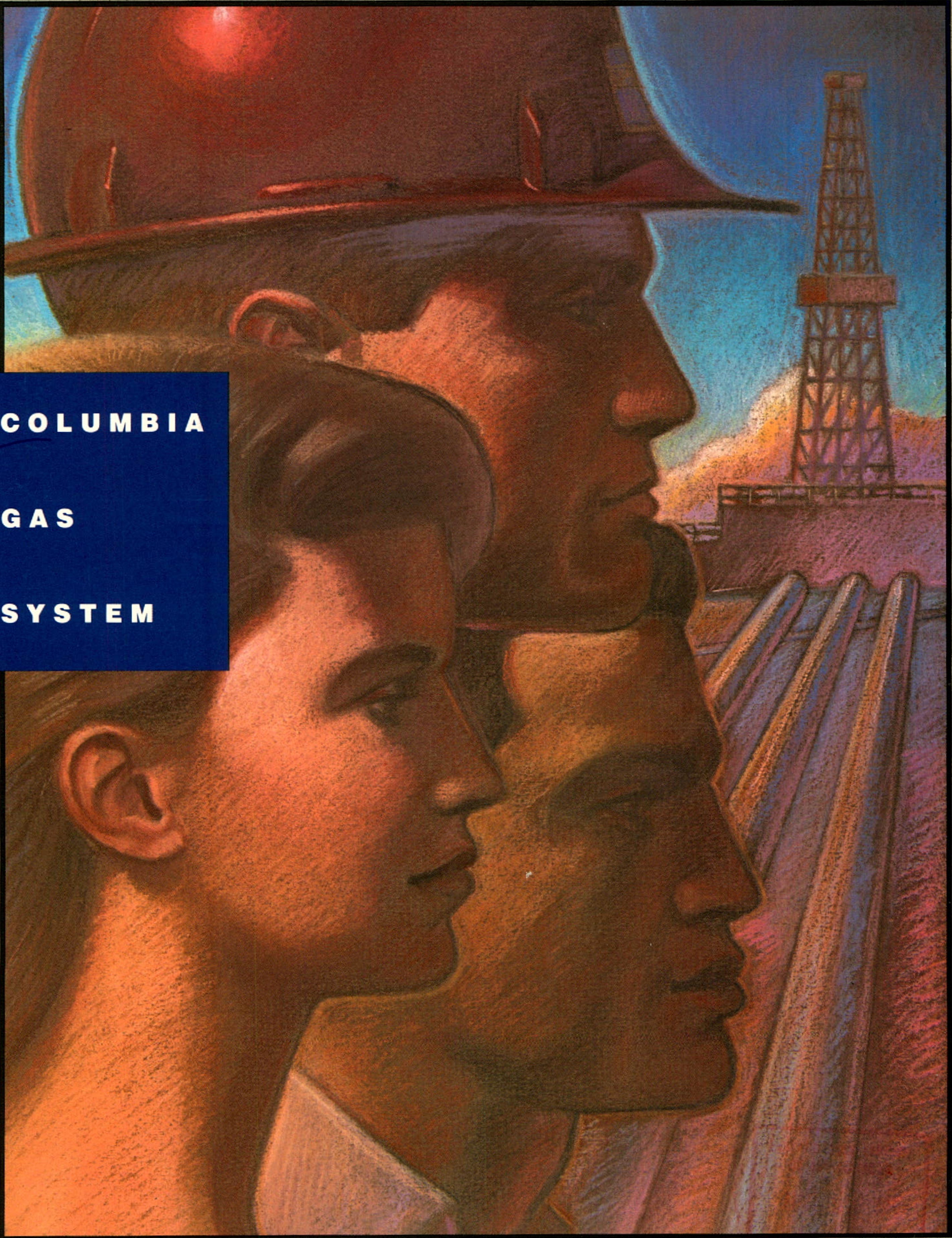
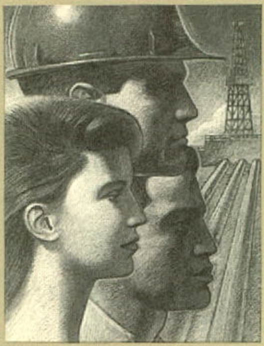
Look to us for ideas and the energy to make them work.



COLUMBIA GAS SYSTEM

1990 ANNUAL REPORT



About the Cover

Throughout its 64-year history, the vision of Columbia's employees has been the source of the System's strength and vitality. In this promising era for natural gas, System employees look forward to overcoming the challenges and taking advantage of the opportunities of the new, highly-competitive natural gas industry.

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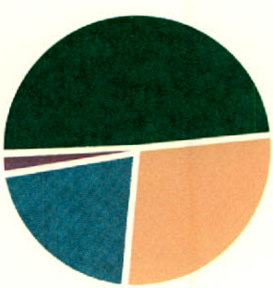
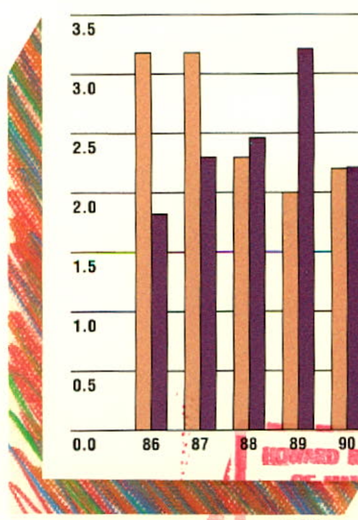
	1990	1989	1988
Income Statement Data ($ in millions)			
Operating Revenues	**2,357.9**	3,204.4	3,168.2
Operating Income	**262.1**	362.5	313.2
Net Income	**104.7**	145.8	119.0
Earnings (Loss):			
Oil and Gas	**39.3**	2.0	8.7
Gas Transmission	**47.2**	76.9	38.1
Gas Distribution	**24.6**	68.6	63.1
Other Energy	**(6.4)**	(1.7)	1.2
Total	**104.7**	145.8	111.1
Per Share Data ($)			
Earnings on Common Stock	**2.21**	3.21	2.46
Dividends	**2.20**	2.00	2.295
Book Value	**34.83**	35.50	34.18
Market Price:			
High	**54¾**	52¾	44¾
Low	**41½**	33¾	26⅞
Close	**46⅞**	52	34½
Common Stock Data (000)			
Average Shares Outstanding	**47,316**	45,494	45,190
Average Daily Shares Traded	**146**	155	191
Operating Statistics			
Gas Production (billion cubic feet)	**75.3**	77.7	74.6
Oil Production (thousands of barrels)	**2,688**	1,924	2,328
Transmission Throughput (billion cubic feet)	**1,386.1**	1,618.9	1,250.4
Distribution Throughput (billion cubic feet)	**465.7**	488.4	469.4
Balance Sheet and Other Data ($ in millions)			
Capital Expenditures	**629.6**	473.5	307.9
Total Assets	**6,196.3**	5,878.4	5,641.0
Capitalization (Including Short-Term Debt and Current Maturities)	**3,957.2**	3,497.7	3,340.8



Net Plant by Segment at December 31, 1990
(in millions of dollars)

Transmission	2,002
Distribution	1,139
Oil & Gas	853
Other Energy	59

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



About Columbia Gas

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

- We explore for and produce gas and oil in the United States and Canada.
- Our pipeline systems transport natural gas from North America's major producing basins to markets in the Midwest, Middle Atlantic, Southern and New England states.
- Columbia's transmission, storage and distribution facilities serve, directly or indirectly, over eight million customers in 15 states.
- We own the most strategically-located liquefied natural gas receiving terminal in the U.S.
- Our propane companies serve more than 63,000 customers in eight states.
- Columbia's TriStar Ventures Corporation is making equity investments in cogeneration projects and other modern gas technologies.

The emerging opportunities of a new era for natural gas reinforce our conviction of the advantages afforded an integrated natural gas system. The path we have chosen will enable stockholders to benefit not only from energy price improvements at the wellhead, but also from the growing markets along our pipeline systems.

Mission Statement

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

To Our Shareholders

In previous years, I have used this opportunity to explain the complex issues accompanying the major transformation that has taken place in the natural gas industry and to describe plans we have implemented so your company can prosper in its more competitive environment.

This year, however, we are being significantly affected by a more fundamental, more understandable issue: the weather, one business variable over which we have no control. The record-setting warm temperatures experienced across our operating territory during 1990 coupled with continued warm weather thus far in 1991 have substantially reduced gas demand, held wellhead prices at depressed levels by extending the nationwide supply surplus and created numerous operating problems.

John H. Croom
Chairman, President and Chief Executive Officer

As a result, 1990 earnings are disappointing and well below anticipated levels. Our outlook for the future, however, remains positive. We have taken the steps necessary to assure we have the financial strength to withstand the temporary negative impact of these record-setting warm temperatures. Our plans remain on schedule and on target, and our long-term prospects continue to be impressive and bright.

This optimism was affirmed by the Board of Directors in January. After a full review of the company's prospects for each of its business segments, the Board unanimously endorsed management's recommendation to increase the quarterly common stock dividend by 5.5 percent to the new indicated annual rate of $2.32 per share.

The Board also reviewed several major events of 1990.

- The oil and gas subsidiaries set a new company record by participating in 220 net wells in the United States and Canada and increased proved reserves.
- The distribution companies added more than 40,000 new customers.
- A longstanding condemnation proceeding in West Virginia was resolved in Columbia's favor.
- The transmission companies completed the first phase of a two-year, $300 million expansion program.
- The distribution companies increased deliveries to their industrial and commercial customers.
- TriStar Ventures and its partners began construction of a 117-megawatt cogeneration project in New Jersey.
- A favorable U. S. Supreme Court ruling allows Columbia to recover $48.4 million of production-related expenses previously paid to other pipelines.
- New York State Electric & Gas agreed to purchase Columbia Gas of New York.
- Columbia gained meaningful relief from overly strict interpretations of the Public Utility Holding Company Act.

Earnings

The decline in 1990 earnings to $2.21 per share, compared to $3.21 per share in 1989, was principally due to reduced gas consumption as temperatures across our operating territory averaged 17 percent warmer than normal. 1990 was the warmest year since Columbia began keeping records in 1946, almost doubling the previous record of nine percent warmer than normal. The impact of weather on 1990 earnings amounted to $1.25 per share when compared with 1989 which was slightly colder than normal.

