31 per dekatherm, once Transmission reduced its purchased gas costs to a designated level.

The significant increase in 1986 operating income over 1985 was due largely to Transmission's success in lowering its purchased gas costs, producing a continual improvement in the sales margin through September 1986. By September, Transmission had reduced its accumulated average gas purchased costs for the settlement period beginning April 1, 1986, below the level designated in the settlement agreement. As a result, as of April 1, 1986, Transmission began recovering the maximum sales margin established in the sales rate, in addition to its gas purchased costs. Operating income in 1985 was depressed by operating losses in the last three quarters resulting from Transmission's high cost of gas.

In addition, the improvement in operating income reflected the following factors:

- A decrease in labor and benefit costs. Expenses in 1985 included $13.6 million for a voluntary severance program accepted by approximately 200 employees.
- Lower depreciation expense due to the 1986 reduction in depreciation rates on transmission properties while a $7.0 million upward adjustment related to the liquefied natural gas facility was recorded in 1985.
- An increased contribution to operating income generated by transportation services which partially offset the effect of lower sales volumes.

Operating income in 1986 improved 4% over 1984 despite the reduction in sales volumes as a result of: (1) the reduction in operating expenses particularly labor and pension costs; (2) the expansion of transportation services; (3) a decision in late 1983 to defer a general rate filing to recover increased costs; and (4) the adverse effect of a rate formula through October 31, 1984, which precluded the recovery of certain fixed costs as sales volumes declined.

OUTLOOK

The costly and difficult actions taken by Transmission in 1985, followed by the major achievements in 1986, provide a foundation for improved financial results in 1987. Success in 1987 will be largely dependent on Transmission's ability to retain and expand existing markets and acquire new markets, and the final outcome of Transmission's new general rate filing with the FERC.

On February 18, 1987, Columbia and ANR Pipeline Company filed an application with the FERC under which a Columbia subsidiary will participate in the proposed Erie Pipeline System. This pipeline will connect in western Ohio with the ANR interstate system and run to western Pennsylvania. The project will expand Columbia's access to supplies of domestic and Canadian gas.

MAJOR 1986 ACHIEVEMENTS

During 1986, the Corporation's distribution subsidiaries were able to match the performance levels of 1985 and 1984, largely through the following marketing achievements:

- The addition of 30,200 new residential and commercial customers.
- Converting 2,400 existing residential and commercial customers to heat usage.
- Tailoring transportation services to meet customer needs thereby retaining industrial markets that could have been lost to competitive suppliers.

MANAGING GAS SUPPLY

Historically, the Corporation's distribution companies concentrated on the marketing function and relied on the affiliated pipeline company, Transmission, to supply most of the natural gas needed to supply customers. In the early 1980's, as natural gas prices rose, the distribution companies bought some local supplies to mitigate the rising costs. Beginning in 1985, the distribution companies were also able to obtain some lower-cost supplies directly from Southwest producers under transportation provisions of the customer settlement agreement with Transmission. Order 436 enables the distribution companies to incrementally reduce their purchase commitments from Transmission over a five-year period and to convert all or a portion of their gas purchase commitments to firm transportation, if appropriate. With Transmission and Gulf operating under Order 436, the distribution companies could immediately increase their direct purchases from Southwest suppliers. To further lower gas costs, the distribution companies also began transporting available gas through nonhistoric pipeline suppliers.

The distribution companies' strategic gas supply plan is intended to provide flexibility to meet uncertainties related to gas availability, the merchant role of pipelines, oil prices and state regulations related to transportation and gas supply. The continuing objective is to obtain gas supplies at the least cost consistent with reliability of delivery.

MANAGING COMPETITION AND EXPANDING MARKETS

Over the 1984-86 period, the distribution companies have exhibited their ability to succeed in an intensively competitive market. The steep drop in 1986 oil prices further sharpened competition. However, the distribution companies met this challenge by offering transportation services tailored to meet individual customer needs, thereby averting a significant reduction in throughput.

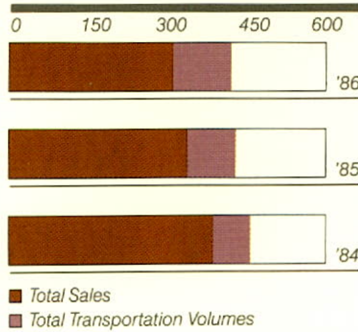
Utilizing their declining rates and the availability of new energy efficient gas appliances, the distribution companies expanded their market share of new housing starts, particularly in new suburban areas. In addition, they sold gas service to 75% of the multi-family housing units completed in the operating area during 1986.

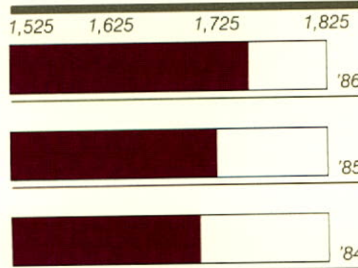
Expanded economic development programs helped bring 43 new manufacturing and distribution facilities into Columbia's retail territory in 1986, providing signifi-

cant new sales volumes, new job opportunities and the potential for additional residential, commercial and industrial growth in adjacent areas.

In the cogeneration market, the distribution companies contracted to serve two major cogeneration plants, one of which will be the largest single industrial customer served by the Pennsylvania subsidiary. To further development in this important market, the Corporation formed a new subsidiary, TriStar Ventures Corporation, to help finance new projects.

In Virginia, the subsidiary presently serving areas adjacent to the city of Richmond has filed for authorization to expand service to an area which is expected to experience substantial economic growth. Another Virginia distributor is also seeking to serve the area in addition to other areas presently served by the Corporation's subsidiary and other companies.





The Commonwealth companies moved into a new headquarters building in suburban Richmond, Virginia in 1986, symbolizing their expanding operations.

FINANCIAL RESULTS

REVENUES

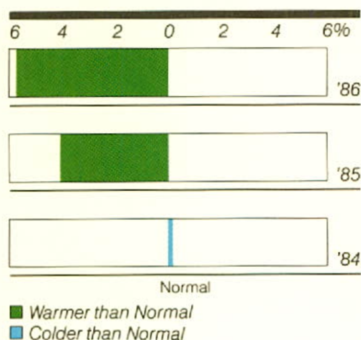
Total revenues declined 14% in 1986 and 12% in 1985 due primarily to: (1) lower sales rates reflecting the continuing effort of the distribution subsidiaries to reduce the cost of gas; (2) the replacement of certain industrial and commercial sales revenues with lower transportation revenues which do not include the cost of gas; and (3) lower sales volumes related to weather.

VOLUMES

Total throughput decreased 2% in 1986 and 5% in 1985. The throughput decreases in both years reflected the effect of warmer weather which reduced heat usage by residential and commercial customers. The weather in each year was warmer than normal and warmer than 1984. In addition, industrial sales volumes were adversely impacted by plant shutdowns. These factors were partially offset by the addition of new customers.

Sales volumes which were reduced due to increased purchases by commercial and industrial customers directly from producers, continued to be substantially offset by transportation volumes.

DEGREE DAYS
(Variation from Normal in Percent)



GAS DISTRIBUTION *($ in thousands)*	*1986*	*1985*	*1984*
Unaffiliated Revenues	**1,853,500**	2,149,000	2,458,700
Intersegment Revenues	**7,600**	3,800	900
Total Revenues	**1,861,100**	2,152,800	2,459,600
Operating Income	**184,700**	135,700	129,200
Depreciation and Depletion	**45,900**	38,300	30,500
Capital Expenditures	**101,000**	80,900	76,600
Identifiable Assets	**1,471,900**	1,519,000	1,315,500

OPERATING INCOME

Operating income was up 36% in 1986 and 5% in 1985. All three years were up substantially over the depressed levels of 1982 and 1983 when income was adversely impacted by the inability to recover operating costs due to declining sales volumes.

Operating income in 1986 was improved $31.1 million by court actions related to the recovery of certain previously expensed uncollectible customer accounts. Absent this adjustment, operating income improved 13% over 1985 due largely to reduced expenses and, to a lesser extent, improved sales margins from general rate filings placed into effect throughout 1985. The reduction in operating expenses is due largely to a reduction in pension expense, continued effect of cost containment programs and a decline in normal uncollectible accounts because of lower average monthly gas bills resulting from lower sales rates, partially offset by the effect of higher depreciation rates.

Operating income in 1985, as well as in 1984, was influenced by general rate increases placed into effect since 1983 and the positive effect of cost containment programs.

FINANCIAL OUTLOOK

Disregarding the effect of the $31.1 million favorable adjustment recorded in 1986, the income level for this segment has been fairly constant and is expected to be at an acceptable level in 1987. The marketing effort is expected to produce additional new loads in 1987 which will help offset the effects of conservation and other economic factors. The effect of conservation has leveled off, but continues to be a factor as customers utilize energy efficient appliances and residences are better insulated.

MARKET CONDITIONS

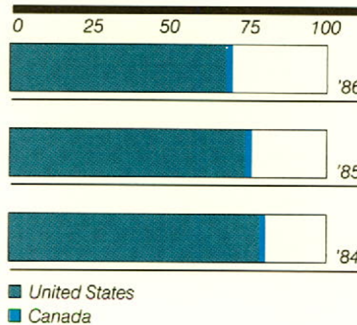
The precipitous fall in 1986 earnings for the oil and gas segment resulted from a 40% drop in the average price of a barrel of oil coupled with an accelerated reduction in average natural gas prices.

Although oil production is less significant in the System's oil and gas operations, competition from oil as an alternative energy source has resulted in a corresponding decline in natural gas prices. Adding to the pressure on gas pricing has been a significant increase in gas-to-gas competition resulting from regulatory changes in transportation policies which have allowed distributors and large end-users to increasingly purchase natural gas at depressed prices on the spot market.

