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Annual Report

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COLUMBIA GAS
System

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

The natural gas flame is a major energy source for homes, commercial business and industries throughout the country. In addition to its established uses, natural gas is finding expanding markets in such applications as cogeneration plants, motor vehicles, fuel cells and, ultimately, heat pumps. Columbia Gas System companies are actively pursuing opportunities both in these new fields as well as through traditional channels.

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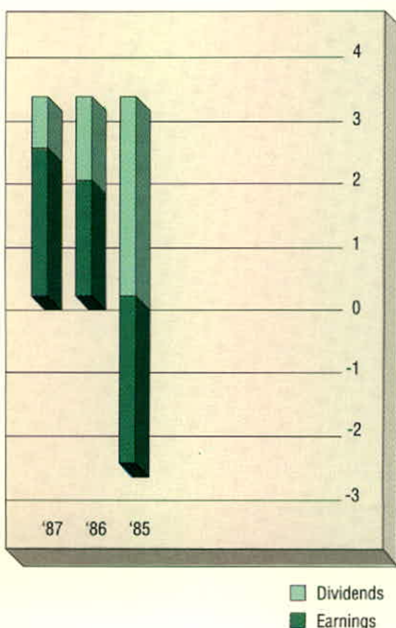
Highlights

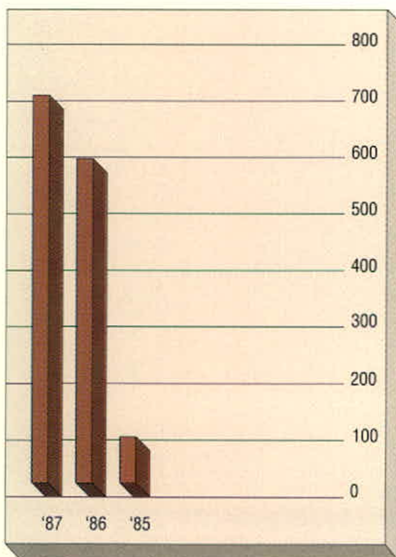
The Columbia Gas System, Inc. and Subsidiaries

	1987	1986	1985
Income Statement Data ($000)			
Operating Revenues	**2,798,004**	3,369,578	4,060,919
Net Income (Loss)	**111,333**	86,847	(93,832)
Earnings (Loss) before Extraordinary Charges:			
Gas Transmission	**39,237**	19,426	(219,697)
Gas Distribution	**39,296**	75,135	62,359
Oil and Gas	**8,946**	(6,546)	46,198
Other	**13,010**	(123)	4,132
Total	**100,489**	87,892	(107,008)
Per Share Data ($)			
Earnings (Loss) before Extraordinary Charges	**2.30**	2.12	(2.67)
Earnings (Loss) on Common Stock	**2.30**	1.82	(2.67)
Dividends	**3.18**	3.18	3.18
Book Value	**34.08**	34.06	35.10
Market Price:			
High	**56.50**	46.00	40.00
Low	**35.50**	34.75	26.75
Close	**40.25**	45.25	39.50
Common Stock Data			
Average Common Shares Outstanding (000)	**43,763**	41,436	40,134
Average Daily Shares Traded	**123,929**	104,828	116,005
Operating Statistics (million cubic feet)			
Gas Sales	**511,039**	606,460	695,017
Transportation Volumes	**745,814**	541,497	511,148
Total Throughput	**1,256,853**	1,147,957	1,206,165
Balance Sheet and Other Data ($000)			
Capital Expenditures	**298,774**	232,283	219,968
Total Assets	**5,426,776**	5,590,161	5,835,166
Capitalization	**3,071,655**	2,942,170	3,202,258

Earnings and Dividends Per Share of Common Stock (in dollars)



Cash from Operations before Extraordinary Charges (in millions of dollars)



HOWARD ROSS LIBRARY OF MANAGEMENT
APR 12 1988
McGILL UNIVERSITY

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

In writing this message about the 1987 results, the word disappointing comes readily to mind. Certainly the year's results fell short of the goal set forth in the previous Annual Report of earning no less than a $3.18 annual dividend. Similarly, the optimism expressed about our prospects for immediately prospering in the gas industry's new competitive climate proved premature.

While the short-range results did not come up to expectations, our future prospects are brighter because of projects undertaken in 1987 to expand business activity in both traditional and nontraditional markets. The distribution segment achieved a notable increase in the number of meters set and embarked on major market-penetrating activities. The transmission segment broadened its operating base by significantly extending its service area. And, we moved in an important way into the promising cogeneration field.

The 1987 results demonstrated that although the gas business is moving into a new market-driven era, the transition is being slowed by a frustrating regulatory maze that impedes the transmission industry. The stranglehold of regulation certainly was brought home to investors in January 1988 when decisions announced by the Federal Energy Regulatory Commission caused the market price of the Corporation's common stock to fall precipitously.

The delay in realizing the benefits of the competitive position we have worked to attain, together with the seeds for growth planted in 1987, show the need for a long-range view in evaluating corporate prospects. In an industry struggling to replace years of tight regulatory control with unfamiliar market-oriented forces, several years of financial uncertainty are perhaps inevitable.

What happened to earnings?

The 1987 per-share earnings of $2.30 represent an 8% increase from the $2.12 per share of 1986, although they were far from the minimum goal of $3.18 per share earlier thought to be attainable.

That projection reasonably assumed, based on FERC policy then in effect, that our principal pipeline subsidiary would be able to recover through rates a major portion of the $850 million that it had expended to renegotiate its Southwest gas purchase contracts to a market-competitive level.

As the year progressed, however, it became increasingly unclear how the FERC was going to deal with the industry's contract problems and the pipelines' recovery of large sums related to renegotiated or take-or-pay contracts. In particular, the Commission's position on our pipeline's recovery of its contract reformation costs never was resolved in the year. In the face of such uncertainty, the Corporation established reserves against the possibility of rate refunds of certain costs already collected in revenues. The specific factors involved are detailed on page 12.

Dividend considerations

Despite the fact that earnings per share have been less than the common stock dividend for the years 1985-87, management has been dedicated to maintaining the annual rate of $3.18 per share. The rate was first set in 1984 with the expectation that earnings in the transmission segment would be restored to more appropriate levels by 1988.

However, on January 13, 1988, the FERC decided two Columbia Transmission rate cases adversely, barring recovery of a substantial part of the contract reformation costs and potentially disallowing certain other gas costs already expended and still being incurred. These decisions will have significant negative impacts on the Corporation's future earnings and cash flow and we are seeking reversal or substantial modification of them. Based on public comments of some commissioners, we are optimistic of having our day in court and of ultimately recovering a portion of the dollars spent. As this report goes to press, Columbia Transmission is awaiting FERC action on requests for rehearings that seek to overturn the adverse actions.

The January 1988 Board of Directors' meeting to review the financial situation and consider the quarterly dividend fell on January 20, only a day after the text of these orders became available. Because there was not sufficient time to fully evaluate the impact of the orders, the Board determined that a change in the dividend rate would be premature. Therefore, it approved a quarterly common stock dividend of 79.5 cents a share, the same rate as in the previous 16 quarters.

At the same time, the Board issued a statement that a reduction in the dividend rate would be considered at the April 1988 meeting, based on developments to that time.

The regulatory tangle

As our recent reports to stockholders have stated, traditional business practices in the natural gas business are changing rapidly, more so in the last four years than the last forty. The pace of change has left gas companies and regulatory agencies a legacy of unresolved issues; chief among these are gas purchase contracts which pipelines signed in the seller's market of the late 1970s. Many contracts called for gas purchases at prices and terms that now are above market levels, and pipelines must pay for the gas even if they don't take it. Estimates are that pipelines owe producers more than $7 billion under such take-or-pay contracts.

Pipelines have sought to deal with the burden of high-cost contracts in various ways. Columbia Transmission successfully renegotiated most of its problem contracts in return for payments to producers that have totaled $850 million.

In a December report on the gas business, a Dow Jones News Service article was headlined: "Natural Gas Business in Disarray as Winter Sets In." The article described the industry as being in regulatory limbo as the FERC sought a formula to deal with the pipelines' contract problem. "Even though the take-or-pay issue has hung over U.S. natural gas pipelines for years, the FERC has caught flak more than ever this year for failure to resolve it," the article stated.

Columbia in particular has been caught in this web of FERC actions and related court decisions. By its January decisions the FERC prolonged the ordeal.

Rather than clarifying the issues for Columbia and the pipeline industry, the rulings raise additional questions about fundamental dealings between pipelines, producers and customers. Furthermore, the rulings raise the specter of increased regulation of an industry in which the FERC's recent policies and statements had promoted competition.

In the words of FERC Commissioner Anthony Sousa, who dissented from the decisions, the rulings "establish precedent which may be injurious to all segments of the natural gas industry and to gas customers."

The System is strong

The Columbia Gas System has the resilience and resources needed to prosper in the new gas business, even as it pursues an equitable resolution of the regulatory issues.

The role of the transmission segment in bringing gas to market, both as supplier and transporter, is expanding. The regulatory uncertainties have not deterred Columbia Transmission from moving into new territories. Contracts now finalized or nearing completion extended Columbia Transmission's range of services in major East Coast markets, including Rhode Island.

The market opportunities for natural gas are abundant, and Columbia's distribution companies have aggressive programs in place to realize those opportunities among residential, commercial and industrial customers. The number of customers continues to grow, and industrial development has been very successful in helping bring new industrial activity to our distribution service area.

The oil and gas segment's supply development activity builds on extensive lease holdings throughout the U.S. and Canada. Drilling activity in 1987 reflected the depressed level of energy prices, but the same market conditions made possible the acquisition of promising properties at attractive prices.

The diversified experience of Columbia companies and people is expected to contribute significantly to the success of the System's venture into the growing cogeneration industry. In 1987, a Columbia subsidiary became an equity partner in Cogeneration Partners of America, a partnership which builds, owns and operates on-site electric generating plants.

Officials responsible for key areas of System activity discuss elements of strategy elsewhere in this report.

Management changes

On December 31, 1987, two members retired from the Corporation's Board of Directors. John P. Roche ended more than 27 years of service as a director, the longest term of service for any individual to date. A lawyer by training, Mr. Roche held high executive positions in the steel industry and helped guide the Corporation through many difficult periods.

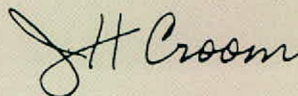
John P. Cornell had been not only a director but executive vice president and chief financial officer. In more than 36 years with the System, Mr. Cornell was a major contributor to the financial strength and stability of the organization. As chief financial officer since 1973, he was responsible for arranging more than $2.4 billion in financing.

Robert A. Oswald, who joined the Board of Directors in September 1987, has been elected a senior vice president of the Corporation and succeeded Mr. Cornell as chief financial officer. A Columbia employee since 1969, Mr. Oswald had been a senior vice president of the System's Service Corporation and assistant chief financial officer.

W. R. Wilson, President and Chief Executive Officer of Lukens, Inc., was elected a director of the Corporation on March 18, 1987. He brought to the Board broad experience in the steel and related industries, which are important natural gas markets.

On January 20, 1988, Daniel L. Bell, Jr., was elected to succeed James T. Connors as Secretary of the Corporation. Mr. Bell is a senior vice president of the Service Corporation in charge of the legal, governmental, communications and investor relations functions, a director of a number of subsidiaries and a former president of the Columbia Distribution Companies. Mr. Connors is also vice president for Investor Relations with the Service Corporation, and the change in the secretarial function allows him to devote full time to expanding our important Investor Relations program.

Stockholders and employees have been both supportive and patient as the System has grappled with the complex problems that have plagued an entire industry in transition. As we work through the difficulties, forecasts as to the duration of the tasks may be optimistic, but confidence in a successful outcome is not. The natural gas industry is strong and solid, and the Columbia Gas System commands a major position in that national industry. Support and patience will be rewarded.



John H. Croom
Chairman, President and
Chief Executive Officer

February 17, 1988

Gas Transmission

Columbia Gas Transmission Corporation (Columbia Transmission) sells at wholesale and transports natural gas to affiliated and unaffiliated customers through its 18,800-mile pipeline network serving parts of eleven mid-Atlantic and Midwest states and the District of Columbia. 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 Columbia 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. An intrastate pipeline network of nearly 600 miles in Virginia is operated by Commonwealth Gas Pipeline Corporation. Columbia LNG Corporation owns 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 28,000 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 3.5 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 Operations

The System has two subsidiaries that sell propane at wholesale and retail to more than 44,000 customers in Virginia, Ohio, Kentucky and Pennsylvania.

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

A new subsidiary, TriStar Ventures Corporation, has joined with affiliates of a major electric utility and a cogeneration engineering company in a partnership to construct and operate cogeneration plants throughout the United States.

The Columbia Gas System Service Corporation provides data processing, financial, accounting, legal, research and other services for the Parent Company and other affiliates.

GAS TRANSMISSION

Wholesale Customers		Storage Facilities	
Unaffiliated	75	No. of Wells	3,673
Affiliated	7	Acreage (000)	769
Total	82	Capacity (Bcf)	698
Total Throughput (Bcf)	1,213	1987 Capital Expenditures ($000)	100,847

GAS DISTRIBUTION

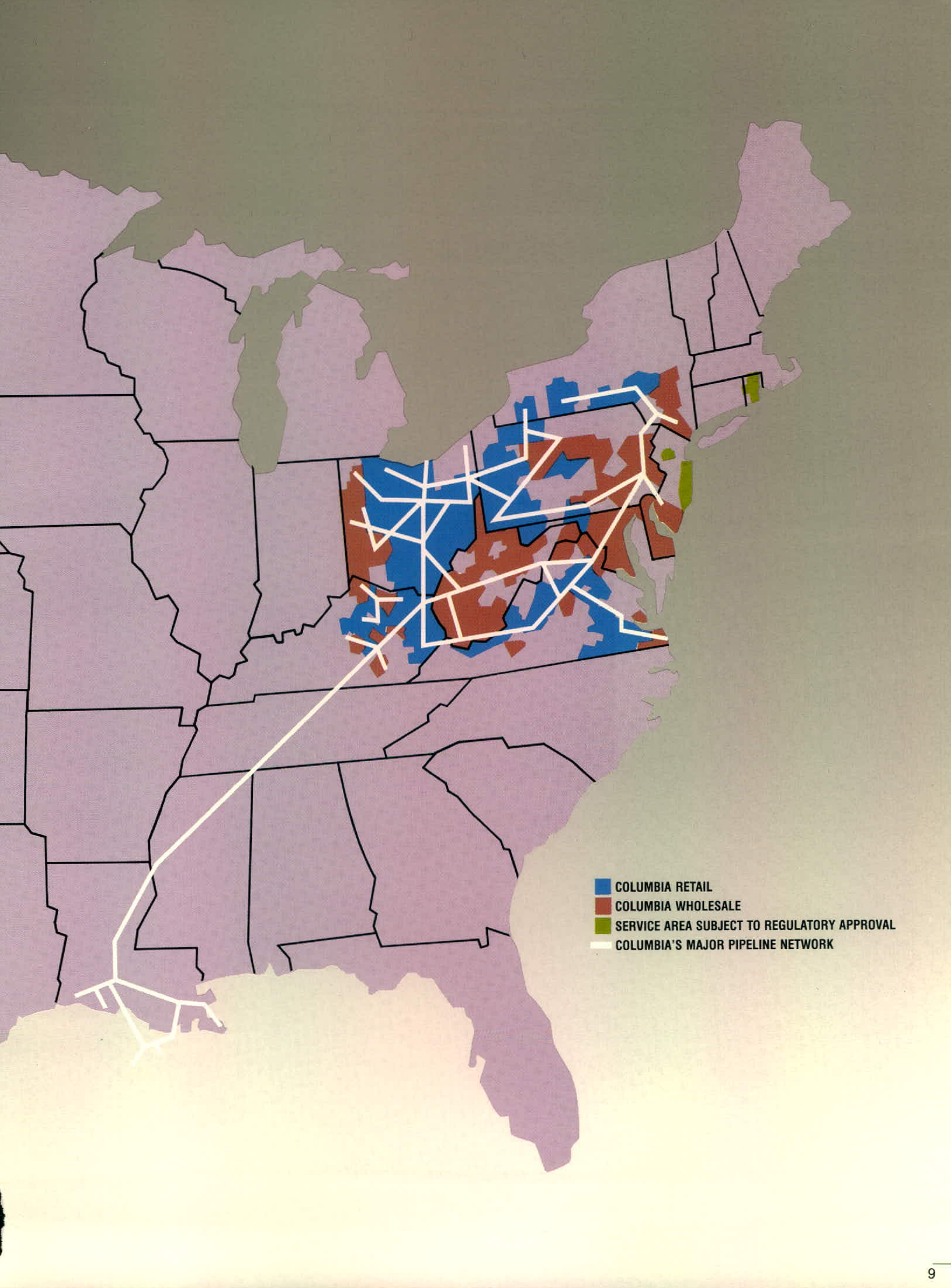
Retail Customers		Total Throughput (Bcf)	421
Residential	1,625,458	1987 Capital Expenditures ($000)	105,841
Commercial	152,071		
Industrial and Other	2,205		
Total	1,779,734		