One-time events helped offset the negative impact of the record warm temperatures. These included the favorable ruling issued by the U. S. Supreme Court and the settlement of the condemnation litigation in West Virginia.

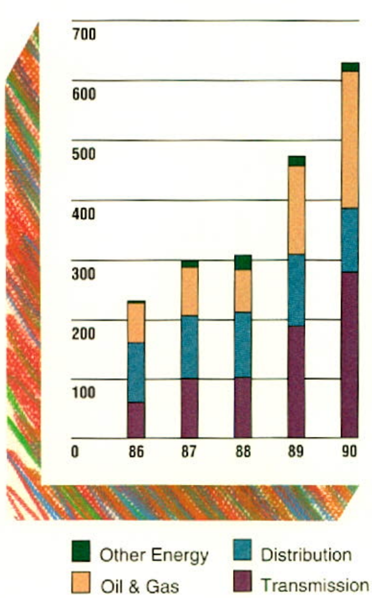
Steps have been taken to mitigate the effects of 1990's warm weather and the warm weather experienced thus far in 1991. However, it along with wellhead price and production levels in the oil and gas segment, decisions in pending Transmission and Distribution rate cases and negotiations with producers to restructure gas purchase contracts to make them market sensitive will affect earnings in 1991.

Capital Expenditures

1991's $525 million capital expenditure program represents a continuation of our long-term strategy of targeting investments to those areas and projects which offer the highest potential for profit.

Success of this corporate strategy is particularly evident in the oil and gas segment. Part of the increased net income from these operations in 1990 reflects our decision in 1988 to increase capital investments in this segment after recognizing the ability of this nonregulated phase of our operations to earn a higher return than regulated segments. We plan to invest an average of $200 million a year, excluding acquisitions, into oil and gas operations over the next five years with a long-term target of increasing its assets until they equal approximately one-third of the System's total plant investment.

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



Marketing Activity

No area better exemplifies the change in corporate culture that continues to take place throughout Columbia than our focus on marketing. Recognition of its importance is evident in all areas of the System. Employees are aware of the importance of quality service in today's gas industry and the effect it can have on our bottom line. The extensive expertise and knowledge of our employees has always been one of our most valuable assets, and we are utilizing it fully as we pursue growth opportunities.

We continue to be highly selective in our marketing efforts to assure the significant capital investments being made for new business result in maximum returns to shareholders. We are seeking to add premium, high-load-factor projects that can be attached at a modest cost and to increase throughput on existing facilities, thereby lowering operating costs and improving our earnings potential.

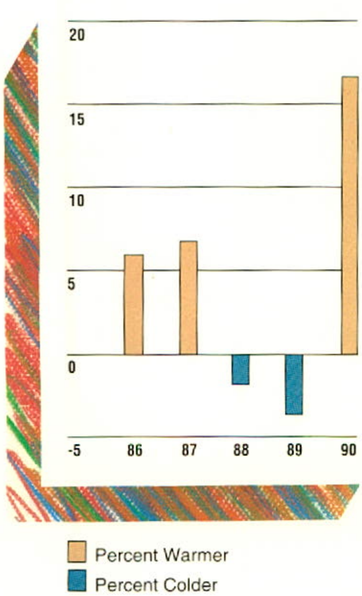
The future holds tremendous potential for natural gas. Its already bright outlook was enhanced in 1990 by events which propelled gas to the forefront as a solution to many of the nation's energy and environmental concerns.

Clean air legislation highlighted the environmental benefits of natural gas and recent events in the Persian Gulf focused attention on the nation's domestic gas reserves as a long-term means of reducing dependence on foreign oil.

Columbia companies are actively seeking to expand the use of gas for electric power generation, air conditioning and as a fuel for motor vehicles. They are also participating in research to perfect a natural gas heat pump and a natural gas fuel cell.

In 1987, we applied for Securities and Exchange Commission authorization to establish a new company to take advantage of marketing opportunities created by the vast changes in the industry since 1985. Authorization has been held up primarily because of SEC staff guidelines for determining the functional relationship of the marketing operations to Columbia's utility business; however, the Gas Related Activities Act signed into law in November 1990 is expected to overcome the SEC's concern and expedite the approval of Columbia's application. This new company will give Columbia additional marketing flexibility and permit it to compete more equally for key markets.

Degree Days
(variation from normal in percent)



Producer Contract Negotiations

As a result of a continuing review of gas purchase contracts to assure they are responsive to market conditions when all controls are removed from wellhead prices in January 1993, Columbia Gas Transmission is negotiating with producers to amend certain existing contracts and resolve pending litigation.

Several contracts were settled in 1990 and we expect to complete other renegotiations in 1991.

Regulatory Issues

Outmoded regulation at both the state and federal levels continued to plague the transmission and distribution segments during 1990.

Regulatory lag–the inability of a company to fully reflect and recover current operating costs in its rates–held down Distribution's earnings in 1990, particularly in Ohio where Columbia Gas of Ohio received a disappointing rate order.

In addition to filing new rate cases to bring earnings to a more acceptable level, Distribution's management is working with regulators to streamline the regulatory processes and to establish more flexible pricing mechanisms to permit quick responses to changing market conditions.

At the federal level, regulators are failing to consider the higher risks associated with a pipeline's merchant function when establishing rates. Our transmission companies are making a concerted effort to convince the Federal Energy Regulatory Commission to address this problem and to authorize flexible rate structures that will permit pipelines to compete effectively with nonregulated gas marketers.

Education 2000

During 1990, we joined other major businesses around the country in a concerted, decade-long effort to improve the nation's public education system. Our Education 2000 program is designed to encourage employees to get more closely involved with local schools, to encourage parents to accept more responsibility for their children's schooling and to focus public attention on the nation's education problems.

We initiated this program because we recognize that too many young people are leaving school less qualified in reading, writing and other basic skills than at any time in recent years. We view our involvement as a good investment, not only for Columbia but for our customers and the public as well. Unless our education system is improved, fewer qualified employees will be available to run our business in the years ahead, and many of those will require expensive remedial training resulting in added costs to the company and its customers. More importantly the country as a whole will suffer because today's students will not have the basic skills they need to lead productive lives.

Management Changes

During 1990, two members of the Corporation's Board of Directors retired. J. Robert Fletcher, who served as a director for 22 years, retired September 1, and Arch A. Sproul, who joined the Board in 1961, retired October 1. Both were recognized by the Board for their service and dedication to the company over the years and elected directors emeriti.

Three new directors were elected during the year, bringing the total membership of the Board to 15.

John W. Snow, chairman, president and chief executive officer of CSX Corporation, one of the nation's largest diversified transportation companies, was elected in May and brings to the Board extensive experience in both the private and public sectors.

John D. Daly, chairman and chief executive officer of the Columbia Transmission Companies since 1985, became an executive vice president and a director of the System in September. He joined Columbia in 1957 as an engineer. After obtaining his law degree, he served as chief counsel and secretary for Columbia Gas Transmission before being named president of the distribution companies in 1978.

James R. Thomas, II, of Charleston, West Virginia, joined the Board in September. He currently serves as president of the Charleston Renaissance Corporation, a public/private partnership organized to revitalize the business and commercial core of West Virginia's capital city. He previously was president and chief executive officer of Carbon Industries, Inc.

The quality membership of Columbia's Board of Directors and the talented, dedicated employees throughout the System make me extremely optimistic about future prospects for your company. We have faced many challenges successfully in the past few years in adapting to the new gas industry forged by legislative and regulatory changes. Continued development and implementation of our plans will enable Columbia and its shareholders to benefit in this "Decade for Natural Gas."

JH Croom

John H. Croom
Chairman, President and
Chief Executive Officer

February 20, 1991

Better Schools, Better Schooling

Columbia's commitment to advance public education reform efforts took tangible shape in 1990. New programs will help involve employees more closely with their local schools, encourage parents to accept more responsibility for their children's schooling, promote local coalitions working for better education and focus public attention on the nation's education problems.

Columbia's support of better public education is not only a vital element of its corporate responsibility but also a cost of doing business. Columbia will always need skilled, literate men and women to provide safe and dependable service to its customers. And the nation needs citizens better schooled than those in other countries to maintain a sound economy in a competitive world.

Karen Hollern helps put Columbia's Education 2000 program into action at Dana Elementary School in Columbus, Ohio.

Columbia is in a unique position to work at the community level for better schools. Throughout our operating territory, Columbia's talented men and women are involved with all segments of the community and are thus able to play a central role in mobilizing attention to education matters. Recognizing these special opportunities, the American Gas Association has also begun a special 10-year education reform support program under the chairmanship of Columbia CEO John Croom.

Columbia's program builds upon longtime Columbia school assistance activities. Our retail companies have a tradition of providing information on energy sources and home economics to primary and secondary schools. Additionally, Columbia companies have established special partnerships to aid school programs in several locations.

In the Pittsburgh area, Columbia employees are mentors to students in an inner-city high school, aiding both their studies and their extracurricular activities. These students are gaining new confidence and a sense of direction from the special relationships.

In Charleston, West Virginia, Columbia employees established a working partnership with an inner-city elementary school, providing a variety of resources to bolster learning. Similarly, Columbia employees in Columbus, Ohio, work closely with another inner-city elementary school where students need an extra serving of attention and guidance.

Programs developed in 1990 extend beyond these traditional school partnerships. They respond to Columbia's 10-year commitment, as part of The Business Roundtable, to help achieve a world-class public education system for the United States.

As reform strategies are planned at the national, state and community level, Columbia hopes to build understanding among customers, employees and others of the need for education reform. Equally, we want to encourage parents to participate more in their children's learning process, something educators at all levels see as vital to better education.

The national education goals point to standards to be achieved by the year 2000. This target recognizes that the required changes will not be easily made.

Columbia's new programs are only the beginning of a decade-long effort, but they are as essential to the operation of our business as the installation of pipelines and protection of the environment.

System Profile

The Columbia Gas System is one of the largest natural gas systems in the United States. It is made up of a parent holding company, a service company and operating subsidiaries engaged in the production, purchase, storage, transmission, and distribution of natural gas at wholesale and retail, 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

Three Columbia subsidiaries explore for, develop, acquire, produce and market oil and gas. These companies hold varying interests amounting to 3.1 million net acres in the United States and Canada.

