COLUMBIA GAS SYSTEM

1991 Annual Report

About the Corporation

The Columbia Gas System is active in all phases of the natural gas business:

- *Exploring for and producing natural gas and oil.*
- *Providing markets in Midwestern, Middle Atlantic, Southern and New England states with access to natural gas from North America's major producing basins.*
- *Serving over eight million customers in 15 states–directly or indirectly–through extensive transmission, storage and distribution facilities.*
- *Meeting the needs of more than 64,000 propane customers in eight states.*
- *Developing cogeneration projects and emerging gas technologies.*

Mission Statement

The Columbia Gas System, through its subsidiaries, is active in pursuing opportunities in all segments of the natural gas industry and in related energy resource development. Symbolized by Columbia's three-star logo, these separately managed companies strive to benefit: System shareholders– *through enhancing the value of their investment;* customers– *through efficient, safe, reliable service; and* employees– *through challenging and rewarding careers.*

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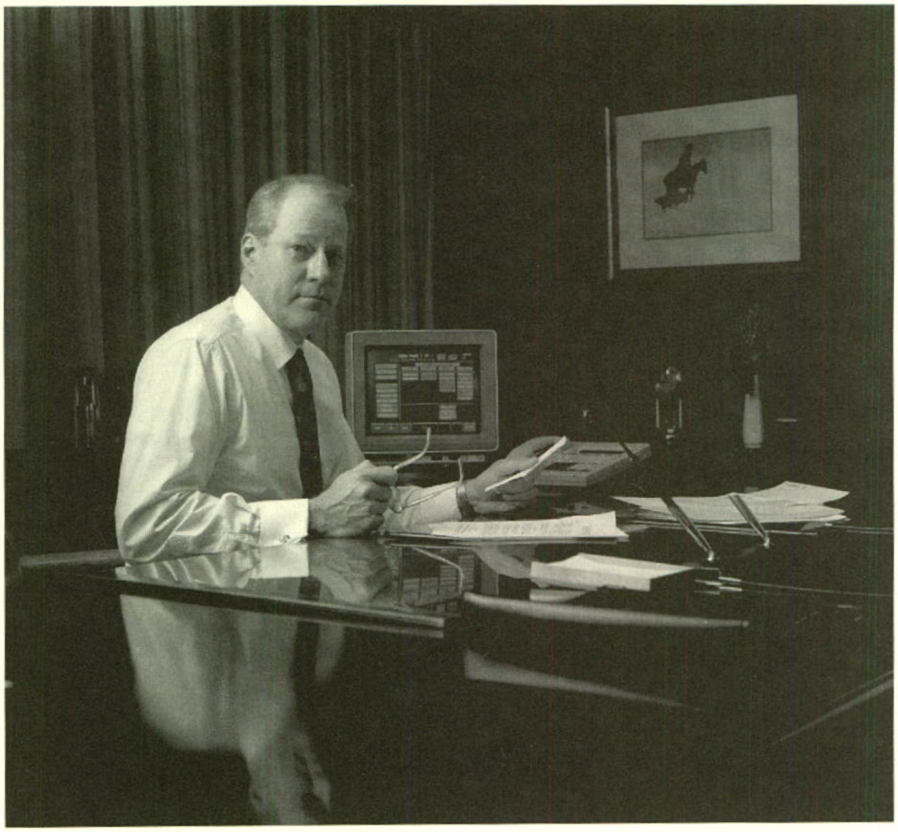
Highlights

	1991*	1990	1989
Income Statement Data ($ in millions)			
Operating Revenues	2,576.8	2,357.9	3,204.4
Net Income (Loss)	(694.4)	104.7	145.8
Operating Income (Loss) by Segment:			
Oil and Gas	(4.5)	43.3	30.2
Transmission	(1,192.2)	128.2	194.8
Distribution	114.9	96.7	146.1
Other Energy & Corporate	(4.6)	(6.1)	(8.6)
Total	(1,086.4)	262.1	362.5
Per Share Data ($)			
Net Income (Loss) on Common Stock	(13.74)	2.21	3.21
Dividends	1.16	2.20	2.00
Book Value	19.92	34.83	35.50
Market Price:			
High	47 1/2	54 3/4	52 3/4
Low	12 7/8	41 1/2	33 3/4
Close	17 1/4	46 7/8	52
Common Stock Data (000)			
Average Shares Outstanding	50,537	47,316	45,494
Average Daily Shares Traded	383	146	155
Operating Statistics			
Gas Production (billion cubic feet)	76.3	75.3	77.7
Oil Production (thousands of barrels)	3,411	2,688	1,924
Transmission Throughput (billion cubic feet)	1,527.2	1,386.1	1,618.9
Distribution Throughput (billion cubic feet)	462.4	465.7	488.4
Balance Sheet and Other Data ($ in millions)			
Capital Expenditures	381.9	629.6	473.5
Total Assets	6,332.2	6,196.3	5,878.4

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financial Statements.

To Our Shareholders



The suspension of the common stock dividend and subsequent bankruptcy filings made 1991 a bleak year for our company. Although essential to protect shareholder assets, these were not easy decisions for your management or for your Board of Directors. We regret the financial hardships that resulted and are working aggressively to emerge from Chapter 11. We are committing all necessary resources in an effort to complete and file reorganization plans as soon as possible.

In our favor is the fact that ours is a rather unusual bankruptcy. It is linked to one specific problem: the legacy of the non-competitive gas purchase contracts that were signed by Columbia Gas Transmission Corporation, our principal pipeline subsidiary, many years ago, when operating, regulatory and economic conditions were far different than they are today. Last year Columbia Transmission faced significant losses under these contracts when a nationwide surplus of gas supply, created by 15 months of record-setting warm temperatures and increases in the nation's gas reserves, resulted in an unprecedented collapse of spot-market prices and little prospect for a prompt turnaround of those price levels. After considering all alternatives, your management and your Board determined it would not be in the best interests of shareholders to absorb these losses and risk the financial value of our other subsidiaries by continuing to service these contracts. Instead, we chose a course of action designed to put the contract problem permanently behind us; confine the effects to Columbia Transmission, in spite of the implications of these actions on the Corporation's continued access to the credit markets; and preserve shareholder value. After attempts to resolve these problems outside of bankruptcy proved impossible, the filings under Chapter 11 were made.

Other than the problem contracts, there wasn't, and still isn't, anything else fundamentally wrong with our businesses or with our operations. This greatly reduces the extent of the cure, and, we believe, the time required to resolve the problem. When we first filed under Chapter 11, we anticipated it would take one to two years to complete and implement reorganization plans. That remains a realistic timetable.

I don't want to minimize the challenges that lie before us because they are significant. There are a number of complex and substantive issues that must be addressed. For example, the Official Creditors' Committee of Columbia Transmission has announced its intent to challenge the validity of $1.7 billion of debt securities of Columbia Transmission that are held by the parent, the transfer by Columbia Transmission of natural resource properties representing 450 billion cubic feet of natural gas reserves, one million barrels of oil reserves and coal interests to Columbia Natural Resources in 1990 and certain other intercompany transactions. In addition, there has also been a tendency for some of Columbia Transmission's creditors to focus on inconsequential, but time-consuming issues, thereby distracting the attention of all parties from more important matters. Despite these and other issues, however, we are confident that we will be able to reach agreements with the requisite number of our creditors in a timely manner and gain approval for reorganization plans that will be in the mutual best interests of all parties, including our shareholders.

Despite the depressed results that we are reporting for 1991, I want to assure you that our company is not going out of business. The day-to-day operations of all of our basic business units, including those of Columbia Transmission, have been affected very little by the bankruptcy proceedings. This was especially evident in the improved earnings we reported in the fourth quarter. The 1991 loss of $13.74 per share was primarily due to special charges relating to losses associated with above-market-priced gas purchase contracts which were the root cause of our financial difficulties.

Columbia Transmission's rejection, following bankruptcy court approval, of some 4,700 noncompetitive gas purchase contracts has enabled it to purchase large volumes of low-cost natural gas under short-term contracts, on the spot market and under the largely market-sensitive contracts it renegotiated in 1985. As a result, its current sales tariffs are among the lowest of all pipelines in its market area, and it should remain competitive in the future.

However, even with its competitive prices for sales and transportation services, the transmission segment's total throughput was lower than anticipated in 1991, principally as a result of the continued warmer-than-normal weather. The warm temperatures also held the 1991 earnings of the distribution segment below expectations despite its success in obtaining new rates that provide an improved return on our investment in this segment. Severely depressed wellhead gas prices resulting from the warm weather and a continuing supply surplus also reduced revenues of our oil and gas segment during 1991. These conditions are continuing to impact our oil and gas operations in 1992, and we are taking steps to mitigate them.

Once the Chapter 11 proceedings are behind us, our company will have many things working in its favor. We own a dependable and cost-efficient pipeline system and one of the nation's largest and most efficient underground storage operations. Our subsidiaries serve a strong and stable market territory that includes a number of the nation's most attractive regional centers where opportunities exist for growth in both historic and nonhistoric energy markets. And they will have access to abundant supplies of competitively-priced gas to meet the needs of those markets.

Another major asset is our skilled and dedicated workforce. Over the years, Columbia employees have, time and again, demonstrated their resourcefulness and their ability to get the job done. But never have their efforts been more supportive, or more meaningful, than during the past year. Despite salary reductions and budget cutbacks, they continued to keep each of our operating subsidiaries functioning smoothly, providing the high-quality service our customers have come to expect from Columbia and maintaining the value of our assets.

For Columbia, the road ahead will not be easily traveled, but I firmly believe that our efforts will prevail. There is no doubt in my mind, and there is no doubt among the members of your Board of Directors, about the future viability of our company. We are confident that we will be able to bring this dark chapter in our company's history rapidly to a close, regain the financial stability that was our company's hallmark for so many years, and begin to take advantage of the many opportunities that lie ahead for the natural gas industry.

Each member of your management, each member of your Board of Directors, and each and every Columbia employee is fully dedicated to these goals.

Sincerely,

JH Croom

John H. Croom
Chairman, President and
Chief Executive Officer

System Profile

The Columbia Gas System is one of the nation's largest natural gas systems. It consists of a parent holding company, a service company and 17 operating subsidiaries. The operating units are engaged in the production, purchase, storage, transmission, and wholesale and retail distribution of natural gas, as well as related resource development. The System is divided into four operating segments: oil and gas, transmission, distribution, and other energy operations.

Oil and gas operations

Two Columbia subsidiaries explore for, develop, acquire, produce, and market oil and natural gas in the United States. These companies hold varying interests in more than three million net acres of gas and oil leases and have proven oil and gas reserves in excess of one trillion cubic feet of gas equivalent.

Operations are focused in the Appalachian, Arkoma, Michigan, Permian, Powder River and Williston basins; both onshore and offshore in the Gulf Coast areas of Texas and Louisiana, and in Utah and California. Offshore holdings include varying interests in federal blocks, most of which are located in the West Cameron, Vermilion, Eugene Island, and Ship Shoal areas in the Gulf of Mexico.

Columbia's exploration and development companies are among the industry's leaders in utilizing new technologies such as horizontal drilling techniques, and their success rates have been consistently above national averages.

Transmission operations

Columbia's two transmission companies operate a 23,700-mile pipeline network that extends from offshore in the Gulf of Mexico to New England and the Eastern Seaboard. In addition, Columbia Gas Transmission owns one of the nation's largest underground storage operations and is the System's principal purchaser of natural gas.

As an open-access pipeline, Columbia Gas Transmission sells gas at wholesale to distribution companies and provides a transportation service that delivers gas these companies and their industrial and commercial end users obtain from other sources. A major portion of this gas is transported through Columbia Gulf Transmission's open-access pipeline network which extends from offshore Louisiana to West Virginia. Columbia Gulf also transports gas for unaffiliated customers along its pipeline system and owns interests in the Ozark, Overthrust and Trailblazer pipelines, which extend into major midcontinent and western gas producing areas. Combined, Columbia Transmission and Columbia Gulf serve customers in 15 Northeastern, Middle Atlantic, Midwestern, and Southern states and the District of Columbia.

Distribution operations

Columbia's five distribution subsidiaries provide natural gas service to more than 1.8 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, and Maryland. These subsidiaries also transport gas for industrial and commercial users who purchase gas from other sources. More than 28,000 miles of distribution pipelines serve such major markets as Columbus, Lorain, Parma, Springfield, and Toledo, Ohio; New Castle, York and a part of Pittsburgh, Pennsylvania; Lynchburg, Staunton and Portsmouth, Virginia; Ashland, Frankfort and Lexington, Kentucky, and Cumberland and Hagerstown, Maryland.

Distribution is a leader in developing new natural gas technologies, guiding research, organizing field tests and encouraging the manufacture and marketing of ventures such as natural gas vehicles, gas air conditioning and heat pumps, compact water and space heaters, and fuel cells.

Other energy operations

The System has two subsidiaries that sell propane at wholesale and retail to more than 64,000 customers in eight states.

In the Appalachian area, system-owned coal reserves exceed 550 million tons, one-half of which contain less than one percent sulfur. Acreage representing some 300 million tons is leased to others for development.

Columbia's TriStar Ventures Corporation pursues cogeneration opportunities by participating in joint venture development partnerships. In 1992, two TriStar projects in New Jersey and New York are slated to begin operation and construction is expected to get under way on two other projects.

TriStar Capital Corporation supports the development of new gas-related technologies by investing in processes and techniques that promote the supply, transportation and utilization of gas.

The Columbia Gas System Service Corporation takes advantage of economies of scale by providing centralized, cost-efficient data processing, financial, accounting, legal, and other services for the parent company and operating subsidiaries.

Oil and Gas

Net Acreage (000)		Net Productive Gas Wells	5,969
Developed	1,593	Net Productive Oil Wells	370
Undeveloped	1,087	Oil and Gas Production	
Proved Reserves		Natural Gas (Bcf)	76
Natural Gas (Bcf)	808	Oil (000 Bbls)	3,411
Oil (000 Bbls)	15,568	1991 Capital Expenditures ($ in millions)	121

Transmission

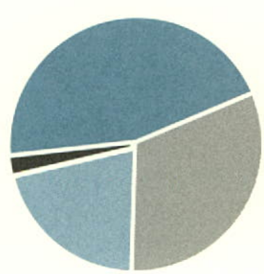
Total Throughput (Bcf)	1,527	Storage Capacity (Bcf)	698
Sales (Bcf)	112	1991 Capital Expenditures ($ in millions)	153
Transportation (Bcf)	1,415		

Distribution

Retail Customers		Total Throughput (Bcf)	462
Residential	1,686,918	1991 Capital Expenditures ($ in millions)	98
Commercial	160,378		
Industrial and Other	2,366		
Total	1,849,662		

Other Energy

Coal Reserves (million tons)	550	Propane Customers	64,618
1991 Capital Expenditures ($ in millions)	10	Gallons Sold (000)	70,509



Net Plant by Segment at December 31, 1991
(in millions of dollars)

Transmission	1,585
Distribution	1,129
Oil & Gas	733
Other Energy	60

Management's Discussion and Analysis

Bankruptcy Matters

On July 31, 1991, the Corporation and its wholly owned subsidiary, Columbia Gas Transmission Corporation (Columbia Transmission), filed separate petitions seeking protection under Chapter 11 of the Federal Bankruptcy Code. Both the Corporation and Columbia Transmission have been granted debtor-in-possession status under the Bankruptcy Code, allowing them to continue operation of their businesses in the normal course subject to the jurisdiction of the Bankruptcy Court. Reference is made to pages 16 through 18 and to Note 2 of Notes to Consolidated Financial Statements for additional information.

Summary of Events Leading to the Bankruptcy Filings

Columbia Transmission continually assesses its gas supply in relation to prevailing and projected market conditions as part of its normal business planning. In early 1990, it concluded that several high-cost Southwest contracts that had not previously been renegotiated were likely to present future marketability problems. The threat being posed by these contracts was the result of several recent developments: increasing deliverability of gas by producers and increased reserves committed under some of those contracts; the potential "fly up" of certain prices as a result of the Natural Gas Decontrol Act of 1989, which would remove as of January 1, 1993, the remaining price controls on gas that had previously been deemed "forever regulated"; and Columbia Transmission's continuing decline in sales volumes, primarily due to the switching by its customers from sales to transportation service. Each of these factors tended to reduce Columbia Transmission's ability to "blend" the high-cost gas it was required to purchase under those contracts with other, cheaper gas supplies in order to achieve a competitive and marketable gas sales rate.

Based on 1990 projections of future spot-market prices, Columbia Transmission undertook to estimate the amount of "excess-over-market" gas costs it would expect to incur over the next ten years pursuant to those Southwest contracts that did not have market-sensitive pricing provisions. By October 1990, Columbia Transmission concluded that a buydown (or reformation) of at least some of those contracts was necessary to maintain a competitive weighted average cost of gas and to achieve sales levels adequate to manage its remaining gas supplies. It also concluded that a buydown of only a portion of the total problem contracts would be sufficient. Such a partial buydown was expected to enable Columbia Transmission to meet the comparability test for the collection of certain buydown costs under the Gas Inventory Charge (GIC) contained in its rate structure and to maintain marketable gas sales rates. In the Corporation's report on Form 10-Q for the quarter ended September 30, 1990, it was reported that Columbia Transmission would attempt to achieve such a buydown of Southwest contracts. The cost of these renegotiations was expected to exceed current reserves of approximately $30 million by no more than $150 million. It was also expected that up to approximately $50 million of the $150 million could be expensed as incurred, with the remainder being amortized over several years depending on the extent to which the costs were incurred for prospective price relief.

Throughout 1990, extraordinarily warm weather across the eastern United States, including Columbia Transmission's 13-state service area, had negatively affected the financial performance of Columbia Transmission. Although December 1989 had been colder than normal, the winter of 1989-90 in the aggregate had been unusually warm, and the twelve months of 1990 were the warmest in the Corporation's history. That warm weather had significant negative impacts on the Corporation's earnings and its cash flow. The warm weather also increased Columbia Transmission's projected borrowing requirements by $300 million for 1990-92, as a result of the reduction in projected revenues and the expected accumulation of higher gas inventory balances. These impacts were viewed by their nature as nonrecurring, caused by the unusual weather. Long-term prospects for Columbia Transmission, assuming a return to normal weather, were still viewed as satisfactory since gas prices over the following five-year period were being projected to rise from $2.03 per Mcf to $3.18 per Mcf, at which levels Columbia Transmission expected to achieve a competitive gas sales rate and manageable gas supply.

As part of its ongoing review of operations, Columbia Transmission established an extensive work plan in early 1991 with a schedule of projects to be completed during the first quarter. The work plan was intended to establish an operating strategy for 1991-92 to respond to the recent developments. The record warm weather continued during January through March setting an all-time record for the 15-month period of January 1990 through March 1991. The negative impact on projected earnings continued to grow as warm winter weather decreased the demand for gas. The decreased demand, in turn, contributed to lower spot-market prices. In February 1991, when spot prices are generally expected to be at their annual peak, they plummeted and continued to fall, reaching levels of gas prices during the early 1970s. At the same time, with usage down across the eastern half of the United States, pipelines generally had excess transportation capacity. Therefore, at the same time that falling spot prices increased the incentives for customers to buy spot gas rather than pipeline gas, there was also ample pipeline transportation capacity available to move that gas to market. As a result of customers transporting cheaper spot-market gas instead of purchasing from Columbia Transmission, its sales for the 1990-91 winter fell to 111 Bcf, compared to the expected level of 200 to 220 Bcf. That dramatic and unexpected drop in sales further increased Columbia Transmission's gas supply management costs and its related borrowing requirements. In response to these business conditions, Columbia Transmission revised its operating and financial plans, undertook steps to reduce operating expenses, decreased its planned capital expenditures, and pursued studies of new rate designs and rate structures.

In the Corporation's 1990 Annual Report it was reported that in February 1991 Columbia Transmission's storage inventory was already 100 Bcf over planned levels (because withdrawals from storage had been only about 50% of normal). Because of this increased inventory, it was expected that Columbia Transmission's ability to purchase gas under existing contracts would be reduced and take-or-pay obligations of up to $100 million could be incurred in 1991. It was also noted that if warmer than normal temperatures continued through the remainder of the current heating season, gas supply issues would become more severe as Columbia Transmission's merchant function would continue to be adversely affected by higher storage balances, lower spot prices, and increased gas supply costs. As to the progress made under Columbia Transmission's buydown plan, the 1990 Annual Report reviewed the status of the contract renegotiations performed in 1990 noting that Columbia Transmission was discussing the renegotiation of other such contracts and, in some cases, the settlement of related litigation with other Southwest producers and that such negotiations could be concluded in 1991.

During the first quarter of 1991, Columbia Transmission also undertook various unusual operating steps to protect the integrity of its storage operations and minimize its contractual exposure. As reported in the Corporation's report on Form 10-Q for the quarter ended March 31, 1991, to assist in the management of its gas supply, Columbia Transmission received Federal Energy Regulatory Commission (FERC) approval to waive certain provisions of its Firm Storage Service (FSS) rate schedule. The waiver permitted Columbia Transmission's FSS customers to postpone delivery of 40 Bcf to Columbia Transmission for injection into storage. Columbia Transmission agreed to make equal quantities available to such FSS customers during the 1991-92 heating season and to protect consenting FSS customers against an increase in the summer 1992 and 1993 spot prices over the summer 1991 price. Efforts to minimize supply management costs in the summer of 1991 and provide additional operating flexibility, together with higher carrying costs due to excess storage positions, were estimated to cost Columbia Transmission approximately $30 million after-tax. Despite such efforts, Columbia Transmission was also expected to incur approximately $65 million of recoupable take-or-pay liabilities in 1991.

In late March 1991, the Corporation's internal gas price analysis group revised forecasts of natural gas spot prices for the period 1991-95 based on a number of factors. The warm weather had exacerbated the current surplus leading to significantly lower current prices. In addition, exploration and drilling reports for 1990 indicated substantial increases in activity with the prospect of greater than expected gas supplies for 1991 onward. Those factors led to a downward revision of the prior gas price projections and a predicted continuation of the "gas bubble" for at least two more years. The forecasts of late 1990, in line with general industry forecasts, had predicted a spot price in January/February 1991 of $2.40 per Mcf with gradual increases in the future years. The actual February 1991 spot price was $1.40 per Mcf. The new forecasts predicted spot prices for the winter of 1991-92 of $2.20 per Mcf and spot prices over the subsequent several heating seasons at $.85 to $.90 per Mcf lower than the prices forecasted in 1990.

In early April, Columbia Transmission was informed that the deliverability of gas under a major gas supply contract had increased significantly over earlier projections. It was decided that a new effort should be undertaken to evaluate all producer deliverabilities and to re-estimate the associated excess costs in light of the reduced spot-price forecasts. Further, in mid-April Columbia Transmission concluded that if spot prices did not recover, actions in addition to the buydown program announced in late 1990 would probably be required. On April 25, 1991, the American Gas Association announced that 1990 national reserve additions were in the range of 105% to 128% of 1990 production. This additional supply increased the likelihood that the "gas supply bubble" would continue. This announcement and other contemporaneous industry price projections were consistent with the Corporation's recent internal forecasts of spot prices.

The 1991 first quarter Form 10-Q, using the revised gas price projections, noted that Columbia Transmission's cost of gas was projected to be higher than generally anticipated, even assuming the successful completion of the announced producer renegotiations. Consequently, gas sales were projected to be insufficient to avoid future gas supply management costs. In addition, Columbia Transmission would not be able to meet the test of price comparability with other pipelines which is required to permit it to collect its GIC. Therefore, Columbia Transmission concluded that actions beyond the previously announced renegotiations of certain producer contracts were necessary. The parameters of the problems, the costs associated with them, and the feasibility of various possible responses, including seeking regulatory changes in the merchant function, underwent intense study in light of current and prospective market conditions.

Actions Leading to the June 19 Board Action and Announcement

Because of the gas supply management problems facing Columbia Transmission, management reported to the Corporation's

Board of Directors on May 15, 1991, that without a significant strategic response, the remaining high-cost supply contracts could seriously threaten Columbia Transmission's viability. Management gave the Board a report on the potential financial exposure presented by those contracts based upon the current spot-market price forecasts and an initial overview of the options and contingency plans being investigated. Management reported that it was still analyzing the risks of continuing operations as usual in light of different weather scenarios and of various possible movements in spot-market prices. Columbia Transmission was also examining various business solutions, including rate structure changes and more extensive buydown negotiations. The Board was also informed that studies were under way concerning various other options available to the Corporation and Columbia Transmission. The results of these investigations and studies were scheduled to be presented at a special meeting of the Board in July 1991.