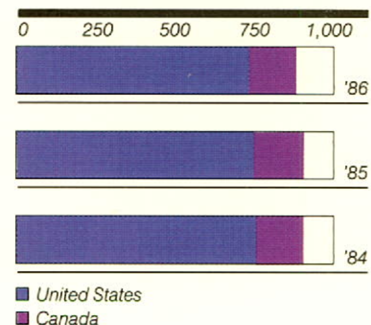
This sharp drop in prices not only impacted earnings, but led to a substantial reduction in expenditure levels. Capital expenditures were limited to $67 million as drilling operations were curtailed earlier in the year and reserve acquisitions failed to materialize later in the year. Contingent plans, developed in conjunction with earlier strategic analyses, provided the means of orderly withdrawal from projects, minimizing the long-term adverse effects on the System and its reserves goals. Capital expenditures for 1987 are expected to be at approximately the same level as in 1986.

A major condominium project planned in Columbus, Ohio will use Columbia-developed space/water heaters in each of its 97 residence units.

GAS PRODUCTION
(In Billions of Cubic Feet)



GAS RESERVES
(In Billions of Cubic Feet)



EXPLORATION AND DEVELOPMENT STRATEGY

During this period of price instability, the System's objective is to position itself to participate in the next upswing in exploration and development activity. The evaluation of and participation in drillable prospects is based on a conservative long-range outlook for world oil prices. Lease acquisition is being carried out in both the Southwestern United States and Canada for new acreage in those areas where Columbia has regional data or data related to specific prospects.

The impact of capital expenditure reductions on exploration and development drilling operations in 1986 varied by region and similar strategies are expected to be followed in the deployment of 1987 funds.

Columbia research engineers conduct studies involving new appliances, more efficient utilization techniques and improved operating methods.

In the Southwest and Rocky Mountain areas, development drilling is being limited to only those wells which are economic at current prices, or which are required to hold valuable leases for future development. A similar program is being operated in the Appalachian area, partially controlled by the funds available to drilling partners and partially by leasehold terms. In Canada, drilling is at a moderate level with emphasis on evaluating selected areas and testing specific projects.

The operator of the Hibernia development project, Mobil Oil Canada Ltd., filed in 1985 on behalf of the Hibernia partners with both the federal and provincial governments the Development Plan and the Canada/Newfoundland Benefits Plan for the development of the Hibernia field. Both of these plans were approved by Canada and Newfoundland during 1986. Commencement of the development project is awaiting finalization of special fiscal terms, currently being negotiated between the Hibernia consortium and the governments of Canada and Newfoundland.

SYSTEM LEASE HOLDINGS

The System's lease holdings total 3.6 million net acres, of which, 1.4 million represents developed acreage. Total net acreage is down from last year's 4.5 million due largely to surrendered interests in Canadian undeveloped mainland and offshore lease holdings under terms of exploration agreements.

Domestic lease holdings total 3.0 million net acres. Of this amount,

90% is in the Appalachian area. Canadian holdings total 0.6 million net acres, including a 5.47% interest in the 256,000 gross acres encompassing the Hibernia, Hebron, Nautilus and Mara structures offshore Newfoundland. Holdings in this block were reduced from the 307,051 gross acres reported last year due to acreage surrendered under terms of exploration agreements.

Columbia continues to have one of the largest lease holdings among major gas companies.

1986 DRILLING ACTIVITY

The System's oil and gas subsidiaries participated in 109 exploration wells and 131 development wells during 1986, with success rates of 26% and 78%, respectively.

FINANCIAL RESULTS

REVENUES AND VOLUMES

Total 1986 revenues decreased 32% from 1985 and 41% from 1984 reflecting the drop in oil and gas prices and production. Intersegment revenues were up slightly over the depressed level in 1985 which resulted from lower sales to Transmission. However, in 1985, sales were increased to unaffiliated customers through special marketing programs, most of which were not available in 1986.

OIL AND GAS *($ in thousands)*	**1986**	*1985*	*1984*
Unaffiliated Revenues	**65,100**	156,200	98,800
Intersegment Revenues	**106,800**	97,700	193,500
Total Revenues	**171,900**	253,900	292,300
Operating Income	**14,800**	100,900	133,900
Depreciation and Depletion	**94,500**	84,700	92,400
Capital Expenditures	**66,800**	78,200	92,100
Identifiable Assets	**746,800**	**766,700**	**836,700**

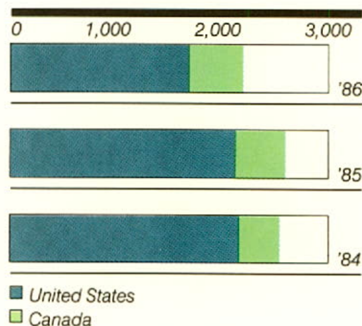
OPERATING INCOME

The significant reduction in 1986 operating income reflects charges to depletion expense totaling $26.6 million relating to the write-downs of the carrying value of Canadian oil and gas properties. The write-downs were necessitated by lower prices for oil and gas at the end of the second and fourth quarters. In addition, 1986 and 1985 results include the effects on revenues described above and slightly higher depletion rates and average lifting costs.

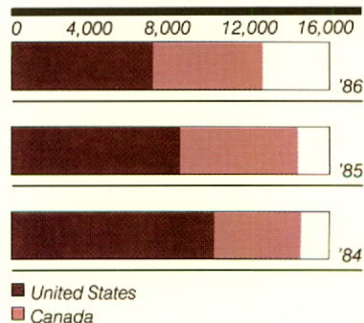
FINANCIAL OUTLOOK

At the beginning of 1987, oil and gas prices began to rebound slightly which would indicate some improvement in 1987 earnings and reduce the possibility of further write-downs of the carrying value of oil and gas properties.

OIL PRODUCTION
(In Thousands of Barrels)



OIL RESERVES
(In Thousands of Barrels)



Well-maintained, efficiently-operated interstate pipelines enable Columbia to provide low-cost transportation for its own gas and that being delivered for other shippers.

PROPANE OPERATIONS

Propane ranks fourth in supplying the nation's energy needs. The market for the versatile fuel has grown steadily since 1982, primarily in 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.

Commonwealth Propane, Inc. is a major propane marketer in Virginia, with a well balanced customer mix of residential, industrial, commercial and other large volume sales. Commonwealth Propane is also a major marketer of gas appliances in the state.

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, its sales are greatly influenced by the level of Appalachian natural gas production. Sales to distributors represent over 50% of propane sales volumes, but potential growth is limited by the cost of deliveries to the customers' bulk terminals.

SYNTHETIC GAS OPERATIONS

Columbia LNG Corporation discontinued the production of synthetic gas at its Green Springs, Ohio plant effective March 31, 1986, and sold the plant.

OTHER OPERATIONS *($ in thousands)*	**1986**	*1985*	*1984*
Unaffiliated Revenues	**59,100**	99,700	145,100
Intersegment Revenues	**5,400**	46,400	103,700
Total Revenues	**64,500**	146,100	248,800
Operating Income	**1,300**	7,400	(54,800)
Depreciation and Depletion	**1,400**	4,100	5,800
Capital Expenditures	**3,800**	5,300	7,200
Identifiable Assets	**70,200**	88,600	96,500

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.

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, Columbia owns approximately 550 million tons of other low-sulphur coal reserves, some of which are now leased to others for development. If and when opportunities develop, certain small blocks may be offered for sale with Columbia retaining overriding royalties.

FINANCIAL RESULTS

REVENUES

Revenues of this segment have been declining since the first quarter of 1984 due to the curtailed operations of the synthetic gas plant up to the permanent cessation of production on March 31, 1986. Revenues from synthetic gas sales were $12.2 million in 1986, $75.6 million in 1985 and $171.3 million in 1984. Wholesale propane sales in Ohio and Kentucky were down substantially in 1986 due to price competition. Revenues from sales of other products recovered from the Appalachian fractionation plant also decreased due to lower volumes and prices. Propane revenues decreased in 1985 due primarily to lower agricultural and wholesale sales.

OPERATING INCOME

The reduction in 1986 operating income is due largely to the operating loss sustained by the operations related to the Appalachian fractionation plant. Operating income since 1984 was improved by the termination of losses related to synthetic gas and other unprofitable operations.

COMPARATIVE GAS OPERATIONS DATA

The Columbia Gas System, Inc. and Subsidiaries

	1986	1985	1984*	1983	1982
Gas Operating Revenues (in thousands)					
Residential	**$1,115,572**	$1,210,623	$1,278,745	$1,357,686	$1,256,348
Commercial	**502,712**	566,608	617,593	646,394	594,316
Industrial	**223,585**	383,177	592,084	841,891	938,120
Wholesale	**1,229,090**	1,566,005	1,843,234	2,032,807	2,074,838
Other	**16,088**	12,195	15,248	16,878	17,370
Total gas operating revenues	**$3,087,047**	$3,738,608	$4,346,904	$4,895,656	$4,880,992
Transportation Revenues (in thousands)	**$ 192,187**	$ 174,581	$ 92,730	$ 59,750	$ 40,857
Sales (million cu. ft.)					
Residential	**178,750**	181,354	188,471	207,225	230,325
Commercial	**87,222**	91,579	97,042	104,606	115,678
Industrial	**47,669**	73,252	108,124	151,034	202,591
Wholesale	**283,593**	344,594	384,967	409,070	502,382
Other	**9,226**	4,238	4,255	4,364	4,821
Total sales	**606,460**	695,017	782,859	876,299	1,055,797
Transportation volumes	**541,497**	511,148	423,427	262,798	198,004
Total throughput	**1,147,957**	1,206,165	1,206,286	1,139,097	1,253,801
Sources of Gas Sold (million cu. ft.)					
Total gas purchased	**596,837**	616,919	705,070	758,739	1,004,117
Total gas produced (natural and synthetic)	**73,214**	101,020	125,462	115,921	138,547
Exchange gas—net	**7,732**	(10,346)	(1,558)	(2,252)	(4,091)
Gas withdrawn from (delivered to) storage	**(24,257)**	44,980	(1,879)	46,062	(38,571)
Company use and other	**(47,066)**	(57,556)	(44,236)	(42,171)	(44,205)
Total sources of gas sold	**606,460**	695,017	782,859	876,299	1,055,797
Customers at Year-End					
Residential	**1,598,960**	1,579,279	1,564,460	1,744,883	1,744,178
Commercial	**148,013**	141,859	138,663	154,063	153,132
Industrial	**2,180**	2,261	2,280	2,450	2,546
Wholesale	**78**	78	75	86	86
Other	**41**	40	48	55	62
Total customers at year-end	**1,749,272**	1,723,517	1,705,526	1,901,537	1,900,004
Average Usage Per Customer (thousand cu. ft.)					
Residential	**111.8**	114.8	120.5	118.8	125.7
Commercial	**589.3**	645.6	699.8	679.0	719.9
Degree Days	**5,067**	5,167	5,410	5,381	5,271
Variation from normal (%)	**(5.7)**	(3.9)	0.1	0.3	(1.7)