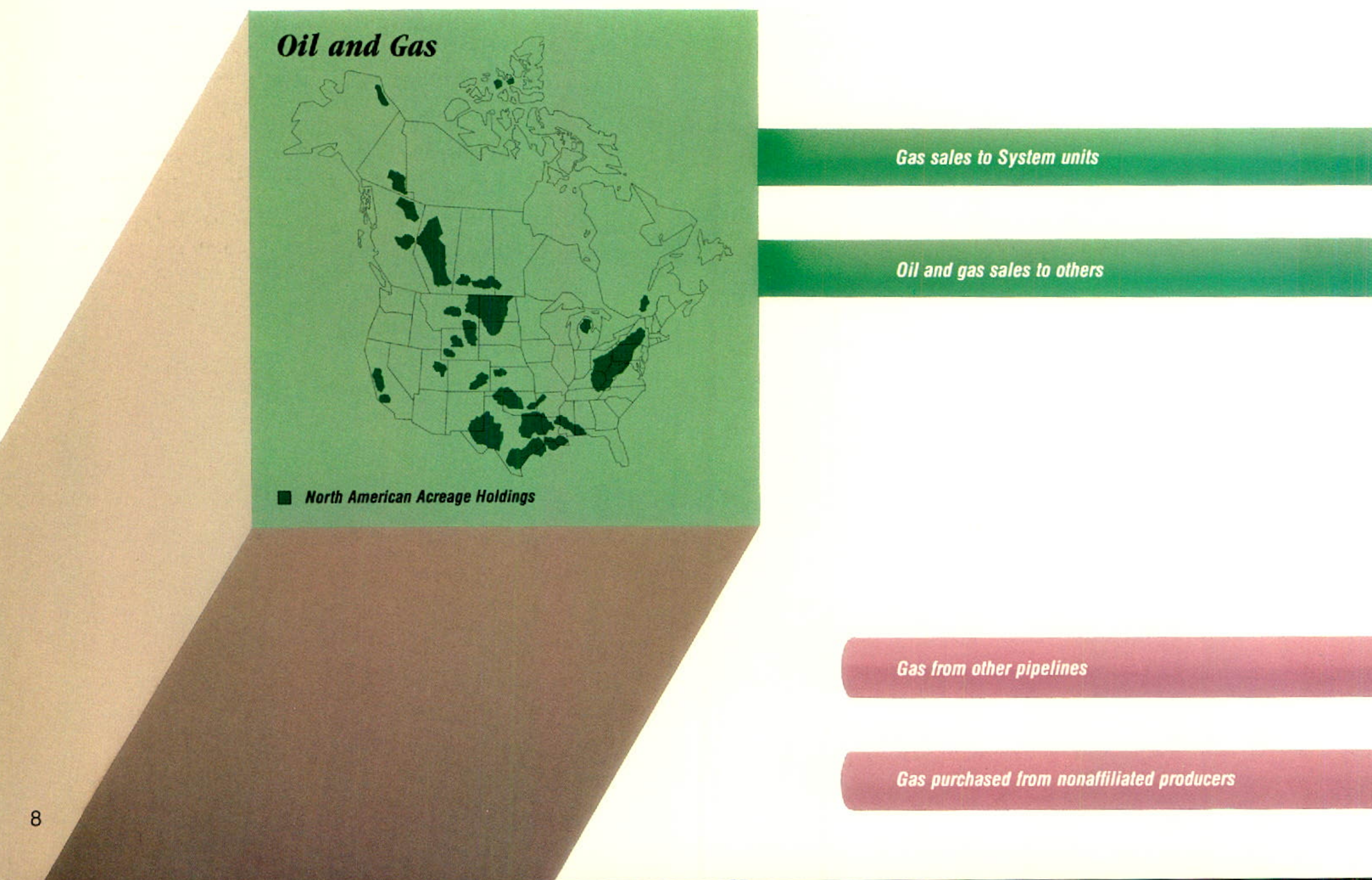
Domestic oil and gas operations are focused in the Appalachian and Michigan basins in the East, Williston and Powder River basins in the West, Permian and Arkoma basins in the Southwest, and onshore and offshore in the Gulf Coast areas of Texas and Louisiana. Domestic offshore holdings include varying interests in federal blocks, most of which are located in the West Cameron, Vermilion, Eugene Island and Ship Shoal areas in the Gulf of Mexico.

Canadian oil and gas operations are primarily situated in Alberta, British Columbia and the Yukon.

Columbia's exploration and development companies are among the industry's leaders in applying horizontal drilling techniques and their finding costs are below U. S. industry averages.

Transmission

Columbia's transmission companies operate a 23,000-mile pipeline network that extends from the Gulf of Mexico to the Northeast. Columbia Gas Transmission sells at wholesale and transports natural gas to affiliated and unaffiliated customers in 13 Northeastern, Middle Atlantic, Midwest and Southern states and the



District of Columbia. Columbia Transmission also operates one of the nation's largest underground storage systems and is the System's principal purchaser of natural gas in the Southwest, Midcontinent and Appalachian producing areas.

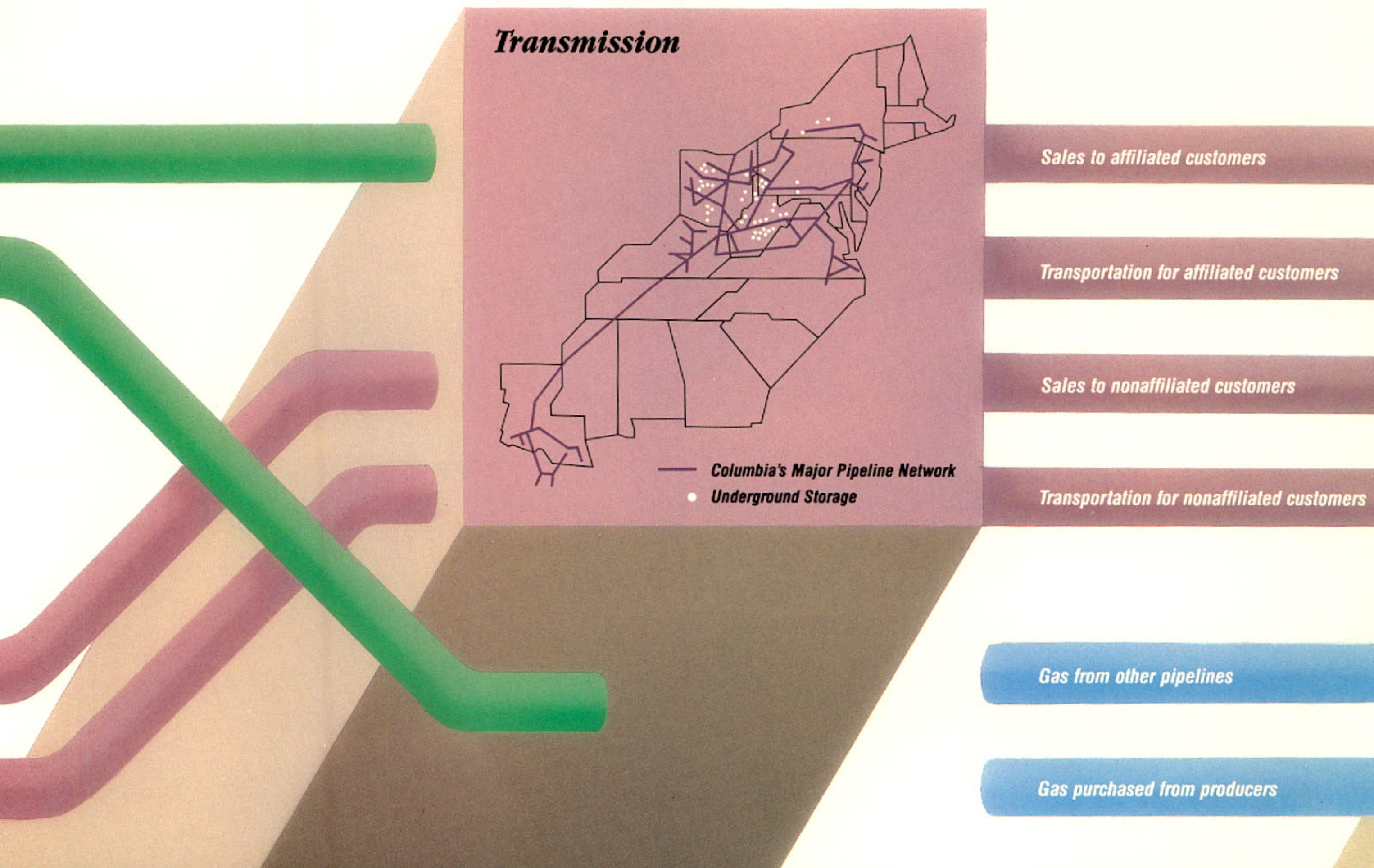
A major part of Columbia Gas Transmission's gas supply is delivered by Columbia Gulf Transmission through its pipeline network which extends from offshore Louisiana into Kentucky. Columbia Gulf also transports gas for unaffiliated customers and owns interests in the Ozark and Trailblazer pipeline systems, which extend into major Midcontinent and western gas production areas.

Columbia LNG Corporation is the owner of a liquefied natural gas receiving terminal on the western shore of the Chesapeake Bay at Cove Point, Maryland. With its partner, Shell Oil Company, Columbia anticipates reactivating the terminal in 1993 and marketing regasified LNG.

Distribution

Columbia's six distribution subsidiaries provide natural gas service to more than 1.8 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland and New York. Columbia's New York subsidiary is scheduled to be sold early in 1991. These subsidiaries also transport gas for industrial and large commercial users who purchase gas from other sources. Approximately 29,000 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; Staunton and Portsmouth, Virginia; Ashland, Frankfort and Lexington, Kentucky; Cumberland and Hagerstown, Maryland; and Binghamton, New York.

Distribution is also taking the lead in developing the end-use market for natural gas and new natural gas technologies. For new ventures such as compact water and space heaters, fuel cells or natural gas vehicles, Distribution guides research, organizes field tests and encourages manufacturers and marketers.



Other Energy Operations

Columbia's TriStar Ventures Corporation is pursuing cogeneration opportunities on its own and in partnership with others.

The System has two subsidiaries that sell propane at wholesale and retail to more than 63,000 customers in eight states.

System-owned coal reserves in the Appalachian area exceed 550 million tons. One-half of the reserves contain less than one percent sulfur, which makes them attractive in meeting current environmental standards. Columbia has leased some of these reserves to others for development.

TriStar Capital Corporation is a new subsidiary formed to support the development of new gas-related technologies.