In mid-to-late May, Columbia Transmission began to finalize the ongoing studies of the parameters of its problems, the costs associated with such problems and feasibility of various possible responses, including seeking regulatory changes in the merchant function and rate restructuring. These studies were designed to yield fundamental structural and strategic solutions to completely resolve Columbia Transmission's gas supply problems. Specifically, the studies estimated the exposure faced by Columbia Transmission from above-market gas supply costs under all of its gas supply contracts. They also focused on the impact on these contracts of the substantially reduced five-year forecasts of spot-market prices, of the pending deregulation and of the increases in deliverability under some contracts. These efforts were intended to evaluate, verify and expand on the preliminary results of the studies performed by Columbia Transmission in April. As May natural gas prices continued to deteriorate and the magnitude of the problems facing Columbia Transmission and the Corporation was clarified by the ongoing special studies, management decided that the results of the ongoing studies should be finalized so that they could be presented to the Columbia Board on June 18, the day before the Board meeting at which action on the dividend would normally be taken, rather than at the special July meeting previously scheduled.

In early June, management reviewed Columbia Transmission's recommendations which included a proposed buydown of all of its high-cost purchase contracts to market-based prices and a restructured GIC. The plan contemplated payments which would be expected to be funded from and be contingent upon a new GIC placed in effect through a change in rate structure which could not become effective until the end of 1992. Therefore, the bulk of the buydown payments to producers and the success of the buydown program would be contingent upon the implementation of the new rate structure. After further discussion, however, it was concluded that the funding of the buydown plan with the GIC was too speculative and the plan was revised to eliminate the GIC contingency and instead to fund the buydown payments through securities issued by Columbia Transmission. The size of the charge associated with the revised plan would depend upon the amount of the payments to be made, whether the contracts would be reformed or terminated, and a detailed analysis of what amount of the payments, if any, could be capitalized for amortization over future periods (as had been done with the $850 million 1985 buydown).

On the morning of June 18, 1991, the Board of Directors of Columbia Transmission held a special meeting. The Board endorsed the recommendation of Columbia Transmission management to undertake a comprehensive effort to terminate all of its above-market gas purchase contracts by offering producers up to $600 million of short-term Columbia Transmission obligations.

At the special briefing, on June 18, 1991, the Corporation's Board of Directors was presented with the financial planning analyses, excess gas cost studies, the reports of other studies and projects and the management proposals for dealing with the excess gas cost problem. The Board was informed that the present value of the total excess of all gas costs over market over the following ten years, based upon the current gas price forecasts of spot prices, could exceed $1 billion.

At the special briefing the Board reviewed Columbia Transmission's proposal to offer producers short-term obligations of Columbia Transmission in exchange for buyouts or full contract reformation to market-sensitive prices. The Board also reviewed the option of Columbia Transmission seeking protection under Chapter 11 of the United States Bankruptcy Code. Finally, the Board was advised that in light of the actions that might be taken and the related disclosures, the Corporation's credit lines would no longer be available and that its officers proposed to commence negotiations with bank lenders seeking to reestablish the Corporation's credit facilities on revised terms in view of Columbia Transmission's financial difficulties. The possibility of a filing for Chapter 11 protection by the Corporation as a result of a liquidity crisis was also discussed.

At its meeting on June 19, 1991, the Board determined that in view of recent developments, including management's conclusions during the course of its studies regarding the likely range of spot-market prices over the next several years, it was no longer in the best interests of the Corporation for Columbia Transmission to attempt to deal with the producers on any basis that did not clearly provide a permanent resolution of the high-cost contract problem. The Board also determined that it was not fair to the Corporation's shareholders and other constituencies for substantially all of the Corporation's resources to be dedicated for an undefined period to efforts to deal temporarily with the high-cost contracts in anticipation that future weather, market developments and regulatory changes would be favorable. Considering the magnitude of Columbia Transmission's high-cost contract problems, it recognized that a substantial portion of these contract losses would be charged to income in the second quarter.

Thus, the Corporation's Board concluded on June 19, 1991, that the magnitude of Columbia Transmission's problem precluded authorization of a dividend. It accepted management's business plan, based upon the Columbia Transmission buyout proposal, and endorsed the proposed subordination of the unsecured debt of the Corporation to the Columbia Transmission obligations that would be used to fund the buyout plan.

On June 19, 1991, the Corporation filed a Form 8-K with the Securities and Exchange Commission (SEC) reporting that: it had suspended the dividend on its common stock; corporate officers were meeting with bank lenders that day seeking to reestablish the Corporation's credit facilities on revised terms in view of Columbia Transmission's financial difficulties; it anticipated that a substantial portion of the exposure on above-market priced gas purchase contracts would be charged to income in the second quarter; and Columbia Transmission was launching a comprehensive effort to renegotiate or terminate all of its above-market gas purchase contracts under a program which contemplated offering producers up to $600 million of Columbia Transmission obligations as compensation for restructuring their contracts.

Following the June 19 announcement, it was no longer possible for the Corporation to issue commercial paper. Because the Corporation only had sufficient cash on hand to fund operational needs for a short time, it was unable to pay maturing short-term debt obligations. As of July 31, 1991, the Corporation was in default of $83.5 million of such obligations.

During June and July the Corporation entered into intense negotiations to reestablish its lines of credit. To further conserve cash, accounts payable were satisfied only as to essential items, deferring all other obligations. After lengthy discussions, the Corporation and the banks were unable to timely reach an acceptable agreement.

While these events were occurring, Columbia Transmission entered into negotiations with its high-cost producers. Because of the disparate interests and objectives among the producers, negotiations between Columbia Transmission and the producers met with only limited success and Columbia Transmission concluded that these negotiations could not be brought to a successful completion within an acceptable timeframe. In an otherwise unrelated matter, Columbia Transmission's financial problems were exacerbated when the West Virginia Supreme Court ordered the posting of a $10 million bond by July 29, 1991, in order to stay the execution of a $29.5 million judgment in Bruen v. Columbia Gas Transmission. As a result of these financial difficulties, on July 31, 1991, the Corporation and Columbia Transmission filed for protection under Chapter 11 of the Federal Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware (Bankruptcy Court).

Proceedings Under Chapter 11 Protection

The discussion below sets forth various aspects of the Chapter 11 cases, but is not intended to be an exhaustive summary.

Both the Corporation and Columbia Transmission are currently operating as debtors-in-possession subject to the jurisdiction of the Bankruptcy Court . Under Chapter 11 protection, substantially all pending litigation and collection of outstanding claims against the Corporation and Columbia Transmission at the date of the filings are stayed. Although the Corporation and Columbia Transmission, as debtors-in-possession, are authorized to operate their businesses, they may not engage in transactions outside the ordinary course of business without first complying with the notice and hearing provisions of the Bankruptcy Code and obtaining Bankruptcy Court approval where and when necessary. SEC jurisdiction over the Corporation's financing activities continues while it is under Chapter 11 protection.

As of July 31, 1991, the petition date, actions to collect prepetition indebtedness are stayed and other prepetition contractual obligations may not be enforced against either the Corporation or Columbia Transmission. As debtors-in-possession both the Corporation and Columbia Transmission have the right, subject to Bankruptcy Court approval and certain other limitations, to assume or reject prepetition executory contracts and unexpired leases. In this context, "rejection" means that the corporations are relieved from their obligations to perform further under the contract or lease but are subject to a claim for damages for the breach thereof. Any damages resulting from rejection are treated as general unsecured claims in the reorganization. The parties affected by these rejections may file claims with the Bankruptcy Court in accordance with bankruptcy procedures. Prepetition claims which were contingent or unliquidated at the commencement of the Chapter 11 proceeding are generally allowable against the debtors-in-possession in amounts fixed by the Bankruptcy Court. Substantially all liabilities as of the petition date are subject to satisfaction under a plan of reorganization.

Under the terms of an order dated November 15, 1991, the Corporation and Columbia Transmission have the exclusive right to file a proposed plan of reorganization until March 30, 1992. Managements of both companies are working toward the filing of proposed plans for both companies as soon as practical. Implementation of the Corporation's plan will be subject to approval by the SEC under the Public Utility Holding Company Act of 1935. Implementation of the plans of both the Corporation and Columbia Transmission will be subject to any required acceptance by affected parties, and to favorable action by the Bankruptcy Court.

Debtor-in-Possession (DIP) Financing

The Bankruptcy Court authorized Manufacturers Hanover Trust Company of New York (MHT), as agent for a syndicate of banks, to provide the Corporation with permanent DIP financing for a period of two years. Bankruptcy Court approval was received on September 10, 1991, and SEC approval on September 20, 1991. The Secured Revolving Credit Facility permits the Corporation to borrow up to $275 million during the two year period ending September 23, 1993.

On August 22, 1991, Columbia Transmission received Bankruptcy Court approval for $80 million of permanent DIP financing which is also being provided by MHT.

For additional information regarding DIP financing for both the Corporation and Columbia Transmission, see the liquidity discussion on pages 32 through 34.

Other Related Issues

Creditors' Committees Formed

Separate unsecured creditors' committees for the Corporation and Columbia Transmission were formed on August 12, 1991, by the U.S. Trustee following a meeting of the largest unsecured creditors of the two companies.

Columbia Transmission Committee to Bring Intercompany Claim

On January 30, 1992, the Bankruptcy Court approved the position taken by the Corporation and Columbia Transmission at the beginning of the bankruptcy proceedings that it would be inappropriate for Columbia Transmission to retain responsibility for intercompany creditors' rights issues. Under the arrangements approved by the Bankruptcy Court, the Official Creditors' Committee of Columbia Transmission has assumed this responsibility.

The Committee has indicated that it intends to challenge the status of the approximately $1.7 billion of debt securities of Columbia Transmission held by the Corporation, the transfer by Columbia Transmission of natural resource properties representing approximately 450 Bcf of gas reserves and one million barrels of oil reserves to another Columbia subsidiary in 1990, as well as intercompany dividends and interest payments of approximately $500 million.

Corporation Equity Committee Formed

A motion requesting the formation of an equity security holders' committee during the bankruptcy proceedings was approved September 10, 1991, by the Bankruptcy Court, and a committee was subsequently appointed by the U.S. Trustee on September 26, 1991.

Columbia Transmission Customer Committee Formed

On September 20, 1991, Columbia Transmission customers were granted Bankruptcy Court approval to form an official committee to participate in Columbia Transmission's Chapter 11 proceedings.

General Creditor Meetings

Meetings called by the U.S. Trustee of Columbia Transmission's and the Corporation's creditors were held in Wilmington on September 24, 1991, and in Philadelphia on October 31, 1991, and December 19, 1991, to provide a forum for their questions.

Financial Advisor Appointed

On October 18, 1991, the Bankruptcy Court approved Salomon Brothers Inc. as financial advisor for both the Corporation and Columbia Transmission.

Tax Claims

The Internal Revenue Service has accelerated its examination of U.S. Federal tax returns for all open years and has indicated that the proposed disallowances will be substantial in amount. Management believes that appropriate reserves have been provided.

Bar Date

The Bankruptcy Court established March 18, 1992, as the deadline for creditors to file claims against the Corporation and Columbia Transmission. On January 7, 1992, notices were mailed to the creditors of the Corporation and Columbia Transmission advising them that claims against either company must be submitted by the "bar date" of March 18, 1992. Creditors who are required to file claims but fail to meet the deadline are forever barred from voting upon or receiving distributions under any plan of reorganization. This "bar date" is not applicable to claims of Federal and state environmental agencies.

Exclusive Period

The Bankruptcy Court approved a joint application by the Corporation and Columbia Transmission which extended the time period within which they have the exclusive right to prepare disclosure statements and to file plans of reorganization to March 30, 1992.

Oil and Gas Operations

Statements of Operating Income from Oil and Gas Operations (Unaudited)

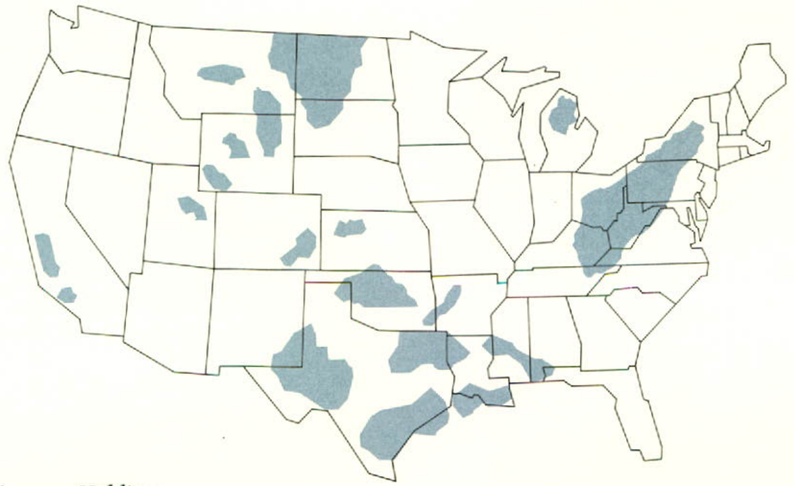
Year Ended December 31 (in millions)	1991	1990	1989
Operating Revenues			
Gas	$142.6	$153.9	$151.5
Oil and liquids	72.2	61.1	31.8
Total Operating Revenues	214.8	215.0	183.3
Operating Expenses			
Operation and maintenance	78.3	62.6	54.4
Depreciation and depletion	130.1	98.5	84.2
Other taxes	10.9	10.6	14.5
Total Operating Expenses	219.3	171.7	153.1
Operating Income (Loss)	$ (4.5)	$ 43.3	$ 30.2

Capital Expenditures

Capital expenditures for the oil and gas segment were $121 million in 1991, well below the original planned spending level of $195 million. The drop in spending reflected the poor outlook for energy prices and the Corporation's financial difficulties. The same factors influence the estimated $93 million program for 1992.

Market Conditions

Natural gas prices continue to decline as a result of the persistent oversupply situation of natural gas combined with the effect of warmer than normal weather and economic conditions. Onshore Southwest spot-market prices in February 1992 were in the $1.03 per Mcf range as compared to $1.44 per Mcf for the same



Acreage Holdings

period in 1991. After increasing in 1989 and 1990, oil prices declined almost 8% in 1991. In 1991, Columbia received an average price of $21.10 per barrel of oil compared to $22.86 per barrel received in 1990. Average natural gas prices received by Columbia in 1991 declined to $1.81 per thousand cubic feet of gas, down 19 cents compared to last year.

Reserves

As a result of the reduced capital program, total proven domestic natural gas reserves declined 4.4 Bcf in 1991 to 808.1 Bcf. Proven domestic oil and liquids reserves increased 6% to approximately 16 million barrels.

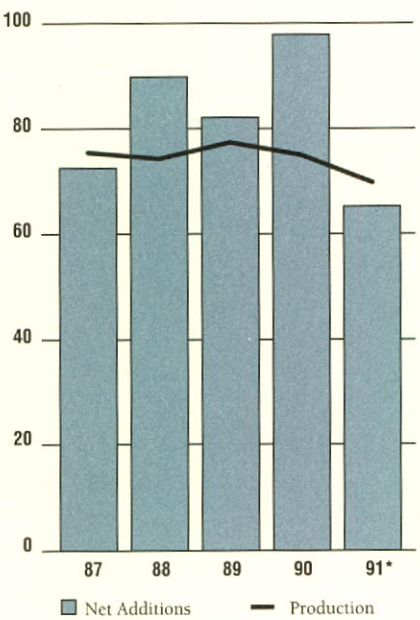
Southwest

Columbia Gas Development Corporation (Columbia Development) participated in 35 gross (19 net) exploratory wells, with a success rate of 14%. Columbia Development's most significant discovery was the Kane Springs Federal #27-1 in Grand County, Utah. This well was the first successful horizontal wildcat well drilled in Utah and was tested at a rate of 914 barrels of oil and 290,000 cubic feet of gas per day. A second exploratory well drilled in the area, the Kane Springs Federal #19-1A, tested at an average rate of 1,158 barrels of oil and 234,000 cubic feet of gas per day. Columbia Development and its partners, Exxon and Enserch, have control over a 50,000 acre block of Federal land in Grand County, Utah, where exploratory drilling continues.

In 1991, Columbia Development successfully completed 29 gross (13 net) horizontal development wells and participated in 31 gross (18 net) vertical development wells with an overall success rate of 93%. In addition, Columbia Development participated in the successful completion of 2 gross (1 net) horizontal exploration wells in 1991. During 1991, approximately 50% of the Southwest capital program was directed toward oil-prone prospects. One of the more significant development wells, located in Burleson County, Texas, was the Alvin Kucera #1-H where a horizontal sidetrack well increased the flow of a previously drilled vertical well 500% to an approximate rate of 1,100 barrels of oil and one million cubic feet of gas per day. Additionally, the Mildred Crnkovic Unit #H-1 in the Giddings Field, Texas, tested at a rate of 1,351 barrels of oil and 458,000 cubic feet of gas per day. Notably, this well had a horizontal displacement of over a mile, which is a company record.

Columbia Development's 1992 development program plans for the drilling of 63 gross (23 net) development wells and participation in the drilling of 21 gross (16 net) exploratory wells with concentration on drilling oil-prone prospects.

Gas Reserves
Net Additions vs. Production
(in billion cubic feet)



**1991 represents domestic activity only*

Appalachia

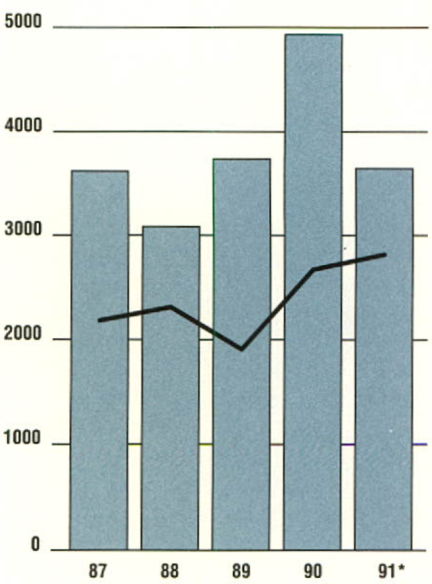
Columbia Natural Resources, Inc. (CNR) drilled 109 gross (75 net) wells during 1991, which was 47% less than the total number of net wells drilled in the prior year. Included in this total were 100 gross (70 net) development wells, with a 91% success rate, and 8 gross (5 net) exploratory wells with a success rate of 20%. The 1991 Appalachian drilling program concentrated on developing prospects which offered attractive returns and immediate access to pipeline capacity.

Anticipated Strategies to Deal with Current Unsettled Conditions

As reported earlier, natural gas prices at the wellhead are at their lowest level since 1979. The average annual onshore spot-market price in the Southwest is projected to be under $1.44 per Mcf in 1992, which is less than the replacement cost of new gas reserves. Therefore, Columbia redirected its Southwest exploration and development focus toward oil prospects. As a result, approximately 85% of its 1992 program in the Southwest is committed to oil prospects where the price is above reserve replacement costs. The remaining 15% is to meet gas development drilling commitments primarily in the Gulf of Mexico.

In Appalachia, where there are limited oil prospects, CNR's marketing strategy has been to commit its gas production to premium long-term and intermediate-term contracts. As an example, approximately 40% of CNR's Appalachian deliverability is

Oil Reserves
Net Additions vs. Production
(in thousands of barrels)



**1991 represents domestic activity only*

under premium priced contracts to cogeneration plants. Because of the long production life that is characteristic of Appalachian reserves and their proximity to the eastern United States market area, during 1991 CNR received an average annual price of $2.25 per Mcf for its Appalachian production.

Due to the decline in natural gas prices since the end of 1991, it is likely that Columbia will be required under SEC accounting rules to writedown the carrying value of its oil and gas properties. The size of any writedown will be affected by actual prices at the time, as well as by the results of the continuing drilling programs. It is currently anticipated that an after-tax writedown at the end of the first quarter of 1992 may be about $100 million.

The negative state of the gas market has led Columbia to shut in production where possible until prices improve. In early February 1992, Columbia also announced a $12 million, or 12%, reduction to the segment's 1992 capital expenditure program.

Sale of Canadian Subsidiary

The Corporation sold Columbia Gas Development of Canada Ltd. (Columbia Canada), its only non-domestic oil and gas subsidiary, to Anderson Exploration, Ltd. effective December 31, 1991, for $94.8 million. (See additional discussion in liquidity section on page 33.)

Volumes

In 1991, domestic gas production of 70 Bcf declined by 3% compared to last year, reflecting the adverse impact of depressed energy prices due in large part to warmer than normal weather and the oversupply situation. Canadian gas production for 1991 increased 3 Bcf compared to 1990.

Oil and liquids production increased to 2,833,000 barrels, up 38% for domestic activities compared to 1990. The improvement is primarily attributable to the Southwest exploration and development program, particularly the success of horizontal wells.

Gas production in 1990 was 75 Bcf, a decline of 3 Bcf compared to 1989. The decrease was due largely to pipeline capacity constraints caused by maintenance activities and unfavorable summer market conditions. In 1990, oil and gas liquids production increased 40% compared to the previous year reflecting the success of the exploration and drilling programs.

Operating Revenues

Operating revenues for 1991 were $214.8 million, a small decrease of $0.2 million from last year. Gas revenues for 1991 were $142.6 million, a decrease of approximately $11.3 million, or 7%, compared to 1990 due to the decline in gas prices combined with the effect of lower domestic production. Average prices dropped from $2.00 per Mcf in 1990 to $1.81 per Mcf in the current year.

Oil and liquids revenues increased to $72.2 million in 1991, up $11.1 million, or 18%, over the level achieved in 1990. The improvement reflects a 27% increase in production which more than offset the decline in prices. During 1991, Columbia's average price for oil and liquids produced in the U.S. was $22.18 per barrel compared to $24.13 per barrel for 1990.

Operating revenues for 1990 were $215 million, an increase from 1989's level of $183.3 million. Higher oil and gas prices and increased oil production more than offset the decline in gas production.

Operating Income

An operating loss of $4.5 million was recorded for 1991 compared to operating income of $43.3 million in 1990. The loss was due largely to depressed energy prices as well as writedowns of Canadian properties totalling $36.4 million in 1991 compared to $22.6 million in 1990. The current year writedowns were necessary to recognize a revised evaluation of undeveloped acreage and lower gas prices. The 1990 writedown reflected unsuccessful results at the Crow River and Grizzly prospects combined with a reduction in reserves related to revisions of prior year estimates. Also contributing to the decline was a 25% rise in operation and maintenance costs principally attributable to increased production expense related to new wells and higher labor and benefit costs.

Operating income for 1990 increased $13.1 million, or 43% compared to 1989. A significant increase in operating revenues was partially offset by higher operation and maintenance costs including increased production expense related to expanded operations and well rehabilitation projects.

Oil and Gas Operating Highlights

	1991	1990	1989	1988	1987
Capital Expenditures ($ in millions)	120.8	229.0	147.9	71.1	81.5
Proved Reserves					
Gas (Bcf)	808.1	925.7	902.7	897.8	882.1
Oil and Liquids (000 barrels)	15,568	18,991	16,731	14,904	14,133
Production					
Gas (Bcf)	76.3	75.3	77.7	74.6	75.8
Oil and Liquids (000 barrels)	3,411	2,688	1,924	2,328	2,199
Average Prices					
Gas ($ per Mcf)	1.81	2.00	1.89	1.72	1.67
Oil and Liquids ($ per barrel)	21.10	22.86	16.71	13.20	15.63

Transmission Operations

Since the July 31, 1991, filing for Chapter 11 protection under the Federal Bankruptcy Code, Columbia Transmission has continued the normal operation of its business, subject to Bankruptcy Court approval. The filing permitted implementation of DIP financing and has enabled Columbia Transmission to reject above-market priced gas purchase contracts which caused its financial difficulties. Reference is made to pages 6 through 13 and to Note 2 of Notes to Consolidated Financial Statements.

Producer Contracts

To date, Columbia Transmission has received Bankruptcy Court approval to reject almost 4,700 high-priced or otherwise onerous gas purchase contracts. The rejection of these contracts is not expected to impair Columbia Transmission's ability to meet its supply commitments to customers. Columbia Transmission continues to review its remaining contracts for possible rejection.

As a result of the continuing transition to a deregulated natural gas industry, management is evaluating its long-term commitment to the merchant function. Should the merchant function fundamentally change, or be terminated, an additional writedown of approximately $82 million for Columbia Transmission's capitalized gas costs would be required as a result of the termination of the remaining producer contracts.