**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)	**1986**	1985	1984	1983	1982
Income Statement Data ($)					
Total operating revenues	**3,369,578**	4,060,919	4,603,122	5,075,085	5,059,006
Products purchased	**1,957,428**	2,689,686	3,099,319	3,586,139	3,720,871
Earnings (Loss) on common stock from continuing operations before extraordinary charges	**87,892**	(107,008)	165,436	184,701	182,736
Earnings (Loss) on common stock	**75,321**	(107,008)	138,564	164,754	180,063
Per Share Data					
Earnings (Loss) per common share ($):					
From continuing operations before extraordinary charges	**2.12**	(2.67)	4.22	4.94	5.17
Earnings (Loss) on common stock	**1.82**	(2.67)	3.53	4.41	5.10
Dividends:					
Per share ($)	**3.18**	3.18	3.18	3.02	2.86
Payout ratio (%)	**174.7**	N/M	90.1	68.5	56.1
Average common shares (000)	**41,436**	40,134	39,227	37,401	35,328
Balance Sheet Data ($)					
Capitalization:					
Common stock equity	**1,448,644**	1,422,688	1,634,225	1,598,634	1,458,326
Preferred stock	**50,000**	50,000	50,000	50,000	—
Redeemable preferred stock	**65,000**	70,000	75,000	80,000	35,000
Long-term debt	**1,378,526**	1,659,570	1,348,484	1,420,075	1,468,894
Total capitalization	**2,942,170**	3,202,258	3,107,709	3,148,709	2,962,220
Total assets	**5,590,161**	5,835,166	5,200,536	5,238,355	5,155,190
Other Financial Data					
Capitalization ratio (%):					
Common stock equity	**49.2**	44.4	52.6	50.8	49.2
Preferred stock	**3.9**	3.8	4.0	4.1	1.2
Long-term debt	**46.9**	51.8	43.4	45.1	49.6
Capital expenditures ($)	**232,283**	219,968	272,009	210,941	584,057
Cash from continuing operations ($)	**573,955**	81,703	725,328	453,063	223,306
Book value per common share ($)	**34.06**	35.10	41.22	41.16	40.73
Return on average common equity before discontinued operations and extraordinary charges (%)	**6.1**	N/M	10.2	12.1	13.0
Average cost of long-term debt at year-end (%)	**8.6**	9.4	9.5	9.6	9.4

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 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

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, 1986 and 1985 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, 1986. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As discussed in Note 12D, Columbia LNG Corporation's (Columbia LNG) liquefied natural gas terminal has not been utilized since 1980, and its use in the near-term is not presently anticipated by management. The portion of the investment in the facility financed with debt continues to be recovered through rates, however, Columbia LNG's equity investment is not being recovered. Although future economic conditions related to the energy industry are uncertain, management believes that the remaining equity 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 1986 and 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, 1986 and 1985, and the results of their operations and changes in their financial position for each of the three years in the period ended December 31, 1986, in conformity with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen & Co.

New York, New York
February 5, 1987

STATEMENTS OF CONSOLIDATED INCOME

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	***1986***	*1985*	*1984*
Operating Revenues			
Gas	**$3,087,047**	$3,738,608	$4,346,904
Other	**282,531**	322,311	256,218
Total operating revenues	**3,369,578**	4,060,919	4,603,122
Operating Expenses			
Products purchased			
Natural gas	**1,929,798**	2,601,961	2,887,581
Other	**27,630**	87,725	211,738
Provision for unrecovered gas costs (Note 3A)	**65,000**	400,000	—
Operation	**457,446**	519,106	493,383
Maintenance	**85,650**	77,982	78,405
Depreciation and depletion	**260,269**	267,597	251,019
Other taxes	**179,214**	195,030	198,144
Loss on synthetic gas operations (Note 3C)	**—**	—	57,700
Total operating expenses	**3,005,007**	4,149,401	4,177,970
Operating Income (Loss)	**364,571**	(88,482)	425,152
Other Income (Deductions)			
Interest income and other, net (Notes 3B and 13)	**19,776**	80,911	36,696
Interest expense and related charges (Note 14)	**(198,989)**	(159,003)	(139,387)
Total other income (deductions)	**(179,213)**	(78,092)	(102,691)
Income (Loss) from Continuing Operations Before Income Taxes	**185,358**	(166,574)	322,461
Income taxes (Note 3B)	**85,940**	(72,742)	142,697
Income (Loss) from Continuing Operations	**99,418**	(93,832)	179,764
Discontinued coal mining operations (Note 4)			
Loss from operations	**—**	—	3,172
Estimated loss on disposal	**—**	—	23,700
Income (Loss) before Extraordinary Charges	**99,418**	(93,832)	152,892
Extraordinary charges (Note 5)	**12,571**	—	—
Net Income (Loss)	**86,847**	(93,832)	152,892
Preferred stock dividend	**11,526**	13,176	14,328
Earnings (Loss) on Common Stock	**$ 75,321**	$ (107,008)	$ 138,564
Earnings (Loss) Per Share of Common Stock			
(based on average shares outstanding)			
Continuing operations	**$ 2.12**	$ (2.67)	$ 4.22
Discontinued operations	**—**	—	.69
Before extraordinary charges	**2.12**	(2.67)	3.53
Extraordinary charges	**.30**	—	—
Earnings (loss) on common stock	**$ 1.82**	$ (2.67)	$ 3.53
Dividends Per Share of Common Stock	**$ 3.18**	$ 3.18	$ 3.18
Average Common Shares Outstanding (thousands)	**41,436**	40,134	39,227

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)*	***1986***	*1985*
Property, Plant and Equipment		
Gas utility and other plant, at original cost	**$4,811,324**	$4,745,957
Accumulated depreciation and depletion	**(2,321,553)**	(2,244,318)
	2,489,771	2,501,639
Oil and gas producing properties, full cost method		
United States cost center	**964,402**	975,146
Canadian cost center ($42,500,000 and $54,000,000, respectively, not being amortized) (Note 1D)	**212,483**	194,187
Accumulated depletion	**(486,389)**	(452,779)
	690,496	716,554
Net property, plant and equipment	**3,180,267**	3,218,193
Investments and Other Assets		
Gas supply prepayments and advances (Note 6)	**886,027**	927,336
Unconsolidated affiliates (less than 50% owned)	**38,689**	37,641
Net assets of discontinued coal segment (Note 4)	**13,465**	12,871
Other	**32,743**	42,705
Total investments and other assets	**970,924**	1,020,553
Current Assets		
Cash and temporary cash investments	**14,469**	58,990
Accounts receivable		
Customers (less allowance for doubtful accounts of $4,893,000 and $5,447,000, respectively)	**462,215**	568,946
Other	**126,800**	79,199
Income tax refunds	**112,424**	129,113
Gas inventory	**378,141**	284,003
Other inventories—at average cost	**40,533**	46,956
Prepayments	**108,763**	104,520
Other	**103,114**	100,906
Total current assets	**1,346,459**	1,372,633
Deferred Charges	**92,511**	223,787
Total Assets	**$5,590,161**	$5,835,166

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

Capitalization and Liabilities *As of December 31 (in thousands)*	***1986***	*1985*
Common Stock Equity		
Common stock, par value $10 per share—outstanding 42,527,330 and 40,529,872 shares, respectively	**$ 425,273**	$ 405,299
Additional paid in capital	**324,029**	263,259
Retained earnings	**713,564**	769,321
Accumulated foreign currency translation adjustment	**(14,222)**	(15,191)
Total common stock equity	**1,448,644**	1,422,688
Preferred Stock (Note 7)	**50,000**	50,000
Redeemable Preferred Stock (Note 7)	**65,000**	70,000
Long-Term Debt (Note 10)	**1,378,526**	1,659,570
Total capitalization	**2,942,170**	3,202,258
Current Liabilities		
Bank loans and commercial paper	**393,400**	418,000
Current maturities of long-term debt and preferred stock	**432,467**	336,132
Accounts and drafts payable	**276,338**	349,514
Accrued taxes	**97,426**	83,221
Accrued interest	**45,665**	41,713
Estimated rate refunds	**65,443**	35,653
Deferred income taxes	**109,634**	164,772
Estimated supplier obligations	**147,150**	244,828
Other	**177,280**	164,700
Total current liabilities	**1,744,803**	1,838,533
Deferred Credits		
Income taxes, noncurrent	**812,705**	679,152
Investment tax credits	**53,365**	54,848
Other	**37,118**	60,375
Total deferred credits	**903,188**	794,375
Commitments and Contingencies (Notes 2 and 12)		
Total Capitalization and Liabilities	**$5,590,161**	$5,835,166