Oil and Gas

Net Acreage (000)		Net Productive Gas Wells	6,217
Developed	1,591	Net Productive Oil Wells	427
Undeveloped	1,542	Oil and Gas Production	
Proved Reserves		Natural Gas (Bcf)	75
Natural Gas (Bcf)	926	Oil (000 Bbls)	2,688
Oil (000 Bbls)	18,991	1990 Capital Expenditures ($ in millions)	229

Transmission

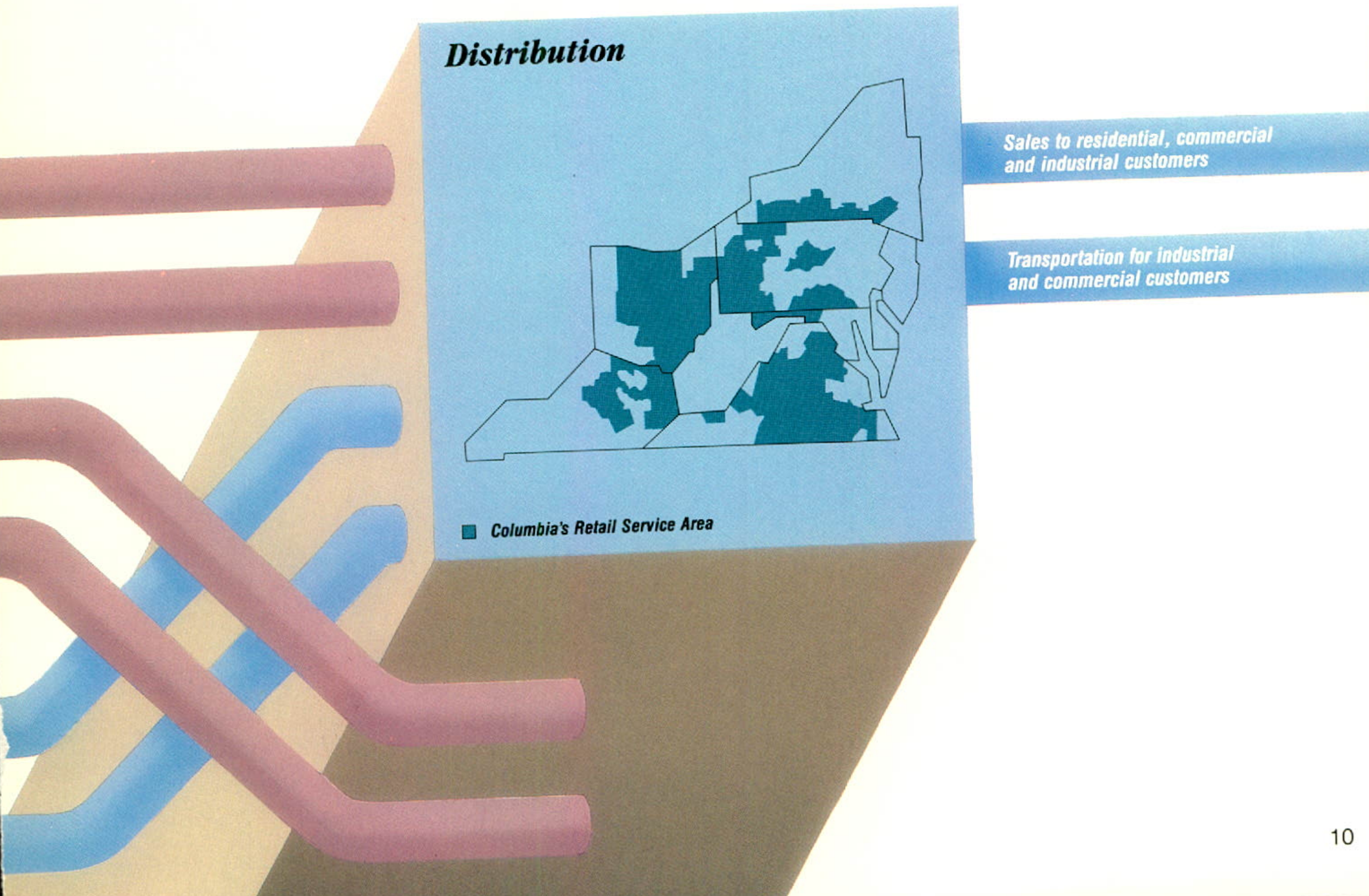
Total Throughput (Bcf)	1,386	Storage Capacity (Bcf)	698
Sales (Bcf)	89	1990 Capital Expenditures ($ in millions)	280
Transportation (Bcf)	1,297		

Distribution

Retail Customers		Total Throughput (Bcf)	466
Residential	1,724,281	1990 Capital Expenditures ($ in millions)	107
Commercial	165,144		
Industrial and Other	2,420		
Total	1,891,845		

Other Energy

Coal Reserves (Million Tons)	550	Propane Customers	63,546
1990 Capital Expenditures ($ in millions)	14	Gallons Sold (000)	74,406



In 1990, Columbia successfully tested horizontal drilling techniques in the Devonian Shale.

January
Columbia's Board of Directors increases quarterly dividend 10 percent.

Columbia initiates record capital expenditure program.

February
Transmission files with Federal Energy Regulatory Commission for its first gas sales to South Carolina and Tennessee.

March
With weather 23 percent warmer than normal, Columbia records warmest first quarter in its history.

April
Columbia of Ohio receives disappointing rate increase.

May
John W. Snow, CSX chairman, elected to Board of Directors.

June
TriStar Ventures and partners begin constructing a major cogeneration facility at Pedricktown, N.J.

July
John H. Croom announces "Education 2000" program.

For fourth consecutive year, Pennsylvania ranks Columbia first in customer service.

August
Columbia agrees to sell New York distribution subsidiary to New York State Electric & Gas.

Columbia Gas Development completes successful horizontal wells in Williston Basin of North Dakota and the Austin Chalk formation in Texas and purchases interest in Gulf of Mexico oil field.

September
John D. Daly becomes System executive vice president and director.

Columbia of Pennsylvania receives general rate increase.

Columbia LNG receives award for outstanding environmental stewardship at Cove Point LNG Receiving Terminal from the Maryland Conservation Council and the Sierra Club.

Columbia of Kentucky announces rate settlement for 1991 and 1992.

Columbia joins partnership to build cogeneration plant in Binghamton, N.Y.

James R. Thomas, II, president of Charleston, W. Va., Renaissance Corporation, elected to Board of Directors.

October
Columbia becomes the sole owner of West Cameron 485/507 blocks in the Gulf of Mexico, where a major discovery was made in 1989.

November
Service begins to customers in New Jersey, Massachusetts and Rhode Island through new Columbia Transmission pipeline.

U.S. Supreme Court upholds Columbia position in two major rate-making cases.

Gas Related Activities Act adopted, easing Public Utility Holding Company Act business restrictions.

December
Columbia Natural Resources completes experimental horizontal well in Kentucky.

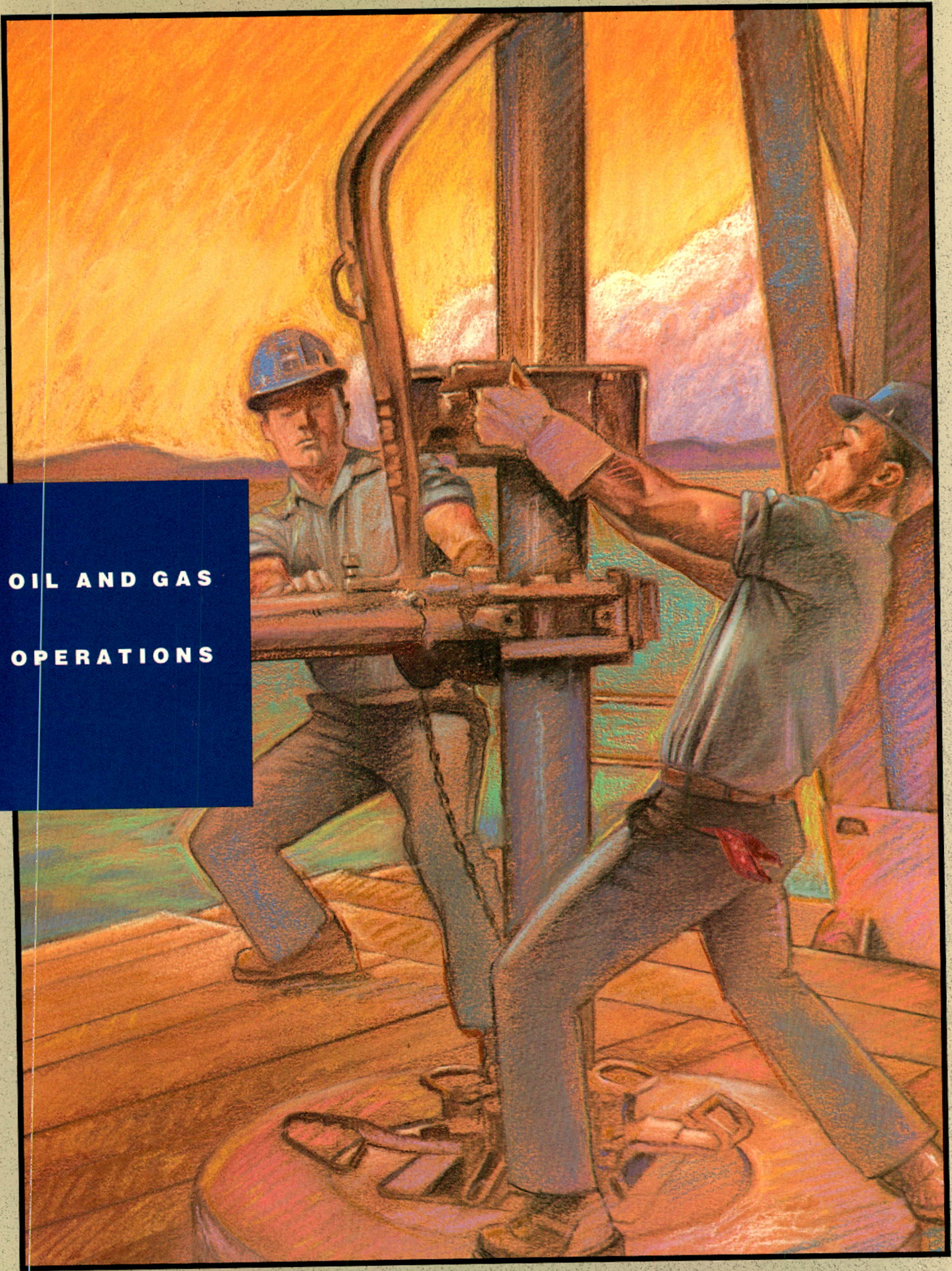
Settlement ends lengthy East Lynn, W. Va., condemnation proceedings.