Statements of Operating Income from Transmission Operations (Unaudited)

Year Ended December 31 (in millions)	1991	1990	1989
Net Revenues			
Sales revenues	$ 609.2	$479.9	$1,538.1
Less: Cost of gas sold	391.0	195.0	1,253.2
Net Sales Revenues	218.2	284.9	284.9
Transportation revenues	430.8	396.8	524.7
Less: Associated gas costs	104.0	100.3	119.6
Net Transportation Revenues	326.8	296.5	405.1
Storage Revenues	89.5	65.9	9.1
Net Revenues	634.5	647.3	699.1
Operating Expenses			
Provision for gas supply charges	1,319.2	–	–
Operation and maintenance	357.7	384.4	354.8
Depreciation	90.4	86.9	97.0
Other taxes	59.4	47.8	52.5
Total Operating Expenses	1,826.7	519.1	504.3
Operating Income (Loss)	$(1,192.2)	$128.2	$ 194.8

Litigation

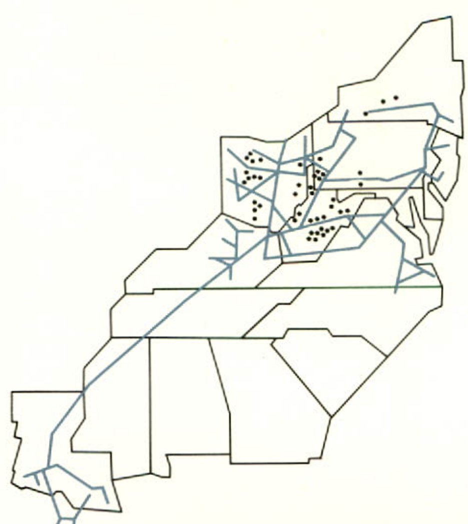
Columbia Transmission was a party to a dispute concerning a gas production lease signed in 1907 with the Bruen family, under which Columbia Transmission produced gas into the 1980s. On May 1, 1991, a Kanawha County, West Virginia Circuit Court ruled that the lease had expired in 1933. A $29.6 million judgment was awarded to the Bruen family, in which $1.6 million was for actual production and $28 million for compound interest. The jury ruled that United Fuel, Columbia Transmission's predecessor, did not intentionally trespass against the Bruens and had no reason to know the lease had expired. On October 18, 1991, the Bankruptcy Court approved a motion permitting Columbia Transmission to file an appeal with the West Virginia Supreme Court seeking to overturn the judgment handed down in May by the Circuit Court. The Supreme Court on December 4, 1991, agreed to hear the appeal.

The Bankruptcy Court granted two producers relief from the automatic stay of litigation pending against Columbia Transmission permitting them to proceed with their prepetition litigation. The Bankruptcy Court denied Columbia Transmission's requests for rehearings and appeals have been filed with the U. S. District Court for the District of Delaware.

Other Bankruptcy Issues

The Bankruptcy Court approved Columbia Transmission's petition seeking authorization to deliver 40 Bcf of firm storage service gas to its customers and authorized Columbia Transmission to honor its winter service contracts during the 1991-92 heating season. It also approved a Columbia Transmission motion on October 3, 1991, requesting an extension of the deadline for assuming or rejecting nonresidential real property leases until a confirmation by the Bankruptcy Court is received on Columbia Transmission's plan of reorganization.

On January 10, 1992, the FERC determined that the Official Committee of Unsecured Creditors of the Corporation has sufficient interest to take part



in the rate cases of Columbia Transmission and Columbia Gulf Transmission Company (Columbia Gulf). The Official Committee of Unsecured Creditors of Columbia Transmission had previously been granted such status in these cases.

On February 13, 1992, the Bankruptcy Court: (1) authorized Columbia Transmission to flow through a portion of the FERC Order No. 528 refunds and Gas Research Institute charges received prepetition; (2) authorized Columbia Transmission to flow through all FERC Order No. 528 refunds received postpetition; and (3) denied Columbia Transmission's request to pay certain prepetition upstream pipeline supplier charges.

Columbia Transmission has also requested Bankruptcy Court approval to settle FERC rate proceedings in the normal course of business. Still pending a Bankruptcy Court decision is a request by Wyoming Interstate Company to withhold a $13 million refund due to Columbia Transmission and place the funds in escrow.

Cove Point LNG Terminal

The Bankruptcy Court approved the sale of the Corporation's remaining interest in Columbia LNG Corporation (Columbia LNG) to Shell LNG Corporation (Shell LNG) under terms of a conditional agreement reached earlier. Shell LNG currently owns approximately 9 percent of the outstanding stock of Columbia LNG. (See additional comments in liquidity section on page 33 and Note 13G of Notes to Consolidated Financial Statements.)

Pipeline Supplier Direct Billing

Pursuant to FERC Order No. 528, Columbia Transmission's pipeline suppliers have revised their allocation of take-or-pay costs previously billed to Columbia Transmission and flowed through to its customers. As a result, Columbia Transmission has or will receive refunds from these upstream suppliers. As noted above, the Bankruptcy Court has held that to the extent that refunds were received prepetition, Columbia Transmission may only flow through a portion of the refunds received. However, Columbia Transmission may flow through all take-or-pay refunds received postpetition.

In June 1991, Tennessee Gas Pipeline Corporation filed a settlement which was intended to resolve numerous outstanding issues, including its allocation of take-or-pay costs. The settlement reduced take-or-pay flowthrough costs allocated to Columbia Transmission from approximately $200 million to approximately $80 million, excluding interest. As a result of payments made under the prior allocation method, Columbia Transmission anticipates receiving a refund of approximately $60 million. In December 1991, FERC approved the settlement on a preliminary basis but deferred action until all parties declared whether or not they contested the proposed settlement.

In July 1991, Panhandle Eastern PipeLine Company and Trunkline Gas Company each filed settlements resolving Order No. 528 liability on their respective systems. Under these settlements, Columbia Transmission's total principal liability to these companies would be reduced from $45 million to approximately $5.5 million. Columbia Transmission previously paid $19 million, therefore, it will receive refunds of approximately $13.5 million. In August 1991, the FERC issued orders approving the settlements as filed.

Also, in July 1991, Columbia Transmission reached agreements with subsidiaries of Panhandle Eastern Corporation resolving outstanding issues regarding Order No. 94 production-related costs. Under the terms of the settlements, which are subject to FERC approval, Columbia Transmission is to receive approximately $30.5 million from Panhandle's subsidiaries. For its part, Columbia Transmission agreed to pay about $16 million to those companies under a revised allocation methodology. The Corporation recorded the earnings effect of the Order No. 94 issue in the third quarter of 1990, reflecting court rulings which allowed Columbia Transmission to recoup costs previously paid to other pipelines for expenses related to the production of natural gas. The settlements, which were filed with the FERC on February 6, 1992, provide that Columbia Transmission will recover the amounts paid to Panhandle's subsidiaries from its customers on an as-billed basis.

Columbia Transmission previously reached a settlement with Kentucky-West Virginia Gas Company (Kentucky-West Virginia) concerning Kentucky-West Virginia's filing to retroactively collect higher prices for gas it produced and sold between 1979 and 1983. The settlement, which was filed with the FERC in August 1990, provided, among other things, for payments by Columbia Transmission of approximately \$21.3 million over an eight year period, plus interest during the period, as well as an additional \$3.8 million to be paid at future dates. The settlement was contingent upon Columbia Transmission fully recovering the costs from its customers.

The settlement was rejected on March 7, 1991. The FERC held that the 1985 PGA Settlement precluded Columbia Transmission from recovering such costs from its customers, and rejected Kentucky-West Virginia's settlement because it was unacceptable to Columbia Transmission without this provision. Since Columbia Transmission's request for rehearing of this order has been denied by the FERC, Columbia Transmission plans to file an appeal with the U.S. Court of Appeals for the D.C. Circuit. Columbia Transmission and Kentucky-West Virginia are still engaged in negotiations seeking an alternative resolution of this matter.

Rate Filings

Columbia Transmission's and Columbia Gulf's rates are established by the FERC. The companies make periodic requests for rate changes to recover costs associated with new facilities, higher operating or capital costs, or to reflect changes in throughput, cost allocation or rate design.

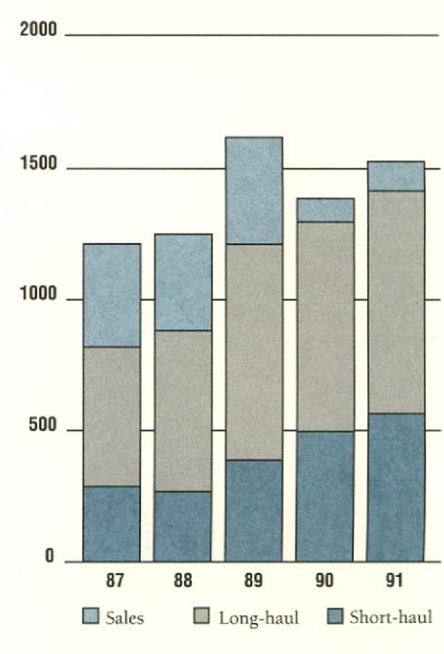
As of the end of 1991, Columbia Transmission and Columbia Gulf had several such rate filings awaiting final FERC approval. Settlement discussions with all interested parties in a 1990 filing are in advanced stages. This filing involved a requested annual revenue increase of \$160 million, over the underlying settled rates which were in effect for the period November 1990 through November 1991.

A 1991 request to increase annual revenues by an additional \$38 million went into effect subject to refund in December 1991. This case is in the early stages of processing.

Proposed rate design changes included in the 1991 rate filing of Columbia Transmission will go into effect, subject to refund, in April 1992. The new rate design, known as "straight fixed variable" will replace the "modified fixed variable" rate design now in effect. Under the straight fixed variable design, fixed costs are reflected in monthly demand (capacity) charges, and all variable costs are reflected in commodity (usage) charges. The new rate design should reduce profit volatility by minimizing the impact of weather on the recovery of fixed costs.

Finally, in its most recent quarterly filing to reflect the current cost of purchased gas, Columbia Transmission has lowered its commodity rate effective February 1, 1992, to \$1.97 per Dth. The new rate is 46% below the rate in effect before the bankruptcy filing, and reflects the impact of the postpetition rejection of high-cost gas contracts.

Transmission Gas Throughput
(in billion cubic feet)



Proposed Regulatory Changes

In July 1991, the FERC proposed new regulations designed to complete the transition of the gas pipeline industry initiated by the FERC in 1985. The new regulations, if approved, will effectively change the present role of an interstate gas pipeline from a city gate merchant of gas to local distribution customers (for which a single tariff rate includes all gas acquisition, transportation and storage costs), to a provider of "unbundled" separate services which allow local distribution and other customers to buy gas directly from producers and marketers and to separately purchase transportation and storage services from pipelines.

These proposed new regulations are expected to be finalized in the first quarter of 1992, and to be effective late in 1993. If so, Columbia Transmission anticipates the need to conduct extensive negotiations with its customers to modify existing contractual commitments, many of which are contained in existing 15-year service agreements. The ultimate transition to the FERC proposal is likely to involve an additional reduction in the merchant role performed by Columbia Transmission. A significant issue to be addressed in the final rule relates to the recovery of costs associated with this major business transition. Such transition costs may, among others, include recovery of previously deferred gas purchase costs, costs associated with facility additions required to offer fully unbundled service options, and costs involving pipeline/producer contracts which may include take-or-pay costs or buyout or buydown costs.

Capital Expenditures

In November 1991, Columbia Transmission completed construction of the facilities which it had agreed to install under the terms of a 1989 comprehensive customer settlement. This included facilities which will allow Columbia Transmission to provide 12,500 Dth per day of incremental firm transportation service to Public Service Electric and Gas of New Jersey. In addition, all facilities required to provide firm transportation of 6,000 Dth per day to a cogeneration facility in Pedricktown, New Jersey, were completed with service beginning in February 1992.

Columbia's $154 million 1992 capital program for the transmission companies (Transmission) is designed to maintain the safe and reliable operation of the pipeline system and preserve the value of transmission assets. More than $48 million, or 31% of the 1992 program is targeted for nondiscretionary age and condition programs. Approximately $33 million will be spent in 1992 to complete facilities necessary to meet new firm service obligations which were entered into in 1989 and 1990. Of this amount, $16 million has been allocated to a three-year project expected to be completed in the summer of 1992 which will provide up to 60,000 Dth of service per day to Piedmont Natural Gas Company in North and South Carolina. Under the second phase of another three-year project, almost $8 million will be spent in 1992 to add additional pipeline capacity and compression in order to provide 43,000 Dth per day of firm transportation to Virginia Electric and Power Company.

Gas Supply

During the 1991-92 winter heating season, storage will represent Columbia Transmission's largest single source of supply, providing nearly 60 percent of its estimated sales volumes. The remainder of the supply will come from old, market-sensitive contracts not rejected by Columbia Transmission, short-term winter-only contracts and spot-market purchases. Columbia Transmission will continue to evaluate its supply portfolio throughout the winter and make adjustments as necessary for changes in market requirements and will continue to evaluate its remaining supply contracts for possible rejection.

In order to maintain adequate access to the Arkoma Basin, a major gas supply area, Columbia Gulf plans to participate with Tennessee Gas and Arkla Energy in construction of facilities to increase capacity from current levels of 85 MMcf per day to 250 MMcf per day. This project will require a Columbia Gulf investment of $73.5 million in 1993 and 1994. In July 1991, the FERC rejected the project application because of Columbia Gulf's inability to state at the time of the filing how it proposed to finance its share of the cost of the new facilities. Columbia Gulf has filed for a rehearing and has submitted information on financing as required. This matter is now pending before the FERC.

Pipeline Partnership Projects

Columbia Gulf is a general partner in the Trailblazer, Overthrust and Ozark partnerships which are all nonrecourse, project-financed pipelines. Columbia Transmission is a shipper whose service contracts with the pipelines were assigned to the banks (or in the case of Ozark to the Indenture Trustee) as collateral for loans. Rejection by Columbia Transmission of these service agreements could reduce the value of Columbia Gulf's investments and result in additional claims against ColumbiaTransmission.

Environmental Matters

As reported in Note 13I of Notes to Consolidated Financial Statements, Columbia Transmission and Columbia Gulf have recorded liabilities for estimated remediation costs, primarily related to the cleanup of low levels of contamination from polychlorinated biphenyl (PCB) based lubricating oils, mercury and other substances. The Environmental Protection Agency (EPA) has provided Columbia Transmission with technical guidance documents which are approved for Columbia's use in classifying pipeline segments for abandonment in place under the Toxic Substance Control Act PCB regulations. Columbia Transmission has also received EPA approval of a Quality Assurance Project Plan for use in conjunction with the technical guidance document. These EPA-approved procedures should permit implementation of pending pipeline abandonment and retirement projects. These new procedures will facilitate the replacement of contaminated pipeline and help to minimize costs. Assessment of potential contaminated sites by outside consultants will continue in 1992. Remediation will be done at these sites as appropriate. The Commonwealth of Kentucky and the Commonwealth of Pennsylvania have each initiated assessments of Columbia Transmission's activities, facilities and their potential environmental impact. Management has been working cooperatively with the respective state agencies responsible for these assessments. (See Note 13I in Notes to Consolidated Financial Statements for additional information.)

In total, at December 31, 1991, Columbia Transmission and Columbia Gulf have recorded liabilities for identified environmental matters of $46 million and $6.6 million, respectively, subject to an ongoing environmental assessment of their facilities.

Volumes

For 1991, throughput increased to 1,527 Bcf, or 10% over last year. Compared to 1990, sales and transportation were up 23 Bcf and 118 Bcf, respectively. Colder weather in the current period accounted for most of the increase in sales. In Transmission's operating area weather was 6% colder than last year; however, it was still

Transmission Operating Highlights

	1991	1990	1989	1988	1987
Capital Expenditures ($ in millions)	152.9	279.5	189.5	102.6	100.9
Throughput (Bcf)					
Sales	112.6	89.2	408.2*	369.3	394.2
Transportation					
Firm	418.1	319.4	195.6	108.3	159.9
Interruptible	431.8	480.1	627.7	504.3	372.3
Short-haul	564.7	497.4	387.4	268.5	286.4
Total	1,414.6	1,296.9	1,210.7	881.1	818.6
Throughput	1,527.2	1,386.1	1,618.9*	1,250.4	1,212.8
Net Storage Activity (Bcf)					
Withdrawals (injections)	18.9	(175.6)	184.6	(19.2)	17.8

*Includes 116 billion cubic feet applicable to the sale of storage inventory gas.

12% warmer than normal. Long-haul transportation increased 50 Bcf due in large part to customers taking advantage of Columbia Transmission's FSS. The FSS allows customers to store their gas in Columbia Transmission's storage facilities for future delivery. Use of firm transportation services has continued to increase over the past few years, replacing interruptible services, as customers switch to more secure transportation arrangements to ensure deliverability of gas supplies purchased off-system. An increase in lower-margin short-haul transportation of 67 Bcf was primarily due to additional arrangements made by marketers for spot-market gas deliveries. The percentage of throughput represented by short-haul transportation has been steadily increasing in recent years as a result of customers moving to lower-priced gas.

Throughput for 1990 of 1,386 Bcf, was down 233 Bcf, or 14% from 1989. During 1990, weather was 20% warmer than the prior year, causing decreased throughput of over 100 Bcf. In addition, during 1989 Columbia Transmission sold 116 Bcf of storage gas of which 70 Bcf was delivered in 1990. These storage deliveries replaced transportation volumes that would have normally been reflected in 1990 throughput under previous circumstances. Timing of deliveries for heating season prepaid gas reduced 1990 sales by 60 Bcf. Improving 1990 throughput was increased short-haul transportation volumes of 110 Bcf, primarily reflecting increased spot-market gas deliveries and the construction of new facilities.

Net Revenues

For 1991, net revenues (revenues less associated gas costs) of $634.5 million, decreased $12.8 million from the prior year. Net sales revenues were down $66.7 million, while net transportation revenues and storage revenues increased $30.3 million and $23.6 million, respectively.

The net sales revenues decline reflects the effect of favorable one-time items recorded in 1990, including the recording of $30.5 million for a court ruling that allows Columbia Transmission to recoup costs previously paid to other pipelines for expenses related to natural gas production, as well as $22 million of revenues collected for Columbia Transmission's GIC. Partially offsetting this decrease was the beneficial impact on 1991 net sales revenues of higher sales volumes and increased demand revenues, reflecting the full year effect of new rates that went into effect during 1990.

Net transportation revenues increased $30.3 million over 1990 due to increased volumes transported and higher demand revenues reflecting customers moving to firm transportation services from interruptible agreements. The effect of increased short-haul transportation volumes was more than offset by lower average rates for this service.

Storage service revenues increased $23.6 million as customers continue to increase their utilization of Columbia Transmission's storage service together with the full year effect of higher rates allowed by 1990 rate settlements.

Transmission's 1990 net revenues decreased $51.8 million from 1989 to $647.3 million. Net transportation revenues were lower by $108.6 million, while net sales revenues were unchanged from the 1989 level despite lower sales volumes. Storage service revenues were $56.8 million higher as a result of the full year effect in 1990 of a new storage service.

The beneficial effect on 1990 net revenues of the favorable court ruling on previously expensed natural gas production costs, together with revenues associated with Columbia Transmission's GIC, were partially offset by lower sales volumes.

Net transportation revenues were lower in 1990, compared to 1989, primarily due to the delivery of storage gas purchased by customers in 1989, and the benefit of lower transportation rate refund requirements as part of the 1989 comprehensive customer settlement.

Operating Income (Loss)

Transmission had an operating loss of $1,192.2 million for 1991, compared with operating income of $128.2 million in 1990. The operating loss reflects the recording of a provision for gas supply charges of $1,319.2 million in the current period by Columbia Transmission to reflect the serious problems created by older high-cost producer contracts, related gas supply management costs and the impact of contract rejection and renegotiation on costs previously capitalized. Operation and maintenance expense in 1991 of $357.7 million was $26.7 million lower than the 1990 level, mainly due to lower gas supply management costs. The effect of these higher prior period expenses was reduced by an increase to the reserve for environmental clean-up costs and higher labor and benefit costs during 1991.

Operating income in 1990 decreased $66.6 million, or 34% from the prior year. Lower net revenues together with increased operating expenses of $14.8 million combined to cause this reduction. Operation and maintenance expense increased $29.6 million over the 1989 level principally due to higher expenses associated with gas supply management costs. These increased costs together with higher labor and benefit costs were partially offset by lower depreciation and other tax expense.

Distribution Operations

Statements of Operating Income from Distribution Operations (Unaudited)

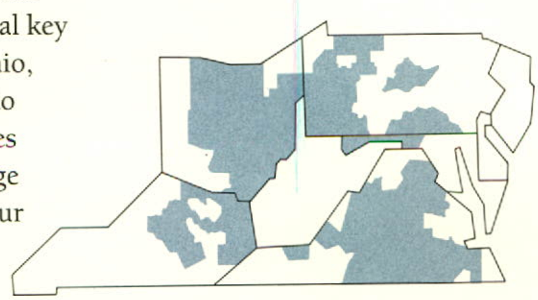
Year Ended December 31 (in millions)	1991	1990	1989
Net Revenues			
Sales revenues	$1,466.9	$1,380.0	$1,672.4
Less: Cost of gas sold	882.2	819.9	1,101.4
Net Sales Revenues	584.7	560.1	571.0
Transportation revenues	66.6	45.2	75.3
Less: Associated gas costs	5.8	(17.1)	14.9
Net Transportation Revenues	60.8	62.3	60.4
Net Revenues	645.5	622.4	631.4
Operating Expenses			
Operation and maintenance	353.9	351.0	323.5
Depreciation	60.5	59.8	50.4
Other taxes	116.2	114.9	111.4
Total Operating Expenses	530.6	525.7	485.3
Operating Income	$ 114.9	$ 96.7	$ 146.1

Market Conditions

Weather is the major factor that influences sales to residential and commercial customers, and 1991 was the second straight year that temperatures in the distribution companies' (Distribution) market area were warmer than normal.

Distribution's primary competition is with electric utilities for residential and commercial loads and fuel oil and, in some cases, coal or other gas companies for industrial loads. This competition is expected to continue for the foreseeable future. In several key market areas, including Ohio, electric rates are expected to increase faster than gas rates as electric utilities with large coal-fired power plants incur the costs of compliance with clean air legislation. This should benefit Distribution's competitive position.

Distribution continues to emphasize low-cost expansion from existing main lines, and higher customer usage through the promotion of year-round gas appliances such as clothes dryers, water heaters, ovens, outdoor grills, gas logs, and gaslights. Distribution added about 31,000 new residential and commercial customers in 1991, slightly below the number added in 1990.

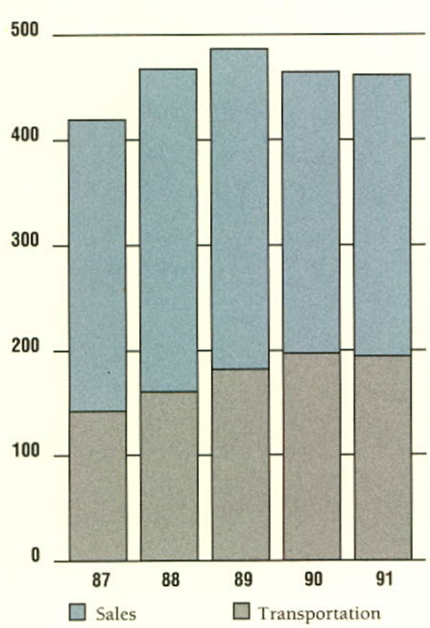


Columbia's Retail Service Area

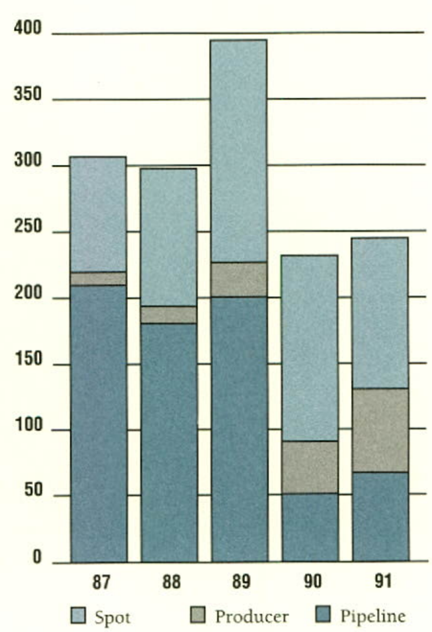
Despite the recession, industrial throughput remained relatively constant compared to the previous year, primarily due to the diversified markets served, competitive transportation rates and success in introducing new gas technologies which provide an advantage over alternative fuels. The continuing public concern for a cleaner environment and the amendment to the Clean Air Act in 1990 have created new opportunities for additional growth for Distribution, particularly for fueling electric power generation facilities. Distribution has established an environmental marketing function in order to retain present customers threatened by environmental legislation and to develop new loads generated by clean air legislation.