OIL AND GAS

Net Acreage (000)		Net Gas Productive Wells	6,200
Developed	1,448	Net Oil Productive Wells	402
Undeveloped	2,037	Oil and Gas Production	
Proved Reserves		Natural Gas (Bcf)	76
Natural Gas (Bcf)	882	Oil (000 Bbls)	2,199
Oil (000 Bbls)	14,133	1987 Capital Expenditures ($000)	81,487

OTHER OPERATIONS

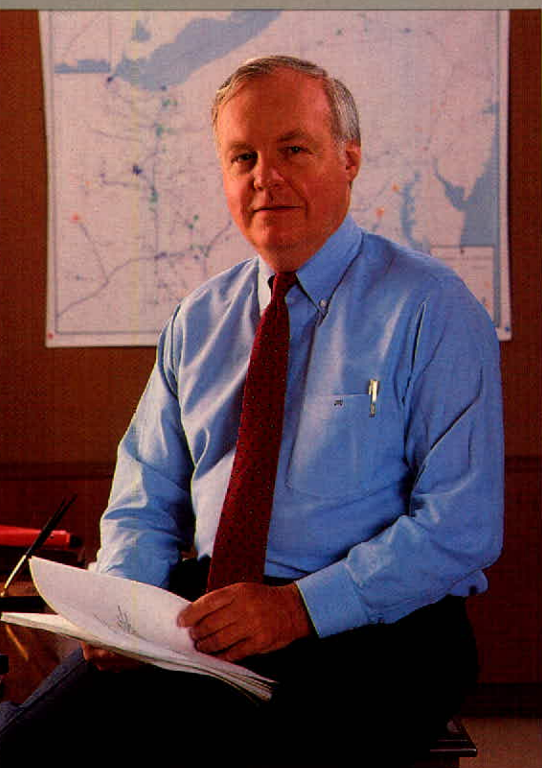
Coal Reserves (Million Tons)	650	Gallons Sold (000)	
1987 Capital Expenditures ($000)	10,599	Propane	75,843
Propane Customers	44,421	Butanes	19,292
		Natural Gasolines	8,731


COLUMBIA RETAIL
COLUMBIA WHOLESALE
SERVICE AREA SUBJECT TO REGULATORY APPROVAL
COLUMBIA'S MAJOR PIPELINE NETWORK

Making the Transmission Segment More Competitive

Commentary by John D. Daly

Chairman, Columbia Gas Transmission Corporation



Columbia Transmission's major focus in 1988 will be to increase the effectiveness of its marketing program of providing competitive sales and transportation services.

In addition to relying on pipelines to serve their high-priority heat-sensitive loads, distribution companies are now obtaining much of their gas supply on the spot market or contracting for it directly from producers. As an open access pipeline, Columbia Transmission has been able to maintain a high level of throughput by offering its existing and new customers the flexibility of using either its sales or its transportation services and by providing competitive rates for each.

Based on recent operating experience and forecasts from customers, Transmission has begun to restructure its existing gas purchase obligations. To this end, Transmission is restructuring its contracts with Southwest pipelines, cancelling rights and obligations to buy gas in the quantities it has in the past, but retaining rights to transport System supply through those lines. This will reduce overall gas costs, and rates, since a larger portion of Columbia Transmission's overall supply will be purchased under its market-sensitive producer contracts, thereby allowing Transmission to be even more competitive in the marketplace.

Significant reductions in the company's workforce have been achieved through consolidation of activities and functions and additional reductions through attrition are being studied. Overall operating costs are also being reduced, recognizing that in the future it will be the pipelines with the most efficient operations that will be the most competitive.

TRANSMISSION UNITS BUILD THROUGHPUT: REGULATORY PROCESS FRUSTRATES PROGRESS

The System's transmission units in 1987 moved on two fronts to carry out their missions of providing reliable, competitive gas service, while developing new markets and revenue sources.

On one front, new markets were opened and agreements made which will extend the reach of the System's supply and transportation service. On the other front, the principal transmission unit, Columbia Transmission, continued to struggle with lingering gas purchase contract issues.

New markets, new services

Persistent regulatory problems have not prevented the System's transmission units from pursuing their programs to expand throughput, with new transportation service and gas sales agreements. These programs include activities which extend pipeline facilities and maintain rates at competitive levels. In pursuit of these goals in 1987:

- Columbia Transmission completed a pipeline which initiated service at the start of 1988 to Delmarva Power and Light Company, Wilmington, Delaware, and South Jersey Gas Company, Folsom, New Jersey. The pipeline will provide up to 20,000 dekatherms daily of both sales and firm transportation to Delmarva and 25,000 dekatherms daily of gas sales to South Jersey.
- Through its open transportation policy, Columbia Transmission increased its total throughput and attained entry to natural gas markets it traditionally had not served. Total 1987 throughput was 900 billion cubic feet, compared to 816 billion cubic feet in 1986. Of the 1987 total, 526 billion cubic feet was from transportation of gas bought by distributors and end-users directly from producers, and 374 billion cubic feet was the direct sale of gas that the company had purchased.
- Columbia Transmission signed agreements to provide 10,000 dekatherms a day of new gas service to New Jersey Natural Gas Company and up to 20,000 dekatherms a day of firm transportation service to Elizabethtown Gas Company, an existing customer. An application has been filed with the Federal Energy Regulatory Commission (FERC) to construct a pipeline to provide this service. It is scheduled for construction in 1988.
- Columbia Transmission and Providence Gas Company of Rhode Island have signed a 20-year agreement which will extend service to New England for the first time. Through construction of a 19-mile segment of pipeline and an interconnection with a nonaffiliated interstate pipeline, Columbia Transmission will sell up to 10,000 dekatherms daily to Providence and provide firm transportation service for an additional 40,000 dekatherms daily. The transaction is subject to FERC approval.
- Columbia Gulf agreed with major producers to build an 18-mile offshore pipeline that will carry up to 92 million cubic feet of gas daily from production platforms in 600 feet of water to a connection with an offshore gathering system.
- Columbia Transmission continued negotiations with non-affiliated pipeline suppliers to restructure gas purchase contracts. The company wants to bring available supplies more in line with customer demand. Applications have been filed with the FERC to release some volumes of gas now under contract; in other cases, purchase rights are being converted to firm transportation rights, providing Columbia Transmission with the ability to move System supply through the pipelines and to access spot market supplies when desirable.
- The sales rates of Columbia Transmission were brought to the lowest level in seven years during 1987 as market-sensitive producer purchase contracts helped lower average gas purchase costs significantly.

Lingering contract issues

Columbia Transmission's contract reformation program and its willingness to transport gas for all shippers has transformed the company into a competitively priced merchant and leading transporter. This progress has been slowed, however, by continuing and frustrating regulatory and court review of contract issues once considered by the company to have been closed.

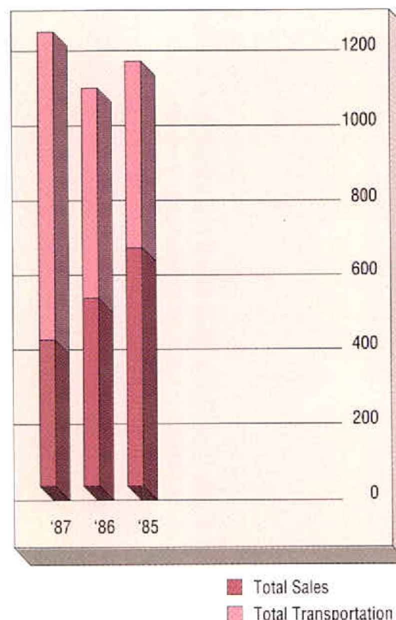
The focal points for much of the current controversy were Columbia Transmission's rate filings to recover part of its $850 million of producer settlement costs and the D.C. Circuit Court of Appeals directive to the FERC to reexamine issues related to certain of the company's past gas purchase practices. Developments unfolded over the year, however, in a number of cases:

■ Because its market-sensitive contracts have reduced gas purchased costs to the benefit of its customers, Columbia Transmission sought early in 1987 to recover a portion of its producer renegotiation costs through its rate structure. After the FERC rejected an attempt to recover these costs in a routine purchased gas adjustment (PGA) filing, Columbia Transmission filed to recover $653 million through its commodity rate. The Commission permitted recovery to begin, subject to refund, in May 1987.

■ Later in 1987, the FERC launched a program (Order No. 500) with a primary goal of encouraging pipelines and producers to settle contract disputes. Order No. 500 established guidelines for pipelines to recover from customers take-or-pay settlement costs and contract reformation costs. The FERC provided that, under the so-called 50/50 sharing approach, if a pipeline would absorb up to half of these costs, the other half would automatically be deemed prudent and passed along to customers through a direct fixed charge. A company wishing 100 percent recovery of its costs could seek this through its commodity rate but would be required to prove the contracts were prudent. Under Order No. 500, customers could still challenge prudence, but if they did so, they would risk absorbing 100 percent of the costs.

■ In late December 1987, Columbia Transmission refiled with the FERC to convert its prior general rate filing proposal to comply with Order No. 500 by seeking permission to recover $349 million plus carrying charges over a four-year period. In this way, the company would recover on a direct charge basis a substantial portion of its contract reformation costs, but less than 25 percent of the roughly $1.5 billion of costs incurred to resolve the gas acquisition controversy.

Transmission Gas Throughput
(in billion cubic feet)



■ While the cost recovery process was underway, the FERC, acting under directives of the D.C. Circuit Court of Appeals, had in May 1987 begun separate reconsideration of Columbia Transmission's still contested gas acquisition practices case dating from 1981.

The FERC effectively merged Columbia Transmission's abbreviated general rate filing to recover the costs of contract reformation and the court ordered reexamination of its supply management practices in companion rulings issued January 19, 1988. The FERC temporarily deferred acting on Columbia Transmission's Order No. 500 proposal. Those decisions, which completely ignored the constructive actions the company took two years ago to address its customer and producer problems, for the most part imposed two penalties:

Columbia Transmission was denied recovery of a significant portion of its contract reformation costs on the basis that the expenditures stemmed from abusive contracts.

Columbia Transmission was subjected to an unprecedented, continuing penalty which would limit the recovery of purchased gas costs incurred under the abusive contracts to a yet-to-be-determined price cap.

Ten days later, the FERC rejected Columbia Transmission's Order No. 500 proposal as originally filed. On February 9, 1988, the company filed an application to recover over a four-year period approximately $310 million, plus carrying charges, of the costs of reforming contracts not previously disallowed.

Columbia Transmission's management believes these FERC decisions are not supportable as a matter of law. Statements by individual commissioners indicate that, on rehearing, the actions may be subject to considerable review and possible reversal by the full Commission. Columbia Transmission is encouraged by these favorable indications and intends to pursue vigorously its amended Order No. 500 proposal and will use all legal remedies available to overturn the FERC's decisions.

A 7,000-foot crossing of the Delaware River south of Philadelphia extended Columbia's transmission lines into New Jersey in 1987. The line was pulled across as sections were welded together. Buoys were released to let the line settle into a trench.

Other supply related issues

While pursuing challenges to Columbia Transmission's past gas acquisitions, certain customers and others are also protesting elements of the company's ongoing purchasing practices in its two 1987 PGA filings. Protestors allege, among other things, that the company does not employ a permissible least-cost purchase plan. Columbia Transmission regards the challenges to be unfounded and believes that its conduct ultimately will be deemed appropriate.

Pipeline supplier considerations

Columbia Transmission's pipeline suppliers are also pursuing the recovery of their take-or-pay settlement and contract reformation costs. Most have indicated a preference for a direct-billing approach to recovery in lieu of commodity rate collections. To date, only one pipeline supplier has received FERC approval of a direct-billing plan and, while adopting the 50/50 cost absorption condition of Order No. 500, the plan did deviate somewhat from the provision to base charges on recent purchase levels in comparison to a historical level of consumption. Columbia Transmission and others have vigorously opposed deficiency-based allocation provisions of Order No. 500 on the grounds that such direct-billing constitutes an illegal form of retroactive ratemaking.

Columbia Transmission's position was bolstered by an October 1987 Court of Appeals ruling that previous FERC orders authorizing pipeline suppliers to bill certain gas costs on the basis of past gas purchase patterns, without due notice, is unlawful retroactive ratemaking.

Columbia Transmission believes that the Order No. 500 cost absorption requirement and the application of the court ruling will limit the billings the company receives and that it will be permitted to fully recover such billings.

Columbia Transmission also undertook in 1987 to balance its supply and demand posture by restructuring its service agreements with its major pipeline suppliers. These negotiations are in various stages of progress and the company is optimistic that it will have achieved its restructuring goals by year-end 1988.

Other regulatory matters

On April 1, 1987, Columbia Transmission and Columbia Gulf placed new rates and tariffs into effect, subject to refund, which restructured rates and services to enhance competitiveness. After extensive meetings with customers and other parties to resolve the proceeding by settlement proved unsuccessful, a lengthy administrative hearing was held. It is not expected that this case will be resolved in 1988.

In January 1988, Columbia elected to withdraw from the proposed Erie Pipeline System which would have expanded access to supplies of Canadian and domestic gas. Protracted delays made further participation unattractive by significantly reducing the project's prospects.

FINANCIAL RESULTS

Gas Transmission ($ in thousands)	**1987**	1986	1985
Unaffiliated Revenues	**1,025,700**	1,391,900	1,653,600
Intersegment Revenues	**891,600**	1,072,900	1,551,900
Total Revenues	**1,917,300**	2,464,800	3,205,500
Operating Income (Loss)	**179,100**	167,600	(326,400)
Depreciation and Depletion	**102,200**	114,600	136,900
Capital Expenditures	**100,900**	60,700	55,600
Identifiable Assets	**3,112,900**	3,362,100	3,630,300

Revenues

Total revenues have declined significantly in each of the three years due primarily to:

- The effect of lower sales rates reflecting the successful efforts of Columbia Transmission to reduce the cost of gas and the impact of regulatory matters previously described.
- The increasing substitution of transportation services in place of gas sales which include the cost of gas delivered.
- Warmer than normal weather in each of the three years, price competition, plant closings and other factors.

Total revenues reflected the downward trend in Columbia Transmission's commodity sales rate which began in April 1985, when, as part of the two-year rate freeze under the 1985 Customer Settlement, Columbia Transmission reduced its commodity sales rate 11.5%. The current year commodity rate reductions were largely a result of the company's successful efforts to reduce its gas purchased costs. Those gas cost reductions began to be fully reflected in sales rates by PGA filings placed into effect on April 1 and again on September 1. Through February 1988, Columbia Transmission's customers will be paying a commodity rate of approximately $2.25 per Mcf, a full 45% below the pre-Customer Settlement rate level.

Volumes

The transmission segment's total throughput, which is the combined measure of sales and transportation volumes, increased to the highest level since 1981. The 14% increase in 1987 represented a reversal of the slight decline experienced in 1986.

Sales volumes declined 21% in 1987 and 22% in 1986 due primarily to price competition and the effect of lower customer requirements related to weather and other economic factors.

On the other hand, volumes transported on behalf of local distribution companies and their end-users increased 43% in 1987 and 34% in 1986. Gas continues to be readily available for the transportation market at delivered prices that are quite competitive with both alternative fuels and gas available for purchase from pipeline suppliers. For the first time, transportation volumes represent more than one-half of throughput.

Nonrecurring charges and adjustments

The settlement agreement between Columbia Transmission and its wholesale customers (as more fully described in Note 2C of Notes to Consolidated Financial Statements) did not provide adequate assurance that Columbia Transmission could recover from customers previously deferred purchased gas costs. Accordingly, the company recorded a charge against operating income of $400 million in 1985 and an additional charge of $65 million in 1986.