CONSOLIDATED STATEMENTS OF CHANGES IN FINANCIAL POSITION

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	***1986***	*1985*	*1984*
Cash From Operations			
Income (loss) from continuing operations	**$ 99,418**	$(93,832)	$179,764
Items not requiring (providing) cash:			
Depreciation and depletion	**260,269**	267,597	252,557
Deferred income taxes, noncurrent and investment credits	**130,873**	73,125	62,280
Nonrecurring charges—net	**(5,906)**	48,038	38,083
Amortization of prepayments for producer contract modifications	**68,413**	42,322	—
Other—net	**(1,747)**	483	(1,353)
Net change in working capital (increase) (Note 15)	**22,635**	(256,030)	193,997
Cash from continuing operations	**573,955**	81,703	725,328
Dividends	**(142,604)**	(140,354)	(138,671)
Net cash from continuing operations	**431,351**	(58,651)	586,657
Discontinued operations	**—**	—	(2,815)
Extraordinary charge	**(8,571)**	—	—
Net cash from operations	**422,780**	(58,651)	583,842
External Financing Activities			
Issuance of long-term debt	**250,000**	—	—
Retirement of long-term debt and preferred stock	**(273,624)**	(76,663)	(53,051)
Issuance of common stock	**80,744**	28,465	25,490
Issuance of production loan	**100,000**	150,000	—
Retirement of production loan	**(75,000)**	—	—
Increase (decrease) in short-term bank loans and commercial paper	**(24,600)**	418,000	(253,300)
Net external financing activities	**57,520**	519,802	(280,861)
Capital Investment Activities			
Capital expenditures	**(232,283)**	(219,968)	(272,009)
Gas supply prepayments and advances—net	**(314,624)**	(321,172)	(34,733)
Sale of subsidiary	**—**	—	30,187
Net capital investment activities	**(546,907)**	(541,140)	(276,555)
Other—net	**22,086**	82,609	614
Increase (Decrease) in Cash and Temporary Cash Investments	**$ (44,521)**	$ 2,620	$ 27,040

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	Common Stock* Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Foreign Currency Translation Adjustment
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 7)				(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 7)				(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)
Net Income				86,847	
Dividends:					
Common ($3.18 per share)				(131,079)	
Preferred:					
10.96% Series B				(2,420)	
10.24% Series C				(5,120)	
Adjustable rate Series D (Note 7)				(3,985)	
Common stock issued:					
Dividend reinvestment plan	707	7,068	20,782		
Employee stock ownership plan	40	406	1,166		
Public offering	1,250	12,500	38,822		
Other					969
Balance at December 31, 1986**	**42,527**	**$425,273**	**$324,029**	**$713,564**	**$(14,222)**

**100 million shares authorized for 1986—$10 par value and 50 million shares authorized for prior years.*

***$554,351,000 of retained earnings is not available for cash dividends and other capital stock distributions at December 31, 1986.*

STATEMENTS OF CONSOLIDATED TAXES

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	**1986**	1985	1984
Income Taxes			
Currently payable:			
Federal	**$ (2,963)**	$(110,752)	$ 95,919
State	**13,807**	(9,186)	7,269
Investment credits*	**(3,357)**	(12,362)	(14,151)
Total currently payable	**7,487**	(132,300)	89,037
Deferred:			
Federal	**84,006**	51,796	43,309
State	**(5,746)**	472	3,775
Foreign	**23**	1,899	1,789
Total deferred	**78,283**	54,167	48,873
Deferred investment credits, net	**(1,484)**	3,929	2,918
Provision for employee stock ownership plan	**1,654**	1,462	1,869
Income taxes included in income from continuing operations	**85,940**	(72,742)	142,697
Federal income taxes—discontinued operations:			
Current	**—**	—	(3,059)
Deferred	**—**	—	(19,832)
Federal income taxes, current—extraordinary charge	**(7,301)**	—	—
Total income taxes	**78,639**	(72,742)	119,806
Other Taxes			
Property	**55,202**	52,921	50,044
Gross receipts	**91,575**	107,630	114,619
Payroll	**21,634**	21,299	20,051
Other	**10,803**	13,180	13,430
Other taxes included in income from continuing operations	**179,214**	195,030	198,144
Other taxes—discontinued operations	**—**	—	153
Total other taxes	**179,214**	195,030	198,297
Total Tax Expense	**$257,853**	$ 122,288	$318,103

**Includes Employee Stock Ownership Plan investment credits of $1,654,000, $1,462,000 and $1,869,000, respectively.*

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

Year Ended December 31 (in thousands)	**1986**		1985		1984	
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 charges*)	**$ 165,486**		$ (166,574)		$272,700	
Tax expense at statutory Federal income tax rate	**$ 76,124**	**46.0%**	$ (76,624)	(46.0)%	$125,442	46.0%
Increases (reductions) in taxes resulting from—						
State income taxes, net of Federal income tax benefit	**4,235**	**2.5**	(5,649)	(3.4)	5,767	2.1
Investment credits not deferred and amortization of credits deferred in prior years	**(3,187)**	**(1.9)**	(6,971)	(4.2)	(9,364)	(3.4)
Depreciation expense for accounting purposes over amounts claimed for income tax purposes	**2,023**	**1.2**	7,153	4.3	4,356	1.5
Extraordinary charge for which no tax benefit has been provided	**1,840**	**1.1**	—	—	—	—
Discontinuing SFAS 71 (Note 3B)**	**—**	**—**	15,133	9.1	—	—
Other	**(2,396)**	**(1.4)**	(5,784)	(3.5)	(6,395)	(2.3)
Total Income Taxes	**$ 78,639**	**47.5%**	$ (72,742)	(43.7)%	$119,806	43.9%

**Includes income (loss) from foreign operations of $(26.0) million, $4.3 million, and $5.1 million, 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.*

	1986	1985	1984
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	**$ 6,549**	$ 1,460	$ (12,922)
Depreciation expense	**19,694**	52,698	34,790
Gas purchased costs	**82,521**	(48,954)	10,253
Estimated rate refunds	**(24,234)**	(862)	12,186
Unbilled utility revenue	**(885)**	5,453	(15,640)
Gains on reacquired debt	**—**	12,961	—
Loss on synthetic gas operations	**2,722**	12,565	(15,287)
Other	**(8,084)**	18,846	15,661
Total Deferred Income Taxes	**$ 78,283**	$ 54,167	$ 29,041

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. Principles of Consolidation. The Consolidated Financial Statements include the accounts of the Corporation and all subsidiaries. All appropriate intercompany accounts and transactions have been eliminated.

Certain reclassifications have been made to the 1985 and 1984 financial statements to conform to the 1986 presentation.

B. Basis of Accounting for Rate Regulated Subsidiaries. Statement of Financial Accounting Standards No. 71 (SFAS No. 71) provides that rate regulated public utilities account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service, and if the competitive environment makes it reasonable to assume that such rates can be charged and collected. In 1985, the Corporation's interstate transmission companies no longer met these criteria, and consequently, discontinued the application of SFAS No. 71 (see Note 3B). The Corporation's gas distribution subsidiaries continue to meet the criteria, and accordingly, follow the reporting and accounting requirements of SFAS No. 71.

C. Gas Utility and Other Plant and Related Depreciation. Property, plant and equipment (principally utility plant) is stated at original cost. The cost of gas utility and other plant includes an allowance for funds used during construction (AFUDC) or interest during construction (IDC), as appropriate. Since January 1, 1985, IDC is capitalized in connection with transmission plant. The before tax rates for AFUDC and IDC were as follows:

Year Ended December 31 (%)	**1986**	*1985*	*1984*
AFUDC	**8.62**	10.79	12.75
IDC	**9.37**	9.70	9.90

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 (%)	**1986**	*1985*	*1984*
Transmission property	**3.6**	4.4	4.0
Distribution property	**3.8**	3.4	2.9
Other property	**7.7**	8.0	7.4

D. Oil and Gas Producing Properties. The Corporation's subsidiaries engaged in exploring for and developing oil and gas reserves 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, (3) less the estimated future operating expenses and development costs. If costs exceed the estimated present value, the excess is charged to current depletion expense. Gains or losses on the sale or other disposition of oil and gas properties are normally recorded as adjustments to capitalized costs.

Depletion related to costs capitalized in the United States cost center is based upon the ratio of current year revenues to expected revenues, utilizing current prices, over the life of production. Depletion related to costs capitalized in the Canadian cost center is based upon the ratio of volumes produced to total reserves.

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 assessed 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 at December 31, 1986:

($ in thousands)	**1986**	*1985*	*1984*	*Prior Years*	*Total*
Exploration costs	**1,500**	3,900	5,600	19,700	30,700
Interest capitalized	**2,700**	2,500	2,300	4,300	11,800
Total	**4,200**	6,400	7,900	24,000	42,500

Columbia owns 256,000 gross acres (15,000 net acres) applicable to the Hibernia Block. In 1986, Columbia reduced its interest in offshore Newfoundland from the 4.0 million gross acres (.6 million net acres) reported in 1985 to 300,000 gross acres (21,000 net acres). The net costs of $42.5 million excluded from depletion at December 31, 1986 were initially incurred in 1979. Management estimates that development of reserves attributed to these properties will begin in the late 1980'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. As a result of the settlement agreement between Columbia Gas Transmission Corporation and its wholesale customers (as more fully described in Note 2A) the effect of liquidations of LIFO layers is reflected in income. During 1985, 73.5 Bcf of gas inventory was liquidated at an average cost of $3.31 per Mcf, which was greater than the cost of gas allowance provided for in Transmission's settled commodity rate. No such liquidation occurred in 1986. The estimated replacement cost of gas inventory in excess of carrying amounts was approximately $170 million at December 31, 1986.