Distribution continues to work with others to gain acceptance of compressed natural gas as a clean transportation fuel alternative, particularly for fleets. Distribution owns 5 compressed natural gas fueling stations which service 450 of its own vehicles as well as a limited number of vehicles owned by others. A recent ruling by the Public Utility Commission of Ohio approved an agreement between Columbia Gas of Ohio and Metropane, Inc. concerning the transportation and compression of natural gas for eventual use as a motor fuel. The Commission ruled that Metropane's retail sales of compressed natural gas to the public would not make Metropane a regulated utility. The "Columbia," the prototype urban transit bus powered by compressed natural gas, is being studied by transit authorities throughout Distribution's operating area.

Distribution Gas Throughput
(in billion cubic feet)



Distribution Gas Purchases
(in billion cubic feet)



Regulatory Matters

As a result of negotiated rate settlements, each of the five distribution companies placed increased rates into effect during 1991. These increases in total should increase Distribution's annual revenues by about $29 million, primarily in Ohio, Pennsylvania and Kentucky. The increases were required to recover the costs associated with adding new customers and higher operating expenses.

In addition to the immediate revenue increase, the Ohio settlement contains a new rate mechanism which addresses the concern about recovery of the capital cost of adding new customers. The Ohio distribution company may now capitalize interest on capital expenditures until those expenditures are added to the rate base in the next full rate filing. Previously, capitalization of interest stopped when the new facilities went into service.

As part of the Pennsylvania settlement a request for recovery of $4.1 million in estimated costs, that may be required to clean up coal tar residue contamination at a York County, Pa., plant site which produced gas from coal about 40 years ago, was postponed to a future proceeding after the method of cleanup is determined and expenses begin. Management anticipates recovery of all cleanup costs incurred through future rate filings.

Supply Management

Distribution maintains a diverse and flexible gas supply portfolio to assure that reliable supplies of competitively priced gas are available to its customers. In 1991, more than 64% of Distribution's supply was purchased directly from various producers and marketers under term and spot-market contracts. The remainder of its supply requirements was purchased from interstate pipelines.

The proposed new FERC regulations discussed previously on page 19 may result in a comprehensive restructuring of many of the interstate pipeline services Distribution has historically relied upon. The proposed regulations could eliminate the merchant services provided by interstate pipelines and replace those services with a combination of transportation, storage and other services without reliance on the pipeline merchant function. Regardless, Distribution's management is confident that even with unbundled interstate pipeline services, Distribution will continue to provide the reliable, competitively priced gas supplies required by its customers. The gas supply portfolio developed by Distribution in recent years has provided substantial flexibility and when combined with existing pipeline transportation and seasonal storage options, enables it to provide a wide variety of services for all classes of customers at competitive rates.

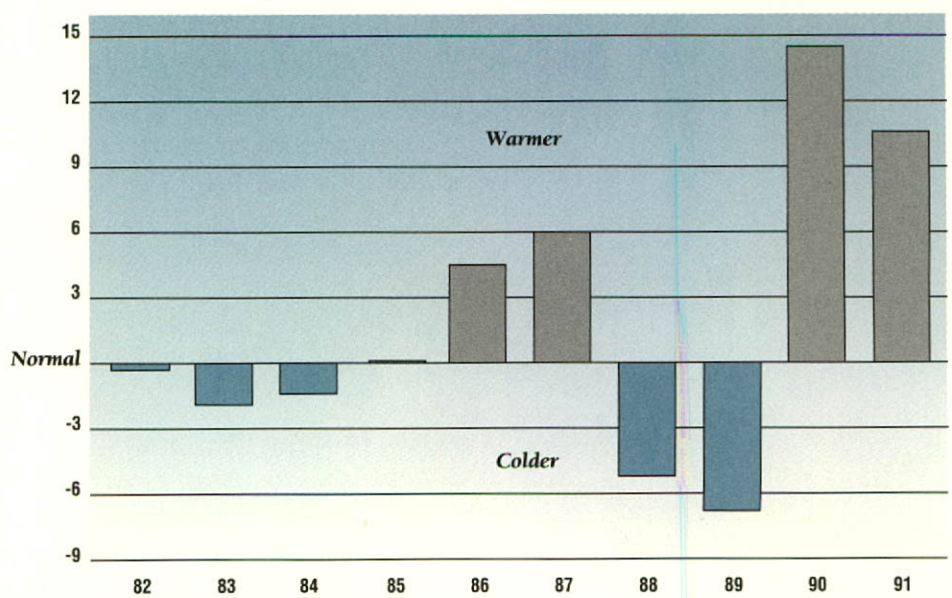
Environmental Matters

Distribution has instituted a comprehensive environmental program designed to ensure complete and prompt compliance with all state and Federal environmental requirements. In certain areas, before natural gas was generally available, a process which involved heating certain combustibles such as coal and oil in a low-oxygen atmosphere was used to manufacture low cost gas. Residues from this process, including lampblack and coal tar, were typically stored on site or sold for commercial use. Certain sites in Distribution's jurisdiction have been identified for further study and, if necessary, remediation. Management anticipates recovery of remediation costs through normal rate proceedings.

Sale of New York Subsidiary

The sale of Columbia Gas of New York, Inc. to New York State Electric & Gas was completed on April 5, 1991. The total selling price was $57.5 million, including $39.2 million for the 328,000 outstanding shares of common stock

Annual Percentage Variation from Normal Weather*



**Distribution Service Territory*

Distribution Operating Highlights

	1991	1990	1989	1988	1987
Capital Expenditures ($ in millions)	98.0	107.0	119.7	110.4	105.8
Throughput (Bcf)					
Sales					
Residential	178.4	173.5	201.5	195.0	175.1
Commercial	78.3	76.8	85.0	85.6	79.8
Industrial	10.8	16.6	16.4	25.0	22.0
Other	0.2	0.2	1.1	0.7	0.7
Total	267.7	267.1	304.0	306.3	277.6
Transportation	194.7	198.6	184.4	163.1	143.8
Throughput	462.4	465.7	488.4	469.4	421.4
Customers					
Residential	1,686,918	1,724,281	1,693,914	1,665,135	1,625,458
Commercial	160,378	165,144	161,864	157,440	152,071
Industrial	2,342	2,400	2,334	2,329	2,177
Other	24	20	26	29	28
Total	1,849,662	1,891,845	1,858,138	1,824,933	1,779,734
Degree Days	4,998	4,783	5,971	5,914	5,259

and $18.3 million for the outstanding debt. The sale was recorded in the second quarter of 1991 and provided an increase to net income of $9.2 million. The sale of this subsidiary will not have a material effect on future financial results.

Volumes

Throughput for Distribution in 1991 was 462 Bcf, a small decrease of 4 Bcf compared to last year. After adjusting for the impact of the sale of Columbia Gas of New York, throughput increased 4 Bcf. The primary reasons for the improvement were the positive effect of 4% colder weather in the current year and the addition of new residential and commercial customers. Also contributing to the improvement were higher transportation deliveries to power generating facilities in Virginia and a refinery operation in Kentucky. Mitigating these increases were reduced industrial sales, principally resulting from customers purchasing gas directly from producers while using Distribution solely as a transporter. A lower customer growth rate also tempered throughput due principally to the current recession and Distribution's more stringent economic guidelines for customer additions. Although 1991 was colder than the prior year, weather was 11% warmer than normal.

Throughput for 1990 of 466 Bcf decreased 22 Bcf, or 5%, over the prior year. Tariff sales volumes declined 37 Bcf due primarily to 20% warmer weather than in 1989. Transportation volumes were higher by 14 Bcf. The negative effect of weather on sales was partially offset by residential and commercial customer growth and increased usage per customer. Higher industrial throughput resulted from increased transportation services due to the availability of lower-cost spot supplies and successful marketing efforts.

Net Revenues

Distribution's 1991 net revenues (operating revenues less associated gas costs) of $645.5 million were $23.1 million, or 4%, higher than in 1990. Net sales revenues improved $24.6 million while net transportation revenues declined $1.5 million.

The increase in net sales revenues was attributable to the beneficial effect of general rate settlements and colder weather in 1991. This improvement was partially offset by a lower level of customer additions in 1991, the impact of the sale of Columbia Gas of New York and revenue effect of the adoption of the Statement of Financial Accounting Standards (SFAS) No. 96, "Accounting for Income Taxes." Decreased net transportation revenues primarily reflect lower average margins.

Net revenues of $622.4 million for 1990 decreased $9 million, or 1%, compared to 1989. This decline reflected the weather-related reduction in sales volumes which was only partially offset by rate increases during 1990 and increased industrial throughput.

Operating Income

Operating income for 1991 increased to $114.9 million, up $18.2 million, or 19%, over 1990. This improvement was due primarily to higher net revenues partially offset by a 3% rise in operating expenses after adjusting for the impact of the sale of Columbia Gas of New York. The increase in operating expense reflects higher labor and benefit expenses together with increased other operation and maintenance costs. Operating income is depressed due to continued warmer than normal weather as well as only a portion of the higher expenses being currently recovered in rates as a result of regulatory lag.

Operating income for 1990 of $96.7 million was $49.4 million, or 34% lower than the level achieved in 1989. The effect of lower net revenues combined with higher operation and maintenance costs largely contributed to the decline.

Other Energy Operations

Statements of Operating Income from Other Energy Operations (Unaudited)

Year Ended December 31 (in millions)	1991	1990	1989
Net Revenues			
Sales revenues	$121.0	$110.1	$75.7
Less: Products purchased	94.4	85.8	54.8
Net Sales Revenues	26.6	24.3	20.9
Other revenues	75.5	76.9	73.2
Net Revenues	102.1	101.2	94.1
Operating Expenses			
Operation and maintenance	87.6	87.4	84.1
Depreciation and depletion	4.0	3.6	2.6
Other taxes	5.6	4.7	4.1
Total Operating Expenses	97.2	95.7	90.8
Operating Income	$ 4.9	$ 5.5	$ 3.3

The System is involved in diverse energy markets related to the natural gas business.

Cogeneration

Subsidiaries of TriStar Ventures Corporation (TriStar), a wholly owned subsidiary of the Corporation, are partners in two limited partnerships that are currently constructing cogeneration projects. In 1990, construction was started on a 117-megawatt cogeneration project at Pedricktown, N.J. It is anticipated that in early 1992, the Pedricktown Plant will commence operations. This plant will supply steam to a major chemical plant and electricity to Atlantic City Electric Company. In 1991, construction commenced on a 50-megawatt plant in Binghamton, N.Y. This plant is to be operational by mid-1992. The Binghamton facility will sell recovered heat to an industrial concern and electricity to New York State Electric & Gas.

Several other cogeneration projects are in the development stage. TriStar expects to own, through its subsidiaries, a 50% interest in a 56-megawatt plant in the Washington, D.C. area, and a 50% interest in a 47-megawatt plant in the Vineland, N.J. area. Both projects should begin construction during 1992.

In June 1991, TriStar recorded a pre-tax writedown of $14.5 million related to a decision to sell four small cogeneration units and to focus its activity on large-scale cogeneration projects. The writedown also included a net realizable value adjustment associated with its investment in a cogeneration development company.

Propane

The two propane companies, Columbia Propane Corporation and Commonwealth Propane, Inc., together sold approximately 70 million gallons of propane during 1991. Through reorganization, consolidation and refocusing its efforts, the operating income contribution of the propane operations improved 42% over last year. Commonwealth Propane's 50% owned affiliate, Atlantic Energy, received 31 million gallons of imported propane and nearly 14 million gallons of butane for storage and export. The propane companies serve nearly 65,000 customers in Virginia, Ohio, Maryland and Pennsylvania.

Coal

Columbia Coal Gasification Corporation owns one of the largest contiguous coal reserves available in the Appalachian area with approximately 550 million tons of proved coal reserves, much of which contains less than one percent sulphur. Some of these reserves have been leased to other companies for development, and in 1991, new mining operations were established in both Lincoln and Wayne Counties in West Virginia. Production royalties from these leases are anticipated to begin during 1993.

Net Revenues

Net revenues for 1991 of $102.1 million were up $0.9 million compared to the prior year. Net sales revenues increased $2.3 million primarily reflecting higher margins for propane sales which were mitigated by a small decrease in volumes sold. Decreased other revenues primarily reflected the one-time favorable effect in 1990 for a prior period adjustment for advance royalty payments.

Net revenues for 1990 were $101.2 million, $7.1 million higher than 1989. Net sales revenues increased $3.4 million primarily due to improved margins on propane sales. Other revenues increased 5% reflecting higher coal leasing revenues and higher billings to affiliated companies.

Operating Income

For 1991, operating income of $4.9 million decreased $0.6 million from the 1990 level. This decrease reflects increased operating expenses which more than offset the small improvement in net revenues.

Operating income of $5.5 million for 1990 increased $2.2 million over 1989. Operating income increased primarily reflecting higher coal leasing revenues. Higher net sales revenues from propane operations were offset by associated increased operating expenses.

Other Energy Highlights

	1991	1990	1989	1988	1987
Capital Expenditures ($ in millions)	10.2	14.1	16.4	23.8	10.6
Propane					
Gallons sold (millions)	70.5	74.4	75.2	73.3	75.8
Customers	64,618	63,546	62,707	50,016	44,421
Coal Reserves (million tons)	550	550	550	650	650

Consolidated Review

Net Income (Loss)

For 1991 the System recorded a loss of $694.4 million, or $13.74 per share. This compares to net income of $104.7 million, or $2.21 per share last year. The loss in the current period is primarily attributable to Columbia Transmission's after-tax charges of $870.7 million ($1,319.2 million pre-tax) recorded during 1991 to reflect the serious problems created by older high-cost producer contracts, related gas supply management costs and the impact of contract rejection and renegotiation on costs previously capitalized. Accounting changes, adopted in the fourth quarter and made effective as of January 1, 1991, resulted in a net benefit to 1991 net income of $100.4 million. Net income improved by $170 million with the adoption of SFAS No. 96, which among other things requires the impact on deferred income taxes to be recognized whenever tax rates change. Adoption of SFAS No. 106, which changes the way certain postretirement benefits are accounted for, resulted in a $69.6 million charge against net income.

Oil and gas operations had an operating loss of $4.5 million for 1991, compared to operating income of $43.3 million last year. The loss primarily reflects current year writedowns for Canadian properties of $36.4 million, the effect of lower energy prices together with higher operation and maintenance costs and higher depletion expense.

Mitigating the decreases in the current period was increased oil production due largely to the success of the Southwest exploration and development program, particularly for horizontal wells.

The Canadian subsidiary was sold in December 1991, which will enable the Corporation to concentrate its exploration and development efforts on domestic oil and gas operations.

Transmission operations had an operating loss of $1,192.2 million for 1991 compared to operating income of $128.2 million in the prior year. The loss primarily reflects the effect of Columbia Transmission's gas supply charges mentioned previously. Mitigating this loss was higher current period demand revenues attributable to the full year effect in 1991 of new rates that went into effect during the prior year, and increased throughput resulting from 6% colder weather. When compared to the prior year, 1991 operating income was depressed due to the beneficial effect in 1990 of recording $30.5 million for a court ruling that allows Columbia Transmission to recoup costs previously paid to other pipelines for natural gas production-related costs.

Distribution had operating income of $114.9 million, up $18.2 million over the 1990 level. This improvement was primarily due to colder weather in the current period. Overall, the effect of warmer than normal weather and regulatory lag continues to depress the operating results of Distribution operations.

System net income for 1990 was $104.7 million, or $2.21 per share, compared to $145.8 million, or $3.21 per share in 1989. Operating income for Transmission and Distribution was significantly reduced during 1990 due to record-setting warm temperatures. Mitigating these decreases were higher oil and gas prices and increased oil production which improved results from oil and gas operations.

Changes in other income (deductions) also affecting income are discussed on page 30.

Revenues

Operating revenues for 1991 of $2,576.8 million increased $218.9 million over the prior year. Gas sales and transportation revenues increased $153.7 million and $51.8 million, respectively. Other revenues improved $13.4 million. Higher gas sales revenues were attributable to increased sales volumes due primarily to colder weather and higher average rates in effect during the year. Also increasing revenues was additional recovery of upstream pipeline supplier take-or-pay costs, the majority of which was offset by associated gas purchase expense.

Operating revenues of $2,357.9 million in 1990 decreased $846.5 million from the 1989 level, reflecting lower gas sales revenues of $789.1 million and reduced transportation revenues of $139.1 million. The sales revenue decrease was due to lower sales volumes in 1990 attributable to the warmer weather, the effect of a 1989 storage sale and the timing of prepaid heating season gas sales. In addition, revenues decreased due to a revenue reduction for upstream pipeline supplier take-or-pay costs which was largely offset by lower associated gas purchase expense. Transportation revenues were lower reflecting customers taking delivery in 1990 of stored gas purchased in 1989 from Columbia Transmission, which replaced volumes that would have normally provided transportation revenues.

Expenses

Products purchased expense in 1991 of $1,056.5 million increased $209.7 million from 1990, primarily reflecting increased volumes purchased for resale. Higher expense associated with the passthrough of upstream pipeline supplier take-or-pay costs was offset by increased associated revenues. In 1990, products purchased expense of $846.8 million decreased $822.2 million compared to 1989. This lower level reflects reduced volumes purchased for resale but was mitigated by a higher unit cost of gas as a result of selling lower-priced storage gas in 1989.

Operation and maintenance expense for 1991 decreased to a level of $810.2 million, a decline of $11.8 million compared to 1990. This decrease primarily represents reduced costs associated with Columbia Transmission's prior efforts to renegotiate certain Southwest producer contracts and settle take-or-pay and other producer disputes, which were offset in large part by increased labor and benefit costs and higher environmental expenses for estimated future cleanup costs in the current year. Operation and maintenance expense was higher in 1990 compared to 1989 due to increased labor and benefit costs and higher take-or-pay and producer settlement expense.

The depreciation and depletion expense increase in 1991 and 1990 was $36.2 million and $14.6 million, respectively. Depletion expense includes the impact of writedowns of the carrying value of Canadian oil and gas operations of $36.4 million for 1991 and $22.6 million for both 1990 and 1989. Also causing depreciation expense to increase over the three-year period was the increased investment in plant, mitigated by lower depreciation rates for Transmission effective April 1990.

Other Income (Deductions)

Interest income and other, net was $32.4 million, a decline of $37.9 million, or 54%, compared to 1990. This reflects a $14.5 million current year writedown for certain cogeneration projects combined with the effects of $17.9 million in interest income recorded last year for the favorable court rulings on production related costs and a $47.9 million settlement in 1990 on the value of land condemned by the Army Corps of Engineers for use in creating the East Lynn Reservoir in West Virginia. Mitigating these decreases was a $17.9 million gain on the sale of Columbia Gas of New York, Inc. and higher pipeline partnership income, as well as increased other interest income in 1991. Additionally, the current year when compared to 1990 is higher due to the impact of the writedowns of a coal mine and coal loading facility of $7.3 million and $5.3 million, respectively, in 1990.

The 1990 increase over the prior year reflected the beneficial impact of the condemnation settlement and interest income on production related costs offset, in large part, by lower interest income relating to the flow through of upstream pipeline take-or-pay payments, the writedowns of the coal mine and coal loading facilities, and the effect of a 1989 gain on the sale of Columbia LNG stock to Shell Oil.

Interest expense and related charges in 1991 decreased $32.4 million compared to 1990. The decline was primarily attributable to the effect of not accruing $83.5 million of interest expense for prepetition debt securities by the Corporation since August 1, 1991. The 1990 level of interest expense and related charges decreased from 1989 due primarily to reduced interest expense for upstream supplier take-or-pay payments, lower interest rates, and decreased average short-term borrowings.

Reorganization items, net totalled $14.4 million in 1991 and reflects expenses incurred by the Corporation and Columbia Transmission related to the bankruptcy filings.

Income Taxes

Income taxes, as detailed in Note 5 of Notes to Consolidated Financial Statements, decreased $468.9 million, primarily due to the tax benefits associated with the provision for gas supply charges recorded in the second and third quarters of 1991.

In addition, the cumulative effect of accounting changes (see Note 4 of Notes to Consolidated Financial Statements) relating to the recording of income taxes and postretirement benefits reduced income taxes $236.6 million.

Effects of Inflation

Because Columbia's subsidiaries are engaged in capital intensive lines of business, the cumulative effects of inflation require substantially greater investment to replace existing productive capacity. However, such replacements occur over extended periods and revenues generally have been adequate to recover plant investment.

During periods of inflation, operating cost increases generally are not concurrently reflected in increased revenues due to delays in the rate-making process governing Columbia's regulated subsidiaries.

Common Stock Prices and Dividends

In 1991, the Corporation paid dividends of $1.16 per share on its common stock prior to the suspension of the dividend on June 19, 1991.

Columbia's common stock is listed on the New York Stock Exchange under the symbol CG. At December 31, 1991, there were approximately 72,200 shareholders of record. The accompanying table shows the dividends paid and the price range of the Corporation's common stock, by quarters, for the last two years.

	Market Price			Quarterly
Quarter Ended	High	Low	Close	Dividends Paid
	$	$	$	¢
1991				
December 31	**19 1/2**	**16**	**17 1/4**	–
September 30	**19 3/4**	**12 7/8**	**18 7/8**	–
June 30	**45 3/4**	**16 1/2**	**19 1/8**	**58**
March 31	**47 1/2**	**42 3/8**	**44 1/8**	**58**
1990				
December 31	54 3/4	44 3/4	46 7/8	55
September 30	52 1/2	43	50 5/8	55
June 30	49	41 1/2	44 1/4	55
March 31	52 1/8	44 1/4	44 1/2	55

Liquidity and Capital Resources

Cash from Operations

Net cash from operations of $531.6 million was up $111.5 million, or 27%, compared to 1990. The increase reflects reduced cash paid to suppliers of $307.1 million due largely to the suspension of payments to suppliers relating to prepetition liabilities resulting from the Chapter 11 filing and lower gas purchase costs made possible by the rejection of Columbia Transmission's high-cost contracts. In addition, 1991 is lower due to cash payments made last year for the purchase of natural gas to meet customer requirements created by the extremely cold December 1989 temperatures. Also contributing to the increase in cash from operations, was lower interest and other taxes paid relating to prepetition obligations, suspended as a result of the Chapter 11 filing, combined with the effect of a prior period payment for the settlement of a tax issue. Partially offsetting these improvements was a decline in cash received from customers in early 1990 due to the unusually cold December 1989 and an increase in income taxes paid resulting from the timing of Federal income tax payments.

For 1990, net cash from operations was $420.1 million, an increase of $19.6 million over 1989. The improvement was primarily due to a decline in other operating cash payments attributable to 1989 rate refund payments made by Columbia Transmission under the terms of a 1989 comprehensive customer settlement, an increase in other operating cash receipts for income tax refunds and a decrease in cash paid to suppliers reflecting reduced gas purchases. These improvements were offset in large part by a decline in cash received from customers reflecting the effect of reduced sales volumes due to warmer weather in 1990, compared to the prior year, and increased income taxes paid during 1990 resulting from higher taxable income.

Prior to the June 19, 1991, announcement and the subsequent Chapter 11 filing on July 31, 1991, the Corporation maintained two committed bank credit facilities which totaled $1.25 billion. One facility was a $750 million subordinated five-year revolving credit agreement, entered into in October 1988. The other facility was a $500 million short-term revolving credit agreement which was renewed annually. The unused portions of these facilities were used to support the Corporation's borrowings in the commercial paper and bank note markets. As of the date of the Chapter 11 filing, the Corporation had $889 million of commercial paper and bank loans outstanding under these facilities.

During 1991, the Corporation also raised $3.4 million through May 1991 through the issuance of 87,657 shares of common stock through the Corporation's Dividend Reinvestment Plan and Long-Term Incentive Plan.

Following the June announcement and the subsequent Chapter 11 filing, the Corporation no longer had access to either its bank lines of credit or the commercial paper market and its access to other capital markets was severely limited. Subsequently, the Corporation negotiated terms and received approval from the Bankruptcy Court and the SEC, under the Public Utility Holding Company Act of 1935, for debtor-in-possession financing (the DIP Facility).

The DIP Facility of $275 million includes the availability of letters of credit of up to $50 million, and will terminate upon the earlier of September 23, 1993, or the substantial consummation of a plan of reorganization following the entry of an order by the Bankruptcy Court in the Corporation's Chapter 11 case. The Corporation has the right to reduce or terminate the facility at any time. A syndicate of banks, led by Manufacturers Hanover Trust Company as agent, is providing the financing.

Loans under the DIP Facility have superpriority claim status pursuant to Section 364(c)(1) of the Bankruptcy Code and are secured by either a first or second priority perfected lien on, and security interest in, all property of the Corporation, including debt and equity securities held by the Corporation, other than the common equity of the Corporation's five local distribution subsidiaries and Columbia LNG.