Operating income

Operating income in 1987 was $179.1 million compared to operating income before nonrecurring charges of $232.6 million in 1986 and $73.6 million in 1985. The decrease in 1987 operating income of 23%, which came about despite a sizable increase in throughput, was due to the following:

- Adjustments of $46.0 million caused by the March 1987 and January 1988 regulatory rulings, retroactive to April 1, 1986, related to the ability of Columbia Transmission to recover funds expended to reform certain gas purchase contracts as well as increases in other rate refund reserves.
- The effect of lower sales volumes and increased operation and maintenance costs, although partially offset by higher income related to transportation services.
- Reductions in sales and transportation rates to reflect lower Federal income tax rates.

The 1986 improvement in operating income was due primarily to the terms of the 1985 settlement agreement. Columbia Transmission incurred operating losses during the last three quarters of 1985, which resulted from the fact that the company's average purchased gas costs were higher than the commodity sales rate placed into effect on April 1, 1985. Throughout 1986, Columbia Transmission had success in significantly reducing its gas purchased costs and as of April 1, 1986, began recovering the maximum sales margin established in the April 1, 1985, commodity sales rate.

Succeeding in a Competitive Market

Commentary
By C. Ronald Tilley

Chairman & Chief Executive Officer
Columbia Gas
Distribution Companies

The distribution companies are well positioned to meet the challenges that lie ahead in the marketplace. Through quality customer service, reliable gas supply at market responsive prices and aggressive marketing strategies, we have the resources and flexibility needed to be successful in what has become an intensely competitive market.

Declining gas costs in 1987 provided the opportunity to modify rate structures and to implement innovative approaches to the pricing of our product.

We intend to take full advantage of the growth opportunities. Armed with competitive prices, our aggressive marketing efforts allow us to effectively compete both in our existing markets and for new markets.

Effective economic development activity, promotion of cogeneration, seeking conversions to gas from other fuels, increased gas equipment research, full utilization of market research in developing strategies–all these are important elements in adding and retaining customers.

Clearly, cost efficiencies are important in competing for markets. Our strategies place strong emphasis on the fundamental fact that we simply cannot have costs in our rates that our competitors don't have.

Our strategic approach recognizes that the competition is changing rapidly. The distribution companies' strategies are calculated to give us the flexibility to plan for and position ourselves to respond to competitive challenges as they emerge.

We see communication as a major factor in our success. Developing good will and an understanding with the regulatory commissions, energy managers, builders, developers and our customers is a high priority.

Certainly, we have been successful in addressing the needs of our customers, and our strategic planning process will assist us in continuing to be successful in 1988 and beyond.

COMPETITIVE SALES, RATE PROGRAMS STRENGTHEN DISTRIBUTION SEGMENT

In the six states in which they operate, Columbia's distribution companies dealt successfully with the rising level of gas versus gas competition as well as competition from other fuels. Columbia's rate, supply and marketing specialists developed innovative programs to deal with both opportunities and problems.

Improved rate and regulatory environment

The year 1987 included several notable events:

■ Consumer gas rates were reduced to the lowest point in the past five years.

■ Customer satisfaction was demonstrated by a 42% decline in complaints to such agencies as utility commissions, consumer agencies, and legislators, etc.

■ Lower rates reflected, in part, continued success in programs to increase flexibility in gas supply management. Distribution companies continued to take on increased responsibility from pipelines for obtaining gas, working to balance the supply reliability offered by long-term pipeline contracts with the lower-cost supplies available on a limited-term basis by direct purchase from producers.

Building markets, expanding service

Among significant developments in the year:

■ A continuing industrial resurgence resulted in the announcement of many new manufacturing, distribution and major office facilities to be located in the distribution companies' operating area. The distribution companies' team of economic development specialists helped convince many decision-makers to locate facilities in the retail area. The 90 facilities announced will add 3.7 billion cubic feet of gas load a year and create 9,400 new manufacturing and distribution jobs. Honda announced a third car line and an engineering and distribution group at Marysville, Ohio. Toyota announced the addition of an engine, axle and transmission manufacturing plant to its auto assembly facility under construction at Georgetown, Kentucky.

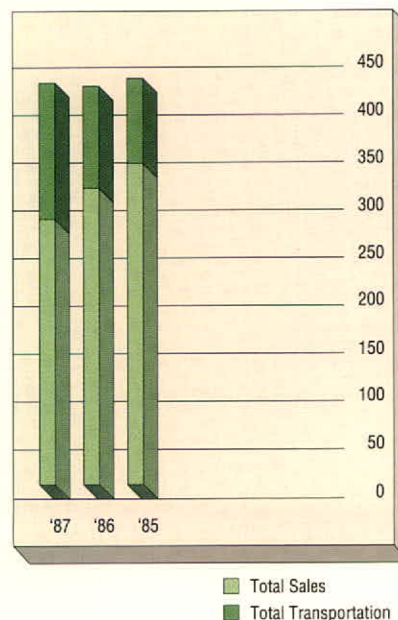
■ Industrial throughput increased by 3.5% over 1986 following a period of stabilization.

■ More than 33,000 new residential and commercial customers were added.

■ More than 2,500 existing residential and commercial customers were converted to gas heat, deepening penetration into competing fuels' markets.

■ The Corporation expects to acquire Lynchburg Gas Company of Lynchburg, Virginia through an exchange of common stock, thereby adding more than 10,400 new retail customers.

Distribution Gas Throughput
(in billion cubic feet)



■ Four additional cogeneration systems in Columbia's territory, added a total estimated annual load of 430 million cubic feet of gas. Two more cogeneration plants are under construction and will begin operating in 1988, adding an additional 4.5 billion cubic feet of gas load a year.

■ Innovative transportation programs helped maintain a high level of industrial throughput by providing industry access to low-cost gas. In 1987, 88% of industrial volumes delivered were owned by the end-user.

■ The reintroduction of gas lights in Ohio, Maryland and Virginia, made possible by changes in Federal and state regulations, provided new marketing opportunities for the sale of natural gas. Even though new regulations permitting gas lights were in effect for less than a full year, the distribution companies connected more than 2,000 new gas lights.

Meeting market competition

The Corporation's distribution subsidiaries continued to position themselves to respond quickly and decisively to conditions arising in the greatly intensified competition for markets. As a result of increased supply flexibility and the availability of competitively priced supplies from their pipeline suppliers, the distribution companies' consumer rates have been brought to their lowest level in several years.

The increased risks of heightened competition presented the distribution companies with significant challenges. In order to attract and retain load, responsive marketing services were developed to maintain competitiveness.

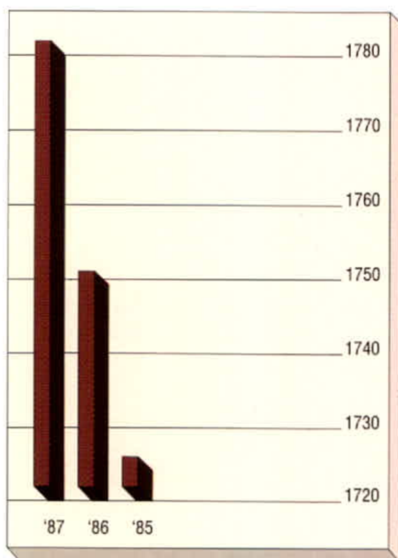
The threat of loss of markets to other gas suppliers–the so-called bypass problem–is closely monitored. The distribution companies have met most such challenges through the development of competitive services. The distribution companies' management has developed a communications program to increase the awareness of state regulators and lawmakers of the adverse implications on all consumers of bypass. The distribution companies expect bypass to remain a market threat while gas supplies remain plentiful. However, they believe that through rate and service flexibility and responsive regulation, they will continue to compete successfully against other gas suppliers.

The distribution companies significantly increased market research activity in 1987. Greater market surveillance enhanced efforts to define profitable new sales opportunities, providing a measurement of consumers' attitudes about gas and competitors' equipment, and important data about gas market share in highly competitive markets. The research data is being used to target particular markets, such as conversions to gas from other fuels; to design effective marketing advertising; and to develop future gas supply plans.

The superior quality of the distribution companies' service to customers is a significant element in their competitive posture in all markets. Conservation programs continue to be promoted. Through highly advanced weatherization programs, in addition to other forms of low-income assistance and attentive customer service activities, the distribution companies have greatly improved relations with customers. The 42% decrease in customer complaints attests to that.

Regulation and the inherent problem of regulatory lag–along with the need for quick response in a competitive marketplace–tends to hold down earnings. General rate filings which are planned for most distribution subsidiaries during 1988, coupled with quality customer service and cost efficient operations, are expected to generate improved earnings.

Number of Retail Customers Served at Year End (in thousands)



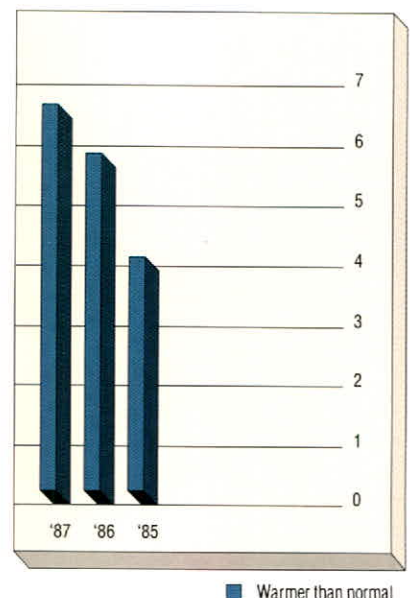
Research for new markets

Columbia's scientists moved forward in 1987 to test and develop new applications for natural gas and improve existing uses:

- A combination space/hot water system designed for the apartment, condominium and starter home markets is being field-tested by Columbia and a number of other utilities. The device is based on a combination single home unit developed by Columbia and successful testing of the smaller unit will provide entry into a new residential market.

- Changing environmental standards for diesel busses provide an opportunity to develop markets for natural gas in fueling major transit fleets. Columbia is acquiring a city bus modified to run on natural gas and plans a demonstration program with the Central Ohio Transit Authority to prove the feasibility of using compressed natural gas to meet stricter pollution standards.
- A proposed strategy for commercialization of a heat pump developed by Columbia is under review, and a proprietary presentation to potential manufacturer/licensees is being prepared. Columbia researchers are also testing under contract gas heat pumps developed by overseas manufacturers.

Degree Days (variation from normal in percent)



FINANCIAL RESULTS

Gas Distribution ($ in thousands)	**1987**	1986	1985
Unaffiliated Revenues	**1,606,800**	1,853,500	2,149,000
Intersegment Revenues	**300**	7,600	3,800
Total Revenues	**1,607,100**	1,861,100	2,152,800
Operating Income	**108,600**	184,700	135,700
Depreciation and Depletion	**47,100**	45,900	38,300
Capital Expenditures	**105,800**	101,000	80,900
Identifiable Assets	**1,488,400**	1,471,900	1,519,000

Revenues

Total revenues decreased approximately 14% annually since 1984 although throughput has remained steady. The continuing decline in total revenues is attributable to:

- Lower average sales rates made possible through lower gas purchased costs. The cost of gas purchased has decreased approximately 23% in 1987 and 16% in 1986.
- The increasing replacement of industrial and commercial sales revenues with transportation service revenues which exclude the cost of gas.
- A continuing decline in residential and commercial customer usage reflecting increasingly warmer weather since 1984.

Gas purchased costs, which had been increasing for some time, began to come down when the affiliated pipeline supplier reduced its sales rates 11.5% on April 1, 1985. Substantial rate reductions followed in 1987. Also, beginning in 1985, the distribution companies were able to buy low-cost gas on the spot market.

Volumes

Total throughput increased 1% in 1987 after decreases of 2% in 1986 and 5% in 1985. The increase in 1987 was due to the low cost of spot market gas available to industrial and large commercial customers, resulting in a 33% increase in volumes transported by the distribution companies. The low cost of gas, coupled with competitive transportation rates, allowed the distribution companies to regain most of the load lost to price competition in previous periods.

Sales volumes for 1987 were also down due largely to the effect of warm weather as average temperatures were slightly warmer than the previous year and 6% above normal. This is the third consecutive year that average temperatures have been significantly above normal, resulting in reduced usage by customers.

Results of marketing efforts have partially offset the effect of lower volumes related to weather in each of the three years, particularly in 1987, and have exceeded forecasts for the year.

Additionally, sales volumes were hurt during the three years by fuel switching through the first quarter of 1987 and plant closings in the first quarter of 1987 and in 1986. Sales volumes in 1985 reflected the effect of low industrial activity.

Operating income

Operating income in 1987 was down 41% while 1986 operating income increased 36% over 1985. The comparisons between years are distorted by a favorable adjustment of $31.1 million recorded in 1986 as a result of court actions related to the recovery of certain uncollectible accounts previously expensed. Absent this adjustment, operating income in 1987 was down 29% while 1986 results would have improved 13% over 1985.

The reduction in 1987 operating income is due to the effect of lower sales volumes, the recording of a rate refund reserve of $8.6 million related to the rate settlement by the Ohio distribution subsidiary, other Ohio rate reductions of approximately $11 million, lower 1987 Federal income tax rates reflected in revenues and, to a lesser extent, the effect of regulatory lag. These reductions were partially offset by increased revenues from transportation services.

Operating results in 1986 reflected the effect of higher average sales margins related to general rate filings throughout 1985, lower operation and maintenance costs, and a reversal of the low level of industrial activity experienced in 1985.

Developing Gas and Oil Production

Commentary
By John P. Bornman, Jr.

President
Columbia Gas
Development Corporation

The three exploration and production units of the System share a basic mission of finding, developing and marketing economic accumulations of gas and oil consistent with the basic System goal of maximizing returns on stockholder investment. The strategy each company pursues reflects in large measure the predominant energy industry factors of its geographic location.

Operating from the offshore Gulf of Mexico through the midcontinent into the northern domestic basins, Columbia Gas Development is focusing on both gas and oil prospects, with current primary concentration on oil. The level of drilling activity necessarily mirrors the status of wellhead prices. We continue to seek opportunities to purchase gas and oil in place. Although the time for acquiring primary oil reserves at a bargain has passed, we believe opportunities still exist to acquire gas properties at attractive prices.

Columbia Natural Resources, Inc. in the Appalachian and Michigan Basins operates in a primarily gas prone province with activities related to maintaining, exploring and developing its very large leasehold position. CNR continues to build its reserve position in the heart of the System's market area and pursues a strategy of seeking long-term markets for existing and new production.

North of the border, Columbia Canada is concentrating on building an acreage inventory in the western provinces. It is also maintaining the frontier high-potential acreage on which significant discoveries have been made. Marketing of production from the Kotaneelee field continues to hold high priority.

In sum, the structure of Columbia's oil and gas units positions the System in major North American hydrocarbon basins to develop reserves for its markets and generate a consistent source of income.

The System's oil and gas segment continues to be adversely affected by low prices. Even though drilling in the United States and Canada was limited, notable results were achieved in exploration and development activities.

Market conditions

As in 1986, U.S. gas prices were depressed in 1987 due to continuing gas-to-gas competition and, to a lesser extent, competition with oil which remains at relatively low price levels. The System's average domestic price for gas sold at the wellhead was $1.68 per Mcf in 1987, compared to $2.11 per Mcf in 1986. Canadian prices followed a similar pattern. Gas prices bottomed during the summer but rebounded a bit during the final months of the year as seasonal gas demand increased and gas availability on the spot market tightened. Despite this recent increase in gas prices, the near-term outlook is for continued competition and an active spot market especially during off-peak periods, thus exerting downward pressure on prices.

Domestic oil pricing in 1987, on the other hand, moved up slightly over 1986 and stabilized–$15.99 per barrel average sales price in 1987 in comparison to $14.37 per barrel in 1986. Canadian prices increased to a lesser extent. Price details are found on page 52.

The oil and gas segment's competitive strategy is a balanced approach aimed at maintaining reserves and ensuring the segment is positioned to participate in the next upswing in exploration and development activities. Operationally, the segment maintained production at normal levels but sought the highest market prices available. Particular emphasis was placed on diversification of gas markets in an effort to dampen adverse price moves which might occur in a single market segment, as well as to realize the benefits of improved market conditions.