Commonwealth Gas Services announces rate case settlement.

Columbia issues 2.6 million shares of common stock.

Warm December closes Columbia's warmest year on record.

OIL AND GAS OPERATIONS



Columbia's oil and gas operations had a successful 1990 through a combination of increased reserves and overall production, higher wellhead prices and low finding costs.

Oil and Gas net income increased to $39 million, as compared with $2 million in 1989. Approximately $29 million of the increase reflects a positive court ruling in December which resolved a dispute with the Army Corps of Engineers that had been pending since the 1970s. At issue was the value of mineral rights condemned by the Corps when it constructed a reservoir in West Virginia.

(l-r) John P. Bornman, Jr., president, Columbia Gas Development; Lawrence J. Macdonald, president and CEO, Columbia Gas Development of Canada; John R. Henning, president and CEO, Columbia Natural Resources

Price/Demand Outlook

The average price Columbia received for its natural gas production increased to $2.00 per thousand cubic feet, six percent above 1989 prices, despite warm weather that weakened overall demand throughout much of the year. This price, when compared to the average wellhead spot price for Southwest gas of $1.83, demonstrates the success of Columbia's marketing strategies and the premium locational value of its Appalachian reserves. As a result of the turmoil in the Middle East, the average sales price Columbia received for oil was $22.86 per barrel, a 37 percent increase over 1989.

In the United States and Canada, natural gas is currently selling at prices below expectations because of abnormally warm weather plus the negative impact of the current recession. Longer-term, real natural gas price growth is anticipated during the 1990s due to a more balanced relationship between supply and demand.

Natural gas has become the fuel of choice. Because of large potential domestic reserves totaling 640 trillion cubic feet, natural gas has the potential to reduce the United States' dependence on oil imports from the volatile Middle East. In addition, its clean-burning characteristics and the passage of clean air legislation during 1990 should boost demand for gas to fuel existing and new electric power plants. Finally, the nation's extensive pipeline network can deliver the gas to the market efficiently and economically.

Production and Reserves Climb

In 1990, Columbia's three oil and gas companies increased overall annual production by two percent while, at the same time, increasing reserves. Oil production increased by almost 40 percent to 2.69 million barrels. Total gas production, which amounted to 75.3 billion cubic feet, was down slightly because of weak summer prices and pipeline maintenance activities which resulted in a limited shut-in of production.

During 1990, while continuing to hold its finding costs below the industry average, Columbia added proved gas reserves of 98.3 billion cubic feet, and proved oil reserves of 4.9 million barrels. Columbia's current combined year-end proved oil and gas reserves are almost 1.04 trillion cubic feet of gas equivalent, an increase of 3.6 percent over 1989.

This horizontal well in North Dakota successfully tested the Bakken formation last year.

Oil and Gas Investment

Over the next five years, Columbia plans to invest an average of $200 million per year in exploration and development to capitalize on its oil and gas strengths:

- The more than three million net acres of gas and oil leases it owns in the United States and Canada, about half of which are undeveloped;
- The expertise and extensive reservoir knowledge of its exploration and production staffs; and
- The use of the most advanced exploration and production techniques.

Columbia's objective is to increase the size of its oil and gas segment from one-fifth to approximately one-third of its total net plant. In terms of total reserves, the oil and gas segment currently ranks among the top 20 independent producers in the United States.

Drilling Program Sets Record

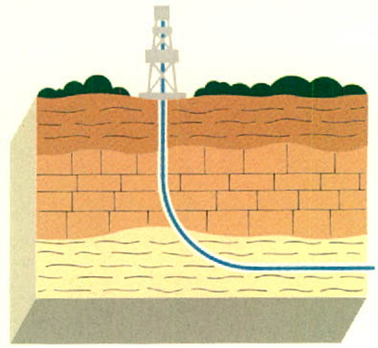
In 1990, the System's exploration and development companies set a new Columbia record by drilling 203 net wells in the United States and 17 net wells in Canada. This is more than double the wells drilled in 1989 and almost triple the number of wells drilled in 1988.

Advanced technology helps geologist Jim Hansen predict changes in complex oil and gas formations.

The U.S. drilling program added 82 billion cubic feet of proved natural gas reserves and almost four million barrels of proved oil reserves, as a result of significant finds in the Gulf of Mexico, South Louisiana and Appalachia, and Columbia's highly-successful horizontal drilling program.

Horizontal Drilling

Columbia was one of the first producers to recognize the potential of horizontal drilling techniques. During 1990, Columbia participated in the drilling of 35 horizontal wells



in the Austin Chalk formation in Texas and the Bakken formation in North Dakota. This represents an increase of 23 wells over the 12 wells projected in last year's annual report. A 96 percent success rate for these wells was a major reason Columbia was able to increase its average domestic daily oil production from 3,000 barrels in January to 6,000 barrels in December. Based on these successes, Columbia plans to participate in 35 horizontal wells during 1991.

Columbia also completed a successful experimental horizontal well in eastern Kentucky into the Devonian Shale, a massive, gas-rich formation that underlies much of the Appalachian Basin. The well was completed with an open flow of 3.2 million cubic feet per day and about five times the average reserves that would be expected from a vertical well in the same formation. Further application of horizontal drilling techniques could significantly increase the value of Columbia's vast Appalachian acreage. Approximately one-third of the 2.3 million acres of oil and gas leases Columbia owns in the Appalachian Basin have Devonian Shale potential. Columbia is planning to drill additional horizontal wells in Appalachia in 1991.

Other Domestic Drilling

In California, Columbia is involved in a major secondary oil recovery project scheduled to begin production in 1992. Columbia's share of recoverable reserves is estimated to be 3 million barrels.

Significant finds and acquisitions in the Gulf of Mexico, southern Louisiana and Texas contributed 29 billion cubic feet of natural gas and 1.7 million barrels of oil to reserves. Columbia plans to set a second platform in the West Cameron 485/507 block in the Gulf of Mexico where it had a significant gas find in 1989.

In the Appalachian Basin, Columbia drilled 144 net wells in 1990, 95 percent of which were successful. Federal tax credits apply to most of these wells. The recent extension of these credits through 1992 will permit additional wells to qualify, including wells drilled into the Devonian Shale.

Geologist Kerima Haddad inspects an Appalachian well core sample.

The quality and production characteristics of Appalachian wells, combined with their proximity to available pipeline capacity, make them a desirable source of gas for cogeneration projects and other longer-term markets in the Northeast and along the Eastern Seaboard.

In 1991, Columbia anticipates conducting a domestic drilling program comparable to 1990's.

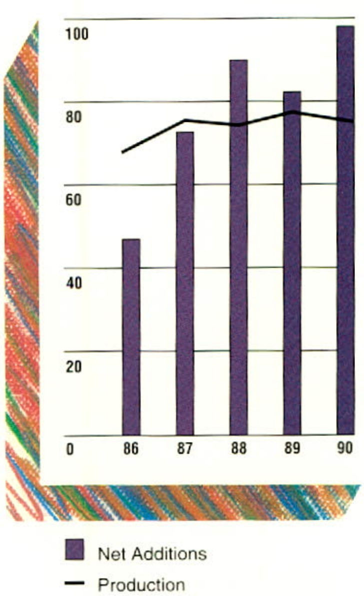
Canadian Activity

In 1990, Columbia made a promising gas and condensate discovery in the Hamburg-Milligan area of northwestern Alberta, with proved reserves of 13 billion cubic feet of gas equivalent, and has acquired acreage to support additional wells to be drilled during 1991. However, results of Columbia's drilling program in British Columbia were disappointing because its Grizzly exploratory well was dry and its Crow River exploratory well cannot be economically produced at current prices and conditions.

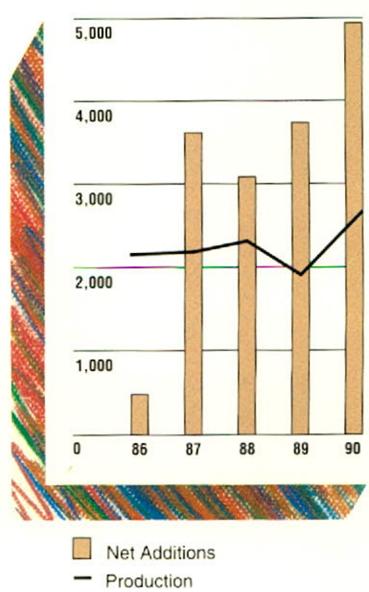
In February 1991, Columbia began production from the large Kotaneelee Field located in the Yukon Territory with its interest yielding an estimated 4 billion cubic feet annually. This production is being sold in British Columbia.