Two borrowing options are available to the Corporation under the DIP Facility. The Corporation may borrow at the agent's alternative reference rate plus 1% or the Eurodollar rate plus 2 ¼% (for either 1, 2 or 3 months). In addition to a commitment fee of ½ of 1% per annum on the average daily unused amount of the facility, other fees have been paid to the lenders under the DIP Facility.

The DIP Facility will be used in conjunction with internally generated funds for general corporate purposes and to provide financing for subsidiaries not involved in the bankruptcy proceedings. The Corporation has repayed all borrowings under the DIP Facility as of the end of January 1992. Subsequent to the end of January 1992, only small amounts of borrowings under the DIP Facility are anticipated. The Corporation is expected thereafter to have a cash surplus as a result of not being required to pay on a current basis certain obligations incurred prior to the filing of the Chapter 11 case. As of December 31, 1991, the Corporation had $136 million outstanding under the DIP Facility.

In October 1991, the Corporation's Board of Directors authorized the termination of the Leveraged Employee Stock Ownership Plan (LESOP) subject to the approval of the Bankruptcy

Court. It was determined that the continuation of the LESOP would substantially increase the cost of providing Thrift Plan benefits to employees. If the Bankruptcy Court approves the termination of the LESOP, the proceeds from the trustee's sale of the common stock held in the LESOP trust will be used to reduce the LESOP debt. Since the Corporation has a subordinated guarantee of LESOP debt, upon termination of the LESOP, the LESOP debt holders could have a claim against the Corporation of up to $84 million. This claim would be subordinated to any claim of the Corporation's debenture holders.

In January 1992, the Corporation completed the sale of Columbia Canada to Anderson Exploration, Ltd. for $94.8 million (U.S.). The sale price includes $27.7 million which will be held in escrow for certain post-closing obligations of the Corporation and to secure the buyer against any settlement or judgment resulting from litigation in which Columbia Canada is currently involved. The amount in escrow may change depending on the occurrence of certain events; however, it is not anticipated that the escrow amount will change materially from the current level.

In April 1991, the sale of Columbia Gas of New York, Inc. to New York State Electric & Gas Corporation was completed. (See discussion on pages 25 and 26 and Note 7A of Notes to Consolidated Financial Statements for additional information.)

During November 1991, the Corporation entered into a conditional agreement for the sale of its remaining interest in Columbia LNG to Shell LNG, a subsidiary of Shell Oil Company, for $128.5 million plus Columbia LNG's debt outstanding to the Corporation at the time of closing. The debt is estimated to be $44 million at the time of closing, and there was $38.6 million outstanding at December 31, 1991. If several substantial conditions are met, Shell LNG will purchase 40.8% of Columbia LNG's stock for $45.7 million at an interim closing in July 1992 and the remaining 50% of the stock for $64.3 million at a final closing which is scheduled to occur in March 1993. Shell LNG had previously purchased 9.2% of Columbia LNG's Stock. The sale must be approved by the SEC under the Public Utility Holding Company Act of 1935. Bankruptcy Court approval has been received.

Subsequent to the Chapter 11 filing, the liquidity needs of Columbia Transmission were provided by a separate DIP financing (the Transmission Facility) provided by Manufacturers Hanover Trust Company for up to $80 million, of which up to $25 million was available for letters of credit. The Transmission Facility has received Bankruptcy Court approval on August 22, 1991. SEC authorization was not required. In November 1991, the commitment under the Transmission Facility was reduced from $80 million to $25 million, which will only be available for the issuance of letters of credit through the termination date. The Transmission Facility will terminate upon the earlier of August 2, 1993, or the substantial consummation of a plan of reorganization following the entry of an order by the Bankruptcy Court in Columbia Transmission's Chapter 11 case. Columbia Transmission retains the option to terminate the Transmission Facility at any time.

As of January 31, 1992, Columbia Transmission has accumulated cash of $402.5 million, which was invested in money market instruments. This cash position has arisen under

Chapter 11, since Columbia Transmission is not currently required to pay certain obligations.

The Corporation will not be making any further investments in Columbia Transmission during the bankruptcy period. Columbia Transmission's cash receipts are anticipated to provide sufficient cash resources to meet normal operating requirements throughout the bankruptcy period.

Certain nonfiling subsidiaries have outstanding debt obligations to the Corporation. It is anticipated that the service of these obligations will continue uninterrupted during the bankruptcy proceedings.

In total, nonfiling subsidiaries of the Corporation are expected to generate sufficient cash receipts during the heating season, which together with financing provided by the Corporation through the DIP Facility, will be sufficient to satisfy the liquidity needs of their ongoing operations. The Corporation expects that it will have sufficient liquidity through September 1993, or until a plan of reorganization can be consummated.

Capital expenditures for 1991 were $382 million, which was $248 million lower than last year and $218 million lower than the original 1991 program. The Corporation's subsidiaries reduced capital expenditures to the extent possible, consistent with the need to maintain safe and efficient operating facilities, the need to meet new service and tariff obligations, drilling commitments and the need to preserve going concern values.

Over $77 million of the reduction was achieved by Transmission. Expenditures in oil and gas were reduced by $44 million by deferring development wells and proceeding on only those exploratory prospects where the System had invested in lease and seismic work and where failure to meet lease and joint venture obligations would result in considerable loss of investment and opportunity. Distribution expenditures were reduced by $12 million.

For 1992, capital expenditures are expected to be further reduced to $375 million. As shown in the table below, expenditures by Columbia Transmission are expected to decrease from $135 million in 1991 to $130 million in 1992. Oil and gas expenditures in 1992 are expected to be $93 million, $28 million lower than the 1991 level. A total of $17 million was spent in Canada in 1991. The 1992 program is lower due to the sale of the Canadian subsidiary and reductions in the U.S. program.

Capital Expenditures

(in millions)	1992	1991
Columbia Transmission	$130	$135
Other Transmission	24	18
Distribution	108	98
Oil and Gas	93	121
Other Energy	20	10
Total	$375	$382

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Comparative Gas Operations Data

	1991	1990	1989	1988	1987
Sales and Transportation Revenues ($ in millions)					
Residential	1,019.3	943.9	1,140.6	1,157.7	1,033.9
Commercial	402.2	369.9	450.7	470.1	427.1
Industrial	51.5	64.0	82.2	118.4	104.6
Wholesale	373.7	321.0	835.2	919.1	862.7
Other	108.2	102.4	81.6	40.6	28.2
Transportation	425.0	373.2	512.3	370.3	320.9
Total Sales and Transportation Revenue	2,379.9	2,174.4	3,102.6	3,076.2	2,777.4
Sales (billion cu. ft.)					
Residential	178.5	173.5	201.5	195.5	175.1
Commercial	78.4	76.8	85.0	85.6	79.8
Industrial	10.8	16.6	16.8	26.9	22.4
Wholesale	93.6	82.7	246.8	220.8	214.8
Other	65.7	52.3	46.1	22.5	18.9
Total Sales	427.0	401.9	596.2	551.3	511.0
Transportation volumes	1,269.8	1,175.0	1,051.5	779.4	745.8
Total Throughput	1,696.8	1,576.9	1,647.7	1,330.7	1,256.8
Sources of Gas Sold (billion cu. ft.)					
Total gas purchased	370.6	453.3	449.4	517.5	491.5
Total gas produced	76.3	75.3	77.9	74.6	76.0
Exchange gas-net	(15.3)	21.1	(15.0)	5.8	(13.1)
Gas withdrawn from (delivered to) storage	24.7	(137.5)	109.0	(0.2)	(4.1)
Company use and other	(29.3)	(10.3)	(25.1)	(46.4)	(39.3)
Total Sources of Gas Sold	427.0	401.9	596.2	551.3	511.0
Customers at Year End					
Residential	1,687,631	1,724,281	1,693,914	1,666,013	1,626,341
Commercial	160,420	165,144	161,864	157,475	152,104
Industrial	2,345	2,400	2,334	2,341	2,190
Wholesale	80	81	78	79	82
Other	200	142	127	96	92
Total Customers at Year End	1,850,676	1,892,048	1,858,317	1,826,004	1,780,809
Average Usage Per Customer (thousand cu. ft.)					
Residential	105.8	100.6	119.0	117.4	107.7
Commercial	488.7	465.1	524.9	543.6	524.7
Degree Days for Retail Operations	4,998	4,783	5,971	5,914	5,259
% Colder (warmer) than normal	(10.6)	(14.5)	6.8	5.2	(6.0)

Selected Financial Data

($ in millions except per share amounts)	1991*	1990	1989	1988	1987
Income Statement Data ($)					
Total operating revenues	2,576.8	2,357.9	3,204.4	3,168.2	2,866.0
Products purchased	1,056.5	846.8	1,669.0	1,822.3	1,534.2
Earnings (Loss) on common stock before accounting changes	(794.8)	104.7	145.8	111.1	100.5
Earnings (Loss) on common stock	(694.4)	104.7	145.8	111.1	100.5
Per Share Data					
Earnings (Loss) per common share ($):					
Before accounting changes	(15.72)	2.21	3.21	2.46	2.30
Earnings (Loss) on common stock	(13.74)	2.21	3.21	2.46	2.30
Dividends:					
Per share ($)	1.16	2.20	2.00	2.295	3.18
Payout ratio (%)	N/M	99.5	62.3	93.3	138.3
Average common shares outstanding (000)	50,537	47,316	45,494	45,190	43,763
Balance Sheet Data ($)					
Capitalization excluding liabilities subject to Chapter 11 (including short-term debt and current maturities**):					
Common stock equity	1,006.9	1,757.8	1,620.3	1,552.6	1,523.7
Preferred stock	–	–	–	–	50.0
Redeemable preferred stock	–	–	–	–	60.0
Long-term debt	6.1	1,428.7	1,196.0	1,038.4	1,438.0
Short-term debt and current maturities	138.9	770.7	681.4	749.8	397.1
Total	1,151.9	3,957.2	3,497.7	3,340.8	3,468.8
Total assets	6,332.2	6,196.3	5,878.4	5,641.0	5,440.9
Other Financial Data					
Capitalization ratio (%) (including short-term debt and current maturities**):					
Common stock equity	87.4	44.4	46.3	46.5	43.9
Preferred stock	–	–	–	–	3.2
Debt	12.6	55.6	53.7	53.5	52.9
Capital expenditures ($)	381.9	629.6	473.5	307.9	298.8
Net cash from operations ($)	531.6	420.1	400.5	429.4	702.0
Book value per common share ($)	19.92	34.83	35.50	34.18	34.08
Return on average common equity before extraordinary charges (%)	N/M	6.2	9.2	7.2	6.8

N/M–Not meaningful

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financial Statements.

**Prior to its Chapter 11 filing, the Corporation made extensive use of variable rate debt since the associated cost was normally less than senior long-term debt. Inclusion of the short-term debt in years prior to 1991 makes those historical ratios more meaningful.

Management's Statement of Responsibility for Financial Statements

The accompanying consolidated financial statements and related notes have been prepared by the Corporation based on generally accepted accounting principles, and are considered by management to present fairly and consistently the Corporation's financial position and results of operations. 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 and has unrestricted access to the audit committee of the Board of Directors.

During 1990, management engaged an independent consulting firm to conduct a review of the Internal Audit Department. This review encompassed such areas as the scope of activities, organizational structure, adequacy of reporting and training. The consultants' report, which included suggestions to further strengthen the Department's effectiveness, concluded that the Internal Audit Department is discharging its responsibilities in accordance with its charter and the standards established by the Institute of Internal Auditors.

The audit committee assists the Board of Directors in its oversight role and is composed of eight directors who are not officers or employees of the Corporation. The audit committee meets periodically with the Vice President and General Auditor to review the results of internal audits 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 to discuss internal accounting controls, auditing and financial reporting matters.

Report of Independent Public Accountants

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

We have audited the accompanying consolidated balance sheets of The Columbia Gas System, Inc. (a Delaware corporation, the "Corporation") and subsidiaries as of December 31, 1991 and 1990, and the related statements of consolidated income, common stock equity and cash flows for each of the three years in the period ended December 31, 1991. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Corporation and subsidiaries as of December 31, 1991 and 1990, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1991 in conformity with generally accepted accounting principles.

On July 31, 1991, the Corporation and Columbia Gas Transmission Corporation ("Columbia Transmission"), a wholly owned subsidiary, filed separate petitions seeking protection under Chapter 11 of the Federal Bankruptcy Code. Note 2 discusses, among other matters, uncertainties associated with the Chapter 11 proceedings, including the validity of the Corporation's loans to Columbia Transmission and certain prepetition intercompany asset transfers. In addition, as discussed in Note 6, uncertainty exists related to the ultimate determination of liabilities associated with Columbia Transmission's high cost producer contracts. Further, as discussed in Note 13D, subsequent to the Corporation's June 19, 1991 announcement of a probable charge to earnings and suspension of the dividend, purported class action and other complaints have been filed against the Corporation generally alleging violations of certain securities laws. The accompanying financial statements do not reflect any liability associated with these complaints as the Corporation believes it has meritorious defenses to these actions; however, the ultimate outcome is uncertain. As a result of the proceedings under Chapter 11 and the other matters noted above, the Corporation may take, or be required to take, actions which may cause assets to be realized or liabilities to be liquidated for amounts other than those reflected in the financial statements. These factors create substantial doubt about the Corporation's ability to continue as a going concern. The accompanying financial statements have been prepared assuming that the Corporation and Columbia Transmission will continue as going concerns which contemplates the realization of assets and payment of liabilities in the ordinary course of business. The appropriateness of the Corporation continuing to present financial statements on a going concern basis is dependent upon, among other items, the terms of the ultimate plan of reorganization and the ability to generate sufficient cash from operations and financing sources to meet obligations.

As discussed in Note 4, effective January 1, 1991, the Corporation changed its method of accounting for income taxes and postretirement benefits other than pensions pursuant to standards promulgated by the Financial Accounting Standards Board.

Arthur Andersen & Co.

New York, New York
February 14, 1992

Year Ended December 31 (in millions)	1991*	1990	1989
Operating Revenues			
Gas sales	$1,954.9	$1,801.2	$2,590.3
Transportation	425.0	373.2	512.3
Other	196.9	183.5	101.8
Total Operating Revenues	2,576.8	2,357.9	3,204.4
Operating Expenses			
Products purchased	1,056.5	846.8	1,669.0
Provision for gas supply charges (Note 6)	1,319.2	–	–
Operation	689.4	714.1	650.7
Maintenance	120.8	107.9	105.4
Depreciation and depletion	285.0	248.8	234.2
Other taxes	192.3	178.2	182.6
Total Operating Expenses	3,663.2	2,095.8	2,841.9
Operating Income (Loss)	(1,086.4)	262.1	362.5
Other Income (Deductions)			
Interest income and other, net (Note 14)	32.4	70.3	55.5
Interest expense and related charges** (Note 15)	(137.4)	(169.8)	(202.9)
Reorganization items, net (Note 2)	(14.4)	–	–
Total Other Income (Deductions)	(119.4)	(99.5)	(147.4)
Income (Loss) before Income Taxes and Cumulative Effect of Accounting Changes	(1,205.8)	162.6	215.1
Income taxes (Note 5)	(411.0)	57.9	69.3
Income (Loss) before Cumulative Effect of Accounting Changes	(794.8)	104.7	145.8
Cumulative effect of change in accounting for income taxes (Note 4B)	170.0	–	–
Cumulative effect of change in accounting for postretirement benefits (Note 4A)	(69.6)	–	–
Net Income (Loss)	$ (694.4)	$ 104.7	$ 145.8

Earnings (Loss) Per Share of Common Stock (based on average shares outstanding)			
Before accounting changes	$ (15.72)	$ 2.21	$ 3.21
Change in accounting for income taxes	$ 3.36	–	–
Change in accounting for postretirement benefits	$ (1.38)	–	–
Earnings (Loss) on Common Stock	$ (13.74)	$ 2.21	$ 3.21
Dividends Per Share of Common Stock	$ 1.16	$ 2.20	$ 2.00
Average Common Shares Outstanding (thousands)	50,537	47,316	45,494

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financial Statements.

**$83.5 million interest expense has not been recorded in 1991 (based upon rates in effect at the time of the bankruptcy filing (Note 2)).

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

Consolidated Balance Sheets

Assets as of December 31 (in millions)	1991*	1990
Property, Plant and Equipment		
Gas utility and other plant, at original cost	$5,575.0	$5,627.4
Accumulated depreciation and depletion	(2,794.8)	(2,802.7)
	2,780.2	2,824.7
Oil and gas producing properties, full cost method		
United States cost center	1,167.6	1,130.7
Canadian cost center	–	260.2
Accumulated depletion	(441.3)	(540.8)
	726.3	850.1
Net Property, Plant and Equipment	3,506.5	3,674.8
Investments and Other Assets		
Gas inventory–noncurrent	375.8	375.8
Gas supply prepayments (Note 8)	85.8	423.3
Accounts receivable–noncurrent	28.6	–
Unconsolidated affiliates	52.4	51.6
Investment in subsidiary to be sold	92.5	–
Other	97.7	64.4
Total Investments and Other Assets	732.8	915.1
Current Assets		
Cash and temporary cash investments	408.3	7.9
Accounts receivable		
Customers (less allowance for doubtful accounts of $9.7 and $8.3, respectively)	535.3	500.3
Other	326.0	300.2
Gas inventory	372.4	435.5
Other inventories–at average cost	50.7	51.1
Prepayments	130.5	138.4
Other	1.6	28.2
Total Current Assets	1,824.8	1,461.6
Deferred Charges	268.1	144.8
Total Assets	$6,332.2	$6,196.3

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financal Statements.

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

Capitalization and Liabilities as of December 31 (in millions)	1991	1990
Common Stock Equity		
Common stock, par value $10 per share–outstanding 50,559,225 and 50,471,568 shares, respectively	$ 505.6	$ 504.7
Additional paid in capital	601.8	599.2
Retained earnings	(13.5)	738.3
Accumulated foreign currency translation adjustment	–	5.1
Unearned employee compensation (Note 11)	(87.0)	(89.5)
Total Common Stock Equity	1,006.9	1,757.8
Long-Term Debt (Note 12)	6.1	1,428.7
Total Capitalization*	1,013.0	3,186.5
Current Liabilities		
Debtor-in-possession financing (Note 12)	136.0	–
Debt obligations	2.9	770.7
Accounts and drafts payable	188.4	321.5
Accrued taxes	135.8	138.5
Accrued interest	16.7	61.7
Estimated rate refunds	67.9	180.8
Estimated supplier obligations	4.3	165.2
Deferred income taxes	21.5	48.7
Other	253.3	245.7
Total Current Liabilities	826.8	1,932.8
Liabilities Subject to Chapter 11 Proceedings (Note 2)	3,903.5	–
Other Liabilities and Deferred Credits		
Income taxes–noncurrent	217.4	964.5
Investment tax credits	42.2	45.2
Postretirement benefits other than pensions	230.2	–
Other	99.1	67.3
Total Other Liabilities and Deferred Credits	588.9	1,077.0
Commitments and Contingencies (Notes 2, 3, 6, 11, 12 and 13)		
Total Capitalization and Liabilities	$6,332.2	$6,196.3

*The Corporation has 10,000,000 shares of preferred stock, $50 par value, authorized but unissued.

Year Ended December 31 (in millions)	1991*	1990	1989
Operations			
Cash received from customers	$2,579.6	$2,829.8	$2,891.4
Other operating cash receipts	173.6	161.2	155.3
Cash paid to suppliers	(1,012.1)	(1,319.2)	(1,351.9)
Interest paid	(101.8)	(172.5)	(176.1)
Income taxes paid	(79.8)	(58.4)	(24.7)
Other tax payments	(164.5)	(197.9)	(175.2)
Cash paid to employees and other employee benefits	(464.2)	(445.2)	(433.8)
Other operating cash payments	(396.0)	(377.7)	(484.5)
Reorganization items–net	(3.2)	–	–
Net Cash From Operations	531.6	420.1	400.5
Investment Activities			
Capital expenditures**	(376.5)	(600.1)	(435.0)
Replacement of base gas inventory	–	(156.9)	–
Gas supply prepayments–net	(36.3)	(17.5)	10.2
Other investments–net	89.3	8.1	20.8
Net Investment Activities	(323.5)	(766.4)	(404.0)
Financing Activities			
Dividends paid	(55.7)	(103.9)	(90.9)
Issuance of revolving credit agreement	20.0	145.0	–
Retirement of long-term debt and preferred stock	(20.3)	(71.7)	(94.3)
Issuance of common stock	3.4	225.3	8.5
Issuance of long-term debt	–	204.5	245.5
Increase (decrease) in short-term debt and other financing activities	108.9	(59.0)	(56.9)
Net debtor-in-possession financing	136.0	–	–
Net Financing Activities	192.3	340.2	11.9
Increase (decrease) in cash and temporary cash investments	400.4	(6.1)	8.4
Cash and temporary cash investments at beginning of year	7.9	14.0	5.6
Cash and temporary cash investments at end of year***	$ 408.3	$ 7.9	$ 14.0
Net Income Reconciliation:			
Net income (loss)	$ (694.4)	$ 104.7	$ 145.8
Items not requiring (providing) cash:			
Depreciation and depletion	285.0	248.8	234.2
Deferred income taxes	(525.7)	(14.6)	94.2
Amortization of prepayments for producer contract modifications	54.5	72.3	72.0
Provision for gas supply charges	1,319.2	–	–
Change in accounting for income taxes	(170.0)	–	–
Change in accounting for postretirement benefits	69.6	–	–
Gain on sale of interest in subsidiaries	(21.4)	–	–
Other-net	39.6	31.3	67.8
Net change in working capital (Note 16)	175.2	(22.4)	(213.5)
Net Cash From Operations	$ 531.6	$ 420.1	$ 400.5

*Reference is made to Notes 1A and 2 of Notes to Consolidated Financial Statements.

**Includes amounts transferred from interest paid, cash paid to employees and other employee benefits and other operating cash payments.

***The Corporation considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents.

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

Statements of Consolidated Common Stock Equity

(In millions except for share amounts)	Common Stock* Shares Outstanding (000)	Common Stock* Par Value	Additional Paid In Capital	Retained Earnings	Unearned Employee Compensation	Accumulated Foreign Currency Translation Adjustment
Balance at December 31, 1988	45,423	$454.2	$415.9	$681.6	$ 0.0	$0.9
Net Income				145.8		
Common stock dividends ($2.00 per share)				(91.0)		
Common stock issued for Long-Term Incentive Plan	220	2.2	6.3			
Other						4.4
Balance at December 31, 1989	45,643	456.4	422.2	736.4	0.0	5.3
Net Income				104.7		
Common stock dividends ($2.20 per share)				(103.9)		
Common stock issued:						
LESOP	2,000	20.0	71.8		(91.7)	
Dividend Reinvestment Plan	64	0.6	2.4			
Long-Term Incentive Plan	165	1.7	5.3			
Public Offering	2,600	26.0	97.5			
Other				1.1	2.2	(0.2)
Balance at December 31, 1990	50,472	504.7	599.2	738.3	(89.5)	5.1
Net Income (loss)				(694.4)		
Common stock dividends ($1.16 per share) (Note 2)				(58.6)		
Common stock issued:						
Dividend Reinvestment Plan	75	0.8	2.4			
Long-Term Incentive Plan	12	0.1	0.4			
Other			(0.2)	1.2	2.5	(5.1)**
Balance at December 31, 1991	50,559	$505.6	$601.8	$(13.5)	$(87.0)	$0.0

*100 million shares authorized at December 31, 1991, 1990 and 1989–$10 par value.

**The Corporation's only foreign subsidiary, Columbia Gas Development of Canada Ltd., was sold during 1991.

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

Notes To Consolidated Financial Statements

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, except for the Corporation's investment in Columbia LNG Corporation (Columbia LNG) which has been reflected in the accompanying consolidated balance sheet as Investment in Subsidiary to be Sold.

On July 31, 1991, the Corporation and its wholly owned subsidiary, Columbia Gas Transmission Corporation (Columbia Transmission), filed separate petitions seeking protection under Chapter 11 of the Federal Bankruptcy Code. The debtor companies are operating their businesses as debtors-in-possession (DIP) under the jurisdiction of the United States Bankruptcy Court for the District of Delaware (Bankruptcy Court). As such, the debtor companies cannot engage in transactions considered to be outside the ordinary course of business without obtaining Bankruptcy Court approval. (See Note 2.)

The accompanying financial statements reflect all adjustments necessary in the opinion of management to present fairly the results of operations in accordance with generally accepted accounting principles applicable to a going concern, which contemplates the realization of assets and payment of liabilities in the ordinary course of business. As a result of the reorganization proceedings under Chapter 11, the debtor companies may take, or be required to take, actions which may cause assets to be realized, or liabilities to be liquidated, for amounts other than those reflected in the financial statements. The appropriateness of continuing to present financial statements on a going concern basis is dependent upon, among other things, the terms of the ultimate plan of reorganization, future profitable operations, the ability to comply with DIP and other financing agreements and the ability to generate sufficient cash from operations and financing sources to meet obligations.