A positive development which may enhance our Canadian oil and gas interests is the pending Free Trade Agreement between Canada and the United States.

Drilling and production activity

Despite fairly high production levels, System-wide total proved gas reserves remained essentially level with the previous year, U.S. reserves declining slightly while those in Canada rose correspondingly. Proved reserves of oil and other liquids increased more than 10% for the year. Details are found on page 52.

Columbia Gas Development's efforts in the Southwest and Rocky Mountain basins resulted in meaningful discoveries in the Gulf of Mexico, the Wind River Basin of Wyoming and the Williston Basin of North Dakota. Both the Wind River (25% Columbia interest) and the Williston Basin (50% Columbia interest) discoveries flowed both oil and gas. Additional drilling is planned in 1988 to delineate the extent of reserves.

In Appalachian drilling, Columbia Natural Resources focused on gas prospects and completed 26 net productive gas wells, which developed 25.5 billion cubic feet of reserves. The average per well of 1.0 Bcf was significant when compared to the average reserves by Appalachian Basin wells of 0.3 Bcf.

Columbia Canada concentrated on acquiring high potential oil prospects in Northern Alberta and Southeastern Saskatchewan where recent technical advancements in the geophysical method make subtle plays in the Devonian section potentially very rewarding. The most significant exploratory drilling results of the year were achieved in the Peerless Lake area of Northern Alberta where the company has participated in three consecutive oil discoveries.

In the offshore East Coast, Columbia Canada plans to participate during the summer of 1988 through its 5.47% interest in an exploratory test located between the Mara and Hebron discoveries southeast of the Hibernia oil field. This area remains highly prospective for additional commercial finds.

The operator of the Hibernia field, Mobil Oil Canada Ltd., continues to negotiate on behalf of the Hibernia participants with the governments of Canada and Newfoundland for special fiscal terms for the development of the Hibernia field. Negotiations were delayed while elements of the new tax reform package introduced into Parliament by the Minister of Finance in June 1987 were studied.

The continued market uncertainties limited somewhat the capital expenditures originally projected for 1987. For the year as a whole, expenditures totaled $81.5 million, up from the even-more depressed level of $66.8 million in 1986. However, to ensure a reasonable reserve position for the future, investments in 1988 are projected to increase over the 1987 outlays.

FINANCIAL RESULTS

Oil and Gas ($ in thousands)	**1987**	1986	1985
Unaffiliated Revenues	**112,500**	65,100	156,200
Intersegment Revenues	**51,200**	106,800	97,700
Total Revenues	**163,700**	171,900	253,900
Operating Income	**41,200**	14,800	100,900
Depreciation and Depletion	**66,100**	94,500	84,700
Capital Expenditures	**81,500**	66,800	78,200
Identifiable Assets	**779,900**	746,800	766,700

Revenues and volumes

Total revenues decreased in each of the three years, primarily reflecting the lower market prices.

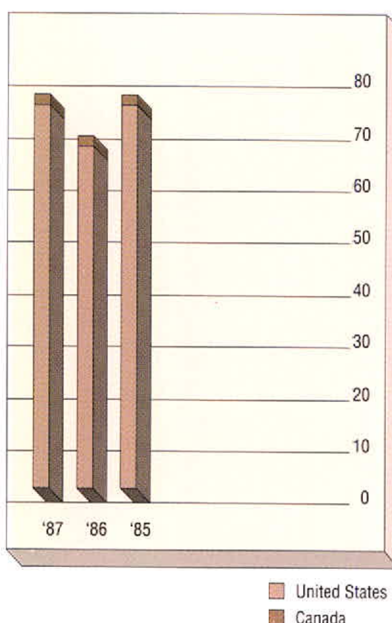
Average sales prices for gas dropped 20% in 1987, 13% in 1986 and 10% in 1985 primarily due to price competition with oil and gas-on-gas competition. Gas production was up 11% in 1987 after falling 11% in 1986.

Average oil prices rebounded slightly from the sharp drop experienced in 1986. Oil production in 1987 remained at the level of 1986, which was 15% below 1985.

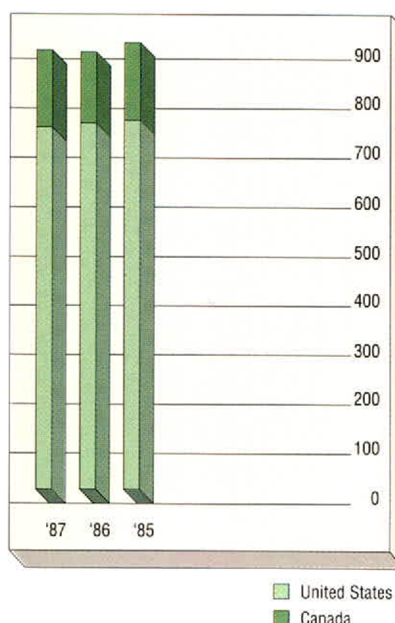
Operating income

The significant increase in 1987 operating income is due to the 1986 write-downs totaling $26.6 million of the carrying value of Canadian oil and gas properties. The write-downs were required due to the low level of energy prices at the end of the second and fourth quarters. The decrease in 1986 operating income, compared to 1985, reflects the effects of the 13% reduction in average gas prices.

Gas Production
(in billions of cubic feet)

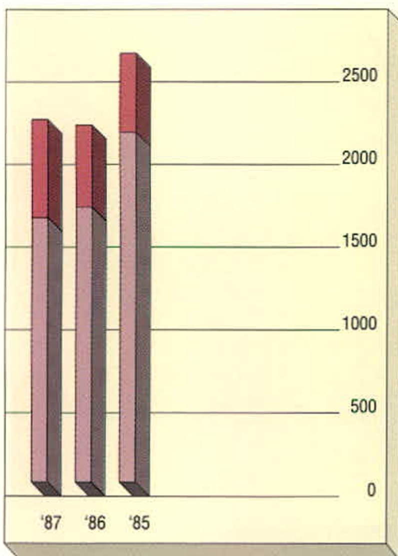


Gas Reserves
(in billions of cubic feet)

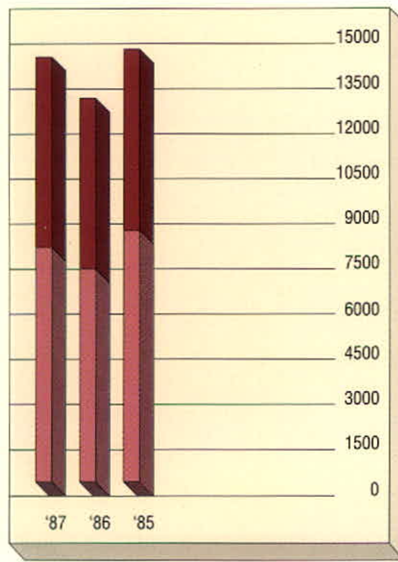


Natural gas from offshore wells passes through this Columbia plant in southern Louisiana for the removal of any liquids or other materials it contains.

Oil Production
(in thousands of barrels)



Oil Reserves
(in thousands of barrels)



OTHER OPERATIONS

In pursuit of its mission to be active in diversified energy activities tied to the natural gas business, the System conducts operations in several significant fields.

Cogeneration investment

The System made a significant investment during 1987 in the growing national cogeneration market. Cogeneration is the simultaneous production of electricity and useful thermal energy from a single primary fuel source, such as natural gas.

In September, Columbia reached an agreement to join, through its TriStar Ventures Corporation subsidiary, with affiliates of a major electric utility and a cogeneration engineering firm in a partnership to construct, own and operate cogeneration plants throughout the United States.

The partnership, Cogeneration Partners of America (CPA), provides Columbia with equity participation in cogeneration projects as well as opportunities to increase throughput on its pipeline and distribution systems by supplying natural gas to the projects CPA will build, own and operate.

Through the partnership, TriStar Ventures holds a 25% interest in a newly completed cogeneration plant at Crozer-Chester Medical Center in suburban Philadelphia. CPA has several other projects in various stages of development.

TriStar Ventures has also invested on its own behalf in a cogeneration plant being built by a major paper company.

Propane marketing

Propane ranks fourth in supplying the nation's energy needs, and 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.

Columbia Hydrocarbon Corporation markets propane to retail customers primarily in Ohio and western Pennsylvania. Commonwealth Propane is a major propane marketer in Virginia, with a well-balanced mix of residential, industrial and commercial customers. Commonwealth Propane is also a major marketer of gas appliances in the state.

During 1987, Commonwealth Propane, Inc., imported approximately 32 million gallons of propane through its jointly owned Atlantic Energy, Inc., terminal in Chesapeake, Virginia.

Coal activities

Columbia sold its Kiah Creek mineral interest of approximately 100 million tons of coal in 1987. Approximately 25,000 acres consisting of some 35 million tons of recoverable coal reserves have been leased to another company which expects to begin operations in the third quarter of 1988 with initial production of nearly 500,000 tons per year. Columbia retains ownership of 200 million tons of reserves dedicated to the Wayne County, West Virginia, coal mining venture discontinued in 1984. In addition, Columbia owns 450 million tons of other low-sulfur coal reserves, some of which are now leased to others for development. A number of small and medium-sized reserve blocks have been delineated and are now being offered for sale or lease to independent operators for development.

Columbia Gas System Service Corporation

In 1987, management determined that the Columbia Gas System Service Corporation (Service Corporation) is more appropriately classified as a segment that provides professional services to affiliates. Data for the Service Corporation were previously included in the corporate category.

FINANCIAL RESULTS

Other Operations ($ in thousands)	1987	1986	1985
Unaffiliated Revenues	**53,000**	59,200	99,700
Intersegment Revenues	**55,600**	58,700	101,500
Total Revenues	**108,600**	117,900	201,200
Operating Income	**5,200**	5,200	11,200
Depreciation and Depletion	**4,600**	5,200	7,600
Capital Expenditures	**10,600**	3,800	5,300
Identifiable Assets	**101,400**	100,000	119,200

Revenues

The reduction in total revenues is due to the discontinuance of synthetic gas production as of March 31, 1986. Synthetic gas revenues were $12.2 million in 1986 and $75.6 million in 1985. Revenues from propane operations, which were depressed in 1986 due to price competition, were up $1.9 million due largely to an increase in spot market sales.

Operating income

Operating income remained the same as in 1986 as further depressed propane sales prices offset the effect of higher sales. The decrease in 1986 operating income reflected an operating loss recorded by operations related to a Columbia Hydrocarbon fractionation plant.

Crozer-Chester Medical Center saves money by generating its own electricity using natural gas. The 400-bed hospital's generating plant is owned and operated by a cogeneration partnership venture in which Columbia has a 25% interest.

Robert A. Oswald, *Senior Vice President and Chief Financial Officer*

Earnings on common stock

Earnings on common stock for 1987 were $100.5 million or $2.30 per share compared to 1986 earnings of $87.9 million or $2.12 per share before extraordinary charges totaling $12.6 million or $0.30 per share. The 1986 extraordinary charges resulted from premiums paid to refund debentures which had interest rates above 1986 market levels and an additional loss incurred in connection with the 1983 sale of a distribution subsidiary.

The 1987 earnings reflect a 10% decrease in operating income which was more than offset by a combination of increased other income, lower interest costs and reduced income taxes. The reduction in operating income is due to lower distribution segment results partially offset by improvements from the transmission and oil and gas segments.

Earnings outlook

The pipeline industry continues to operate in an environment of uncertainty and transition. Competition and pressure on distribution companies to utilize diverse sources of supply affect profitability of pipelines. At the same time, the Federal Energy Regulatory Commission (FERC), subject to court reviews, is slowly developing the rules and procedures for a more deregulated industry.

Pending before the FERC are several specific issues of importance to the financial performance of Columbia Gas Transmission Corporation (Columbia Transmission) and the Corporation. Given the complexity of these matters, both substantively and procedurally, their eventual outcomes remain uncertain.

In the meantime, the Corporation will take all necessary steps to maintain its financial strength. The Corporation has confidence that over time it can restore the financial health of the transmission segment, and it will not permit the recent adverse FERC decisions to divert attention from plans that are underway to ensure the continuing strength of the System's other primary business segments–gas distribution and oil and gas exploration and production.

Revenues

As was the case in 1986 and 1985, gas operating revenues continued to decline in 1987. The main reason is a reduction in average sales rates which reflects the success of Columbia Transmission in renegotiating producer contracts. This has significantly reduced gas purchased costs and, in turn, enabled Columbia Transmission to reduce its commodity sales rate. Sales volumes also continued to decline due to the replacement of sales revenues with transportation service revenues and warm weather, as average temperatures were 6% above normal. This is the third consecutive year that temperatures have been warmer than normal, resulting in significant reductions in heat usage by customers.

Other revenues were up substantially due to a 38% increase in transportation volumes and a slight increase in revenues related to the sale of propane and other hydrocarbons. Although oil prices recovered slightly and gas production increased, lower wellhead prices for gas caused revenues to decline. Other revenues were down in 1986 because of the depressed price of oil. This also influenced the price of propane and other hydrocarbons.

Expenses

Gas purchased costs decreased in each of the three years due to lower sales volumes as well as a significant reduction in unit costs. Other products purchased decreased by $8.9 million from 1986 due to the phasing out of synthetic gas operations.

Operating and maintenance expenses increased 7% in 1987 after adjusting 1986 expenses which included a reduction of $31.1 million. This reduction resulted from favorable court actions related to the right to recover the cost of previously expensed uncollectible accounts.

The decrease in 1987 depreciation and depletion is primarily due to lower rates applicable to transmission properties. In 1986, depletion expense was increased $26.6 million to record a write-down of the carrying value of Canadian oil and gas properties.

Interest income and other, net

The increase in interest and other income includes $13.8 million from the sale of certain coal interests. The decline in 1986 was due to a decrease in temporary cash investments and the recording in 1985 of an accounting adjustment of $48.3 million related to gains on reacquired debt.

Interest expense and related charges

Interest expense and related charges decreased $16.4 million in 1987 due largely to completion of the amortization of debt discount on producer settlement obligations. Long-term debt interest also declined as a result of debt refunding in 1986. The increase in 1986 interest expense reflected the financial impact of the customer and producer settlements by the System's principal transmission subsidiary.

Income taxes

Income taxes, as detailed on the Statements of Consolidated Taxes, decreased $13.7 million in 1987 primarily due to the effect of the reduction in the 1987 Federal corporate income tax rate to 40%. Income taxes in 1986 increased primarily due to an increase in pre-tax book income.

In December 1987, the Financial Accounting Standards Board issued a new statement on accounting for income taxes. The Corporation is required to adopt the new accounting and disclosure rules no later than its year ending December 31, 1989, although early adoption is permitted. The Corporation expects to adopt the new standard effective January 1, 1989, and does not plan to restate prior periods. The statement requires among other things, immediate financial statement recognition of changes in tax regulations by redefining as liabilities the amounts previously recognized as deferred tax obligations arising from the measure of the difference between pre-tax accounting income and statutory income for tax purposes.

The new method of accounting also requires that the cumulative effects on accrued future tax liabilities of future tax rate changes be recorded in current earnings except for rate regulated entities.

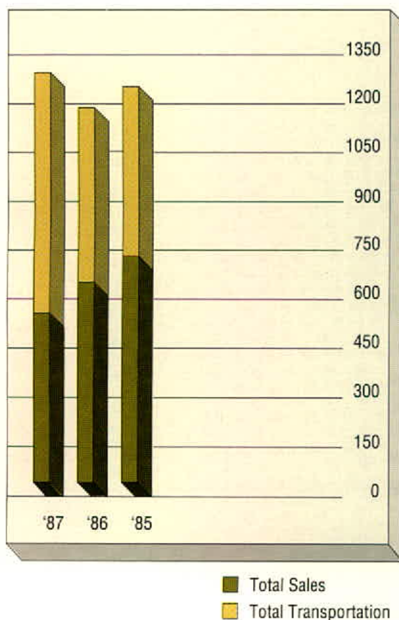
The Corporation continues to analyze the effects of adopting this statement and a substantial one-time benefit to earnings is expected for the Corporation's unregulated operations in the year of adoption. Legislation has been introduced in Congress which will permit regulatory commissions to adopt their own rules for determining the timing in which excess deferred taxes reduce customer rates. Until this matter is resolved, the earnings and cash flow impact on the Corporation's regulated operations cannot be determined.