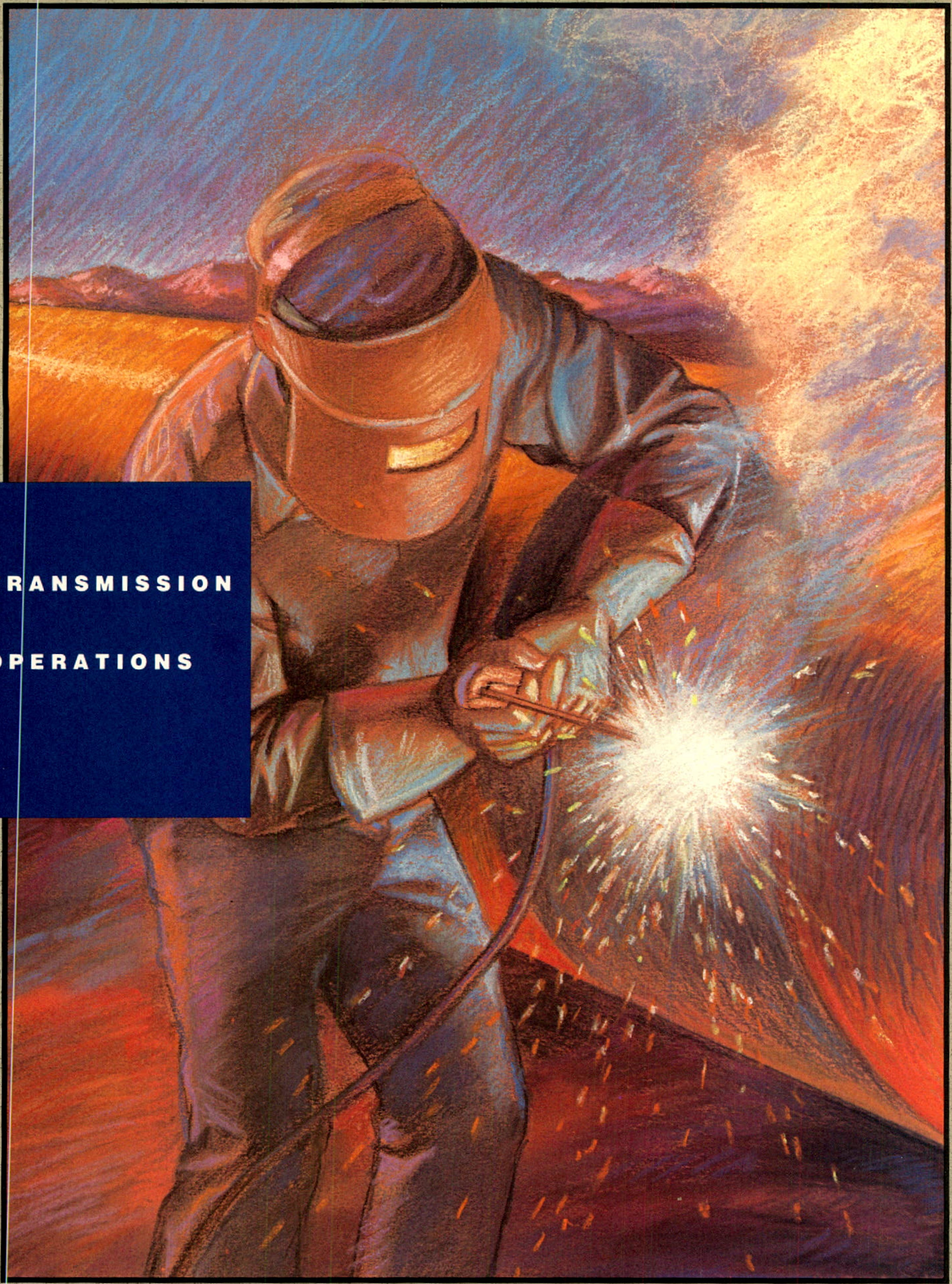
Regulatory actions and pipeline capacity constraints have delayed Columbia's planned sale of about 5 billion cubic feet of gas per year to cogeneration plants in the northeastern United States.

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



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





TRANSMISSION OPERATIONS

Dramatically warmer-than-normal weather was the primary cause of Transmission's disappointing financial results in 1990 and interrupted the rebound it began in 1989. Transmission's merchant function will continue to be adversely affected by 1990's record-setting warm weather through higher

(l-r) James T. Connors, senior vice president; R. Larry Robinson, president, and James P. Holland, chairman and CEO, Columbia Transmission Companies.

gas storage balances, lower spot gas prices and higher gas supply management costs. Nevertheless, Columbia's longer-term outlook for Transmission remains strong and the strategies for this business segment remain on course. Columbia expects demand for natural gas to increase and expects to capitalize on Transmission's inherent strengths to profit from that demand.

Throughput and Earnings

Total throughput for Transmission in 1990 amounted to 1,386 billion cubic feet, down 14 percent from the previous year. Earnings of $47.2 million were 39 percent below 1989. The warmer weather and the effects of the 1989 sale of storage gas primarily account for the decrease in throughput.

A Supreme Court action upholding a court of appeals decision will enable Transmission to recoup $48.4 million, including interest, pre-tax, previously paid to other pipelines for production-related costs incurred during the early 1980s. The earnings effect of this Supreme Court action was recorded in 1990.

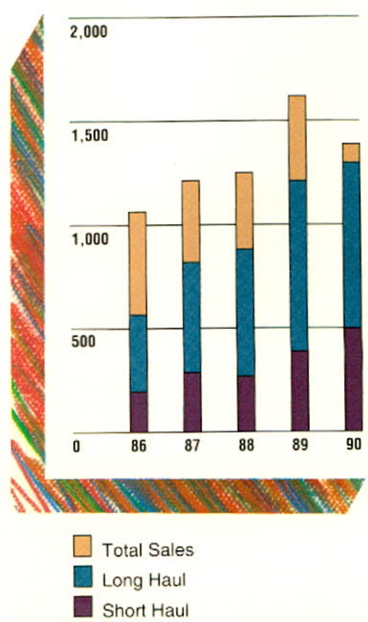
Marketing

Transmission has completed the first phase of a two-year, $300-million pipeline construction and expansion program. The completion of the final phase of the program will provide expanded capacity to meet new long-term service commitments.

As a transporter and marketer of gas, Transmission's strengths lie in its access to virtually every major producing area in the United States, its extensive underground storage system, the efficiency and flexibility of its 23,000-mile pipeline network and the quality service provided by its workforce.

Transmission's marketing efforts focus on high-quality loads near its pipelines which

Transmission Gas Throughput
(in billion cubic feet)



can be attached at modest cost. Transmission is working to maximize the use of existing facilities, thereby lowering its cost of providing service and increasing its ability to improve earnings.

Marketing opportunities exist throughout Transmission's recently expanded market territory. Providing natural gas service for new electric power generation, including cogeneration, is one of the most promising. Additionally, the Clean Air Act Amendments passed by Congress during 1990 provide significant marketing opportunities as older power plants strive to meet new, more stringent emissions standards.

After construction and restoration work have been completed, a Columbia pipeline marker is the only indication that a major pipeline crosses this historical acreage in Pennsylvania.

Competition

Transmission's transportation rates are among the lowest of all pipelines serving the highly competitive Northeast and Midwest markets, allowing it to compete successfully for the transportation market. This is significant because, during 1990, 94 percent of all gas moving through Columbia's interstate pipeline system was being transported for others.

Like most pipelines, Transmission's sales rates generally exceed the delivered spot market prices except during peak winter demand periods. Transmission is attempting to reduce its sales rates by renegotiating prices under certain gas supply contracts and by modifying rate designs.

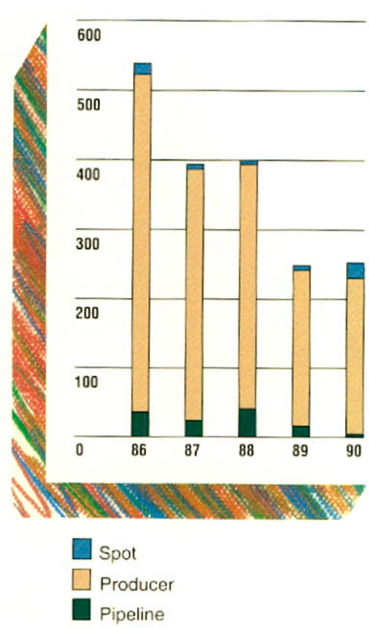
Rate Initiatives

Looking toward the future, Transmission is working to modify existing Federal regulatory practices to permit new flexible rate structures allowing regulated pipelines to compete with unregulated natural gas sellers and to earn returns that bear a reasonable relationship to the increased risks they are incurring in today's more competitive marketplace. As chairman of the Interstate Natural Gas Association of America, System Executive Vice President John D. Daly is leading industry efforts to promote these regulatory reforms.

Supply Management

Transmission is renegotiating certain producer contracts to make them more market-responsive when all controls are removed from wellhead prices in January 1993 and to resolve

Transmission Gas Purchases
(in billion cubic feet)



Lathe operator Greg Jordan prepares a power piston for a compressor engine.

pending litigation. Several contracts were renegotiated in 1990, and others are expected to be renegotiated in 1991.

To help offset the lingering effects of the warm weather and balance supply against reduced demand, Transmission is continuing its program of securing temporary releases from obligations under gas purchase contracts.

Cove Point LNG Terminal

Efforts by Columbia and Shell Oil to reactivate the liquefied natural gas receiving terminal at Cove Point on the Chesapeake Bay and to import LNG continued to make progress in 1990. The facility is scheduled to resume operation in 1993.

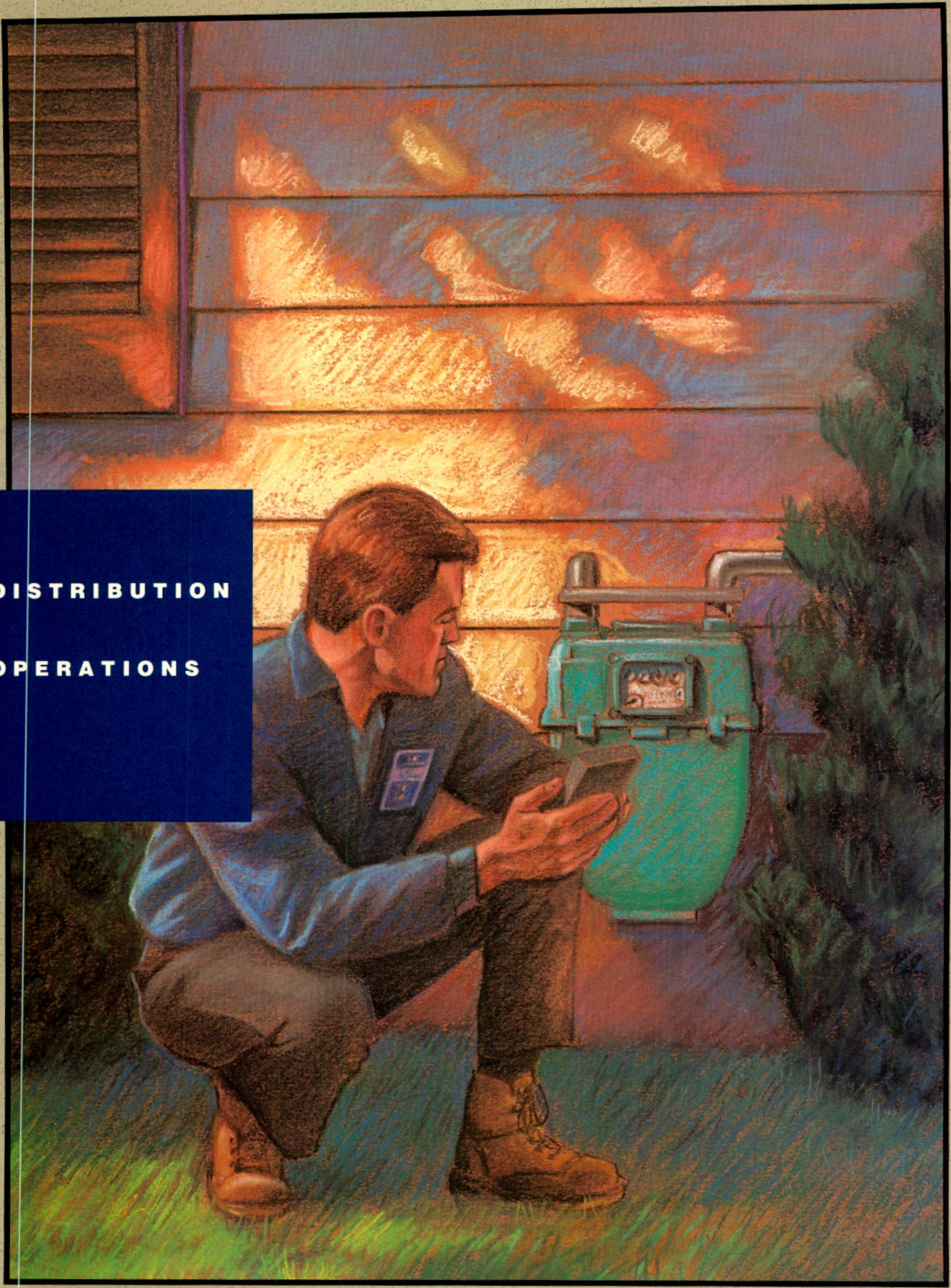
The terminal, which can deliver up to a billion cubic feet of natural gas daily by regasifying LNG, is strategically located close to several major pipelines. It is capable of serving markets along the Eastern seaboard and elsewhere in the nation through transportation arrangements on other pipelines.