F. Income Taxes and Investment Tax Credits. The Corporation's subsidiaries record income taxes 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 $170 million at December 31, 1986, 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. In 1986, investment tax credits were, for the most part, eliminated by the Tax Reform Act of 1986.

Additional information related to the components of tax expense is contained in the Statements of Consolidated Taxes. Management's Discussion and Analysis of Financial Condition and Results of Operations provides additional information related to the effects of the Tax Reform Act of 1986 and to the Financial Accounting Standards Board's project on accounting for income 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 gas distribution subsidiaries defer differences between gas purchased costs and the recovery of such costs in revenues, and adjust future billings for such deferrals on a basis consistent with applicable tariff provisions.

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

2. REGULATORY MATTERS

A. Wholesale Rate Settlement. In the first quarter of 1985, Columbia Gas Transmission Corporation (Transmission) reached a settlement with its customers and other parties resolving more than 20 dockets pending before the FERC. Pursuant to the settlement agreement, Transmission lowered its commodity sales rate by 11.5% for a two-year period commencing April 1, 1985. Further, Transmission's customers agreed to allow Transmission the opportunity to collect up to $600 million of unrecovered costs relating to gas purchased prior to April 1, 1985. This opportunity was conditioned on Transmission's ability to reduce gas purchase costs below a specified rate during the two-year settlement period and is subject to annual comparisons of Transmission's gas costs with gas costs incurred by Transmission's five major pipeline suppliers over a seven-year period ending December 31, 1992. The savings realized, should Transmission reduce its gas costs below the designated levels, would be shared equally by Transmission and its customers.

At December 31, 1986, Transmission had recorded a receivable of $32.0 million related to unrecovered gas purchased costs incurred prior to April 1, 1985, net of: (1) supplier refunds and other credits associated with gas purchased prior to April 1, 1985; (2) a reserve for unrecovered gas purchased costs (discussed in Note 3A); and (3) recovery of such gas purchased costs in the third and fourth quarters of 1986 as Transmission reduced its gas purchased costs below the designated level. In conjunction with the recovery of unrecovered gas purchased costs in the last two quarters of 1986, Transmission recorded refund liabilities which, in management's opinion, are appropriate under the terms of the settlement agreement. In management's opinion, Transmission will be able to recover the receivable by March 31, 1987, the end of the primary settlement period.

B. Direct Billing of Take-or-Pay Payments and Contract Reformation Costs. All of Transmission's pipeline suppliers have proposed to bill producer take-or-pay and contract reformation costs directly to their customers on the basis of past purchases from such pipeline supplier. Transmission and others have vigorously opposed such proposals on the grounds, among others, that such direct billing would constitute an illegal form of retroactive rate-making, would reduce a pipeline's incentive to bargain aggressively with its producers and would be inconsistent with a FERC order which eliminated the cost of gas in minimum commodity bills. Transmission has solicited the FERC to establish generic rules that would provide for appropriate recovery of such costs only after a FERC finding that the costs incurred were prudent, and then only if such costs are reflected in the pipeline's commodity rate, subjecting recovery to the competitive test of the marketplace.

If direct billing by Transmission's suppliers is permitted, it could have a material adverse effect on Transmission's business unless Transmission would have the parallel right to pass such billings through to its customers and doing so would not have an adverse impact on Transmission's competitive market position. The FERC is considering issuing a nonbinding policy statement providing for a form of direct billing and pass through by downstream pipelines like Transmission, which would be considered in individual pipeline cases. Nevertheless, management is of the opinion that direct billing by pipelines of take-or-pay and contract reformation costs will ultimately not be permitted.

3. NONRECURRING ITEMS AND ADJUSTMENTS

A. Unrecovered Gas Purchased Costs. At December 31, 1985, Transmission had deferred in excess of $540 million of unrecovered costs related to gas purchased prior to April 1, 1985. Since in management's opinion, the settlement agreement described in Note 2A did not provide adequate assurance that all of these costs would be recoverable in the future, Transmission recorded a pre-tax charge in 1985 of $400 million, establishing a reserve for unrecovered gas purchased costs. In 1986, an additional pre-tax charge of $65 million was recorded to increase the reserve for unrecovered gas purchased costs reflecting changes in estimates of retroactive billings from suppliers and the recoverability of unreserved gas purchased costs.

B. Discontinuance of Application of Statement of Financial Accounting Standards No. 71. Because of the competitive environment in the pipeline industry, together with Transmission's December 1985 announced acceptance of recently promulgated FERC rules related to open-access transportation, management concluded that the rates charged by the interstate transmission companies were no longer cost-based and continued application of the financial reporting and accounting requirements of SFAS 71 for the transmission segment was not appropriate. The accounting adjustments which were 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 1985 earnings	11.0

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 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 Columbia LNG would not incur any additional losses. Columbia LNG discontinued the production of synthetic gas effective March 31, 1986.

4. 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 (net of income taxes of $2.7 million). Efforts to sell or lease the net assets related to Columbia's interest in the mine are continuing.

5. EXTRAORDINARY CHARGES

The following extraordinary charges were recorded during 1986:

($ in millions)	
Additional loss on sale of distribution subsidiary[a]	4.0
Cost of refunding long-term debt (net of income tax benefits of $7.3 million)[b]	8.6
Total extraordinary charges	12.6

[a] *In the third quarter of 1986, the Corporation recorded an additional loss of $4.0 million related to the sale of an unprofitable West Virginia gas distribution subsidiary. The loss resulted from the settlement of various lawsuits associated with the sale. Tax benefits related to the transaction are available to the Corporation only on a carry-forward basis.*

[b] *In the fourth quarter of 1986, the Corporation refunded $135.5 million of debentures at prices in excess of the principal amount as more fully discussed under Liquidity and Capital Resources in the foregoing report to stockholders.*

6. GAS SUPPLY PREPAYMENTS AND ADVANCES

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

At December 31 ($ in thousands)	**1986**	*1985*
Prepayments for producer contract modifications	**658,960**	615,898
Gas supply prepayments	**214,389**	279,549
Gas supply advances	**12,678**	31,889
Total	**886,027**	927,336

A. Prepayments for Producer Contract Modifications. Prepayments have been made to certain producers in return for contract modifications related to future purchases of gas. The prepayments are being amortized on a volumetric basis over a ten-year period ending June 30, 1995, the primary period of benefit.

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 or cash payments.

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

7. PREFERRED STOCK

As of December 31, 1986, the Corporation had authorized 10,000,000 shares of preferred stock, par value $50.00 per share, and had outstanding 400,000 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 $20 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 per share.

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 $15 million over the next five years. Shares are redeemable for the sinking fund at a per share price of $50.00 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 (%)	***1986***	*1985*	*1984*
November	**7.50**	9.75	11.65
August	**7.50**	10.45	12.30
May	**7.50**	10.30	10.75
February	**8.25**	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.

8. 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. Effective January 1, 1986, the Corporation began accounting for pension costs under new standards promulgated by the Financial Accounting Standards Board (FASB). The new standard requires a significantly different measure of annual pension cost as well as expanded disclosures concerning pension cost components, plan funding status and actuarial assumptions.

The new method of accounting requires use of the "projected unit credit" actuarial method for determination of pension expense. In prior years, the Corporation's pension expense was based on the "modified-entry age normal" actuarial method.

The Corporation's funding policy is to contribute annually based on a percentage of expected employee's earnings, estimated at the beginning of the year, which approximated 5% in 1986 and 6% in 1985. The following table provides cost components used to estimate pension expense, contribution amount and plan assets earnings rate assumption for 1986.

Pension Costs ($ in millions)	***1986***
Service costs	**14.4**
Interest cost	**46.7**
Return on assets	**(49.2)**
Other, net	**(0.3)**
Net pension expense	**11.6**
Annual contribution	**17.9**
Assumed asset earnings rate	**9%**

Actual return on plan assets for 1986 amounted to $92.2 million.

Pension expense accrued and contributed to the plan in 1985 and 1984 was $22.8 million and $31.6 million, respectively. These amounts were based on the modified-entry age normal actuarial method and include amortization of prior service cost over periods ranging from 10 to 40 years. The reduction in pension expense for 1986 resulted from the adoption of the new standard and a change in several actuarial assumptions, the most significant being an increase in the assumed earnings rate on plan assets from 8% to 9%.

Pension plan assets consist principally of common stock equities, real estate investments and fixed income securities. The new accounting standards require disclosures to reconcile the plan assets and liabilities to the funded status of the plan as shown in the table below:

Plan Assets and Obligations At December 31 ($ in millions)	***1986***
Plan assets at fair value	**626.5**
Actuarial present value of benefit obligations:	
Vested benefits	**478.4**
Nonvested benefits	**32.1**
Accumulated benefit obligation	**510.5**
Effect of projected future salary increases	**122.3**
Total projected benefit obligation	**632.8**
Projected benefit obligation in excess of plan assets	**6.3**
Plus unrecognized in 1986 net gain	**6.0**
Less unrecognized transition obligation	**(18.6)**
Prepaid pension cost	**6.3**
Discount rate assumption	**7.5%**
Compensation growth rate	**7.0%**

The 1985 actuarial present value of accumulated plan benefits, using a discount rate of 8%, were $474.3 million ($462.7 million vested). 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 total of actuarial present value of accumulated benefits for 1985 reflects pay levels and past years of service accumulated through the valuation date. The net assets available for benefits were $560.3 million.

In addition to providing pension benefits, the Corporation's subsidiaries provide other post-retirement benefits including medical care and life insurance which cover substantially all active employees upon their retirement. Medical care benefits for retirees are expensed as paid. Life insurance benefits are expensed and funded based on normal cost and the amortization of an accrued unfunded actuarial liability. The expense recognized for these post-retirement benefits was $6.1 million in 1986, $5.6 million in 1985 and $5.7 million in 1984.