Effects of inflation

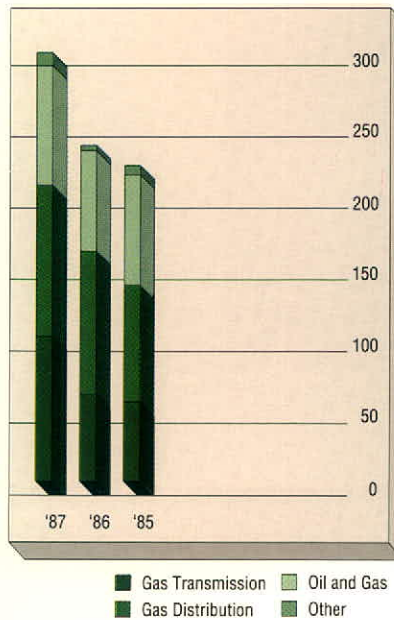
Because the Corporation's subsidiaries are engaged in capital intensive lines of business, cumulative effects of inflation cause substantially greater investment to replace existing productive capacity. However, such replacements occur gradually and revenues generally have kept pace in order to recover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

During periods of high inflation, current operating cost increases generally are not concurrently reflected in increased revenues due to lag effects inherent in the ratemaking process governing the Corporation's regulated subsidiaries. Recently, inflation rates have been increasing and most of the Corporation's distribution subsidiaries have planned general rate filings for 1988 to recover current cost and return levels.

Total System Gas Throughput (in billion cubic feet)



Summary of Gross Capital Expenditures by Segment (in millions of dollars)



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, 1987, there were 98,154 stockholders of record. The table on the right 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

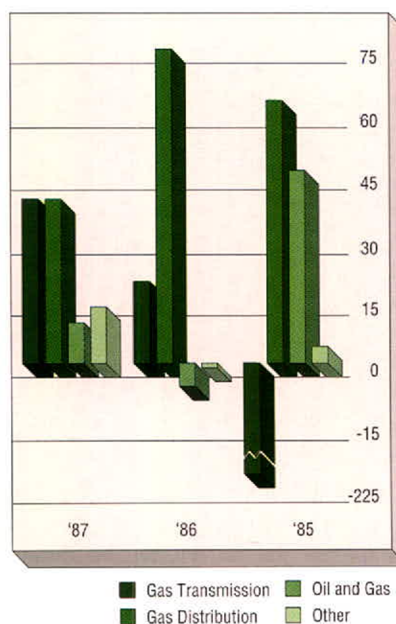
Adverse rulings on matters pending before the FERC concerning Columbia Transmission's rates, as discussed elsewhere in this report, could significantly reduce the Corporation's liquidity. Despite the possible negative impact, the Corporation believes it has financial resources to maintain adequate liquidity.

As a result of the January 19, 1988 FERC orders discussed beginning on page 12, two major credit rating agencies have reduced the rating on the Corporation's senior long-term debt. However, it is not expected that those downgradings will materially increase the cost of new debt issuances or reduce the market for new long-term debt.

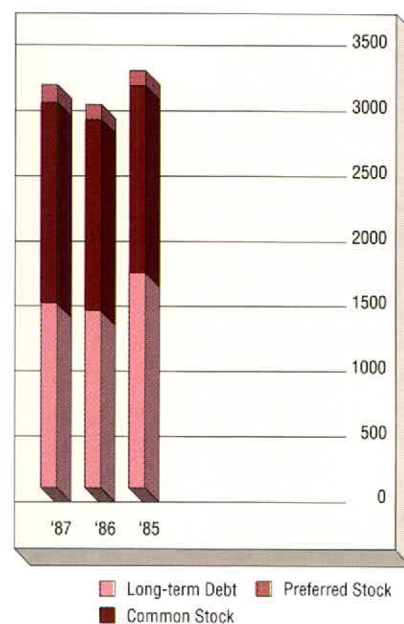
TOTAL REVENUES AND THROUGHPUT	1987	1986	1985
Gas Operating Revenues ($000):			
Residential	**1,028,536**	1,115,572	1,210,623
Commercial	**425,122**	502,712	566,608
Industrial	**104,213**	223,585	383,177
Wholesale	**876,090**	1,229,090	1,566,005
Other	**28,207**	16,088	12,195
Total Gas Operating Revenues	**2,462,168**	3,087,047	3,738,608
Transportation Revenues	**247,202**	192,187	174,581
Other Operating Revenues	**88,634**	90,344	147,730
Total Revenues	**2,798,004**	3,369,578	4,060,919
Sales (Million Cubic Feet):			
Residential	**175,132**	178,750	181,354
Commercial	**79,811**	87,222	91,579
Industrial	**22,419**	47,669	73,252
Wholesale	**214,794**	283,593	344,594
Other	**18,883**	9,226	4,238
Total Sales	**511,039**	606,460	695,017
Total Transportation Volumes	**745,814**	541,497	511,148
Total Throughput	**1,256,853**	1,147,957	1,206,165

QUARTER ENDED	Market Price High	Market Price Low	Market Price Close	Quarterly Dividends Paid
1987	**$**	**$**	**$**	**¢**
December 31	**52¼**	**35½**	**40¼**	**79.5**
September 30	**56½**	**47⅝**	**51¼**	**79.5**
June 30	**51½**	**44**	**50⅛**	**79.5**
March 31	**56¼**	**45½**	**48¾**	**79.5**
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

Earnings by Segment before Extraordinary Charges (in millions of dollars)



Capitalization (in millions of dollars)



Cash from operations before extraordinary charges increased from $574.0 million in 1986 to $684.2 million in 1987. The increase is primarily attributable to revenues which are being collected subject to refund.

On June 10, 1987, the Corporation sold through competitive bidding $200 million of 10½% debentures due 2012, with an effective cost to the Corporation of 10.554%. Between March and July 1987, the Corporation sold 1,750,000 shares of common stock under a continuous offering program. In addition, approximately 435,000 shares of common stock were issued under the Dividend Reinvestment Plan, the Payroll Stock Ownership Plan and the Long-Term Incentive Plan. Proceeds to the Corporation from these sales were $108 million.

Columbia Transmission has a $350 million Production Loan facility. Under this facility there was $175 million outstanding at the beginning of 1987, but it was paid down to $75 million by the end of the year.

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 1987 was $107 million. Commercial paper outstanding on December 31, 1987, was $328 million. The commercial paper program is supported by $525 million of bank credit facilities.

Capital expenditures increased from $232 million in 1986 to $299 million in 1987. This increase is primarily attributable to Columbia Transmission's active program to attach new loads. Capital expenditures for 1988 are projected to be $380 million, an increase of approximately $80 million over 1987. Approximately $50 million of this increase is for investment in transmission facilities. The majority of increased expenditures for transmission are for the maintenance and improvement of operating conditions, and to a lesser extent, expansion into new markets. Distribution expenditures are at the same level as 1987 with approximately 50% devoted to new business activities. Expenditures for oil and gas activities are expected to increase approximately $10 million primarily for exploration activities. Capital expenditures for other operations are expected to increase $20 million primarily related to expenditures by TriStar Ventures Corporation for cogeneration projects.

During 1987, the Corporation continued a program, begun in 1986, of refunding high-cost debt. This is being pursued under 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 by this method.

In 1987, the Corporation paid dividends of $3.18 per share on its common stock. As of December 31, 1987, the Corporation had $121 million of retained earnings available for preferred and common stock dividends under the most restrictive covenants of the Corporation's loan agreements. As a result of various FERC regulatory issues, and other matters, the Board of Directors has informed stockholders that a reduction in the common stock dividend will be considered at the April 1988 Board meeting.

Long-term financing requirements for 1988 are currently projected to be approximately $275 million. Approximately $125 million is for the retirement of long-term debt. It is expected that $75 million of the 1988 requirement will be obtained by drawing on Columbia Transmission's $350 million Production Loan facility. The additional $200 million is likely to be obtained through the sale of debentures. The Corporation has approximately $200 million of bondable credit available under the most restrictive covenant of its Indenture at year-end 1987.

The Corporation believes that it will have sufficient resources to meet its 1988 requirements. The resources include: (1) the additional $275 million available under the Production Loan; (2) sales of its commercial paper and the $197 million available at December 31, 1987, under $525 million of credit facilities; and (3) senior debt capacity available under its Indenture. Although not currently planned, preferred and common stock issues are available.

Comparative Gas Operations Data

The Columbia Gas System, Inc. and Subsidiaries

	1987	1986	1985	1984*	1983
Gas Operating Revenues ($ in thousands)					
Residential	**1,028,536**	1,115,572	1,210,623	1,278,745	1,357,686
Commercial	**425,122**	502,712	566,608	617,593	646,394
Industrial	**104,213**	223,585	383,177	592,084	841,891
Wholesale	**876,090**	1,229,090	1,566,005	1,843,234	2,032,807
Other	**28,207**	16,088	12,195	15,248	16,878
Total gas operating revenues	**2,462,168**	3,087,047	3,738,608	4,346,904	4,895,656
Transportation Revenues ($ in thousands)	**247,202**	192,187	174,581	92,730	59,750
Sales (million cu. ft.)					
Residential	**175,132**	178,750	181,354	188,471	207,225
Commercial	**79,811**	87,222	91,579	97,042	104,606
Industrial	**22,419**	47,669	73,252	108,124	151,034
Wholesale	**214,794**	283,593	344,594	384,967	409,070
Other	**18,883**	9,226	4,238	4,255	4,364
Total sales	**511,039**	606,460	695,017	782,859	876,299
Transportation volumes	**745,814**	541,497	511,148	423,427	262,798
Total throughput	**1,256,853**	1,147,957	1,206,165	1,206,286	1,139,097
Sources of Gas Sold (million cu. ft.)					
Total gas purchased	**491,553**	596,837	616,919	705,070	758,739
Total gas produced (natural and synthetic)	**75,981**	73,214	101,020	125,462	115,921
Exchange gas–net	**(13,080)**	7,732	(10,346)	(1,558)	(2,252)
Gas withdrawn from (delivered to) storage	**(4,076)**	(24,257)	44,980	(1,879)	46,062
Company use and other	**(39,339)**	(47,066)	(57,556)	(44,236)	(42,171)
Total sources of gas sold	**511,039**	606,460	695,017	782,859	876,299
Customers at Year-End					
Residential	**1,626,341**	1,598,960	1,579,279	1,564,460	1,744,883
Commercial	**152,104**	148,013	141,859	138,663	154,063
Industrial	**2,190**	2,180	2,261	2,280	2,450
Wholesale	**82**	78	78	75	86
Other	**92**	41	40	48	55
Total customers at year-end	**1,780,809**	1,749,272	1,723,517	1,705,526	1,901,537
Average Usage Per Customer (thousand cu. ft.)					
Residential	**107.7**	111.8	114.8	120.5	118.8
Commercial	**524.7**	589.3	645.6	699.8	679.0
Degree Days	**5,029**	5,067	5,167	5,410	5,381
Variation from normal (%)	**(6.4)**	(5.7)	(3.9)	0.1	0.3

*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)	1987	1986	1985	1984	1983
Income Statement Data ($)					
Total operating revenues	**2,798,004**	3,369,578	4,060,919	4,603,122	5,075,085
Products purchased	**1,466,196**	1,957,428	2,689,686	3,099,319	3,586,139
Earnings (Loss) on common stock from continuing operations before extraordinary charges	**100,489**	87,892	(107,008)	165,436	184,701
Earnings (Loss) on common stock	**100,489**	75,321	(107,008)	138,564	164,754
Per Share Data					
Earnings (Loss) per common share ($):					
From continuing operations before extraordinary charges	**2.30**	2.12	(2.67)	4.22	4.94
Earnings (Loss) on common stock	**2.30**	1.82	(2.67)	3.53	4.41
Dividends:					
Per share ($)	**3.18**	3.18	3.18	3.18	3.02
Payout ratio (%)	**138.3**	174.7	N/M	90.1	68.5
Average common shares (000)	**43,763**	41,436	40,134	39,227	37,401
Balance Sheet Data ($)					
Capitalization:					
Common stock equity	**1,523,704**	1,448,644	1,422,688	1,634,225	1,598,634
Preferred stock	**50,000**	50,000	50,000	50,000	50,000
Redeemable preferred stock	**60,000**	65,000	70,000	75,000	80,000
Long-term debt	**1,437,951**	1,378,526	1,659,570	1,348,484	1,420,075
Total capitalization	**3,071,655**	2,942,170	3,202,258	3,107,709	3,148,709
Total assets	**5,426,776**	5,590,161	5,835,166	5,200,536	5,238,355
Other Financial Data					
Capitalization ratio (%):					
Common stock equity	**49.6**	49.2	44.4	52.6	50.8
Preferred stock	**3.6**	3.9	3.8	4.0	4.1
Long-term debt	**46.8**	46.9	51.8	43.4	45.1
Capital expenditures ($)	**298,774**	232,283	219,968	272,009	210,941
Cash from continuing operations ($)	**684,179**	573,955	81,703	725,328	453,063
Book value per common share ($)	**34.08**	34.06	35.10	41.22	41.16
Return on average common equity before discontinued operations and extraordinary charges (%)	**6.8**	6.1	N/M	10.2	12.1
Average cost of long-term debt at year-end (%)	**9.2**	8.6	9.4	9.5	9.6

N/M–Not Meaningful

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, 1987 and 1986 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, 1987. 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 2A, the Federal Energy Regulatory Commission issued an order in January 1988 which would limit the ability of Columbia Gas Transmission Corporation to recover from customers a portion of the cost of gas purchased or to be purchased under certain contracts after March 31, 1987. Due to the early stage of this aspect of these proceedings and the novel legal and regulatory issues involved, the amount of such costs, if any, that ultimately may not be recovered cannot be predicted by management at this time.

In our report covering the 1986 and 1985 consolidated financial statements of The Columbia Gas System, Inc. and subsidiaries dated February 5, 1987, we expressed an opinion on such consolidated financial statements which was qualified as being subject to the realization of the equity portion of Columbia LNG Corporation's investment in the Cove Point liquefied natural gas terminal. As discussed in Note 10D, in January 1988 the Federal Energy Regulatory Commission issued an order approving a settlement agreement which management believes assures recovery of such investment. Accordingly, our present opinion on the 1986 and 1985 consolidated financial statements, as presented herein, is unqualified.

In our opinion, subject to the effect on the 1987 consolidated financial statements of such adjustments, if any, as might have been required had the outcome of the matter discussed in the second 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, 1987 and 1986, and the results of their operations and the changes in their financial position for each of the three years in the period ended December 31, 1987, in conformity with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen & Co.

New York, New York
February 4, 1988

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 six 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.