A supply agreement for Algerian liquefied natural gas was signed in February 1991 and an agreement for Nigerian LNG is expected to be finalized in March. The agreements will clear the way for filings seeking regulatory approvals to reactivate the terminal and to import the LNG to help meet projected gas demand. The recommissioning of the terminal will begin after these approvals have been received.

Completion of this project will return an idle asset to service as well as provide a source of earnings from marketing the LNG. It will also enhance throughput on Columbia's pipeline system.

Nancy Kuhl checks a natural gas storage well in West Virginia.

DISTRIBUTION OPERATIONS



Record warm weather held Distribution's earnings to $24.6 million in 1990, as compared with $68.6 million in 1989.

Throughput totaled 466 billion cubic feet in 1990, down five percent from 1989. If temperatures had been normal, throughput would have been approximately 500 billion cubic feet.

(l-r) Columbia Distribution Companies' Chairman and CEO C. Ronald Tilley with Distribution subsidiary presidents, Thomas E. Harris, Gary J. Robinson, and Richard J. Gordon.

Overall, however, markets for natural gas in Columbia's operating areas continue to grow. Deliveries to industrial and commercial customers, which are less sensitive to fluctuations in the weather than deliveries to residential customers, increased by two percent over 1989. In addition, Distribution added more than 40,000 new customers during the year and currently serves more than 1.8 million homes, businesses and industries.

Marketing Strengths

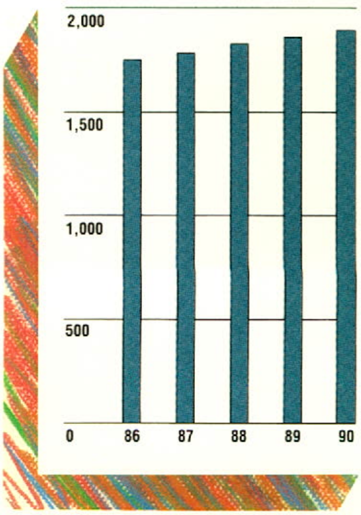
Distribution's service territory is one of its major strengths. Columbus, Lexington, Richmond, Pittsburgh and York, hubs of Distribution's operations, now have diversified economies. They are no longer overly reliant on heavy industry and, therefore, are less vulnerable to economic downturns. In these regional centers, the number of Distribution customers increased more than five percent last year, about three times the national average.

Distribution also benefits from its ongoing economic development program which, in 1990 alone, helped attract nearly 70 new businesses–representing about 8,000 new jobs and 3 billion cubic feet of new annual gas load–to its operating area.

Technical marketing services that Distribution offers its industrial customers maximize load retention and attract new large volume customers. These services provide a blend of energy audits, qualitative and economic comparisons of gas equipment and assessments of competing technologies.

Distribution also supports the commercialization of new natural gas technologies, developed through research sponsored by Columbia and other companies. Among these is the natural gas fuel cell which converts gas to electricity without combustion. Several 200-kilowatt fuel cell units are slated for installation in Distribution's market areas in 1992 and 1993.

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

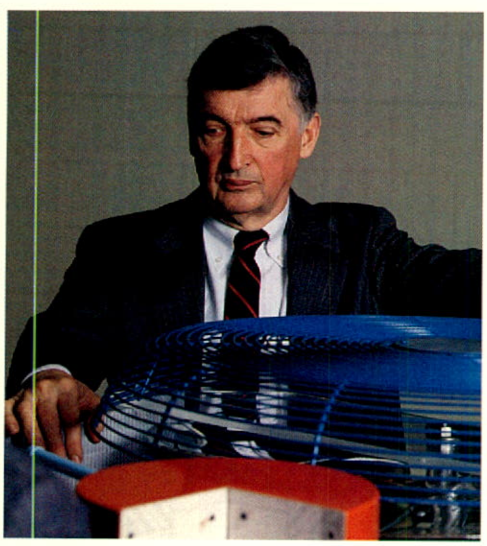


Marketing Opportunities

Distribution is promoting natural gas as one of the prime solutions to growing U.S. energy and environmental concerns.

Distribution helped develop the nation's first urban transit bus, the "Columbia," designed to run exclusively on compressed natural gas. It has converted a large portion of its service fleet to natural gas, and, in 1991, it will open several new natural gas filling stations. In addition, Distribution Chairman and CEO Ron Tilley will become the chairman of the Natural Gas Vehicle Coalition, the national organization working to develop commercial markets for natural gas vehicles.

During 1990, Distribution began gas deliveries to two new gas-fueled power plants in Virginia; and, by 1992, it expects its annual gas deliveries for power generation will be more than 30 billion cubic feet.



Howard Meacham leads a research team preparing an advanced natural gas heat pump for eventual commercialization.

Clean air legislation recently passed by Congress holds the promise of further increases in the use of natural gas to generate electric power. By 1996, projects now on the drawing boards could increase Distribution's gas deliveries to the power generation market to more than 50 billion cubic feet annually, about 10 percent of its current total throughput.

Supply Management

Distribution maintains a diverse gas supply portfolio to assure that reliable supplies of competitively-priced gas are available to its customers. In 1990, more than three-quarters of its supply was purchased from various producers and the remainder from interstate pipelines.

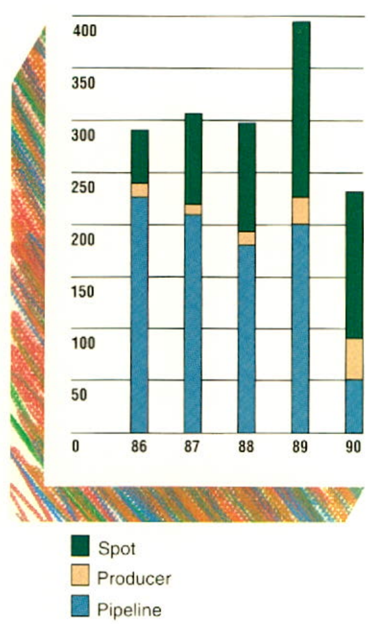
The flexibility provided by this supply portfolio, combined with storage and pipeline transportation options it now has available, enables Distribution to provide a wide variety of services for all classes of customers at competitive rates. Currently, its rates are more than 20 percent below those in effect in the mid-1980s.

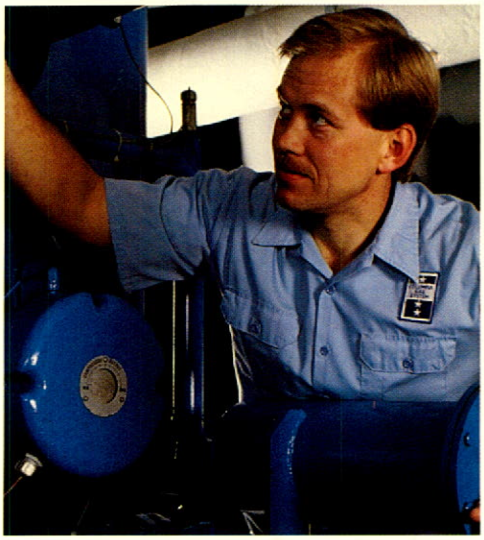
Regulatory Environment

While rate increases were approved for each distribution company during 1990, regulatory lag continues to be a problem. One of Distribution's main objectives is to streamline the regulatory process to assure its rates reflect current costs of doing business.

During 1990, progress was made toward this goal in Kentucky and Virginia where rate

Distribution Gas Purchases
(in billion cubic feet)





Technician Larry DeMint inspects an economical, high-efficiency gas-fired cooling system.

increases reflected broader recognition of future operating cost levels and capital investment rather than relying solely on costs incurred during a prior period. However, rates approved in Ohio were disappointing because they were based on historic cost levels which were out of date long before the new rates went into effect. Because of this regulatory lag, Columbia Gas of Ohio made a new rate filing in early 1991 to recover current operating costs and bring its earnings to a more acceptable level.

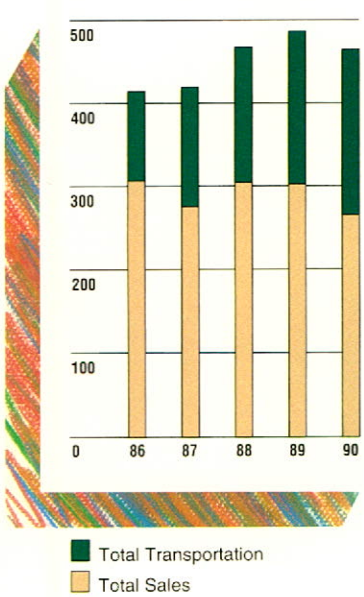
Distribution is also working to establish flexible pricing mechanisms that will permit the quick response necessary to meet changing competitive conditions in the energy marketplace.