9. LONG-TERM INCENTIVE PLAN

The Corporation adopted a Long-Term Incentive Plan in 1985. A total of 1,500,000 shares of the Corporation's common stock is reserved for issuance under the Plan's provisions for stock options and awards, of which 1,147,320 shares remained available for future grants at December 31, 1986. All options and awards are granted under the direction of the Compensation Committee of the Board of Directors.

Under the plan, 50% of the options granted are exercisable beginning one year after the date of grant and 50% beginning two years from the date of grant. Options expire ten years from the date of grant.

Changes in the Corporation's stock options for the years ended December 31, 1986 and 1985 were as follows:

	Number of Shares	*Option Price per Share*
Granted 1985	165,050	$38.30/38.31
Balance, December 31, 1985	165,050	
Granted	166,770	$42.99
Forfeited	(4,950)	
Balance, December 31, 1986	326,870	

At December 31, 1986, options to purchase 80,050 shares were exercisable at a price of $38.30 or $38.31 per share.

Certain nonqualified options contained in the above table include stock appreciation rights which entitle the holders to receive stock, cash or a combination thereof equal to the excess of market value at exercise over the grant price. During 1986 and 1985, grants with stock appreciation rights, of 25,380 and 6,100 shares, respectively, were made at exercise prices per share of $42.99 and $38.30, respectively. At December 31, 1986, options for 3,050 shares with such rights were exercisable.

In addition to the options described above, contingent stock awards were granted to certain key executives without cost to the recipients. During 1986 and 1985, contingent stock awards of 12,860 and 12,950 shares, respectively, were granted. These shares, subject to meeting the vesting requirement, will be issued as follows: 15,810 shares in 1987, 4,000 shares in 1988, 3,000 shares in 1989, and 3,000 shares in 1990.

10. LONG-TERM DEBT

The long-term debt (exclusive of current maturities) of the Corporation and its subsidiaries is as follows:

At December 31 ($ in thousands)	***1986***	*1985*
The Columbia Gas System, Inc.		
Debentures:		
4½% Series due June 1987	—	7,500
4⅝% Series due August 1987	—	5,903
4⅜% Series due November 1987	—	9,000
4⅜% Series due January 1988	**7,490**	7,500
4⅝% Series due May 1989	**16,742**	18,500
4⅝% Series due October 1989	**13,400**	14,800
9⅝% Series due November 1989	**15,000**	22,500
4⅝% Series due May 1990	**14,700**	16,200
4⅞% Series due October 1990	**14,800**	16,200
6¼% Series due October 1991	**16,200**	17,600
6⅝% Series due October 1992	**11,000**	11,875
7¼% Series due May 1993	**23,745**	25,500
9% Series due August 1993	**150,000**	—
7% Series due October 1993	**19,000**	20,400
9% Series due October 1994	**25,500**	27,250
8¾% Series due April 1995	**21,800**	23,200
9⅛% Series due October 1995	**27,250**	29,000
10⅛% Series due November 1995	**37,400**	42,100
8⅜% Series due March 1996	**42,995**	46,125
9⅛% Series due May 1996	**42,100**	46,800
8¼% Series due September 1996	**34,800**	36,900
7½% Series due March 1997	**30,152**	32,496
7½% Series due June 1997	**36,246**	38,942
15⅜% Series due June 1997	**51,774**	100,000
7½% Series due October 1997	**34,631**	39,000
7½% Series due May 1998	**32,419**	34,250
10¼% Series due May 1999	**60,000**	65,000
9⅞% Series due June 1999	**27,400**	28,800
11¾% Series due October 1999	**31,250**	81,250
12¾% Series due August 2000	**31,250**	87,500
10¼% Series due August 2011	**100,000**	—
	969,044	952,091
Unamortized debt discount, less premium	**(5,957)**	(5,575)
	963,087	946,516
Revolving credit agreement[(a)]	**300,000**	300,000
Subsidiary debt:		
Production loan[(b)]	**71,250**	150,000
Contract modification obligation[(c)]	—	225,718
Other	**12,108**	7,393
Capitalized lease obligations	**32,081**	29,943
Total long-term debt	**1,378,526**	1,659,570

(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 ½% per annum on the unused portion of the facility through July 31, 1988. 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, 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 of ½% per annum on the daily average unused commitment through October 15, 1987. Borrowings under the Production Loan 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, or Fixed Rate Options) to be selected by the company for various time periods.

(c) The Contract Modification Obligation is a noninterest bearing liability to producers which has been discounted based on an imputed interest rate of 9.5% compounded semi-annually.

The aggregate maturities of long-term debt for the five years ending December 31, 1991, are as follows:

($ in thousands)	
1987	427,467
1988	157,387
1989	158,859
1990	142,728
1991	127,104

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 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 1986 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)	***1986***	*1985*	*1984*
Maximum outstanding:			
Commercial paper	**448,300**	—	303,500
Bank loans	**418,000**	418,000	—
Minimum outstanding:			
Commercial paper	**—**	—	—
Bank loans	**—**	—	—
Daily average outstanding:			
Commercial paper	**118,500**	—	26,300
Bank loans	**46,400**	86,700	—
Interest rates:			
Commercial paper	**5.7%-8.5%**	—	8.8%-10.1%
Bank loans	**8.9%-9.4%**	8.9%-9.2%	—
Weighted daily average rate:			
Commercial paper	**6.4%**	—	9.6%
Bank loans	**9.0%**	9.0%	—
Weighted average rate at year end:			
Commercial paper	**6.2%**	—	—
Bank loans	**—**	9.1%	—
Weighted average maturity at year end (days):			
Commercial paper	**30.0**	—	—
Bank loans	**—**	26.8	—
Credit lines at year end	**525,000**	518,000	525,000
Less—outstanding commercial paper/bank loans	**393,400**	418,000	—
Unused credit lines	**131,600**	100,000	525,000
Approximate compensating balances at year end	**—**	—	2,870

12. OTHER COMMITMENTS AND CONTINGENCIES

A. Capital Expenditures. Capital expenditures for 1987 are estimated at $300 million. Of this amount, $128 million is for transmission operations, $98 million for distribution operations, $71 million for oil and gas operations and $3 million for other operations. In addition, possible 1987 acquisitions in various segments of the natural gas business might aggregate up to $200 million.

B. Producer Contract Negotiations. Transmission began a program in 1985 to amend its gas purchase contracts with high-cost gas producers in the Southwest and Rocky Mountain areas. In connection with such contract renegotiations, Transmission agreed to indemnify producers against potential liabilities that may be incurred by them as a result of contract modifications. During 1986, several lawsuits were filed by royalty owners challenging certain provisions of the contract modifications. In management's opinion, these indemnifications will not result in liabilities that will have material adverse effects on the consolidated financial position 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 and 1986, substantially all of the Transmission's tangible assets, having a net book value of approximately $1.2 billion, have been pledged as security under various mortgages and financing agreements.

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

D. Cove Point LNG Terminal. Deliveries of liquefied natural gas to Columbia LNG's Cove Point 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 minimum bill provision does not, however, provide for the recovery of Columbia LNG's equity investment. Although future economic conditions related to the energy industry remain uncertain and utilization of the facility in the near-term is not presently anticipated, management believes that the remaining equity investment of $86 million will be recovered through the resumption of trade, appropriate rate relief, lease of the facility or sale.

On June 6, 1986, Columbia LNG and the joint-owner of the Cove Point facility filed a settlement agreement with the FERC which provides for: (1) the abandonment by the joint-owner of its 50% interest in the facility and its recovery of that interest through rates over a ten-year period; (2) full ownership of the facility by Columbia LNG which will continue to maintain it in standby condition and be allowed to recover the additional costs through rates; (3) the joint-owner sharing equally in retirement costs should Columbia LNG abandon the facility prior to mid-1992; and (4) the recovery by Columbia LNG of its investment through rates should it decide to abandon the facility. Comments supporting the agreement have been filed with the FERC as well as some objecting to certain provisions of the agreement.

E. Legal Proceedings. The Corporation and its subsidiaries have been named as defendants in various other 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 the Corporation's consolidated financial position or results of operations.

F. Operating Leases. Payments made in connection with operating leases are charged to operation and maintenance expenses as incurred. Such amounts were $27.9 million in 1986, $31.4 million in 1985 and $42.6 million in 1984. Minimum rental commitments for noncancellable leases are as follows:

($ in thousands)

1987	5,400
1988	5,700
1989	4,500
1990	5,600
1991	5,000
After 1991	73,600

13. INTEREST INCOME AND OTHER, NET

Year Ended December 31 ($ in thousands)	**1986**	*1985*	*1984*
Gains on reacquired debt previously deferred	**—**	48,324	—
Interest income	**15,216**	23,772	29,053
Income from equity investments	**2,843**	7,697	9,928
Allowance for other funds used during construction	**—**	—	330
Write-down of Alaskan pipeline investment	**—**	—	(4,844)
Miscellaneous	**1,717**	1,118	2,229
Total	**19,776**	80,911	36,696

14. INTEREST EXPENSE AND RELATED CHARGES

Year Ended December 31 ($ in thousands)	**1986**	*1985*	*1984*
Interest on long-term debt	**136,032**	131,686	138,903
Amortization of debt discount on contract modification obligation	**44,213**	—	—
Interest on short-term debt	**13,246**	8,138	2,555
Other interest charges	**11,631**	25,636	4,817
Allowance for borrowed funds used and interest during construction	**(4,239)**	(6,457)	(6,888)
Gains on reacquired debt	**(1,894)**	—	—
Total	**198,989**	159,003	139,387

15. CHANGES IN COMPONENTS OF WORKING CAPITAL

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

Year Ended December 31 ($ in thousands)	**1986**	*1985*	*1984*
Accounts receivable	**59,130**	(63,096)	264,338
Income tax refunds	**16,689**	(129,113)	17,232
Gas inventory	**(94,138)**	144,340	(102,558)
Accounts and drafts payable	**(73,176)**	(147,977)	(114,675)
Accrued taxes	**14,205**	(2,759)	(3,243)
Estimated rate refunds	**29,790**	10,625	(26,876)
Estimated supplier obligations	**(97,678)**	(22,414)	267,242
Deferred income taxes	**(55,138)**	(19,030)	(8,479)
Miscellaneous	**16,504**	(61,479)	(60,894)
Change in working capital	**(183,812)**	(290,903)	232,087
Non-cash items	**206,447**	34,873	(38,090)
Net change (increase) in working capital	**22,635**	(256,030)	193,997

16. BUSINESS SEGMENT INFORMATION

The information shown in the following tables is provided for the Corporation's segments for three calendar years, 1986, 1985 and 1984. 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. Identifiable assets are those assets used in the operations of each segment.