Certain reclassifications have been made to the 1990 and 1989 financial statements to conform to the 1991 presentation.

B. Basis of Accounting for Rate-Regulated Subsidiaries. Statement of Financial Accounting Standards (SFAS) No. 71 "Accounting for the Effects of Certain Types of Regulation" 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, it was determined that the Corporation's interstate transmission companies no longer met these criteria, and consequently, these companies discontinued the application of the provisions of SFAS No. 71. The Corporation's gas distribution subsidiaries 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). Property, plant 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 (%)	1991*	1990	1989
AFUDC	8.0	9.4	9.2
IDC	9.6	9.5	9.7

*The portion of interest capitalized by subsidiaries during the period for which the Corporation is in bankruptcy is expensed at the Corporation level. The 1991 rates represent those in effect prior to the Chapter 11 filings.

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 annual depreciation on a composite straight-line basis. The annual depreciation rates were as follows:

Year Ended December 31 (%)	1991	1990	1989
Transmission property	2.6	2.6	2.9
Distribution property	3.6	3.7	3.3

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 countrywide 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 for domestic subsidiaries is based upon the ratio of current year revenues to expected total revenues, utilizing current prices, over the life of production. Depletion for the Canadian subsidiary, which was sold as of December 31, 1991, was based upon the ratio of volumes to total reserves.

E. Futures Contracts. Futures transactions are used from time to time to hedge crude oil production in order to minimize the risk of market fluctuations. Under internal guidelines, positions can be taken for up to twelve months in the future, and for up to 80% of the expected uncommitted monthly Southwest production. Gains or losses on the futures transactions are recognized when the hedged production is sold.

F. Gas Inventory. Current inventory is carried at cost on a last-in, first-out (LIFO) basis. The estimated replacement cost of gas inventory (including noncurrent) in excess of carrying amounts at December 31, 1991 was approximately $366 million for Columbia Transmission and $59 million for the distribution companies. Liquidation of LIFO layers related to gas delivered by the distribution companies does not affect income since the effect is passed through to customers as part of purchased gas adjustment tariffs. Columbia Transmission also reflects billing adjustments for LIFO liquidation, except for capitalized costs associated with certain producer payments not eligible for recovery in gas adjustment tariffs. In 1989, as part of a settlement agreement, Columbia Transmission sold 120 million dekatherms of storage inventory gas to its customers. Under the terms of the agreement, the liquidation of LIFO layers related to the sale resulted in a gain, as discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations.

G. Income Taxes and Investment Tax Credits. The Corporation and its subsidiaries account for income taxes under the provisions of SFAS No. 96, "Accounting for Income Taxes." (See Note 4B.)

The Corporation and its subsidiaries record income taxes to recognize full interperiod tax allocations. Under the liability method, deferred income taxes are recognized for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities.

Previously recorded investment tax credits of the gas distribution subsidiaries were deferred and are being amortized over the life of the related properties to conform with regulatory policy.

H. Estimated Rate Refunds. Certain rate-regulated subsidiaries 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 the proceedings. No provisions are made when in the opinion of management, the facts and circumstances preclude a reasonable estimate of the outcome.

I. 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.

J. 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 revenues to reflect future billing adjustments to recover or refund the difference between current gas costs and amounts billed through its purchased gas adjustment tariff.

2. Reorganization Proceedings Under Chapter 11 of the Bankruptcy Code

Under the Bankruptcy Code, actions by creditors to collect prepetition indebtedness are stayed and other contractual obligations may not be enforced against either the Corporation or Columbia Transmission. As debtors-in-possession, both the Corporation and Columbia Transmission have the right, subject to Bankruptcy Court approval and certain other limitations, to assume or reject executory contracts and unexpired leases. In this context, "rejection" means that the debtor companies are relieved from their obligations to perform further under the contract or lease but are subject to a claim for damages for the breach thereof. Any damages resulting from rejection are treated as general unsecured claims in the reorganization. The parties affected by these rejections may file claims with the Bankruptcy Court in accordance with bankruptcy procedures. Prepetition claims which were contingent or unliquidated at the commencement of the Chapter 11 proceeding are generally allowable against the debtor-in-possession in amounts fixed by the Bankruptcy Court. Substantially all liabilities as of the petition date are subject to resolution under a plan of reorganization to be approved by the Bankruptcy Court after submission to any required vote by affected parties. The Corporation's reorganization plan also requires approval by the Securities and Exchange Commission (SEC). The accompanying consolidated balance sheet includes approximately $3.9 billion of liabilities subject to the Chapter 11 proceedings of the Corporation and Columbia Transmission as follows:

($ in millions)	
The Columbia Gas System, Inc. (primarily debt obligations)	2,385.4
Columbia Transmission (excluding 1,837.2 payable to affiliates)	1,518.1
	3,903.5

Prepetition obligations of the Corporation primarily represent debentures, bank loans and commercial paper outstanding on the filing date together with accrued interest to that date (See Note 12 for additional information). The Corporation's plan of reorganization (which will be influenced by the plan of Columbia Transmission) will address the resolution of these liabilities. Both the Corporation and Columbia Transmission have received approval from the Bankruptcy Court to extend the time period within which they have the exclusive right to file plans of reorganization to March 30, 1992.

Columbia Transmission's prepetition obligations include secured and unsecured debt payable to the Corporation, estimated supplier obligations, estimated rate refunds, accrued taxes and other trade payables and liabilities. Substantial uncertainty exists regarding the measurement of certain of these liabilities and ongoing Bankruptcy Court proceedings could result in the reclassification of certain liabilities currently subject to Chapter 11 proceedings.

The Bankruptcy Court established March 18, 1992, as the deadline (the bar date) for creditors to file claims against the Corporation and Columbia Transmission other than claims by Federal and state environmental agencies. On January 7, 1992, notices were mailed to the creditors of the Corporation and Columbia Transmission advising them that claims against either company must be submitted by the "bar date". Creditors who are required to file claims but fail to meet the deadline are forever barred from voting upon or receiving distributions under any plan of reorganization.

A substantial amount of Columbia Transmission's liabilities subject to Chapter 11 proceedings relate to amounts owed to the Corporation. Columbia Transmission's borrowings have been funded by the Corporation on a secured basis since June 1985. Under an Inventory Financing Agreement, the Corporation agreed to lend Columbia Transmission up to $410 million, which was the amount outstanding on the petition date. The loan is secured by Columbia Transmission's gas in underground storage. In addition, substantially all of Columbia Transmission's other assets have been pledged to the Corporation as security for First Mortgage Bonds issued by Columbia Transmission to the Corporation. On the petition date, the principal amount of the First Mortgage Bonds outstanding was $930.4 million. In addition to these secured claims, the Corporation has an unsecured claim against Columbia Transmission in the amount of $343.9 million in the form of installment notes issued prior to 1985. Creditors of Columbia Transmission have indicated that they intend to challenge the status of the $1.7 billion of debt securities held by the Corporation, as well as intercompany transfers related to interest and dividend payments of approximately $500 million to the Corporation.

Creditors of Columbia Transmission have also indicated a prepetition property transfer from Columbia Transmission to Columbia Natural Resources will be challenged on the basis of fraudulent conveyance under the Bankruptcy Code. The exploration and production properties of Columbia Natural Resources have a reserve value of $348 million (utilizing SEC standardized measurement procedures) as of December 31, 1991, a significant portion of which is attributable to the transfer from Columbia Transmission.

Management believes that the Corporation's position on these transactions will be upheld by the Bankruptcy Court; however, the ultimate outcome of these issues is uncertain at this stage of the proceedings.

The issues discussed in the preceding paragraphs have significant impact on the value of the estate of Columbia Transmission and therefore on amounts available for unsecured creditors. Resolution of these issues (and resolution of the producer contract damage issues discussed in Note 6) will determine in large part the cost of ending Columbia Transmission's bankruptcy proceeding. Because of the uncertainty regarding this cost, the Corporation is evaluating the economics of ultimate retention of Columbia Transmission and available financing alternatives, including capital markets, bank financing and asset disposition.

There are other significant issues which will arise as a result of the bankruptcies of the debtor companies, including:

a. the interrelationship of the Federal Energy Regulatory Commission (FERC) and Bankruptcy Court jurisdiction and authority in the case of Columbia Transmission;

b. the impact of the Corporation's bankruptcy on pending subsidiary transactions involving financial credit support from the Corporation; and

c. the measure of damages arising from Columbia Transmission's rejection of numerous burdensome contractual obligations, and the status of prepetition intercompany receivables and payables.

Resolution of these and other complex issues are expected to result in substantial legal and other professional fees and expenses. During 1991, the Corporation and Columbia Transmission have incurred the following expenses associated with professional fees and related expenses partially offset by interest income earned on cash accumulated from the suspension of payments related to prepetition liabilities (See Note 12):

($ in millions)	
Professional fees and related expenses	18.8
Interest income on accumulated cash	(4.5)
Other reorganization items	0.1
Net Reorganization Items	14.4

The Corporation's Board of Directors suspended the payment of dividends on the Corporation's common stock on June 19, 1991. In addition, the Corporation has discontinued payments related to debt service on obligations existing at the time of the Chapter 11 filing. Columbia Transmission has suspended dividend and interest payments and debt repayments to the Corporation. The Corporation and Columbia Transmission have also suspended the payment of most other prepetition obligations. Management cannot predict at this time when or whether any financial restructuring plans will be approved or what provisions such plans, if any, would contain as related to the resumption of dividends, debt service and other payments. Provisions of the plan of reorganization for Columbia Transmission cannot yet be determined, and since the ultimate plan of reorganization of the Corporation depends in part on the value ascribed to Columbia Transmission and the ultimate value of the securities of Columbia Transmission owned by the Corporation, provisions of the Corporation's plan also cannot yet be determined. Provisions of such plans, or the inability by the Corporation and/or Columbia Transmission to obtain approval of a plan, could have a material adverse effect on the Corporation and its subsidiaries and on the rights of shareholders and holders of debt and other obligations.

Due to the Chapter 11 filing, the Internal Revenue Service has advised the Corporation that it has accelerated its examination of all open years, and has indicated disallowances will be substantial in amount. Management believes appropriate reserves have been established.

Condensed financial information of the Debtor Companies as of and for the year ended December 31, 1991, is as follows:

($ in millions)	Corporation	Columbia Transmission
Current assets	1,260.7	1,188.8*
Current liabilities	(174.6)	(286.7)
Working capital	1,086.1	902.1
Noncurrent assets	2,314.5	2,085.2
Estimated liabilities subject to Chapter 11 proceedings	(2,390.3)	(3,355.3)
Noncurrent liabilities	(3.4)	(113.4)
Net Equity	1,006.9	(481.4)
Operating revenues	–	1,003.5
Operating expenses	9.5	2,213.0
Operating loss	(9.5)	(1,209.5)
Other deductions	(644.6)	(133.8)
Income taxes	36.4	(463.3)
Cumulative effect of changes in accounting	(3.9)	50.5
Net Loss	(694.4)	(829.5)

*Includes $386.5 million of cash and temporary cash investments.

Information related to additional aspects of the Corporation's and Columbia Transmission's Chapter 11 proceeding is included in other notes.

3. Regulatory Matters

Columbia Transmission has petitioned the Bankruptcy Court to permit the flow-through to its customers of, among other items, take-or-pay refunds under FERC Order No. 528 expected to be received from pipeline suppliers. On February 13, 1992, the Bankruptcy Court granted, in part, Columbia Transmission's request. The Bankruptcy Court held that approximately $21 million of prepetition pipeline refunds received by Columbia Transmission were, in fact, held in trust for Columbia Transmission' s customers and could be refunded to them. However, the funds available to satisfy the liability were limited to Columbia Transmission's cash balance at the filing date. The Bankruptcy Court also authorized Columbia Transmission to flow through to its customers more than $100 million of postpetition refunds anticipated under Order No. 528 since Columbia Transmission's postpetition cash balances supported such amounts held in trust. Finally, the Bankruptcy Court denied Columbia Transmission's motion for authorization to pay charges in the amount of $16 million previously billed to it by upstream pipelines for prepetition services rendered. It was ruled that these funds were not held in trust since they had not been collected by Columbia Transmission from its customers and as such the liabilities are part of the estate.

In 1989, FERC authorized Kentucky-West Virginia Gas Company (Kentucky-West Virginia) to retroactively collect higher prices from Columbia Transmission for certain gas it produced and sold between 1979 and 1983. The order permits Kentucky-West Virginia to directly bill its customers, including Columbia Transmission, for the price increase based on their levels of purchases during this period.

Kentucky-West Virginia filed to recover approximately $27 million, including interest, from Columbia Transmission effective March 15, 1989, but reserved the right to seek recovery of additional amounts once certain conditions are met. Based on a filing previously rejected by the FERC, the additional exposure was estimated to be $30 million, including interest.

Columbia Transmission and Kentucky-West Virginia reached a settlement in principle in 1990 which provided, among other things, for various payments by Columbia Transmission over a period of years. The settlement was contingent upon the FERC affirming that Columbia Transmission would have the right to flow through the payments to its customers. By order issued March 7, 1991, the FERC rejected the settlement, ruling that Columbia Transmission's recovery of these payments is barred by its 1985 Customer Settlement. Since Columbia Transmission's request for rehearing of this order has been denied by the FERC, Columbia Transmission plans to file an appeal with the U.S. Court of Appeals for the D.C. Circuit. Settlement negotiations between Columbia Transmission and Kentucky-West Virginia are continuing. In the opinion of management, the ultimate resolution of this issue will not have a material impact on the consolidated financial statements.

4. Accounting Changes

A. In the fourth quarter of 1991, the Corporation adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," retroactive to January 1, 1991. This method of accounting for postretirement benefits accrues the actuarially determined costs ratably to the date an employee becomes eligible for such benefits. The Corporation's subsidiaries have previously expensed these costs as cash payments were made. In accordance with the provisions of SFAS No. 106, the subsidiaries have elected to record the full amount of their estimated accumulated postretirement benefits obligation other than pensions of $223.8 million. These obligations represent the actuarial present value, at 8%, of the postretirement benefits to be paid to current employees and retirees based on services rendered. The first three quarters of 1991 have been restated to reflect its provisions.

   Management believes that the cost of providing such postretirement benefits, including the transition obligation , will ultimately be recoverable in the rates charged by its regulated subsidiaries. Accordingly, the cost-of-service rate-regulated subsidiaries, which follow the accounting and reporting requirements of SFAS No. 71, have deferred their portion of the transition obligation as a regulatory asset pending recovery through future rates. Of the $223.8 million transition obligation, $112.7 million has been deferred.

B. In the fourth quarter of 1991, the Corporation adopted SFAS No. 96, "Accounting for Income Taxes," retroactive to January 1, 1991.

   This Statement changes the criteria for measuring the provision for income taxes and recognizing deferred tax assets and liabilities. Under the provisions of SFAS No. 96, current and deferred tax assets and liabilities are determined based on tax rates and laws enacted as of the balance sheet date, rather than the historical tax rates.

   The cumulative effect to January 1, 1991, of this change in accounting for income taxes increased net income in 1991 by $170.0 million. This amount is net of a $16.6 million Canadian ceiling test writedown resulting from this change. Prior years' consolidated financial statements have not been restated to apply the provisions of SFAS No. 96. However, the first three quarters of 1991 have been restated to reflect its provisions.

   A portion of the Corporation's consolidated deferred income tax balance relates to its regulated subsidiaries. The regulated subsidiaries generally will not recognize the effect of this change as income, since they will reduce rates to return the "excess" deferred income taxes to ratepayers over the remaining life of the properties that gave rise to the taxes. In general, the new standard permits income recognition for the excess deferred income taxes attributable to nonregulated operations.

   In February 1992, the Financial Accounting Standards Board issued SFAS No. 109, "Accounting for Income Taxes." This statement supersedes SFAS No. 96 to change the criteria for recognition and measurement of deferred tax assets and reduce complexity. This statement will have no significant impact on the Corporation's financial statements.

5. Income Taxes

The components of income taxes are as follows:

Year Ended December 31 ($ in millions)	1991	1990	1989
Income Taxes			
Currently payable			
Federal	106.7	68.1	(28.0)
State	8.0	4.4	3.8
Investment credits	–	–	(0.7)
Total Currently Payable	114.7	72.5	(24.9)
Deferred			
Federal	(510.2)	(15.5)	91.7
State	(13.7)	3.6	4.2
Total Deferred	(523.9)	(11.9)	95.9
Deferred Investment Credits–Net	(1.8)	(2.7)	(1.7)
Income taxes included in income before cumulative effect of changes in accounting	(411.0)	57.9	69.3
Deferred tax related to cumulative effect of changes in accounting	(236.6)	–	–
Total Income Taxes	(647.6)	57.9	69.3

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:

Year Ended December 31 ($ in millions)	1991		1990		1989	
Book income (loss) before incomes taxes (excluding before tax loss associated with cumulative change in accounting principle)*	(1,205.8)		162.6		215.1	
Tax expense (benefit) at statutory Federal income tax rate	(410.0)	(34.0)%	55.3	34.0%	73.1	34.0%
Increases (reductions) in taxes resulting from:						
State income taxes, net of Federal income tax benefit	(4.7)	(0.4)	5.2	3.3	5.3	2.5
Investment credits not deferred and amortization of credits deferred in prior years	(1.8)	(0.1)	(2.7)	(1.7)	(2.4)	(1.1)
Sale of assets	5.4	0.4	–	–	–	–
Depreciation expense for accounting purposes over amounts claimed for income tax purposes	–	–	4.1	2.5	2.7	1.2
Effect of change in tax rates on certain deferred taxes previously provided	–	–	(5.6)	(3.4)	(2.8)	(1.3)
Loss carryforward utilized	–	–	–	–	(1.9)	(0.9)
Other	0.1	–	1.6	0.9	(4.7)	(2.2)
Income Taxes Before Cumulative Effect of Changes in Accounting	(411.0)	(34.1)%	57.9	35.6%	69.3	32.2%

*Includes losses from foreign operations of $41.5 million, $21.8 million and $2.9 million, respectively.

Effective January 1, 1991, the Corporation adopted the provisions of SFAS No. 96 "Accounting for Income Taxes." Deferred tax liabilities/(assets) are reflected in the Consolidated Balance Sheets as follows:

At December 31 ($ in millions)	1991	1990
Net current liabilities (assets)		
Federal	22.7	42.9
State	(1.2)	5.8
Total	21.5	48.7
Net noncurrent liabilities		
Federal	158.8	924.1
State	58.6	40.4
Total	217.4	964.5
Total Deferred Income Taxes	238.9	1,013.2

Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The source of these differences and tax effect of each is as follows:

At December 31 ($ in millions)	1991	1990
Property basis differences	621.0	682.9
Provision for gas supply matters	(336.3)	–
Postretirement benefits	(44.0)	–
Acquisition, exploration and development costs	33.3	93.8
Gas purchase costs	30.9	245.9
Partnership deferrals	29.2	27.8
Accrued interest	28.5	–
Capitalized inventory overheads	(24.4)	(18.9)
Estimated rate refunds	(40.4)	(14.3)
Unbilled utility revenue	(12.6)	(9.0)
Alternative minimum tax	(12.2)	(8.8)
Other	(34.1)	13.8
Total Deferred Income Taxes	238.9	1,013.2

6. Provisions for Gas Supply Charges

As a result of extensive studies, Columbia Transmission has recorded charges of $870.7 million ($1.3 billion pre-tax) to reflect the estimated effects of its high-cost producer contracts (discounted at 13%), other related gas supply management costs and the impact of contract rejection on gas costs previously capitalized.

The studies supporting the charges were based on projections of future spot-market prices and contract deliverability as well as contract pricing, discount rate and measurement date assumptions which bases are not necessarily the same as those applicable to the measurement of contract rejection damages. Under alternative assumptions considered by Columbia Transmission, additional pre-tax losses exceeding $400 million could be incurred. Additionally, estimated supplier obligations have previously been recorded associated with pricing disputes and take-or-pay obligations including matters that were subject to litigation and regulatory jurisdiction. The ultimate resolution of these liabilities will be decided by the Bankruptcy Court and could result in material differences from recorded amounts.

7. Sale of Subsidiaries

A. The sale of Columbia Gas of New York, Inc. to New York State Electric & Gas Corporation was completed on April 5, 1991. The total price was $57.5 million including $39.2 million for the 328,000 outstanding shares of common stock and $18.3 million for the outstanding debt. The sale was recorded in the second quarter of 1991 and provided an increase to net income of $9.2 million.

B. The Corporation completed the sale of Columbia Gas Development of Canada Ltd. (Columbia Canada), its wholly owned Canadian oil and gas exploration and production subsidiary, to Anderson Exploration, Ltd. effective as of December 31, 1991. Closing was completed on January 15, 1992. The agreement was approved by the Bankruptcy Court on December 31, 1991.

The purchase price for the sale of Columbia Canada was $94.8 million, subject to an adjustment of approximately $1 million for reductions in Columbia Canada's working capital subsequent to June 30, 1991. Of the $94.8 million purchase price, $27.7 million was placed in escrow as security for certain post-closing obligations of the Corporation including indemnification for potential losses arising from litigation involving Columbia Canada. The Corporation expects to receive all or substantially all of the escrow account when the litigation is concluded.

8. Gas Supply Prepayments

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

At December 31 ($ in millions)	1991	1990
Prepayments for producer contract modifications	81.9	356.6
Take-or-pay prepayments	3.9	66.7
Total	85.8	423.3

A. *Prepayments for Producer Contract Modifications.* Payments were made at various times to certain producers in return for contract modifications related to future purchases of gas. These payments are amortized on a volumetric basis over a ten-year period the majority of which will be amortized by June 30, 1995, the primary period of benefit.

B. *Take-or-Pay 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, in some cases, cash payments.

9. Accounting for Pension Costs and Other Postretirement Benefits

The Corporation has a trusteed, noncontributory pension plan which, with minor exceptions, cover all regular employees, 21 years of age and over. The plan provides defined benefits based on the largest three-year average annual compensation in the final five years of service, and years of accredited service. It is the Corporation's funding policy to contribute annually to the plan based on a percentage of payroll, estimated at the beginning of the year and subject to the statutory minimum and maximum limits.

The following table provides 1991-1989 pension cost components for the plan, along with additional relevant data:

Pension Costs ($ in millions)	1991	1990	1989
Service cost	21.7	20.3	17.2
Interest cost	63.2	59.2	56.7
Actual return on assets	(171.7)	10.6	(132.3)
Net amortization and deferral	115.0	(74.6)	77.7
Net pension expense	28.2	15.5	19.3
Annual contribution	24.0	17.3	23.1
Assumed asset earnings rate	9%	9%	9%

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

Plan Assets and Obligations at December 31 ($ in millions)	1991	1990
Plan assets at fair value	845.6	723.4
Actuarial present value of benefit obligations:		
Vested benefits	649.5	611.5
Nonvested benefits	45.0	41.3
Accumulated benefit obligation	694.5	652.8
Effect of projected future salary increases	186.1	152.2
Total projected benefit obligation	880.6	805.0
Plan assets less than projected benefit obligation	(35.0)	(81.6)
Unrecognized net (gain) loss	(40.6)	2.2
Unrecognized prior service cost	74.4	79.3
Unrecognized transition obligation	12.8	13.5
Prepaid pension cost	11.6	13.4
Discount rate assumption	7.5%	8.0%
Average compensation growth rate	6.0%	6.0%

During 1990, the Corporation approved an increase in pension benefits for retired participants which became effective January 1, 1991. The cost of the amendment was approximately $33.1 million and was reflected in the 1990 unrecognized prior service cost.

In addition to providing pension benefits, the Corporation's subsidiaries provide other postretirement benefits, including medical care and life insurance, which cover substantially all active employees upon their retirement. The following table provides the total postretirement benefit cost components recognized during 1991, along with additional relevant data:

Net Periodic Costs ($ in millions)	1991
Service cost (benefits earned during period)	12.2
Interest cost on projected benefit obligation	21.4
Actual return on assets	(2.5)
Other net	(0.7)
Net periodic cost	30.4
Transition obligation	223.8
Annual contribution	–
Assumed asset earnings rate	9.0%

Plan Assets and Obligations at December 31, 1991 ($ in millions)	
Accumulated benefit obligation:	
Retirees	164.5
Fully eligible active plan participants	66.9
Other actives	65.0
Total	296.4
Plan assets at fair value	(37.6)
Unrecognized actuarial loss	(15.3)
Accrued postretirement benefit cost	243.5
Discount rate assumption	7.5%

The health care cost trend rate assumption significantly affects the amounts reported. For example, a 1% increase in this rate would increase the accumulated postretirement benefit obligation by $21.7 million at December 31, 1991, and increase the net periodic cost by $3.3 million for the year. The postretirement benefit cost components for 1991 were calculated assuming health care cost trend rates ranging up to 18% and decreasing to 6.5% after approximately 25 years.