Statements of Consolidated Income

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	1987	1986	1985
Operating Revenues			
Gas	**$2,462,168**	$3,087,047	$3,738,608
Other	**335,836**	282,531	322,311
Total operating revenues	**2,798,004**	3,369,578	4,060,919
Operating Expenses			
Products purchased			
Natural gas	**1,447,435**	1,929,798	2,601,961
Other	**18,761**	27,630	87,725
Provision for unrecovered gas costs (Note 2C)	**—**	65,000	400,000
Operation	**531,739**	457,446	519,106
Maintenance	**82,852**	85,650	77,982
Depreciation and depletion	**220,005**	260,269	267,597
Other taxes	**170,711**	179,214	195,030
Total operating expenses	**2,471,503**	3,005,007	4,149,401
Operating Income (Loss)	**326,501**	364,571	(88,482)
Other Income (Deductions)			
Interest income and other, net (Note 11)	**32,406**	19,776	80,911
Interest expense and related charges (Note 12)	**(182,588)**	(198,989)	(159,003)
Total other income (deductions)	**(150,182)**	(179,213)	(78,092)
Income (Loss) before Income Taxes and Extraordinary Charges	**176,319**	185,358	(166,574)
Income taxes	**64,986**	85,940	(72,742)
Income (Loss) before Extraordinary Charges	**111,333**	99,418	(93,832)
Extraordinary charges (Note 3)	**—**	12,571	—
Net Income (Loss)	**111,333**	86,847	(93,832)
Preferred stock dividends	**10,844**	11,526	13,176
Earnings (Loss) on Common Stock	**$ 100,489**	$ 75,321	$ (107,008)
Earnings (Loss) Per Share of Common Stock (based on average shares outstanding)			
Before extraordinary charges	**$ 2.30**	$ 2.12	$ (2.67)
Extraordinary charges	**—**	.30	—
Earnings (loss) on common stock	**$ 2.30**	$ 1.82	$ (2.67)
Dividends Per Share of Common Stock	**$ 3.18**	$ 3.18	$ 3.18
Average Common Shares Outstanding (thousands)	**43,763**	41,436	40,134

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)	1987	1986
Property, Plant and Equipment		
Gas utility and other plant, at original cost	**$ 4,979,076**	$ 4,811,324
Accumulated depreciation and depletion	**(2,445,281)**	(2,321,553)
	2,533,795	2,489,771
Oil and gas producing properties, full cost method		
United States cost center	**961,093**	964,402
Canadian cost center ($48,600,000 and $42,500,000, respectively, not being amortized) (Note 1D)	**244,226**	212,483
Accumulated depletion	**(488,016)**	(486,389)
	717,303	690,496
Net property, plant and equipment	**3,251,098**	3,180,267
Investments and Other Assets		
Gas supply prepayments and advances (Note 4)	**761,336**	886,027
Unconsolidated affiliates (less than 50% owned)	**45,243**	38,689
Other	**55,237**	46,208
Total investments and other assets	**861,816**	970,924
Current Assets		
Cash and temporary cash investments	**3,750**	14,469
Accounts receivable		
Customers (less allowance for doubtful accounts of $6,719,000 and $4,893,000, respectively)	**471,975**	485,936
Other	**148,689**	160,756
Income tax refunds	**25,619**	112,424
Gas inventory	**332,030**	378,141
Other inventories–at average cost	**43,437**	40,533
Prepayments	**105,505**	108,763
Other	**41,227**	45,437
Total current assets	**1,172,232**	1,346,459
Deferred Charges	**141,630**	92,511
Total Assets	**$5,426,776**	$5,590,161

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

Capitalization and Liabilities As of December 31 (in thousands)	**1987**	1986
Common Stock Equity		
Common stock, par value $10 per share–outstanding 44,711,502 and 42,527,330 shares, respectively	**$ 447,115**	$ 425,273
Additional paid in capital	**409,767**	324,029
Retained earnings	**675,256**	713,564
Accumulated foreign currency translation adjustment	**(8,434)**	(14,222)
Total common stock equity	**1,523,704**	1,448,644
Preferred Stock (Note 5)	**50,000**	50,000
Redeemable Preferred Stock (Note 5)	**60,000**	65,000
Long-Term Debt (Note 8)	**1,437,951**	1,378,526
Total capitalization	**3,071,655**	2,942,170
Current Liabilities		
Bank loans and commercial paper	**327,518**	393,400
Current maturities of long-term debt and preferred stock	**69,640**	432,467
Accounts and drafts payable	**259,452**	276,338
Accrued taxes	**100,451**	97,426
Accrued interest	**39,754**	45,665
Estimated rate refunds	**245,439**	88,032
Estimated supplier obligations	**85,508**	147,150
Deferred income taxes	**—**	109,634
Other	**117,648**	154,691
Total current liabilities	**1,245,410**	1,744,803
Deferred Credits		
Income taxes, noncurrent	**981,471**	812,705
Investment tax credits	**51,527**	53,365
Other	**76,713**	37,118
Total deferred credits	**1,109,711**	903,188
Commitments and Contingencies (Notes 2 and 10)		
Total Capitalization and Liabilities	**$5,426,776**	$5,590,161

Consolidated Statements of Changes in Financial Position

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	1987	1986	1985
Cash From Operations			
Income (loss) before extraordinary charges	**$ 111,333**	$ 99,418	$ (93,832)
Items not requiring (providing) cash:			
Depreciation and depletion	**220,005**	260,269	267,597
Deferred income taxes	**35,854**	76,799	58,096
Estimated rate refunds	**157,407**	52,379	10,626
Nonrecurring charges–net	**—**	(5,906)	48,038
Amortization of prepayments for producer contract modifications	**77,000**	68,413	42,322
Other–net	**(17,730)**	(1,747)	483
Net change in working capital (increase) (Note 13)	**100,310**	24,330	(251,627)
Cash from operations before extraordinary charges	**684,179**	573,955	81,703
Dividends	**(149,641)**	(142,604)	(140,354)
Net cash from operations before extraordinary charges	**534,538**	431,351	(58,651)
Extraordinary charge	**—**	(8,571)	—
Net cash from operations	**534,538**	422,780	(58,651)
External Financing Activities			
Issuance of long-term debt	**200,000**	250,000	—
Retirement of long-term debt and preferred stock	**(156,568)**	(273,624)	(76,663)
Issuance of common stock	**107,580**	80,744	28,465
Issuance of production loan	**—**	100,000	150,000
Repayment of production loan	**(100,000)**	(75,000)	—
Increase (decrease) in short-term bank loans and commercial paper	**(65,882)**	(24,600)	418,000
Net external financing activities	**(14,870)**	57,520	519,802
Capital Investment Activities			
Capital expenditures	**(298,774)**	(232,283)	(219,968)
Gas supply prepayments and advances–net	**(226,547)**	(314,624)	(321,172)
Net capital investment activities	**(525,321)**	(546,907)	(541,140)
Other–net	**(5,066)**	22,086	82,609
Increase (Decrease) in Cash and Temporary Cash Investments	**$ (10,719)**	$ (44,521)	$ 2,620

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, 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 5)				(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 5)				(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)
Net Income				111,333	
Dividends:					
Common ($3.18 per share)				(138,797)	
Preferred:					
10.96% Series B				(1,872)	
10.24% Series C				(5,120)	
Adjustable rate Series D (Note 5)				(3,852)	
Common stock issued:					
Dividend reinvestment plan	358	3,576	12,819		
Employee stock ownership plan	31	305	1,312		
Continuous offering program	1,750	17,500	70,114		
Long-term incentive plan	46	461	1,493		
Other					5,788
Balance at December 31, 1987**	**44,712**	**$447,115**	**$409,767**	**$ 675,256**	**$ (8,434)**

*100 million shares authorized for 1987 and 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, 1987.

Statements of Consolidated Taxes

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31 (in thousands)	1987	1986	1985
Income Taxes			
Currently payable:			
Federal	**$ 23,225**	$ (2,963)	$(110,752)
State	**6,551**	13,807	(9,186)
Investment credits	**(644)**	(3,357)	(12,362)
Total currently payable	**29,132**	7,487	(132,300)
Deferred:			
Federal	**36,959**	84,006	51,796
State	**(71)**	(5,746)	472
Foreign	**804**	23	1,899
Total deferred	**37,692**	78,283	54,167
Deferred investment credits, net	**(1,838)**	(1,484)	3,929
Provision for employee stock ownership plan	**—**	1,654	1,462
Income taxes included in income before extraordinary charge	**64,986**	85,940	(72,742)
Federal income taxes, current–extraordinary charge	**—**	(7,301)	—
Total income taxes	**64,986**	78,639	(72,742)
Other Taxes			
Property	**57,123**	55,202	52,921
Gross receipts	**80,725**	91,575	107,630
Payroll	**21,882**	21,634	21,299
Other	**10,981**	10,803	13,180
Total other taxes	**170,711**	179,214	195,030
Total Tax Expense	**$235,697**	$257,853	$122,288

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

Year Ended December 31 (in thousands)	1987		1986		1985	

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:

	1987		1986		1985	
Book income before income taxes (including extraordinary charges)*	**$176,319**		$165,486		$(166,574)	
Tax expense at statutory Federal income tax rate	**$ 70,528**	**40.0%**	$ 76,124	46.0%	$ (76,624)	(46.0)%
Increases (reductions) in taxes resulting from–						
State income taxes, net of Federal income tax benefit	**4,213**	**2.4**	4,235	2.5	(5,649)	(3.4)
Investment credits not deferred and amortization of credits deferred in prior years	**(2,482)**	**(1.4)**	(3,187)	(1.9)	(6,971)	(4.2)
Depreciation expense for accounting purposes over amounts claimed for income tax purposes	**1,879**	**1.0**	2,023	1.2	7,153	4.3
Extraordinary charge for which no tax benefit has been provided	**—**	**—**	1,840	1.1	—	—
Discontinuing SFAS 71 (Note 1B)**	**—**	**—**	—	—	15,133	9.1
Loss carryforward utilized	**(3,250)**	**(1.8)**	—	—	—	—
Other	**(5,902)**	**(3.3)**	(2,396)	(1.4)	(5,784)	(3.5)
Total Income Taxes	**$ 64,986**	**36.9%**	$ 78,639	47.5%	$ (72,742)	(43.7)%

*Includes income (loss) from foreign operations of $3.2 million, $(26.0) million, and $4.3 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.

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:

	1987	1986	1985
Acquisition, exploration and development costs	**$ (2,925)**	$ 6,549	$ 1,460
Depreciation expense	**26,565**	19,694	52,698
Gas purchased costs	**81,720**	153,374	(37,954)
Estimated rate refunds	**(32,008)**	(117,747)	(862)
Unbilled utility revenue	**(4,111)**	(885)	5,453
Gains on reacquired debt	**—**	—	12,961
Loss on synthetic gas operations	**—**	2,722	12,565
Alternative minimum tax	**(15,042)**	—	—
Other	**(16,507)**	14,576	7,846
Total Deferred Income Taxes	**$ 37,692**	$ 78,283	$ 54,167

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 1986 and 1985 financial statements to conform to the 1987 presentation.

B. Basis of Accounting for Rate Regulated Subsidiaries. Statement of Financial Accounting Standards (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. The accounting adjustments which were necessary to reflect the discontinued application of SFAS No. 71 improved 1985 earnings by $11.0 million, consisting of an improvement to earnings of $35.4 million (net of deferred income taxes of $12.9 million) related to gains on reacquired debt previously deferred, partially offset by a provision for previously unprovided deferred taxes of $24.4 million. The Corporation's gas distribution subsidiaries continue to meet the criteria, and, accordingly, follow the accounting and reporting 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 of the distribution companies includes an allowance for funds used during construction (AFUDC). Plant, property and equipment of other subsidiaries includes interest during construction (IDC). The before tax rates for AFUDC and IDC were as follows:

Year Ended December 31 (%)	**1987**	1986	1985
AFUDC	**9.3**	8.6	10.8
IDC	**9.2**	9.4	9.7

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.

The Corporation's subsidiaries provide for depreciation on a composite straight line basis. The annual depreciation rates were as follows:

Year Ended December 31 (%)	**1987**	1986	1985
Transmission property	**3.1**	3.6	4.4
Distribution property	**3.5**	3.8	3.4

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. If costs exceed the sum of the estimated present value of the cost centers' net future oil and gas revenues and the lower of cost or estimated value of unproved properties, an amount equivalent to 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:

($ in thousands)	1987	1986	1985	Prior Years	**Total 12/31/87**
Exploration costs	500	1,600	4,100	26,900	**33,100**
Interest capitalized	3,000	2,900	2,700	6,900	**15,500**
Total	3,500	4,500	6,800	33,800	**48,600**

Columbia owns 256,000 gross acres (15,000 net acres) applicable to the Hibernia Block. Columbia's interest in offshore Newfoundland totaled 300,000 gross acres (21,000 net acres). The net costs of $48.6 million excluded from depletion at December 31, 1987, were initially incurred in 1979. Management estimates that development of reserves attributed to these properties will begin in the early 1990's.

E. Gas Inventory. Current inventory is carried at cost on a last-in, first-out basis (LIFO). Liquidation of LIFO layers related to gas delivered to market does not affect income since the effect is reflected in revenues currently. As a result of the settlement agreement between Columbia Gas Transmission Corporation (Columbia Transmission) and its wholesale customers (as more fully described in Note 2C), the effect of liquidating LIFO layers was reflected in income during 1985. In 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 Columbia Transmission's settled commodity rate. The estimated replacement cost of gas inventory in excess of carrying amounts was approximately $160 million at December 31, 1987.

F. Income Taxes and Investment Tax Credits. The Corporation's subsidiaries record income taxes to recognize full interperiod tax allocation arising 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 $150 million at December 31, 1987, principally related to accelerated depreciation income tax deductions of the Corporation's gas distribution subsidiaries.

Investment tax credits were eliminated by the Tax Reform Act of 1986. Prior to 1986, investment tax credits were recorded in income currently, except for credits of the gas distribution subsidiaries, which have been deferred and are being amortized over the life of the related properties to conform with regulatory policy.

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 Financial Accounting Standards Board's recently issued pronouncement which will require the Corporation to adopt a new method of accounting for income taxes by 1989.

G. Estimated Rate Refunds. Certain rate regulated subsidiaries are allowed to collect revenues subject to refund pending 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, in the opinion of management, consideration of the facts and circumstances precludes a reasonable estimate of the refund amount.

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. Revenue Recognition. 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. Columbia Transmission also records revenue adjustments to reflect future billings to recover or refund the difference between current gas costs and amounts billed through its Purchased Gas Adjustment (PGA) tariff.

2. REGULATORY MATTERS

A. Purchased Gas Cost Filings. In January 1988, the Federal Energy Regulatory Commission (FERC) issued an order which would limit the ability of Columbia Transmission to collect from customers a portion of its purchased gas costs under certain contracts and require refunds for the collection of such costs since April 1987. This action, together with an additional remedy related to the recovery of contract reformation costs addressed in Management's Discussion and Analysis of Financial Condition and Results of Operations, was developed in the proceedings involving the gas acquisition policies and practices of Columbia Transmission at issue in FERC Opinion No. 204 (issued in January 1984).

In Opinion No. 204, the FERC applied a new two-prong definition of abuse under the Natural Gas Policy Act (NGPA) in its review of two 1981 PGA filings made by Columbia Transmission. While finding that Columbia Transmission had exhibited a "reckless disregard" of its duty to provide service at the lowest reasonable cost (the first prong of the definition), the FERC failed to find that Columbia Transmission's purchasing practices had an adverse impact on its customers (the second prong). Consequently, the FERC did not order refunds. Upon appeal, the D.C. Circuit Court of Appeals, in 1986, rejected that aspect of the FERC's definition of abuse which required an adverse impact upon customers and directed the FERC to develop appropriate remedies. The Court noted that to find abuse, it was only necessary to determine that the pipeline made excessive payments.

In May 1987, responding to the Court's remand, the FERC redefined abuse following the Court's guidelines, set a number of issues for hearing, but did not establish remedies. At the request of certain intervenors, the Court ruled, in August 1987, that the FERC's action did not fully comply with its mandate and directed the FERC to fashion remedies to be imposed, as of January 16, 1984, the date Opinion No. 204 was issued, for Columbia Transmission's past practices and directed compliance with its mandate in terms of considering remedies under Section 5 of the Natural Gas Act (NGA).

Responding to the 1987 Court order, the FERC issued its January 1988 decision which imposes remedies pertaining to Columbia Tranmission's 1981 PGA filings. It concluded that Columbia Transmission's problem contracts were abusive under the NGPA when entered into, thereby reversing its earlier conclusion in Opinion No. 204 that such contracts were not unreasonable when entered into, but became so under present market conditions.

Recognizing that Columbia Transmission's 1985 settlement agreement with customers (Note 2C) limited any refund liability stemming from the 1981 PGA filings to $1 million and provided that Columbia Transmission would have no refund obligations related to its gas purchases for the period March 1, 1982, through March 31, 1987, the FERC ordered Columbia Transmission to refund $1 million to its customers.

The FERC also ruled that an additional remedy is appropriate and limited the recovery of certain gas purchased costs incurred after March 31, 1987, under the problem contracts, to the price of alternative fuel in Columbia Transmission's service area and tentatively determined that the relevant fuel is No. 6 fuel oil. The determination of which contracts were covered under the FERC's new abuse finding and the appropriate alternative fuel was remanded to an Administrative Law Judge. In management's opinion, the FERC order establishing the price cap is contrary to the intent of the NGPA, violates the concept of rolled in pricing and the relevant alternative fuel identified is not appropriate under present market conditions. However, due to the early stage of this aspect of these proceedings and the novel legal and regulatory issues involved, the amount of such costs which ultimately may not be recovered, if any, cannot be predicted at this time.

B. Direct Billing of Take-or-Pay Payments and Contract Reformation Costs. In August 1987, the FERC issued Order No. 500 which, among other measures, provided guidelines for the rate recovery of up to 50% of take-or-pay and contract reformation costs by way of direct billings if an applicant pipeline agrees to forego the recovery of a commensurate amount. The direct billed amounts would be allocated among customers on the basis of past-purchase deficiencies. Columbia Transmission and others have vigorously opposed the deficiency-based allocation provisions of this order on the grounds that such direct billing would constitute an illegal form of retroactive ratemaking.