Earnings from continuing operations include the allocation of certain corporate income and expenses. 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 income, interest expense and preferred stock dividends are allocated in proportion to capital employed by identifiable segments. The provision for income taxes is allocated based on pre-tax income of individual segments, adjusted by directly assignable items.

Identifiable assets related to other operations include the net assets of coal mining operations discontinued in 1984. Such amounts were $13.5 million in 1986, $12.9 million in 1985, and $11.1 million in 1984.

($ in thousands)		***1986***	*1985*	*1984*
Revenues				
Transmission	-Unaffiliated	**1,391,884**	1,653,609	1,903,983
	-Intersegment	**1,072,866**	1,551,851	1,543,491
	Total	**2,464,750**	3,205,460	3,447,474
Distribution	-Unaffiliated	**1,853,513**	2,149,049	2,458,641
	-Intersegment	**7,620**	3,765	910
	Total	**1,861,133**	2,152,814	2,459,551
Oil and gas	-Unaffiliated	**65,034**	156,193	98,844
	-Intersegment	**106,820**	97,674	193,458
	Total	**171,854**	253,867	292,302
Other	-Unaffiliated	**59,147**	99,708	145,120
	-Intersegment	**5,349**	46,393	103,653
	Total	**64,496**	146,101	248,773
Adjustments and eliminations	-Unaffiliated	**—**	2,360	(3,466)
	-Intersegment	**(1,192,655)**	(1,699,683)	(1,841,512)
	Total	**(1,192,655)**	(1,697,323)	(1,844,978)
Consolidated		**3,369,578**	4,060,919	4,603,122

($ in thousands)	1986	1985	1984
Operating Income (Loss)			
Transmission	**167,576**	(326,356)	224,120
Distribution	**184,734**	135,692	129,182
Oil and gas	**14,786**	100,944	133,871
Other	**1,336**	7,363	(54,836)
Corporate	**(3,861)**	(6,125)	(7,185)
Consolidated	**364,571**	(88,482)	425,152
Earnings (Loss) from Continuing Operations Before Extraordinary Charges			
Transmission	**19,703**	(218,714)	79,192
Distribution	**75,264**	62,790	54,839
Oil and gas	**(6,497)**	46,507	63,279
Other	**(578)**	2,409	(31,874)
Consolidated	**87,892**	(107,008)	165,436
Depreciation & Depletion			
Transmission	**114,606**	136,913	120,677
Distribution	**45,897**	38,306	30,495
Oil and gas	**94,547**	84,733	92,397
Other	**1,354**	4,070	5,762
Corporate and unallocated	**3,865**	3,575	1,688
Consolidated	**260,269**	267,597	251,019
Identifiable Assets			
Transmission	**3,362,100**	3,630,343	3,045,212
Distribution	**1,471,948**	1,518,995	1,315,493
Oil and gas	**746,772**	766,667	836,704
Other	**70,202**	88,574	96,468
Adjustments and eliminations	**(167,257)**	(322,162)	(234,182)
Corporate and unallocated	**106,396**	152,749	140,841
Consolidated	**5,590,161**	5,835,166	5,200,536
Capital Expenditures			
Transmission	**60,700**	55,600	96,200
Distribution	**101,000**	80,900	76,600
Oil and gas	**66,800**	78,200	92,100
Other	**3,800**	5,300	7,200
Consolidated	**232,300**	220,000	272,100

17. QUARTERLY FINANCIAL DATA (Unaudited)

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 Before Extraordinary Charges*	*Earnings (Loss) on Common Stock*	*Earnings (Loss) Per Share Before Extraordinary Charges*	*Earnings (Loss) Per Share*
1986						
December 31[1]	**$ 906,875**	**$ 79,751**	**$ 35,752**	**$27,181**	**$ .84**	**$ .64**
September 30[2]	**453,828**	**30,102**	**15,475**	**11,475**	**.37**	**.28**
June 30[3][4]	**522,877**	**16,022**	**7,620**	**7,620**	**.19**	**.19**
March 31[5]	**1,485,998**	**59,483**	**29,045**	**29,045**	**.71**	**.71**
1985						
December 31[6]	$ 1,178,861	$ 68,892	$ 21,616	$21,616	$ .53	$ .53
September 30	608,837	(23,771)	(16,007)	(16,007)	(.40)	(.40)
June 30	555,372	(17,554)	(18,923)	(18,923)	(.47)	(.47)
March 31[7]	1,717,849	(194,141)	(93,694)	(93,694)	(2.36)	(2.36)

[1] Includes a decrease in earnings of $8.6 million reflecting an extraordinary charge applicable to refunding of high-cost debentures (see Note 5).
[2] Includes a decrease in earnings of $4 million reflecting an extraordinary charge applicable to the sale of a distribution subsidiary, previously reported as a decrease in operating income (see Note 5).
[3] Includes an increase in earnings of $20.6 million related to uncollectible customer accounts of which $3.1 million is applicable to the first quarter of 1986 and the remaining $17.5 million prior to 1986.
[4] Includes a decrease in earnings of $10.3 million to record a writedown of the carrying value of Canadian oil and gas properties.
[5] Includes a decrease in earnings of $38.8 million related to unrecovered gas purchased costs (see Note 3A).
[6] Includes an increase in earnings of $11 million related to discontinued application of SFAS No. 71 (see Note 3B).
[7] Includes a decrease in earnings of $207 million reflecting the establishment of a reserve for unrecovered gas purchased costs (see Note 3A).

18. OIL AND GAS PRODUCING ACTIVITIES (Unaudited)

Introduction. Reserve information contained in the following tables for the U.S. properties for 1986 and 1985 are the System's estimates which are reviewed by the independent consulting firm of Ryder Scott Company Petroleum Engineers. 1984 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.

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 1986	1985	1984	Canada 1986	1985	1984	Total 1986	1985	1984
Capitalized Costs at Year End									
Proved properties	**916,115**	885,116	885,129	**148,329**	119,963	109,977	**1,064,444**	1,005,079	995,106
Unproved properties[a]	**48,287**	90,030	91,961	**64,154**	74,224	69,897	**112,441**	164,254	161,858
Total capitalized costs	**964,402**	975,146	977,090	**212,483**	194,187	179,874	**1,176,885**	1,169,333	1,156,964
Accumulated depletion	**(445,195)**	(441,963)	(407,674)	**(41,194)**	(10,816)	(7,957)	**(486,389)**	(452,779)	(415,631)
Net capitalized costs	**519,207**	533,183	569,416	**171,289**	183,371	171,917	**690,496**	716,554	741,333
Costs Capitalized During Year									
Acquisition	**9,346**	10,037	16,200	**3,149**	1,864	4,226	**12,495**	11,901	20,426
Exploration	**24,027**	25,147	23,484	**7,214**	15,127	15,320	**31,241**	40,274	38,804
Development	**16,046**	18,475	25,550	**5,548**	7,120	7,311	**21,594**	25,595	32,861
Costs capitalized	**49,419**	53,659	65,234	**15,911**	24,111	26,857	**65,330**	77,770	92,091

[a]Represents expenditures associated with properties on which evaluations have not been completed.

HISTORICAL RESULTS OF OPERATIONS

($ in thousands)	United States 1986	1985	1984	Canada 1986	1985	1984	Total 1986	1985	1984
Gross revenues									
Unaffiliated	**56,302**	135,770	83,526	**8,886**	14,535	13,896	**65,188**	150,305	97,422
Affiliated	**106,573**	97,615	192,563	**—**	—	—	**106,573**	97,615	192,563
Production costs	**32,226**	44,194	41,848	**2,795**	3,933	3,570	**35,021**	48,127	45,418
Depletion	**63,769**	80,427	89,179	**30,228**[a]	3,364	2,965	**93,997**	83,791	92,144
Income tax expense	**30,609**	49,237	66,107	**(11,103)**	3,329	3,386	**19,506**	52,566	69,493
Results of operations	**36,271**	59,527	78,955	**(13,034)**	3,909	3,975	**23,237**	63,436	82,930

Results of operations for producing activities exclude administrative and general costs, corporate overhead and interest expense. Income tax expense is expressed at statutory rates less investment tax credits.
[a]Includes write down of the carrying value of $26.6 million.