The medical plans of the Corporation's subsidiaries are currently funded on a pay-as-you-go basis and they have funded 80% of the accrued benefits related to retiree life insurance benefits. The life insurance funds are being invested in a voluntary employee beneficiary association and employee contributions are not required.

Prior to 1991, postretirement benefits were expensed as paid. The cash payments were $10.6 million and $10.2 million for 1991 and 1990, respectively.

10. Long-Term Incentive Plan

The Corporation has a Long-Term Incentive Plan (Plan) which provides for the granting of nonqualified stock options, stock appreciation rights and contingent stock awards as determined by the compensation committee of the Board of Directors. That committee also has the right to modify any outstanding award. A total of 1,500,000 shares of the Corporation's authorized common stock was initially reserved for issuance under the Plan's provisions. There were 297,775 shares remaining available for awards at December 31, 1991.

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

Transactions for the three years ended December 31, 1991, are as follows:

	Options		
	Without Stock Appreciation Rights	With Stock Appreciation Rights	Option Price Range
Outstanding 12/31/88	615,685	93,930	\$34.30-\$42.99
1989			
Granted	240,990	32,000	\$44.49-\$49.74
Exercised	(212,060)	(22,250)	\$34.30-\$45.81
Cancelled	(28,790)	(4,830)	\$34.30-\$42.99
Reinstated	5,200	–	\$43.68-\$45.81
Outstanding 12/31/89	621,025	98,850	\$34.30-\$49.74
1990			
Granted	167,500	52,500	\$46.68
Exercised	(149,595)	(5,840)	\$34.30-\$42.99
Cancelled	(22,195)	–	\$34.30-\$49.74
Converted	(19,580)	19,580	\$34.30-\$44.49
Outstanding 12/31/90	597,155	165,090	\$34.30-\$46.68
1991			
Granted	–	–	–
Exercised	(12,065)	(1,440)	\$34.30-\$42.99
Cancelled	(21,330)	–	\$34.30-\$46.68
Converted	–	–	–
Outstanding 12/31/91	563,760	163,650	\$34.30-\$46.68
Exercisable 12/31/91	198,220	68,650	\$34.30-\$42.99

In addition to the options, a contingent stock award of 4,110 shares was granted to a key executive in 1991. Shares of common stock that have been issued for vested awards are as follows: 1991–none; 1990–14,400 shares; and 1989–3,000 shares. At December 31, 1991, 4,110 awards were outstanding.

11. Defined Contribution (Thrift) Plan

Eligible employees may participate in the Thrift Plan by contributing up to 16 percent of monthly basic earnings to any one or more of four separate investment funds. The Corporation's participating subsidiaries make matching contributions of 50% to 100% of deposits by each of its employees up to 6% of basic earnings based upon the months of participation in the plan by the employee. However, a participating subsidiary does not match employee deposits over 6% of basic earnings. Participants age 55 and older may invest their employer contributions in any one or more of the four separate funds. All employer matching contributions for participants under age 55 are invested by the Trustee in the fund holding common stock of the Corporation. Employees are eligible for participation in the Thrift Plan after completing one year of service.

In April 1990, the Corporation established a Leveraged Employee Stock Ownership Plan (LESOP). The LESOP was designed to pre-fund a portion of the matching obligation under the terms of the Thrift Plan and to utilize tax advantages afforded by the Internal Revenue Code.

The LESOP Trust issued \$91.75 million of debentures at an interest rate of 9.875% for 11¾ years. These debentures are guaranteed by the Corporation on a subordinated basis. The proceeds from the debt were used to purchase two million newly issued shares of the Corporation's common stock at a cost of \$45⅞ per share.

The Corporation reflected the guaranteed LESOP borrowing as long-term debt and recorded a corresponding entry to a contra-equity account. As the principal amount of the loan is repaid, the "Subordinated Guarantee of Leveraged Employee Stock Ownership Plan" debt will be reduced accordingly. As of December 31, 1991, the debt is reflected as a prepetition obligation of the Corporation subject to the outcome of the Chapter 11 filing. The Corporation's annual contributions to the LESOP, plus the tax deductible cash dividends paid on the Corporation's common stock held by the Trust, were to be used to repay the debt principal and interest. The two million shares held by the Trust were to be allocated to Thrift Plan participants' accounts periodically, based on the proportion of the Trust's debt service payments for the year to the total debt service payments for the term of the Trust. A total of 139,047 shares of common stock was allocated in 1991.

The Board of Directors of the Corporation suspended payment of the dividend in June 1991. In October 1991, the Board of Directors of the Corporation authorized the termination of the LESOP subject to the approval of the Bankruptcy Court. Following discussions with the Corporation's Creditors' Committee, the filing of a motion with the Court for approval of the termination was deferred so that the Committees would have time to study the proposed termination. As of December 31, 1991, 1,420,355 shares were held in the LESOP suspense account. The Corporation and its subsidiaries ceased making contributions to the LESOP for debt service payments but continued to contribute the matching obligations of the Thrift Plan.

Upon termination, any shares of common stock of the Corporation remaining in the LESOP suspense account would be sold and proceeds paid to the holders of debentures issued under the LESOP. The unpaid balance due to the holders of debentures issued under the LESOP would become subject to the subordinated guarantee of the Corporation and would become a claim to be resolved as part of the reorganization plan. Termination of the plan, or interim debt service payments through sale of shares, could result in pre-tax charges of approximately $62 million, based on current stock prices.

Contributions to the Thrift Plan were $8.6 million, $10.0 million and $9.2 million in 1991, 1990 and 1989, respectively. Prior to 1990, contributions to the Thrift Plan were expensed as paid. Thrift Plan expense for 1991 and 1990 was $17.9 million and $13.1 million, respectively.

In 1991, the LESOP trust paid $11.3 million in debt service, including $2.5 million in principal and $8.8 million in interest. Of this amount, $3.4 million was provided by contributions by participating subsidiaries, $2.3 million was provided by dividends on shares held by the Trust, and the remaining $5.6 million was provided by the sale of 340,400 shares from the LESOP suspense account.

12. Debt Obligations

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

At December 31 ($ in millions)	1991	1990
The Columbia Gas System, Inc.		
Debentures:		
$6\frac{5}{8}\%$ Series due October 1992	–	7.4
$7\frac{1}{4}\%$ Series due May 1993	15.0	15.0
9% Series due August 1993	150.0	150.0
7% Series due October 1993	12.0	12.0
9% Series due October 1994	16.7	18.5
$8\frac{3}{4}\%$ Series due April 1995	14.8	16.2
$9\frac{1}{8}\%$ Series due October 1995	18.5	20.3
$10\frac{1}{8}\%$ Series due November 1995	9.2	13.9
$8\frac{3}{8}\%$ Series due March 1996	30.4	33.0
$9\frac{1}{8}\%$ Series due May 1996	13.9	18.6
$8\frac{1}{4}\%$ Series due September 1996	24.3	26.4
$7\frac{1}{2}\%$ Series due March 1997	22.0	23.7
$7\frac{1}{2}\%$ Series due June 1997	26.3	26.5
$7\frac{1}{2}\%$ Series due October 1997	26.4	28.4
$7\frac{1}{2}\%$ Series due May 1998	23.7	23.7
$10\frac{1}{4}\%$ Series due May 1999	20.0	32.5
$9\frac{7}{8}\%$ Series due June 1999	20.4	21.8
$10\frac{1}{4}\%$ Series due August 2011	100.0	100.0
$10\frac{1}{2}\%$ Series due June 2012	200.0	200.0
$10\frac{3}{20}\%$ Series due November 2013	100.0	100.0
$9\frac{1}{5}\%$ to $9\frac{1}{2}\%$ Series A Medium-Term Notes due 1998 through 2019	200.0	200.0
$8\frac{19}{20}\%$ to $9\frac{49}{50}\%$ Series B Medium-Term Notes due 1998 through 2020	200.0	200.0
$9\frac{11}{20}\%$ to $9\frac{37}{50}\%$ Series C Medium-Term Notes due 2000 through 2020	50.0	50.0
	1,293.6	1,337.9
Unamortized debt discount, less premium	(7.2)	(7.8)
	1,286.4	1,330.1
Subordinated Guarantee of Leveraged Employee Stock Ownership Plan debt	83.7	87.0
Subsidiary debt:		
Miscellaneous	2.5	6.8
Capitalized lease obligations	3.6	4.8
Less: Long-term debt of Debtor Companies reclassified to liabilities subject to Chapter 11 proceedings	1,370.1	–
Total long-term debt	6.1	1,428.7

The Corporation's filing for protection under the Bankruptcy Code constituted an event of default under substantially all of its debt agreements. Consequently, the Corporation's long-term debt became immediately due and payable in accordance with the terms of its Indenture (dated June 1, 1961). Because payment of debt which existed at the filing date is suspended by the Bankruptcy Code, substantially all of the Corporation's debt, including short-term debt, has been classified as liabilities subject to Chapter 11 proceedings. In addition, payment of interest on prepetition debt is suspended, and no interest expense on such debt will be recorded during the course of the bankruptcy proceedings.

Dependent upon the outcome of the matters discussed in Note 2 of Notes to Consolidated Financial Statements, the Corporation will restructure substantially all debt agreements, including the Indenture and bank credit facilities.

Following the Chapter 11 filing, the Corporation confirmed terms and received approval from the Bankruptcy Court and the SEC, under the Public Utility Holding Company Act of 1935, for debtor-in-possession financing (the DIP Facility).

The DIP Facility of $275 million includes the availability of letters of credit of up to $50 million, and will terminate upon the earlier of September 23, 1993, or the substantial consummation of a plan of reorganization following the entry of an order by the Bankruptcy Court in the Corporation's Chapter 11 case. The Corporation has the right to reduce or terminate the facility at any time. A syndicate of banks, led by Manufacturers Hanover Trust Company as agent, is providing the financing.

Two borrowing options are available to the Corporation under the DIP Facility. The Corporation may borrow at the agent's alternative reference rate plus 1% or the Eurodollar rate plus 2¼ % (for either 1, 2 or 3 months). In addition to a commitment fee of ½ of 1% per annum on the average daily unused amount of the facility, other fees have been paid to the lenders under the DIP Facility.

13. Other Commitments and Contingencies

A. Capital Expenditures. Capital expenditures for 1992 are estimated at $375 million. Of this amount, $93 million is for oil and gas operations, $154 million for transmission operations, $108 million for distribution operations and $20 million for other energy operations.

B. Producer Contract Matters. Following its Chapter 11 filing, Columbia Transmission identified 4,141 natural gas purchase contracts to reject which collectively made the company's gas sales rate noncompetitive and, on August 22, 1991, the Bankruptcy Court granted Columbia Transmission's petition to permanently reject these contracts. A second motion seeking to reject an additional 532 contracts was also approved by the Bankruptcy Court. Customer requirements will be met with gas purchased under remaining contracts, from additional winter-only contracts, from underground storage facilities, and by gas purchased from the spot market. Rejection of additional contracts could result in liabilities which could require future charges against earnings.

Among other unsettled claims against Columbia Transmission, now subject to Bankruptcy Court proceedings, are a number of suits, including one class action suit, which have been filed on behalf of certain Appalachian gas producers challenging the price paid by Columbia Transmission under their contracts.

In connection with producer contract renegotiations completed in 1985 and 1986, Columbia Transmission agreed to indemnify certain producers against potential liabilities that may be incurred by them as a result of such contract modifications. Since 1986, several lawsuits have been filed by royalty owners challenging certain provisions of the contract modifications. Certain of the suits name Columbia Transmission as a party but some do not. The outstanding lawsuits that name Columbia Transmission as a party have been stayed as to Columbia Transmission by Columbia Transmission's Chapter 11 filing. Claims under the terms of the indemnification provisions of the contracts will be subject to the bankruptcy proceedings and their ultimate resolution is subject to the outcome of those proceedings.

C. Future of Merchant Function and Partnership Projects. As a result of a continuing transition to a deregulated natural gas industry and the effects of Columbia Transmission's Chapter 11 bankruptcy filing, management is evaluating its long-term commitment to the merchant function. Should management ultimately terminate its merchant function, an additional writedown of $81.9 million (as of December 31, 1991) for Columbia Transmission's capitalized gas costs could be required.

Columbia Gulf is a general partner in the Trailblazer, Overthrust and Ozark partnerships, all of which are nonrecourse, project financed pipelines. Columbia Transmission is a shipper whose service contracts with the pipelines were assigned to the banks (or in the case of Ozark to the Indenture Trustee) as collateral for loans. Rejection by Columbia Transmission of these service agreements could have an adverse effect on Columbia Gulf's investments and add to the claims against Columbia Transmission. At December 31, 1991, these investments amounted to $26.6 million in Trailblazer, $11 million in Ozark, and $3.1 million in Overthrust.

D. Security Holder Litigation. After the announcement on June 19, 1991, regarding the Corporation's probable charge to second quarter earnings and the suspension of the dividend, seventeen complaints including purported class actions were filed against the Corporation and its directors and certain officers of the debtor companies in the U.S. District Court of Delaware. The actions, which generally allege violations of certain antifraud provisions of the Securities Act of 1933 and the Securities

Exchange Act of 1934, have been consolidated. In addition, three derivative actions were filed in the Court of Chancery in and for New Castle County (Delaware) by stockholders purporting to sue on behalf of all other stockholders similarly situated, in the name of the Corporation, alleging that directors breached their fiduciary duty. The seventeen securities suits and the three derivative suits against the Corporation have been stayed by the Bankruptcy Court filing. While the Corporation believes that it has meritorious defenses to these actions, the outcome is uncertain at this time.

E. Other Legal Proceedings. The Corporation and its subsidiaries have been named as defendants in various other legal proceedings. 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. All litigation against the Corporation and Columbia Transmission commenced prior to the Chapter 11 filings has been stayed under the provisions of the Bankruptcy Code other than *Fred K. Fox and New Ulm Gas Ltd. v. Mobil Oil Corp., Columbia Gas Transmission v. Alamco, et al.,* and *Alexander J. Bruen, et al., v. Columbia Gas Transmission, et al.* Columbia Transmission has filed with the U.S. District Court appeals of the orders of the Bankruptcy Court lifting the stays as to the *Fox* and *Alamco* suits.

F. Assets Under Lien. Substantially all of Columbia Transmission's properties have been pledged to the Corporation as security for debt owed by Columbia Transmission to the Corporation. Also, certain customers have made prepayments for gas service which are secured by a pledge of an interest in Columbia Transmission's gas inventory.

The loans under debtor-in-possession financing arrangement for the Corporation are given superpriority claim status pursuant to Section 364(c) (1) of the Bankruptcy Code. Loans for the Corporation are secured by either a first or second priority perfected lien on, and security interest in, all property of the Corporation including intercompany loans, other than the voting securities of the Corporation's local distribution subsidiaries and Columbia LNG. Columbia Transmission's letter of credit facility is secured by either a first or second priority perfected lien on, and security interest in, all property of Columbia Transmission.

G. Cove Point LNG Terminal. Deliveries of liquefied natural gas to Columbia LNG's Cove Point terminal ceased in April 1980 due to a price dispute between the Algerian government and the company from whom Columbia LNG was purchasing the gas.

On November 10, 1988, the Corporation agreed to sell 50 percent of its stock in Columbia LNG to a subsidiary of Shell Oil Company (Shell). Subsequently, on December 15, 1989, the Corporation sold 5.2 percent of its Columbia LNG stock to Shell for $11.5 million and on January 16, 1991, sold an additional 4 percent of the stock to Shell for $7.0 million.

During November 1991, the Corporation entered into a conditional agreement for the sale of its remaining interest in Columbia LNG to Shell LNG Company (Shell LNG), a subsidiary of Shell, for $128.5 million plus Columbia LNG's debt outstanding to the Corporation at the time of closing. The debt is estimated to be $44 million at the time of closing, and there was $38.6 million outstanding at December 31, 1991. If several substantial conditions are met, Shell LNG will purchase 40.8% of Columbia LNG's stock for $45.7 million at an interim closing in July 1992 and the remaining 50% of the stock for $64.3 million at a final closing which is scheduled to occur in March 1993. The sale must be approved by the SEC under the Public Utility Holding Company Act of 1935. Bankruptcy Court approval was received on December 18, 1991.

H. Operating Leases. Payments made in connection with operating leases are charged to operation and maintenance expense as incurred. Such amounts were $57.9 million in 1991, $54.2 million in 1990 and $44.2 million in 1989. Future minimum rental payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year are:

($ in millions)

1992	13.0
1993	14.4
1994	16.0
1995	16.1
1996	15.7
After	64.7

I. Environmental Matters. The Corporation's subsidiaries are subject to extensive Federal, state and local laws and regulations relating to environmental matters. These laws and regulations, which are constantly changing, require expenditures for corrective action at various operating facilities, waste disposal sites and former gas manufacturing sites.

Since 1989, certain subsidiaries have recorded liabilities to provide for estimated future cleanup costs primarily related to the cleanup of low levels of contamination from polychlorinated biphenyl (PCB)-based lubricating oils in certain air compressors. Columbia Transmission's continuing environmental assessment of its facilities and operations has identified other pollutants, including mercury, which continues to be utilized in certain natural gas facilities. Its use is being phased out as equipment using mercury is replaced. Current estimates of cost to address these additional environmental concerns resulted in $25.7 million (pretax) charges in 1991 bringing total recorded liabilities for identified environmental matters to $57.4 million at December 31, 1991. At this early stage it is impossible to estimate with precision the total cost of cleanup; however, the Corporation believes the additional costs, if any, associated with identified matters will not exceed the established reserve by more than $40 million, exclusive of fines and penalties.

The Corporation's operating subsidiaries, in some cases with the assistance of outside professional advisors, have been assessing, and continue to assess, the extent to which facilities and operations are in compliance with existing environmental laws in the ordinary course of business.

Certain subsidiaries have received notice from the United States Environmental Protection Agency (EPA) that they are among several parties responsible under Federal law for contaminated sites and may be required to share in the cost of the cleanup of such sites. In management's opinion, current exposure relating to such Federal notices is not material. More recently, Columbia Transmission has received an EPA request for information which Columbia Transmission believes will require several months to investigate and respond. Columbia Transmission has also received notices of violations from the environmental authorities of Kentucky. Such alleged violations provide for fines and penalties that apply separately for each violation and each day of non-compliance, which in the aggregate are significant. However, the Corporation's prior experiences, as well as other companies in the industry, have demonstrated that theoretical fines and penalties have been reduced in connection with negotiated compliance plans. Liabilities for possible fines and penalties are recorded when reasonably estimable.

The Chapter 11 proceeding of Columbia Transmission results in additional complexity in addressing environmental issues. Management is continuing its ongoing comprehensive review of past operational activities to identify potential site problems, conduct thorough site reviews and remediation and, if appropriate, settlement discussions with governmental agencies. Some governmental agencies may seek to have their potential claims resolved in the Bankruptcy Court. Such issues could delay resolution of the Chapter 11 proceeding.

The cost of additional future System environmental cleanup is impossible to estimate due to: (1) the unknown magnitude of possible contamination; (2) the possible effect of future legislation; (3) the possibility of future litigation; (4) the possibility of future designation as a potential responsible party by the EPA and the difficulty in determining liability, if any, in proportion to other responsible parties; (5) the possibility of additional claims of violations by state enforcement agencies; and (6) the effect of possible technological and other changes affecting the cost of future cleanups. However, considering known facts, existing laws and possible insurance and rate recoveries, management does not believe such matters will have a material adverse effect on the Corporation's financial position.

14. Interest Income and Other, Net

Year Ended December 31 ($ in millions)	1991	1990	1989
Interest income	17.0	27.8	37.7
Condemnation award, including interest	–	47.9	–
Gain on sale of Columbia Gas of New York	17.9	–	–
Gain on sale of Columbia Canada	2.9	–	–
Writedown in coal mine investment	–	(7.3)	–
Writedown in coal terminal investment	–	(5.3)	–
Writedown of cogeneration investment	(14.5)	–	–
Gain on sale of Columbia LNG stock	0.6	–	7.7
Income from equity investments	5.5	0.9	8.8
Miscellaneous	3.0	6.3	1.3
Total	32.4	70.3	55.5

15. Interest Expense and Related Charges

Year Ended December 31 ($ in millions)	1991	1990	1989
Interest on debt	108.3	170.6	159.7
Interest on DIP financing	4.1	–	–
Interest on rate refunds	8.4	10.1	16.4
Other interest charges	19.2	0.4	31.6
Allowance for borrowed funds used and interest during construction	(2.6)	(11.3)	(4.8)
Total	137.4	169.8	202.9

16. Changes in Components of Working Capital

(excludes cash and temporary cash investments, short-term debt and current maturities of long-term debt)

Year Ended December 31 ($ in millions)	1991	1990	1989
Accounts receivable, net	(60.8)	366.3	(274.2)
Gas inventory	63.1	(164.4)	67.2
Accounts and drafts payable	(120.9)	(2.8)	65.0
Accrued taxes	70.9	13.3	13.7
Estimated rate refunds	9.5	45.0	(119.7)
Estimated supplier obligations	67.6	(73.6)	44.9
Deferred income taxes	(26.5)	(5.1)	53.8
Miscellaneous	75.7	(44.3)	58.5
Change in working capital	78.6	134.4	(90.8)
Reclassifications	96.6	(156.8)	(122.7)
Net change in working capital	175.2	(22.4)	(213.5)

17. 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.

($ in millions)		1991	1990	1989
Revenues				
Oil and gas	–Unaffiliated	201.2	195.4	151.8
	–Intersegment	13.6	19.6	31.5
	Total	214.8	215.0	183.3
Transmission	–Unaffiliated	727.3	626.6	1,230.8
	–Intersegment	402.2	316.0	841.1
	Total	1,129.5	942.6	2,071.9
Distribution	–Unaffiliated	1,533.5	1,425.2	1,747.7
	–Intersegment	–	–	–
	Total	1,533.5	1,425.2	1,747.7
Other energy	–Unaffiliated	114.8	110.7	74.1
	–Intersegment	81.7	76.3	74.8
	Total	196.5	187.0	148.9
Adjustments	–Unaffiliated	–	–	–
and eliminations	–Intersegment	(497.5)	(411.9)	(947.4)
	Total	(497.5)	(411.9)	(947.4)
Consolidated		2,576.8	2,357.9	3,204.4

($ in millions)	1991	1990	1989
Operating Income (Loss)			
Oil and gas	(4.5)	43.3	30.2
Transmission	(1,192.2)	128.2	194.8
Distribution	114.9	96.7	146.1
Other energy	4.9	5.5	3.3
Corporate	(9.5)	(11.6)	(11.9)
Consolidated	(1,086.4)	262.1	362.5
Depreciation & Depletion			
Oil and gas	130.1	98.5	84.2
Transmission	90.4	86.9	97.0
Distribution	60.5	59.8	50.4
Other energy	4.0	3.6	2.6
Consolidated	285.0	248.8	234.2
Identifiable Assets			
Oil and gas	871.8	1,010.2	913.5
Transmission	3,544.9	3,288.9	3,126.1
Distribution	1,868.2	1,749.8	1,916.6
Other energy	158.5	140.3	135.2
Adjustments and eliminations	(382.1)	(55.4)	(276.2)
Corporate and unallocated	270.9	62.5	63.2
Consolidated	6,332.2	6,196.3	5,878.4
Capital Expenditures			
Oil and gas	120.8	229.0	147.9
Transmission	152.9	279.5	189.5
Distribution	98.0	107.0	119.7
Other energy	10.2	14.1	16.4
Consolidated	381.9	629.6	473.5

18. Quarterly Financial Data (Unaudited)

Comparison of results of operations among quarters during a year may be misleading in obtaining an understanding of the trend of the System's business operations, since total throughput is predominantly influenced by seasonal weather patterns which, in turn, affect earnings and related components of operating revenues and expenses. The first three quarters of 1991 have been restated to reflect the provisions of SFAS No. 106 and SFAS No. 96 adopted in the fourth quarter (see Note 4). The total of quarterly amounts may not equal annual earnings per share due to increasing average shares outstanding.