In October 1987, the Court of Appeals for the D.C. Circuit ruled that previous FERC orders authorizing pipeline suppliers to bill certain gas costs (other than take-or-pay and contract reformation costs) on the basis of past gas purchase patterns without due notice is unlawful retroactive ratemaking. This Court ruling further supports management's belief that deficiency-based direct billing will ultimately not be permitted.

Management believes that the Order No. 500 cost absorption requirement and application of the Court ruling will ultimately reduce billings to Columbia Transmission by its pipeline suppliers for their take-or-pay and contract reformation costs.

Although customer opposition is expected, it is management's opinion that Columbia Transmission will ultimately be able to pass on such costs to its customers through some direct billing mechanism that would assure the recovery of such costs without significantly impacting Columbia Transmission's market position.

One of Columbia Transmission's pipeline suppliers has filed to recover such costs under the guidelines of Order No. 500. In late January 1988, the FERC approved, in principle, this proposal.

C. Wholesale Rate Settlement. In the first quarter of 1985, Columbia Transmission reached a settlement with its customers and other parties resolving more than 20 dockets pending before the FERC. Pursuant to the settlement agreement, Columbia Transmission lowered its commodity sales rate by 11.5% for a two-year period commencing April 1, 1985. Further, Columbia Transmission's customers agreed to allow Columbia 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 Columbia 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 Columbia Transmission's gas costs with gas costs of its five major pipeline suppliers over a seven-year period ending December 31, 1992. The savings realized, should Columbia Transmission reduce its gas costs below the designated levels, would be shared equally by Columbia Transmission and its customers.

At December 31, 1985, Columbia Transmission had incurred $540 million of unrecovered costs related to gas purchased prior to April 1, 1985. Since in management's opinion, the settlement agreement did not provide adequate assurance that all of these costs would be recoverable in the future, Columbia Transmission recorded a pre-tax charge in 1985 of $400 million, establishing a reserve for unrecovered gas costs. During 1986, the reserve was increased to $465 million.

In conjunction with the recovery of unrecovered gas purchased costs in the last two quarters of 1986 and the first quarter of 1987, Columbia Transmission recorded refund liabilities which, in management's opinion, are appropriate under the terms of the settlement agreement. On September 1, 1987, Columbia Transmission began to pass through to its customers a refund of $114.3 million, plus interest, by way of a 12-month rate reduction. Recovery of additional gas purchased costs previously reserved is possible should Columbia Transmission meet the specified conditions in any calendar year between 1988 and 1992.

3. EXTRAORDINARY CHARGES

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.

In the fourth quarter of 1986, the Corporation refunded $135.5 million of debentures at a premium cost of $15.9 million ($8.6 million net of income tax benefits).

4. 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)	1987	1986
Prepayments for producer contract modifications	**592,251**	658,960
Gas supply prepayments	**163,266**	214,389
Gas supply advances	**5,819**	12,678
Total	**761,336**	886,027

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.

5. PREFERRED STOCK

As of December 31, 1987, the Corporation had authorized 10,000,000 shares of preferred stock, par value $50.00 per share, and had outstanding 300,000 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 $15 million over the next three 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 $20 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. The adjustable dividend rate varies from 7½% to 13½% per annum and is adjustable quarterly in accordance with a formula based on certain U.S. Treasury securities. The annual rates used for each quarterly period were as follows:

Quarter Ended (%)	1987	1986	1985
November	**7.95**	7.50	9.75
August	**7.70**	7.50	10.45
May	**7.50**	8.25	10.30
February	**7.50**	9.20	10.70

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.

6. ACCOUNTING FOR PENSION COSTS AND OTHER POST-RETIREMENT BENEFITS

The Corporation has trusteed, noncontributory pension plans which, with certain minor exceptions, cover all regular employees, 21 years of age and over. The plans provide defined benefits based on final average compensation. It is the Corporation's funding policy to contribute annually to the plans based on a percentage of expected employees' earnings, estimated at the beginning of the year and subject to the statutory minimum and maximum limits.

Effective January 1, 1986, the Corporation adopted SFAS No. 87. Net periodic pension expense and plan contributions for 1985, determined under prior accounting standards and using other assumptions, were $22.8 million.

The following table provides 1987 and 1986 pension cost components for the plans along with additional relevant data:

Pension Costs ($ in millions)	1987	1986
Service costs	**14.4**	14.4
Interest cost	**45.5**	46.7
Return on assets	**(54.7)**	(49.2)
Other, net	**1.2**	(0.3)
Net pension expense	**6.4**	11.6
Annual contribution	**7.2**	17.9
Assumed asset earnings rate	**9%**	9%

Actual return on plan assets for 1987 and 1986 was $39.4 million and $92.2 million, respectively. The difference between the assumed return on assets used in the calculation of net periodic pension expense and the actual return on assets is included in the following table in unrecognized net gain.

Pension plan assets consist principally of common stock equities, real estate investments and fixed income securities. The following table provides a reconciliation of plan assets and liabilities to the funded status of the plans:

Plan Assets and Obligations at December 31 ($ in millions)	1987	1986
Plan assets at fair value	**628.3**	626.5
Actuarial present value of benefit obligations:		
Vested benefits	**504.2**	478.4
Nonvested benefits	**26.7**	32.1
Accumulated benefit obligation	**530.9**	510.5
Effect of projected future salary increases	**87.7**	122.3
Total projected benefit obligation	**618.6**	632.8
Plan assets in excess of (less than) projected benefit obligation	**9.7**	(6.3)
Less unrecognized net gain	**(20.0)**	(6.0)
Plus unrecognized transition obligation	**17.4**	18.6
Prepaid pension cost	**7.1**	6.3
Discount rate assumption	**8.0%**	7.5%
Compensation growth rate	**6.5%**	7.0%

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 1987 and 1986 and $5.6 million in 1985.

7. LONG-TERM INCENTIVE PLAN

The Corporation has a Long-Term Incentive Plan which provides for grants of incentive stock options, nonqualified stock options, stock appreciation rights and contingent stock awards. A total of 1,500,000 shares of the Corporation's common stock is reserved for issuance under the Plan's provisions. There were 947,155 shares remaining available for awards at December 31, 1987.

Stock options are granted at an exercise price equal to the fair market value on the date of the grant. One-half of the options are exercisable beginning one year after the date of grant, and one-half beginning two years from the date of grant. Options expire ten years from the date of grant.

Stock appreciation rights, which are granted in connection with nonqualified stock options, entitle the holders to receive stock, cash or a combination thereof equal to the excess market value over the grant price.

Plan activity for the three years ended December 31, 1987, follows:

	Option Shares		
	Without Stock Appreciation Rights	With Stock Appreciation Rights	Option Price Range
1985			
Granted	158,950	6,100	$38.30-$38.31
Outstanding	158,950	6,100	$38.30-$38.31
1986			
Granted	141,390	25,380	$42.99
Cancelled	(4,950)	—	$38.30-$38.31
Outstanding	295,390	31,480	$38.30-$42.99
1987			
Granted	**177,680**	**26,910**	**$37.74**
Exercised	**(30,245)**	**—**	**$38.30-$42.99**
Cancelled	**(13,325)**	**—**	**$38.30-$42.99**
Converted	**(2,480)**	**2,480**	**$42.99**
Outstanding	**427,020**	**60,870**	**$37.74-$42.99**
Exercisable at December 31, 1987	**182,195**	**20,030**	**$38.30-$42.99**

In addition to stock options, contingent stock awards have been granted to certain key executives without cost to recipients. Contingent stock awards have been granted of 8,900, 12,860 and 12,950 for 1987, 1986 and 1985, respectively. In 1987, 15,810 shares of common stock were issued for vested awards. The outstanding contingent stock awards, subject to meeting the award contingencies, will be issued as follows: 4,000 shares in 1988, 3,000 shares in 1989 and 11,900 shares in 1990.

8. 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)	1987	1986
The Columbia Gas System, Inc.		
Debentures:		
4⅜% Series due January 1988	—	7,490
4⅝% Series due May 1989	**15,000**	16,742
4⅝% Series due October 1989	**12,000**	13,400
9⅝% Series due November 1989	**7,500**	15,000
4⅝% Series due May 1990	**13,400**	14,700
4⅞% Series due October 1990	**13,400**	14,800
6¼% Series due October 1991	**14,800**	16,200
6⅝% Series due October 1992	**10,125**	11,000
7¼% Series due May 1993	**22,000**	23,745
9% Series due August 1993	**150,000**	150,000
7% Series due October 1993	**17,600**	19,000
9% Series due October 1994	**23,750**	25,500
8¾% Series due April 1995	**20,307**	21,800
9⅛% Series due October 1995	**25,500**	27,250
10⅛% Series due November 1995	**28,000**	37,400
8⅜% Series due March 1996	**40,654**	42,995
9⅛% Series due May 1996	**32,613**	42,100
8¼% Series due September 1996	**32,700**	34,800
7½% Series due March 1997	**28,217**	30,152
7½% Series due June 1997	**34,800**	36,246
15⅜% Series due June 1997	**49,774**	51,774
7½% Series due October 1997	**34,626**	34,631
7½% Series due May 1998	**30,667**	32,419
10¼% Series due May 1999	**47,500**	60,000
9⅞% Series due June 1999	**25,963**	27,400
11¾% Series due October 1999	**15,625**	31,250
12¾% Series due August 2000	**15,625**	31,250
10¼% Series due August 2011	**100,000**	100,000
10½% Series due June 2012	**200,000**	—
	1,062,146	969,044
Unamortized debt discount, less premium	**(5,687)**	(5,957)
	1,056,459	963,087
Revolving credit agreement[a]	**281,250**	300,000
Subsidiary debt:		
Production loan[b]	**75,000**	71,250
Other	**9,235**	12,108
Capitalized lease obligations	**16,007**	32,081
Total long-term debt	**1,437,951**	1,378,526

[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 an amended Limited Recourse Loan Agreement (Production Loan), Columbia Transmission has available up to $350 million on a revolving basis through October 14, 1989, (subject to the value of the underlying reserves) with any borrowings outstanding at the end of that period being repayable in twenty equal quarterly installments from October 15, 1989, to July 15, 1994. Columbia Transmission pays a fee of ½% per annum on the daily average unused commitment through October 15, 1989. 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 Columbia Transmission for various time periods. At December 31, 1987, debt of $75 million was outstanding under this agreement.

The aggregate maturities of long-term debt for the five years ending December 31, 1992, are as follows:

($ in thousands)	
1988	64,640
1989	160,600
1990	157,428
1991	142,004
1992	118,299

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

9. SHORT-TERM BORROWINGS

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 day 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 is through a fee paid to the participating banks.

Year Ended December 31 ($ in thousands)	1987	1986	1985
Maximum outstanding:			
Commercial paper	**401,400**	448,300	—
Bank loans	—	418,000	418,000
Minimum outstanding:			
Commercial paper	—	—	—
Bank loans	—	—	—
Daily average outstanding:			
Commercial paper	**106,900**	118,500	—
Bank loans	—	46,400	86,700
Interest rates:			
Commercial paper	**5.9%-8.7%**	5.7%-8.5%	—
Bank loans	—	8.9%-9.4%	8.9%-9.2%
Weighted daily average rate:			
Commercial paper	**6.8%**	6.4%	—
Bank loans	—	9.0%	9.0%
Weighted average rate at year end:			
Commercial paper	**8.1%**	6.2%	—
Bank loans	—	—	9.1%
Weighted average maturity at year end (days):			
Commercial paper	**21.8**	30.0	—
Bank loans	—	—	26.8
Credit lines at year end	**525,000**	525,000	518,000
Less–outstanding commercial paper/bank loans	**327,500**	393,400	418,000
Unused credit lines	**197,500**	131,600	100,000

10. OTHER COMMITMENTS AND CONTINGENCIES

A. Capital Expenditures. Capital expenditures for 1988 are estimated at $380 million. Of this amount, $150 million is for transmission operations, $110 million for distribution operations, $90 million for oil and gas operations and $30 million for other operations.

B. Producer Contract Negotiations. Columbia 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, Columbia Transmission agreed to indemnify producers against potential liabilities that may be incurred by them as a result of contract modifications. Since 1986, several lawsuits have been 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. Substantially all of Columbia Transmission's production properties have been pledged as security under its Production Loan (as more fully described in Note 8); and certain customers have made prepayments for gas service which are secured by a pledge of an interest in Columbia Transmission's gas inventory. Other assets of Columbia Transmission are pledged to the Corporation as security for debt owed by Columbia Transmission to the Corporation.

D. Cove Point LNG Terminal. Deliveries of liquefied natural gas to Columbia LNG's Cove Point terminal ceased 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. Columbia LNG presently continues to charge its minimum bill to Columbia Transmission, which, in turn, passes such costs to its customers through the PGA clause in its tariff.

On January 13, 1988, the FERC approved a settlement agreement filed by Columbia LNG and the joint-owner of the Cove Point facility. The settlement provides for: (1) abandonment by the joint-owner of its 50% interest in the facility and recovery of its 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; (3) Columbia LNG being allowed to recover the additional operation and maintenance costs and taxes resulting from 100% ownership through the minimum bill provision through January 1, 1990, with the right to seek FERC approval for an extension beyond that date; (4) equal sharing of retirement costs with the joint-owner should Columbia LNG abandon the facility prior to June 30, 1992; and (5) recovery over ten years by Columbia LNG of its investment, plus carrying charges of 6.5%, should it decide to abandon the facility in the future, without any resumption of trade.

Although the FERC order approving the settlement agreement is subject to request for rehearing and possible appeal, management believes it will ultimately be approved substantively in its present form. Consequently, in the event Columbia LNG Corporation is unable to resume operation of, or to sell or lease the facility, management believes this order assures recovery of the Corporation's total remaining investment in the facility ($154 million at December 31, 1987) and abandonment costs.

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 $35.2 million in 1987, $27.9 million in 1986, and $31.4 million in 1985.

Future minimum rental payments required under operating leases that have initial or remaining noncancellable lease terms in excess of one year are:

($ in thousands)	
1988	8,900
1989	6,200
1990	6,200
1991	4,900
1992	4,800
After 1992	69,500

11. INTEREST INCOME AND OTHER, NET

Year Ended December 31 ($ in thousands)	**1987**	1986	1985
Interest income	**15,542**	15,216	23,772
Gain on sale of coal interests	**13,795**	—	—
Income from equity investments	**1,841**	2,843	7,697
Gains on reacquired debt previously deferred	**—**	—	48,324
Miscellaneous	**1,228**	1,717	1,118
Total	**32,406**	19,776	80,911

12. INTEREST EXPENSE AND RELATED CHARGES

Year Ended December 31 ($ in thousands)	**1987**	1986	1985
Interest on long-term debt	**131,596**	136,032	131,686
Amortization of debt discount on contract modification obligations	**22,516**	44,213	—
Interest on short-term debt	**8,645**	13,246	8,138
Interest on rate refunds	**9,714**	1,209	1,274
Other interest charges	**14,894**	8,528	24,362
Allowance for borrowed funds used and interest during construction	**(4,777)**	(4,239)	(6,457)
Total	**182,588**	198,989	159,003

13. 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)	**1987**	1986	1985
Accounts receivable, net	**26,028**	1,453	(63,096)
Income tax refunds	**86,805**	16,689	(129,113)
Gas inventory	**46,111**	(94,138)	144,340
Accounts and drafts payable	**(16,886)**	(73,176)	(147,977)
Accrued taxes	**3,025**	14,205	(2,759)
Estimated rate refunds	**157,407**	52,379	10,625
Estimated supplier obligations	**(61,642)**	(97,678)	(22,414)
Deferred income taxes	**(109,634)**	(55,138)	(19,030)
Miscellaneous	**(38,390)**	51,592	(61,479)
Change in working capital	**92,824**	(183,812)	(290,903)
Non-cash items	**7,486**	208,142	39,276
Net change (increase) in working capital	**100,310**	24,330	(251,627)

14. BUSINESS SEGMENT INFORMATION

The following tables provide information concerning the Corporation's major business segments. Revenues include intersegment sales to affiliated subsidiaries, which are eliminated when consolidated. Affiliated sales are recognized on the basis of prevailing market or regulated prices. Operating income is derived from revenues and expenses directly associated with each segment. Identifiable assets include only those attributable to the operations of each segment.