OTHER OIL AND GAS PRODUCTION DATA

	United States 1986	1985	1984	Canada 1986	1985	1984
Average sales price per Mcf of gas ($)	**2.11**	2.42	2.69	**1.41**	1.59	1.89
Average sales price per barrel of oil and other liquids ($)	**14.37**	23.42	27.56	**14.30**	23.84	26.36
Production (lifting) cost per dollar of gross revenue ($)	**0.20**	0.19	0.15	**0.32**	0.27	0.26
Depletion rate per dollar of gross revenue ($)	**0.39**	0.35	0.32	**—**	—	—
Depletion rate per equivalent Mcf ($)	**—**	—	—	**0.74**	0.69	0.73

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, 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
Revisions of previous estimate	36,353	(97)	(9,762)	(671)
Extensions, discoveries and other additions	20,717	482	—	791
Production	(66,088)	(1,667)	(1,965)	(503)
Purchase/(sale) of minerals-in-place	—	—	—	(18)
Reserves as of December 31, 1986	**742,348**	**7,096**	**142,656**	**5,603**
Proved developed reserves as of December 31				
1984	579,473	7,648	150,982	4,252
1985	683,797	7,706	154,383	6,004
1986	702,102	6,845	142,656	5,206

[a]Gross working interest reserves.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	United States			Canada			Total		
($ in thousands)	***1986***	*1985*	*1984*	***1986***	*1985*	*1984*	***1986***	*1985*	*1984*
Future cash inflows	**1,663,842**	2,261,210	2,415,156	**241,899**	380,317	381,544	**1,905,741**	2,641,527	2,796,700
Future production costs	**(375,497)**	(496,945)	(519,418)	**(49,923)**	(70,737)	(57,095)	**(425,420)**	(567,682)	(576,513)
Future development costs	**(127,790)**	(147,939)	(191,041)	**(4,630)**	(4,079)	(3,455)	**(132,420)**	(152,018)	(194,496)
Future income tax expense	**(345,251)**	(667,495)	(702,393)	**(51,254)**	(120,780)	(129,411)	**(396,505)**	(788,275)	(831,804)
Future net cash flows	**815,304**	948,831	1,002,304	**136,092**	184,721	191,583	**951,396**	1,133,552	1,193,887
Less 10% discount	**382,734**	428,242	436,756	**71,435**	99,920	106,944	**454,169**	528,162	543,700
Standardized measure of discounted future net cash flows	**432,570**	520,589	565,548	**64,657**	84,801	84,639	**497,227**	605,390	650,187

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, 1986, 1985 and 1984 follows:

	United States			*Canada*			*Total*		
($ in thousands)	***1986***	*1985*	*1984*	***1986***	*1985*	*1984*	***1986***	*1985*	*1984*
Beginning of year	**520,589**	565,548	623,851	**84,801**	84,639	78,516	**605,390**	650,187	702,367
Oil and gas sales, net of production costs	**(130,649)**	(189,190)	(234,241)	**(6,090)**	(10,602)	(10,326)	**(136,739)**	(199,792)	(244,567)
Net changes in prices and production costs	**(236,243)**	(103,423)	(64,211)	**(45,853)**	(19,363)	(8,949)	**(282,096)**	(122,786)	(73,160)
Extensions, discoveries and other additions, net of related costs	**22,614**	23,899	18,550	**1,733**	15,460	11,805	**24,347**	39,359	30,355
Revisions of previous estimates, net of related costs	**31,584**	151,997	30,228	**(6,866)**	1,482	3,990	**24,718**	153,479	34,218
Accretion of discount	**86,769**	94,649	105,644	**14,014**	14,172	13,414	**100,783**	108,821	119,058
Net change in income taxes	**174,525**	33,839	51,643	**31,152**	1,740	(1,465)	**205,677**	35,579	50,178
Other	**(36,619)**	(56,730)	34,084	**(8,234)**	(2,727)	(2,346)	**(44,853)**	(59,457)	31,738
End of year	**432,570**	520,589	565,548	**64,657**	84,801	84,639	**497,227**	605,390	650,187

The estimated discounted future net cash flows have decreased over the last three years due to declining well-head prices as indicated in the table entitled "Other Oil and Gas Production Data". In addition, discoveries and other reserve additions have not kept pace with production over the last three years, reflecting reduced capital expenditures.

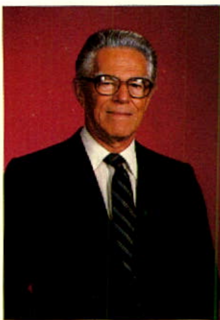
Thomas S. Blair

John P. Cornell

John H. Croom

Frank J. Durzo

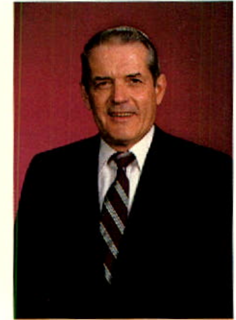
Dr. Sherwood L. Fawcett


J. Robert Fletcher

Robert H. Hillenmeyer

Malcolm T. Hopkins

W. Frederick Laird


Dr. William E. Lavery

James D. Little

George P. MacNichol, III

Ernesta G. Procope

John P. Roche

Arch A. Sproul

DIRECTORS

Thomas S. Blair[2,3]
Chairman, Blair Strip Steel Company
New Castle, Pennsylvania

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Executive Vice President and Chief Financial Officer

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Chairman, President and Chief Executive Officer

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Former Chairman and Chief Executive Officer
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Acquired by Dresser Industries, Inc.
Industrial Equipment, Columbus, Ohio

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

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Chairman, J.H. Fletcher & Co.
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Chairman, Hillenmeyer Nurseries, Inc.
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Former Chairman of the Board

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Private Investor; Former Vice President, Libbey-Owens-Ford Company, Glass and Plastics Business
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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

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Chairman, President and Chief Executive Officer

John P. Cornell
Executive Vice President and Chief Financial Officer

James D. Little
Executive Vice President

James T. Connors
Secretary

Stanley C. Kauffman
Treasurer

Alexander P. McCann
Assistant Treasurer and Assistant Secretary

Hart T. Mankin
Assistant Secretary

COLUMBIA GAS SYSTEM SERVICE CORPORATION

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Chairman, President and Chief Executive Officer

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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 D. 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
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G. A. Martin
Roger E. McVey
W. F. Morse
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Bruce Quayle
R. C. Skaggs
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Controller

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Assistant Secretary

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Joseph V. Yandoli
Assistant Treasurers

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Kenneth P. Murphy
Mark P. O'Flynn
Assistant Controllers

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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

Robert W. Davis
President
Columbia Gulf Transmission Company

Edward D. Callahan
President
Columbia Hydrocarbon Corporation
Columbia LNG Corporation
Inland Gas Company, Inc.

Paul R. Bigley
Chairman
Commonwealth Group Companies

DIVIDEND DISBURSEMENT AND CERTIFICATE INQUIRIES:
The Columbia Gas System, Inc.
Stockholder Services Department
P.O. Box 2318
Columbus, Ohio 43216

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:
The Columbia Gas System, Inc.
Stockholder Services Dept.
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
Corporate Trust Services
4 King Street
Toronto, Ontario, Canada M5H 3W7

TRUSTEE AND PAYING AGENT FOR DEBENTURES:
Morgan Guaranty Trust Company of New York
30 West Broadway
13th Floor
New York, New York 10015

COMMON STOCK DATA
The Columbia Gas System, Inc.

Year	*Number of Shares Traded (000)*	*Market Price High $*	*Low $*
1986	26,311	46	34¾
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 10-K 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 1987 Annual Meeting of Stockholders will be held at the Hotel du Pont, Wilmington, Delaware, on May 13, 1987, at 1:00 p.m. Proxy material will be mailed on or about April 6, 1987.

GLOSSARY

Defined below are some generally used energy industry terms.

Alternate Fuels—Fuels competing with natural gas such as electricity, coal, distillate and residual fuel oil.

Btu—Abbreviation for British thermal unit, a measure of heating value—the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

Cubic Foot—measured in thousands (mcf), millions (mmcf), billions (bcf)—The most common measurement of gas volume. It is the amount of gas required to fill a volume of one cubic foot under stated conditions of temperature and pressure.

Degree Day—A measure of the coldness of the weather experienced.

Dekatherm—A measure of heating value meaning one million Btu's. One dekatherm roughly equals one thousand cubic feet of gas (one Mcf) in heating value.

Deregulation—Phased, legislated decontrol of certain categories of U.S. natural gas supplies as provided for by provisions of the Natural Gas Policy Act of 1978.

Development—The drilling and related activities necessary after initial discovery of oil or gas to begin production.

Exploratory Well—A well drilled to a previously untested geologic structure to determine the presence of oil or gas.

Federal Energy Regulatory Commission (FERC)—The federal agency that has regulatory jurisdiction over the System's interstate natural gas operations. The FERC is an independent agency within the U.S. Department of Energy.

Long-Haul Transportation—Transportation of natural gas owned by others over long distances. The customer pays transmission charges for the transportation service.

Market-Responsive—This term refers to pricing gas so that it is competitive (marketable) against alternative fuels and other sources of gas.

Minimum Bill—A provision in a gas purchase contract specifying a minimum volume of gas the purchaser is obligated to pay for on an annual basis.

Open Access—A transportation plan under which pipelines that agree to transport natural gas for one customer are required to transport gas for all customers on a nondiscriminatory basis.

Proved Reserves—Oil or gas still in the ground that has been discovered and determined to be recoverable.

Reserves—The amount of oil, gas or other minerals that can be recovered from deposits in the earth.

Short-Haul Transportation—Transportation of gas owned by others over relatively short distances, such as that by Columbia Gulf Transmission Company in offshore areas. The customer pays transmission charges for the transportation service.

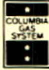
Spot Market—Free market purchase and sale of gas or coal on a short term basis.

Take-or-Pay—A clause in a gas supply contract providing for minimum quantity of gas to be paid for, whether or not taken by the purchaser.

Tariff—The rate and general terms and conditions under which natural gas will be supplied by a pipeline.

Throughput—Total volume of transportation volumes and tariff sales; all gas volumes delivered.

COLUMBIA GAS
System



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