						Per Share Amounts		
Quarter Ended ($ in millions except per share data)	Operating Revenue	Operating Income	Earnings/ (Loss) on Common Stock Before Accounting Changes	Cumulative Effect of Changes in Accounting	Earnings/ (Loss)on Common Stock	Earnings/ (Loss) Before Accounting Changes	Cumulative Effect of Changes in Accounting	Earnings/ (Loss)
1991								
December 31	790.3	127.2	81.5 (a)	–	81.5	1.61	–	1.61
September 30	378.1	(151.8)	(122.1)(a)(b)(c)(e)	–	(122.1)	(2.41)	–	(2.41)
June 30	426.0	(1,178.8)	(802.0)(b)(d)(e)(f)	–	(802.0)	(15.88)	–	(15.88)
March 31	982.4	117.0	47.8(e)	100.4	148.2	0.95	1.99	2.94
1990								
December 31	645.9	102.2	60.8(e)(g)(h)	–	60.8	1.25	–	1.25
September 30	370.5	22.2	0.9(c)(i)	–	0.9	0.02	–	0.02
June 30	458.8	23.8	(4.6)	–	(4.6)	(0.10)	–	(0.10)
March 31	882.7	113.9	47.6	–	47.6	1.04	–	1.04

(a) Includes an increase in earnings of $22.3 million and $31 million in the third and fourth quarters, respectively, relating to not recording interest expense on prepetition debt.

(b) Includes a decrease in earnings of $772 million and $98.7 million in the second and third quarters, respectively, to record a provision for gas supply charges.

(c) Includes a decrease in earnings of $14.3 million in 1991 and $7.9 million in 1990 to record a liability for future environmental clean-up costs.

(d) Includes a decrease in earnings of $9.6 million to record a writedown related to certain cogeneration projects.

(e) Includes a decrease in earnings of $13.8 million, $4.8 million, and $5.4 million for the first, second and third quarters, respectively, of 1991 and $14.9 million for 1990 to record writedowns in the carrying value of Canadian oil and gas properties.

(f) Includes an increase in earnings of $9.2 million to record a gain on the sale of Columbia Gas of New York, Inc.

(g) Includes an increase in earnings of $26.5 million related to the East Lynn condemnation settlement.

(h) Includes a decrease in earnings of $6.2 million to record a writedown in the carrying value of the Wayne Mine investment ($2.7 million) and the Glenhayes coal terminal ($3.5 million).

(i) Includes an increase in earnings of $28.9 million related to a favorable court ruling on the treatment of production-related costs under FERC Order No. 94/473.

19. Oil and Gas Producing Activities (Unaudited)

Introduction. Reserve information contained in the following tables for the U.S. properties is management's estimate which was reviewed by the independent consulting firm of Ryder Scott Company Petroleum Engineers. Reserve information for the Canadian properties was supplied by McDaniel & Associates Consultants Ltd. U.S. reserves are reported as net working interest, while Canadian reserves are gross 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.

The Corporation sold its Canadian subsidiary to Anderson Exploration Ltd. of Calgary effective December 31, 1991. Accordingly, the reserve and other information for the Canadian properties is not included in certain tables for 1991.

Capitalized Costs	United States			Canada			Total		
($ in millions)	1991	1990	1989	1991(b)	1990	1989	1991(b)	1990	1989
Capitalized Costs at Year End									
Proved properties	1,086.9	1,041.4	962.8	–	232.6	192.6	1,086.9	1,274.0	1,155.4
Unproved properties(a)	80.7	89.3	72.4	–	27.6	40.2	80.7	116.9	112.6
Total capitalized costs	1167.6	1,130.7	1,035.2	–	260.2	232.8	1167.6	1,390.9	1,268.0
Accumulated depletion	(441.3)	(422.0)	(456.0)	–	(118.8)	(88.9)	(441.3)	(540.8)	(544.9)
Net capitalized costs	726.3	708.7	579.2	–	141.4	143.9	726.3	850.1	723.1
Costs Capitalized During Year									
Acquisition									
Proved properties	–	29.4	41.2	–	0.3	–	–	29.7	41.2
Unproved properties	6.4	13.2	9.9	–	3.3	3.9	6.4	16.5	13.8
Exploration	32.8	53.3	36.4	–	13.6	15.7	32.8	66.9	52.1
Development	62.9	100.4	34.8	–	14.6	5.0	62.9	115.0	39.8
Costs capitalized	102.1	196.3	122.3	–	31.8	24.6	102.1	228.1	146.9

(a) Represents expenditures associated with properties on which evaluations have not been completed.

(b) Due to the sale of the Canadian subsidiary no information is provided for costs capitalized by that subsidiary throughout 1991.

Historical Results of Operations	United States			Canada			Total		
($ in millions)	1991	1990	1989	1991	1990	1989	1991	1990	1989
Gross revenues									
Unaffiliated	181.8	179.4	139.2	15.7	15.6	12.3	197.5	195.0	151.5
Affiliated	14.1	18.9	24.7	–	–	–	14.1	18.9	24.7
Production costs	41.6	36.0	31.1	5.6	4.3	4.3	47.2	40.3	35.4
Depletion	82.1	68.1	56.6	47.1(a)	30.0(a)	27.2(a)	129.2	98.1	83.8
Income tax expense	22.8	31.2	25.9	(12.6)	(6.4)	(6.5)	10.2	24.8	19.4
Results of operations	49.4	63.0	50.3	(24.4)	(12.3)	(12.7)	25.0	50.7	37.6

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 Section 29 credits.

(a) Includes writedown of the carrying value of $36.4 million for 1991, $22.6 million for 1990, and $22.6 million for 1989.

Other Oil and Gas Production Data	United States			Canada		
	1991	1990	1989	1991	1990	1989
Average sales price per Mcf of gas ($)	1.88	2.03	1.92	1.02	1.21	1.16
Average sales price per barrel of oil and other liquids ($)	22.18	24.13	17.57	15.83	18.69	14.88
Production (lifting) cost per dollar of gross revenue ($)	0.21	0.18	0.19	0.36	0.28	0.35
Depletion rate per dollar of gross revenue ($)	0.42	0.34	0.35	–	–	–
Depletion rate per equivalent Mcf ($)	–	–	–	1.10	1.09	0.73

Reserve Quantity Information

Proved Reserves	United States Gas (Bcf)	United States Oil and Other Liquids (000 Bbls)	Canada(a) Gas (Bcf)	Canada(a) Oil and Other Liquids (000 Bbls)
Reserves as of December 31, 1988	742.2	8,245	155.6	6,659
Revisions of previous estimate	4.8	64	(57.5)(b)	(1,302)(b)
Extensions, discoveries and other additions	92.4	1,626	16.2	20
Production	(75.1)	(1,310)	(2.6)	(614)
Purchase/(sale) of minerals-in-place	26.7	3,343	–	–
Reserves as of December 31, 1989	791.0	11,968	111.7	4,763
Revisions of previous estimate	22.3	1,936	(2.1)	(206)
Extensions, discoveries and other additions	59.9	1,797	16.8	749
Production	(72.3)	(2,057)	(3.0)	(631)
Purchase/(sale) of minerals-in-place	11.6	1,097	(10.2)	(425)
Reserves as of December 31, 1990	812.5	14,741	113.2	4,250
Revisions of previous estimate	14.2	(854)	–	–
Extensions, discoveries and other additions	62.7	4,514	–	–
Production	(70.1)	(2,833)	(6.2)	(578)
Purchase/(sale) of minerals-in-place	(11.2)	–	(107.0)	(3,672)
Reserves as of December 31, 1991	808.1	15,568	–	–
Proved developed reserves as of December 31				
1989	702.8	7,160	111.7	4,763
1990	730.1	11,210	113.2	4,250
1991	697.7	13,338	–	–

(a) Gross working-interest reserves.

(b) The reductions occurred for a variety of reasons including a reclassification of reserves from proved to probable, a reduction of estimated reserves in place, a reduction in recovery factors and deletion of small working-interest properties not considered to be economic.

Standardized Measure of Discounted Future Net Cash Flows

($ in millions)	United States 1991	United States 1990	United States 1989	Canada 1991	Canada 1990	Canada 1989	Total 1991	Total 1990	Total 1989
Future cash inflows	2,152.3	2,420.2	2,193.7	–	226.4	219.9	2,152.3	2,646.6	2,413.6
Future production costs	(511.9)	(508.8)	(425.3)	–	(61.1)	(59.0)	(511.9)	(569.9)	(484.3)
Future development costs	(157.8)	(165.4)	(139.9)	–	(12.2)	(13.3)	(157.8)	(177.6)	(153.2)
Future income tax expense	(411.6)	(514.3)	(498.0)	–	(29.3)	(27.4)	(411.6)	(543.6)	(525.4)
Future net cash flows	1,071.0	1,231.7	1,130.5	–	123.8	120.2	1,071.0	1,355.5	1,250.7
Less 10% discount	504.0	562.0	537.5	–	46.5	49.7	504.0	608.5	587.2
Standardized measure of discounted future net cash flows	567.0	669.7	593.0	–	77.3	70.5	567.0	747.0	663.5

Future cash inflows 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 the Financial Accounting Standards Board, 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.

Prices of natural gas declined since December 31, 1991. Although many factors influence the calculation of the Standardized Measure of Discounted Future Net Cash Flows (the standardized measure), the effect of lower prices could significantly reduce this calculation and have a negative impact on the Corporation's oil and gas assets. Current projections anticipate an after-tax writedown at the end of the first quarter of 1992 aggregating approximately $100 million. Further, the standardized measure of the Corporation's oil and gas properties can be influenced by affiliated and unaffiliated pipeline transporter rate design (which is presently being evaluated as part of the FERC's so-called MEGA-NOPR) and operational matters such as pipeline pressures.

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, 1991, follows:

	United States			Canada			Total		
($ in millions)	1991	1990	1989	1991*	1990	1989	1991	1990	1989
Beginning of year	669.7	593.0	516.3	–	70.5	82.3	669.7	663.5	598.6
Oil and gas sales, net of production costs	(154.3)	(162.3)	(132.8)	–	(11.3)	(8.0)	(154.3)	(173.6)	(140.8)
Net changes in prices and production costs	(140.0)	(11.6)	53.9	–	6.1	3.5	(140.0)	(5.5)	57.4
Extensions, discoveries and other additions, net of related costs	84.4	109.8	98.6	–	11.4	7.5	84.4	121.2	106.1
Revisions of previous estimates, net of related costs	8.9	35.7	5.7	–	(2.3)	(39.3)	8.9	33.4	(33.6)
Purchases (sales) of reserves	(15.8)	30.3	34.0	–	–	–	(15.8)	30.3	34.0
Accretion of discount	93.5	84.4	73.6	–	8.6	11.0	93.5	93.0	84.6
Net change in income taxes	64.4	(14.5)	(31.9)	–	(2.4)	11.2	64.4	(16.9)	(20.7)
Timing of production and other changes	(43.8)	4.9	(24.4)	–	(3.3)	2.3	(43.8)	1.6	(22.1)
End of year	567.0	669.7	593.0	–	77.3	70.5	567.0	747.0	663.5

*The Corporation believes that a reconciliation for 1991 is not meaningful due to the sale of the Canadian subsidiary.

The estimated discounted future net cash flows decreased during 1991 primarily due to net changes in prices and production costs.

The Columbia Gas System, Inc.

Directors

Thomas S. Blair
A director since 1962, Thomas Blair is chairman of Blair Strip Steel Company, a diversified steel manufacturer in New Castle, Pennsylvania. He also serves as a director of Tuscarora Plastics, Inc.

Committee Memberships: Audit, Executive and Finance

John H. Croom
John Croom has been chairman, president and chief executive officer of the Columbia Gas System since 1984. He was first elected to the board in 1981. Mr. Croom is a director and was first vice chairman of the American Gas Association. He is also a director of the National Petroleum Council and a director and former board chairman of the Gas Research Institute.

Committee Chairman: Executive

John D. Daly
John Daly was elected executive vice president and director of the Columbia Gas System in September 1990. He served as chairman of the board and chief executive officer at Columbia Gas Transmission Corporation from 1985 to August 1990. Mr. Daly is a director and former chairman of the Interstate Natural Gas Association of America.

Dr. Sherwood L. Fawcett
A director since 1984, Dr. Fawcett is chairman of Transmet Corporation, a manufacturer of rapidly solidified metals. He retired as chairman of the board of trustees and chief executive officer of Battelle Memorial Institute in 1985, and was a research and development consultant until 1989.

Committee Memberships: Compensation and Finance

Robert H. Hillenmeyer
Robert Hillenmeyer was first elected to the Board in 1970. He is the former chairman and chief executive officer of Hillenmeyer Nurseries, Inc., in Lexington, Kentucky. Mr. Hillenmeyer also serves as a director of GTE South.

Committee Memberships: Audit, Compensation and Executive

Malcolm T. Hopkins
A director since 1982, Malcolm Hopkins is retired vice chairman, chief financial officer and director of the former St. Regis Corporation, one of the nation's major forest products, oil, gas and insurance firms. Since 1984 he has been a private investor. Mr. Hopkins currently serves as director of Metropolitan Series Fund, Inc.; MAPCO, Inc.; Wangner Systems Corporation; and Kinder-Care Learning Centers, Inc.

Committee Memberships: Audit, Compensation and Executive
Committee Chairman: Finance

W. Frederick Laird
Frederick Laird retired as chairman of the board and chief executive officer of the Columbia Gas System in 1984. He has been a director since 1974. He also serves as a director of Wilmington Trust Company.

Committee Membership: Executive

Dr. William E. Lavery
Dr. Lavery was elected to Columbia's board in 1985. He is president emeritus of Virginia Polytechnic Institute and State University in Blacksburg, Virginia. He served as president from 1975 through 1987 and was a professor of international affairs from 1987 through 1991. He also serves as a director of Dominion Bankshares Corporation and Shenandoah Life Insurance Company.

Committee Memberships: Audit and Finance

George P. MacNichol, III
George MacNichol was first elected to the board in 1971. He has been a private investor since 1979 when he retired as an officer and director of Libbey-Owens-Ford Company, the glass and plastics manufacturer in Toledo, Ohio.

Committee Memberships: Audit and Finance

Robert A. Oswald
Robert Oswald has been executive vice president and chief financial officer of the Columbia Gas System since 1989. He was first elected to the board in 1987.

Ernesta G. Procope
A director since 1979, Ernesta Procope is president and chief executive officer of E. G. Bowman Co., Inc., a commercial insurance brokerage firm in New York City. She also serves as a director of Avon Products, Inc. and Chubb Corporation.

Committee Memberships: Compensation and Finance

Dr. Ronald W. Skeddle
Dr. Skeddle was elected to the board in 1989. He is president and chief executive officer of Libbey-Owens-Ford Company, manufacturers of glass and plastics, in Toledo, Ohio. Dr. Skeddle also serves as a director of Cooper Tire and Rubber Company and Federal Mogul Corporation.

Committee Memberships: Audit and Compensation

John W. Snow
Elected to the board in 1990, John Snow is chairman, president and chief executive officer of CSX Corporation, a diversified transportation company with headquarters in Richmond, Virginia. He is also a director of Bassett Furniture Industries, Inc., Textron Inc., NationsBank Corporation, and Energy Resources & Logistics.

Committee Memberships: Audit and Compensation

James R. Thomas II
Elected to the board in 1990, James Thomas has been a private investor since 1983. He was president and chief executive officer of Carbon Industries, Inc. from 1974 to 1982. Mr. Thomas is also on the board of directors of One Valley Bank NA, Camcare, Inc. and Shoney's, Inc.

Committee Membership: Finance
Committee Chairman: Audit

William R. Wilson
William Wilson, a director since 1987, recently retired as chairman and chief executive officer of Lukens Inc., steel and industrial products manufacturer located in Coatesville, Pennsylvania. In addition to serving on the Lukens board of directors, Mr. Wilson is a director of Provident Mutual Life Insurance Company.

Committee Membership: Finance
Committee Chairman: Compensation

The Columbia Gas System, Inc.

Officers

John H. Croom
Chairman, President and Chief Executive Officer

John D. Daly
Executive Vice President

Robert A. Oswald
Executive Vice President
and Chief Financial Officer

Daniel L. Bell, Jr.
Senior Vice President, Chief Legal Officer
and Secretary

Michael W. O'Donnell
Senior Vice President and
Assistant Chief Financial Officer

Richard A. Casali
Vice President

Richard E. Lowe
Vice President and Controller

Larry J. Bainter
Treasurer

Tejinder S. Bindra
Joyce Koria Hayes
James B. Lange
Assistant Secretaries

Columbia Gas System Service Corporation

John H. Croom
Chairman, President and Chief Executive Officer

John D. Daly
Executive Vice President

Robert A. Oswald
Executive Vice President
and Chief Financial Officer

Operating Company Executives

OIL AND GAS

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

Columbia Natural Resources, Inc.
John R. Henning
President and Chief Executive Officer

TRANSMISSION

Columbia Gas Transmission Corporation
Columbia Gulf Transmission Company
James P. Holland
Chairman and Chief Executive Officer

R. Larry Robinson
President

James T. Connors
Senior Vice President and Chief Financial Officer

Columbia LNG Corporation
L. Michael Bridges
President

DISTRIBUTION

Columbia Gas of Kentucky, Inc.
Columbia Gas of Maryland, Inc.
Columbia Gas of Ohio, Inc.
Columbia Gas of Pennsylvania, Inc.
Commonwealth Gas Services, Inc.
C. Ronald Tilley
Chairman and Chief Executive Officer

James R. Lee
Executive Vice President

Robert C. Skaggs, Jr.
Executive Vice President

Richard J. Gordon
President and Chief Operating Officer
Columbia Gas of Kentucky and Ohio

Gary J. Robinson
President and Chief Operating Officer
Columbia Gas of Maryland and Pennsylvania

Thomas E. Harris
President and Chief Operating Officer
Commonwealth Gas Services, Inc.

OTHER ENERGY COMPANIES

Columbia Atlantic Trading Corporation
L. Michael Bridges
President

Columbia Coal Gasification Corporation
John R. Henning
President and Chief Executive Officer

Columbia Propane Corporation
Commonwealth Propane, Inc.
A. Mason Brent
President

The Inland Gas Company, Inc.
Logan W. Wallingford
President

TriStar Capital Corporation
William F. Morse
President

TriStar Ventures Corporation
Bartholomew F. Cranston
President

Shareholder Information

Common Stock
The common stock of The Columbia Gas System, Inc., is traded on the New York Stock Exchange under the ticker symbol CG and abbreviated as either ColumGas or ColGs in trading reports. The number of shareholders of record on December 31, 1991, was approximately 72,000. Columbia's fiscal year is from January 1 to December 31.

10-K Report Requests
Copies of Columbia's Form 10-K and Form 10-Q reports to the Securities and Exchange Commission and a supplementary report containing more detailed operational, financial and statistical data are available at no charge, by writing to Columbia's Investor Relations Department.

Transfer Agents and Registrars
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Corporate Trust Department
77 Water Street, 4th Floor
New York, NY 10005
(212) 701-7600

Debenture Trustee
Marine Midland Bank, N.A.
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New York, NY 10015
(212) 658-6524

Debenture Paying Agent and Registrar
Morgan Guaranty Trust Company of New York
Security Holder Relations
30 West Broadway
New York, NY 10015
(212) 483-2323

Common Stock Data
The Columbia Gas System, Inc.

Year	Number of Shares Traded (000)	Market Price High $	Market Price Low $
1991	82,756	$47\frac{1}{2}$	$12\frac{7}{8}$
1990	31,777	$54\frac{3}{4}$	$41\frac{1}{2}$
1989	39,132	$52\frac{3}{4}$	$33\frac{3}{4}$
1988	47,906	$44\frac{3}{4}$	$26\frac{7}{8}$
1987	31,491	$56\frac{1}{2}$	$35\frac{1}{2}$
1986	26,311	46	$34\frac{3}{4}$
1985	29,135	40	$26\frac{3}{4}$
1984	14,624	$37\frac{1}{2}$	27
1983	14,191	$35\frac{1}{2}$	$27\frac{7}{8}$
1982	7,414	$33\frac{7}{8}$	$26\frac{7}{8}$

Annual Meeting
Columbia's 1992 Annual Stockholders' Meeting will be held at 1 p.m. (EDT) on Thursday, April 30, in the duBarry Room of the Hotel du Pont, 11th and Market Streets, Wilmington, Del. Proxy material will be mailed on or about March 23, 1992. Columbia will include a report of significant business conducted at the meeting in its first 1992 quarterly report to shareholders.

Dividend Reinvestment Plan
Even though Columbia suspended its dividend in 1991, the Corporation continues to offer shareholders of record a convenient method to acquire additional shares of common stock through lump sum contributions to its Dividend Reinvestment Plan. If you elect to discontinue participation, you may receive either a stock certificate or cash for shares credited to your account. There is a small brokerage commission on shares purchased or sold through the Plan. A complete Plan description is available by writing Columbia's Shareholder Services Department.

Communicating with Columbia
Mailing Addresses:

The Columbia Gas System, Inc.
20 Montchanin Road
Wilmington, DE 19807-0020

or

The Columbia Gas System, Inc.
Shareholder Services Department
P.O. Box 2318
Columbus, OH 43216-2318

Telephone Inquiries:
(8:00 a.m. - 4:45 p.m. eastern time)

Main Telephone: (302) 429-5000

Corporate Communications:
(302) 429-5262

Corporate Secretary: (302) 429-5349

Investor Relations: (302) 429-5331

Shareholder Services: (800) 245-4588 or (614) 481-1000

Facsimile: (302) 429-5730

Glossary

Defined below are some common natural gas industry and financial terms.

Bcf
Billion cubic feet.

Bond
An interest-bearing corporate security (see debenture) that obligates the issuer to pay the holder a specified sum at specific intervals, and to repay the principal amount of the loan at maturity. A secured bond is backed by collateral. An unsecured bond is backed by the full faith and credit of the issuer.

Cash Flow
A widely used measure of a company's earning power and/or ability to make debt payments.

Chapter 11
A provision of the federal bankruptcy code that protects a company from its creditors and allows the debtor to continue to operate the business while a plan of reorganization is completed. Debtor and creditors are allowed considerable flexibility in working out a reorganization plan.

Cogeneration
A process that produces electrical and thermal energy simultaneously from a single fuel source, often natural gas.

Compressed Natural Gas (CNG)
Natural gas stored in special high-pressure containers. It is used as a transportation fuel for automobiles, trucks and buses.

Debenture
General debt obligation (see Bond) backed by the integrity of the borrower and documented by an agreement called an indenture.

Degree Day
One degree of departure in the mean daily outdoor temperature below 65°F. (The colder the weather, the greater the number of degree days.)

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

Distribution Company
A natural gas utility selling gas directly to consumers under the jurisdiction of a state commission.

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

Federal Energy Regulatory Commission (FERC)
An independent federal agency within the Department of Energy with jurisdiction over interstate natural gas operations.

Firm Service
Service offered to customers under tariff authority and associated contracts. It anticipates no interruptions other than from unexpected and uncontrollable events.

Horizontal Drilling
A form of directional drilling deviating from the vertical that exposes a greater portion of a formation to the well bore and generally improves productivity.

Interruptible Service
A low-priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice.

Liquefied Natural Gas (LNG)
Natural gas that has been liquefied by reducing its temperature to minus 260°F at atmospheric pressure.

Liquidity
Ability to convert assets into cash or cash equivalents without significant loss.

Market-Sensitive Contract
A contract whose pricing and sales terms can be adjusted to reflect changes in supply and demand conditions in the marketplace.

Mcf
Thousand cubic feet–the most common measurement of gas volume.

MMcf
Million cubic feet.

Merchant Function
Buying and selling of natural gas.

Net Acres/Net Wells
A company's share of the total acreage or number of wells in which it has a participating interest.

Net Plant
Property, plant and equipment less accumulated depreciation and depletion.

Normal Weather
The average of 30 years of historic weather data compiled by the National Weather Service.

Propane
A heavier-than-air gaseous hydrocarbon found with crude petroleum and natural gas.

Proved Reserves
The amount of commercially recoverable gas or oil estimated to lie within a given reservoir.

Regulatory Lag
When existing rates do not adequately reflect the current level of operating costs, investment or throughput.

Reorganization
The reconstruction of a corporation or its financial structure.

Reserve
Earnings that a corporation sets aside to meet future losses or contingent liabilities.

Sales Service
Traditional service agreements under which gas pipeline companies purchase gas from suppliers for resale to customers.

Spot-Market Sales
Short-term direct sales, generally 30 days or less, of natural gas, crude oil or refined petroleum products by producers or brokers to others.

Take-or-Pay Costs
Charges incurred by pipelines when they do not take minimum quantities of gas specified under terms of gas purchase contracts.

Throughput
Total of transportation volumes and tariff sales. All gas volumes delivered.

Transportation Service
Service agreements under which pipelines transport gas supplies that customers purchase directly from other parties.

Underground Storage
An operation that permits the injection of large quantities of natural gas into underground rock formations during periods of low market demand and withdrawal during peak market demand.

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