Earnings 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. Other 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 upon each segment's pre-tax income adjusted for assignable statutory tax rate differences.

The classification of the Columbia Gas System Service Corporation revenues, income and assets has been changed from corporate to a specific segment, and is grouped within the "other" category. The Service Corporation is more appropriately classified as a segment that provides professional services to affiliates. For comparison purposes, prior year segment data presented has been reclassified for the effect of this change.

Identifiable assets related to other operations include the net assets of coal mining operations discontinued in 1984. Such amounts were $12.4 million in 1987, $13.5 million in 1986 and $12.9 million in 1985.

($ in thousands)		**1987**	1986	1985
Revenues				
Transmission	–Unaffiliated	**1,025,682**	1,391,884	1,653,609
	–Intersegment	**891,583**	1,072,866	1,551,851
	Total	**1,917,265**	2,464,750	3,205,460
Distribution	–Unaffiliated	**1,606,769**	1,853,513	2,149,049
	–Intersegment	**363**	7,620	3,765
	Total	**1,607,132**	1,861,133	2,152,814
Oil and gas	–Unaffiliated	**112,545**	65,034	156,193
	–Intersegment	**51,188**	106,820	97,674
	Total	**163,733**	171,854	253,867
Other	–Unaffiliated	**53,008**	59,147	99,708
	–Intersegment	**55,583**	58,710	101,526
	Total	**108,591**	117,857	201,234
Adjustments and eliminations	–Unaffiliated	**—**	—	2,360
	–Intersegment	**(998,717)**	(1,246,016)	(1,754,816)
	Total	**(998,717)**	(1,246,016)	(1,752,456)
Consolidated		**2,798,004**	3,369,578	4,060,919

($ in thousands)	**1987**	1986	1985
Operating Income (Loss)			
Transmission	**179,137**	167,576	(326,356)
Distribution	**108,551**	184,734	135,692
Oil and gas	**41,246**	14,786	100,944
Other	**5,201**	5,218	11,198
Corporate	**(7,634)**	(7,743)	(9,960)
Consolidated	**326,501**	364,571	(88,482)
Earnings (Loss) Before Extraordinary Charges			
Transmission	**39,237**	19,426	(219,697)
Distribution	**39,296**	75,135	62,359
Oil and gas	**8,946**	(6,546)	46,198
Other	**13,010**	(123)	4,132
Consolidated	**100,489**	87,892	(107,008)
Depreciation & Depletion			
Transmission	**102,229**	114,606	136,913
Distribution	**47,069**	45,897	38,306
Oil and gas	**66,151**	94,547	84,733
Other	**4,556**	5,219	7,645
Consolidated	**220,005**	260,269	267,597
Identifiable Assets			
Transmission	**3,112,895**	3,362,100	3,630,343
Distribution	**1,488,400**	1,471,948	1,518,995
Oil and gas	**779,869**	746,772	766,667
Other	**101,418**	100,035	119,211
Adjustments and eliminations	**(125,846)**	(168,240)	(323,208)
Corporate and unallocated	**70,040**	77,546	123,158
Consolidated	**5,426,776**	5,590,161	5,835,166
Capital Expenditures			
Transmission	**100,847**	60,717	55,620
Distribution	**105,841**	101,029	80,826
Oil and gas	**81,487**	66,798	78,210
Other	**10,599**	3,739	5,312
Consolidated	**298,774**	232,283	219,968

15. 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 Revenues	Income (Loss) Before Income Taxes and Extra-ordinary Charges	Earnings (Loss) on Common Stock Before Extra-ordinary Charges	Earnings (Loss) on Common Stock	Earnings (Loss) Per Share Before Extra-ordinary Charges	Earnings (Loss) Per Share
1987						
December 31	**911,809**	**54,360**	**33,598**	**33,598**	**0.75**	**0.75**
September 30[1]	**353,497**	**(1,128)**	**(6,391)**	**(6,391)**	**(0.14)**	**(0.14)**
June 30	**445,696**	**4,454**	**123**	**123**	**—**	**—**
March 31[2]	**1,087,002**	**118,633**	**73,159**	**73,159**	**1.71**	**1.71**
1986						
December 31[3]	906,875	79,751	35,752	27,181	0.84	0.64
September 30[4]	453,828	30,102	15,475	11,475	0.37	0.28
June 30[5][6]	522,877	16,022	7,620	7,620	0.19	0.19
March 31[7]	1,485,998	59,483	29,045	29,045	0.71	0.71

[1]Includes an increase in earnings of $9.1 million related to the sale of certain coal interests.

[2]Includes a decrease in earnings of $19.2 million as a result of regulatory rulings related to the ability of Columbia Transmission to recover certain gas purchase contract reformation costs retroactive to April 1, 1986, of which $12.1 is applicable to 1986.

[3]Includes a decrease in earnings of $8.6 million reflecting an extraordinary charge applicable to refunding of high-cost debentures (see Note 3).

[4]Includes a decrease in earnings of $4 million reflecting an extraordinary charge applicable to the sale of a distribution subsidiary (see Note 3).

[5]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.

[6]Includes a decrease in earnings of $10.3 million to record a write-down of the carrying value of Canadian oil and gas properties.

[7]Includes a decrease in earnings of $38.8 million related to unrecovered gas purchased costs (see Note 2C).

16. OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

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

	United States			Canada			Total		
($ in thousands)	**1987**	1986	1985	**1987**	1986	1985	**1987**	1986	1985
Capitalized Costs at Year End									
Proved properties	**904,096**	916,115	885,116	**169,025**	148,329	119,963	**1,073,121**	1,064,444	1,005,079
Unproved properties[a]	**56,997**	48,287	90,030	**75,201**	64,154	74,224	**132,198**	112,441	164,254
Total capitalized costs	**961,093**	964,402	975,146	**244,226**	212,483	194,187	**1,205,319**	1,176,885	1,169,333
Accumulated depletion	**(440,974)**	(445,195)	(441,963)	**(47,042)**	(41,194)	(10,816)	**(488,016)**	(486,389)	(452,779)
Net capitalized costs	**520,119**	519,207	533,183	**197,184**	171,289	183,371	**717,303**	690,496	716,554
Costs Capitalized During Year									
Acquisition	**19,470**	9,346	10,037	**5,787**	3,149	1,864	**25,257**	12,495	11,901
Exploration	**17,987**	24,027	25,147	**8,689**	7,214	15,127	**26,676**	31,241	40,274
Development	**24,892**	16,046	18,475	**4,119**	5,548	7,120	**29,011**	21,594	25,595
Costs capitalized	**62,349**	49,419	53,659	**18,595**	15,911	24,111	**80,944**	65,330	77,770

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

HISTORICAL RESULTS OF OPERATIONS

	United States			Canada			Total		
($ in thousands)	**1987**	1986	1985	**1987**	1986	1985	**1987**	1986	1985
Gross revenues									
Unaffiliated	**101,156**	56,302	135,770	**11,439**	8,886	14,535	**112,595**	65,188	150,305
Affiliated	**50,665**	106,573	97,615	**—**	—	—	**50,665**	106,573	97,615
Production costs	**33,982**	32,226	44,194	**2,640**	2,795	3,933	**36,622**	35,021	48,127
Depletion	**60,856**	63,769	80,427	**4,862**[a]	30,228[a]	3,364	**65,718**	93,997	83,791
Income tax expense	**22,785**	30,609	49,237	**1,575**	(11,103)	3,329	**24,360**	19,506	52,566
Results of operations	**34,198**	36,271	59,527	**2,362**	(13,034)	3,909	**36,560**	23,237	63,436

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 $0.8 million for 1987 and $26.6 million for 1986.

OTHER OIL AND GAS PRODUCTION DATA

	United States			Canada		
	1987	1986	1985	**1987**	1986	1985
Average sales price per Mcf of gas ($)	**1.68**	2.11	2.42	**1.23**	1.41	1.59
Average sales price per barrel of oil and other liquids ($)	**15.99**	14.37	23.42	**14.66**	14.30	23.84
Production (lifting) cost per dollar of gross revenue ($)	**0.22**	0.20	0.19	**0.23**	0.32	0.27
Depletion rate per dollar of gross revenue ($)	**0.40**	0.39	0.35	**—**	—	—
Depletion rate per equivalent Mcf ($)	**—**	—	—	**0.72**	0.74	0.69

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, 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
Revisions of previous estimate	29,430	761	3,983	(53)
Extensions, discoveries and other additions	27,024	1,445	3,748	1,371
Production	(73,850)	(1,597)	(2,015)	(602)
Purchase (sale) of minerals-in-place	7,755	27	1,070	82
Reserves as of December 31, 1987	**732,707**	**7,732**	**149,442**	**6,401**
Proved developed reserves as of December 31				
1985	683,797	7,706	154,383	6,004
1986	702,102	6,845	142,656	5,206
1987	**694,429**	**6,562**	**149,442**	**6,024**

[a]Gross working interest reserves.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	United States			Canada			Total		
($ in thousands)	**1987**	1986	1985	**1987**	1986	1985	**1987**	1986	1985
Future cash inflows	**1,688,148**	1,663,842	2,261,210	**281,180**	241,899	380,317	**1,969,328**	1,905,741	2,641,527
Future production costs	**(355,682)**	(375,497)	(496,945)	**(53,114)**	(49,923)	(70,737)	**(408,796)**	(425,420)	(567,682)
Future development costs	**(131,546)**	(127,790)	(147,939)	**(6,126)**	(4,630)	(4,079)	**(137,672)**	(132,420)	(152,018)
Future income tax expense	**(356,977)**	(345,251)	(667,495)	**(62,359)**	(51,254)	(120,780)	**(419,336)**	(396,505)	(788,275)
Future net cash flows	**843,943**	815,304	948,831	**159,581**	136,092	184,721	**1,003,524**	951,396	1,133,552
Less 10% discount	**386,673**	382,734	428,242	**82,274**	71,435	99,920	**468,947**	454,169	528,162
Standardized measure of discounted future net cash flows	**457,270**	432,570	520,589	**77,307**	64,657	84,801	**534,577**	497,227	605,390

Future cash flows are computed by applying year-end prices 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. Discounted future net cash flows are derived by applying a 10% discount rate, as required by SFAS No. 69, to the future net cash flows. This data is not intended to reflect the actual economic value of the Corporation's oil and gas producing properties or the true present value of estimated future cash flows since many arbitrary assumptions are used. The data does provide a means of comparison among companies through the use of standardized measurement techniques.

A reconciliation of the components resulting in changes in the standardized measure of discounted cash flows attributable to proved oil and gas reserves for the three years ending December 31, 1987, follows:

	United States			Canada			Total		
($ in thousands)	**1987**	1986	1985	**1987**	1986	1985	**1987**	1986	1985
Beginning of year	**432,570**	520,589	565,548	**64,657**	84,801	84,639	**497,227**	605,390	650,187
Oil and gas sales, net of production costs	**(117,839)**	(130,649)	(189,190)	**(8,799)**	(6,090)	(10,602)	**(126,638)**	(136,739)	(199,792)
Net changes in prices and production costs	**22,919**	(236,243)	(103,423)	**8,526**	(45,853)	(19,363)	**31,445**	(282,096)	(122,786)
Extensions, discoveries and other additions, net of related costs	**34,247**	22,614	23,899	**9,971**	1,733	15,460	**44,218**	24,347	39,359
Revisions of previous estimates, net of related costs	**30,650**	31,584	151,997	**2,050**	(6,866)	1,482	**32,700**	24,718	153,479
Accretion of discount	**60,515**	86,769	94,649	**8,885**	14,014	14,172	**69,400**	100,783	108,821
Net change in income taxes	**(9,941)**	174,525	33,839	**(5,871)**	31,152	1,740	**(15,812)**	205,677	35,579
Other	**4,149**	(36,619)	(56,730)	**(2,112)**	(8,234)	(2,727)	**2,037**	(44,853)	(59,457)
End of year	**457,270**	432,570	520,589	**77,307**	64,657	84,801	**534,577**	497,227	605,390

The estimated discounted future net cash flows increased during 1987 primarily due to the recovery of wellhead prices. However, discoveries and other reserve additions have not kept pace with production over the last three years, reflecting reduced levels of exploration and development expenditures.

THE COLUMBIA GAS SYSTEM, INC.

DIRECTORS

Thomas S. Blair[3,4]
Chairman, Blair Strip Steel Company
New Castle, Pennsylvania

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

Frank J. Durzo[1,3]
Former Chairman and Chief
Executive Officer
Jeffrey Galion, Inc.
Acquired by Dresser Industries, Inc.
Industrial Equipment, Columbus, Ohio

Dr. Sherwood L. Fawcett[3,4]
Trustee and Former Chairman,
Board of Trustees
Battelle Memorial Institute
Columbus, Ohio

J. Robert Fletcher[2,4]
Chairman, J. H. Fletcher & Co.
Manufacturer of Mining Equipment
Huntington, West Virginia

Robert H. Hillenmeyer[1,2]
Chairman, Hillenmeyer Nurseries, Inc.
Lexington, Kentucky

Malcolm T. Hopkins[2,3]
Former Vice Chairman, Chief Financial
Officer and Director
St. Regis Corporation
Forest Products, Oil, Gas and Insurance
New York, New York

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

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

James D. Little
Executive Vice President

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

Robert A. Oswald
Senior Vice President and
Chief Financial Officer

Ernesta G. Procope[3,4]
President and Chief Executive Officer
E. G. Bowman Co., Inc.
Insurance Brokerage Firm
New York, New York

Arch A. Sproul[2,3]
Chairman
Virginia Trading Company
Staunton, Virginia

William R. Wilson[2,4]
President and Chief Executive Officer
Lukens, Inc.
Steel and Industrial Products

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

James D. Little
Executive Vice President

Robert A. Oswald
Senior Vice President and
Chief Financial Officer

Daniel L. Bell, Jr.
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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Executive Vice President

Robert A. Oswald
Senior Vice President and
Chief Financial Officer

Daniel L. Bell, Jr.
Edward D. Callahan
Robert L. Geiler
Max M. Levy
Senior Vice Presidents

Stanley C. Kauffman
Vice President and Treasurer

Richard E. Lowe
Vice President and General Auditor

Hart T. Mankin
Vice President and General Counsel

Larry J. Bainter
Richard A. Casali
James T. Connors
John W. F. Faircloth
Philip L. Magley
Gilbert A. Martin
Roger E. McVey
William F. Morse
Bruce Quayle
Robert C. Skaggs
Robert W. Welch, Jr.
Vice Presidents

William J. Forsythe
Controller

Alexander P. McCann
Secretary

Lawrence J. Doyle
Joseph V. Yandoli
Assistant Treasurers

Donato Furlano
John F. Litzinger
Kenneth P. Murphy
Martin J. Vitek
Assistant Controllers

OPERATING COMPANY EXECUTIVES

C. Ronald Tilley
Chairman
Eugene Gralla
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
Robert M. Bennett
President
Columbia Gas Transmission Corporation

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

Thomas E. Harris
President
Columbia Gulf Transmission Company

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

Paul R. Bigley
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Commonwealth Group Companies

Max M. Levy
President
Columbia LNG Corporation

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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:
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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 $
1987	31,491	56½	35½
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

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 1988 Annual Meeting of Stockholders will be held at the Hotel du Pont, Wilmington, Delaware, on May 11, 1988, at 1:00 p.m. Proxy material will be mailed on or about March 28, 1988.

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 economically 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.

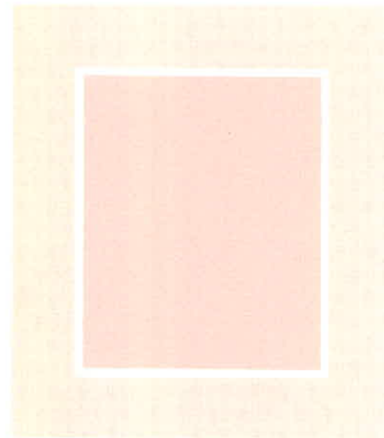
Take-or-Pay–A clause in a gas supply contract providing for a minimum quantity of gas to be paid for, whether or not taken by the purchaser.

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

20 Montchanin Road, Wilmington, Delaware 19807



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