Quality Customer Service

For the fifth consecutive year, Columbia Gas of Pennsylvania's operations were ranked first in customer service among all Pennsylvania natural gas companies by the state's Bureau of Consumer Services. In addition, customer complaints declined 30 percent throughout Distribution's market area. These examples highlight the quality customer service that is the hallmark of Distribution's operations.

Janet Kinzer gives the clean-burning exhaust of the nation's first urban transit bus, the "Columbia," a white handkerchief test.

Distribution Gas Throughput
(in billion cubic feet)



Columbia pursues opportunities in other energy markets: cogeneration, propane and coal. In the next few years, investments in these nonregulated businesses should begin to improve earnings, particularly as major cogeneration projects begin operations.

Cogeneration

Cogeneration, a highly efficient process which simultaneously produces electricity and useful thermal energy from a single fuel, continues to be a key growth area for natural gas. It is also an excellent example of the benefits of Columbia's integrated system. In addition to having an equity interest in the cogeneration projects themselves, Columbia's transmission and distribution companies can benefit from the increased throughput the projects generate, and the oil and gas companies can benefit from increased sales opportunities.

OTHER ENERGY OPERATIONS

Columbia's TriStar Ventures is a partner in Cogeneration Partners of America, which broke ground in 1990 for a 117-megawatt cogeneration project at Pedricktown, N.J., and anticipates commencing construction of a 50-megawatt plant in Binghamton, N.Y. Beginning in 1992, the Pedricktown plant will supply steam to a major chemical plant and electricity to Atlantic Electric Company. 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 planning stage, including two major plants in the Washington, D.C., area and another plant in southern New Jersey.

Columbia intends to pursue further cogeneration opportunities and is supporting regulatory reforms to facilitate these investments. In addition, Columbia will support legislation to encourage independent power production and to allow the expansion of Columbia's activities beyond cogeneration.

(l-r) A. Mason Brent, president, Columbia's propane companies; Bartholomew F. Cranston, president, TriStar Ventures Corporation.

Propane

Propane is the fourth largest source of energy in the U.S. and demand continues to grow, primarily in suburban and rural areas not served by natural gas.

Commonwealth Propane is the largest Virginia-based propane marketer with a balanced mix of residential, industrial, commercial and agricultural customers. Columbia Propane markets in parts of Ohio, Maryland and Pennsylvania.

Columbia's propane companies sold 74.4 million gallons of propane in 1990, down slightly from 1989, primarily because of warmer than normal weather. The two companies serve more than 63,000 customers.

Coal

Columbia owns approximately 550 million tons of coal reserves, approximately 50 percent of which contains less than one percent sulfur. Over the past few years, Columbia has leased some of these reserves to third parties for development.

Financial Review

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	1990	1989	1988	1987	1986
Sales and Transportation Revenues					
Residential	**943.9**	1,140.6	1,157.7	1,033.9	1,083.2
Commercial	**369.9**	450.7	470.1	427.1	491.2
Industrial	**64.0**	82.2	118.4	104.6	221.3
Wholesale	**321.0**	835.2	919.1	862.7	1,275.3
Other	**102.4**	81.6	40.6	28.2	16.1
Transportation	**373.2**	512.3	370.3	320.9	237.7
Total Sales and Transportation Revenues	**2,174.4**	3,102.6	3,076.2	2,777.4	3,324.8
Sales (billion cu. ft.)					
Residential	**173.5**	201.5	195.5	175.1	178.8
Commercial	**76.8**	85.0	85.6	79.8	87.2
Industrial	**16.6**	16.8	26.9	22.4	47.7
Wholesale	**82.7**	246.8	220.8	214.8	283.6
Other	**52.3**	46.1	22.5	18.9	9.2
Total Sales	**401.9**	596.2	551.3	511.0	606.5
Transportation volumes	**1,175.0**	1,051.5	779.4	745.8	541.5
Total Throughput	**1,576.9**	1,647.7	1,330.7	1,256.8	1,148.0
Sources of Gas Sold (billion cu. ft.)					
Total gas purchased	**453.3**	449.4	517.5	491.5	596.8
Total gas produced	**75.3**	77.9	74.6	76.0	73.2
Exchange gas–net	**21.1**	(15.0)	5.8	(13.1)	7.7
Gas withdrawn from (delivered to) storage	**(137.5)**	109.0	(0.2)	(4.1)	(24.2)
Company use and other	**(10.3)**	(25.1)	(46.4)	(39.3)	(47.0)
Total Sources of Gas Sold	**401.9**	596.2	551.3	511.0	606.5
Customers at Year End					
Residential	**1,724,281**	1,693,914	1,666,013	1,626,341	1,598,960
Commercial	**165,144**	161,864	157,475	152,104	148,013
Industrial	**2,400**	2,334	2,341	2,190	2,180
Wholesale	**81**	78	79	82	78
Other	**142**	127	96	92	41
Total Customers at Year End	**1,892,048**	1,858,317	1,826,004	1,780,809	1,749,272
Average Usage per Customer (thousand cu. ft.)					
Residential	**100.6**	119.0	117.4	107.7	111.8
Commercial	**465.1**	524.9	543.6	524.7	589.3
Degree Days for Retail Operations	**4,893**	6,083	6,014	5,470	5,521
% Colder (warmer) than normal	**(16.7)**	3.6	1.8	(6.8)	(6.0)

(Dollars in millions except for per share amounts)	**1990**	1989	1988	1987	1986
Income Statement Data ($) (Note 2C)					
Total operating revenues	**2,357.9**	3,204.4	3,168.2	2,866.0	3,415.1
Products purchased	**846.8**	1,669.0	1,822.3	1,534.2	2,002.9
Earnings on common stock before extraordinary charges	**104.7**	145.8	111.1	100.5	87.9
Earnings on common stock	**104.7**	145.8	111.1	100.5	75.3
Per Share Data					
Earnings per common share ($):					
Before extraordinary charges	**2.21**	3.21	2.46	2.30	2.12
Earnings on common stock	**2.21**	3.21	2.46	2.30	1.82
Dividends:					
Per share ($)	**2.20**	2.00	2.295	3.18	3.18
Payout ratio (%)	**99.5**	62.3	93.3	138.3	174.7
Average common shares outstanding (000)	**47,316**	45,494	45,190	43,763	41,436
Balance Sheet Data ($)					
Capitalization (including short-term debt and current maturities*):					
Common stock equity	**1,757.8**	1,620.3	1,552.6	1,523.7	1,448.7
Preferred stock	**—**	—	—	50.0	50.0
Redeemable preferred stock	**—**	—	—	60.0	65.0
Long-term debt	**1,428.7**	1,196.0	1,038.4	1,438.0	1,378.5
Short-term debt and current maturities	**770.7**	681.4	749.8	397.1	825.9
Total	**3,957.2**	3,497.7	3,340.8	3,468.8	3,768.1
Total assets	**6,196.3**	5,878.4	5,641.0	5,440.9	5,590.2
Other Financial Data					
Capitalization ratio (%) (including short-term debt and current maturities*):					
Common stock equity	**44.4**	46.3	46.5	43.9	38.4
Preferred stock	**—**	—	—	3.2	3.1
Debt	**55.6**	53.7	53.5	52.9	58.5
Capital expenditures ($)	**629.6**	473.5	307.9	298.8	232.3
Net cash from operations ($)	**420.1**	400.5	429.4	702.0	559.1
Book value per common share ($)	**34.83**	35.50	34.18	34.08	34.06
Return on average common equity before extraordinary charges (%)	**6.2**	9.2	7.2	6.8	6.1

*The Corporation makes extensive use of variable rate debt on a continuing basis since it normally costs less than the Corporation's senior long-term debt. Because of this the Corporation believes that the capitalization ratios are more meaningful when short-term debt and current maturities are included.

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 six directors who are not officers or employees of the Corporation. The audit committee meets periodically with the Vice President and General Auditor to review 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) and subsidiaries (the "Corporation") as of December 31, 1990 and 1989, and the related statements of consolidated income, taxes, common stock equity and cash flows for each of the three years in the period ended December 31, 1990. 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 as of December 31, 1990 and 1989, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1990 in conformity with generally accepted accounting principles.

As discussed in Note 2C, the Federal Energy Regulatory Commission issued an order in January 1989 authorizing a pipeline supplier of Columbia Gas Transmission Corporation to retroactively collect higher prices from its customers for gas it produced and sold in prior years. The ultimate outcome of this matter is uncertain.

Arthur Andersen & Co.

New York, New York
February 6, 1991

Statements of Consolidated Income

Year Ended December 31 (in millions)	1990	1989	1988
Operating Revenues			
Gas sales	$1,801.2	$2,590.3	$2,705.9
Transportation	373.2	512.3	370.3
Other	183.5	101.8	92.0
Total Operating Revenues	2,357.9	3,204.4	3,168.2
Operating Expenses			
Products purchased	846.8	1,669.0	1,822.3
Operation	714.1	650.7	567.3
Maintenance	107.9	105.4	82.6
Depreciation and depletion	248.8	234.2	212.8
Other taxes	178.2	182.6	170.0
Total Operating Expenses	2,095.8	2,841.9	2,855.0
Operating Income	262.1	362.5	313.2
Other Income (Deductions)			
Interest income and other, net (Note 10)	70.3	55.5	36.5
Interest expense and related charges (Note 11)	(169.8)	(202.9)	(180.1)
Total Other Income (Deductions)	(99.5)	(147.4)	(143.6)
Income before Income Taxes	162.6	215.1	169.6
Income Taxes	57.9	69.3	50.6
Net Income	104.7	145.8	119.0
Preferred Stock Dividends	—	—	7.9
Earnings on Common Stock	$ 104.7	$ 145.8	$ 111.1
Earnings Per Share of Common Stock (based on average shares outstanding)	$ 2.21	$ 3.21	$ 2.46
Dividends Per Share of Common Stock	$ 2.20	$ 2.00	$ 2.295
Average Common Shares Outstanding (thousands)	47,316	45,494	45,190

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

Consolidated Balance Sheets

Assets as of December 31 (in millions)	1990	1989
Property, Plant and Equipment		
Gas utility and other plant, at original cost	**$6,014.1**	$5,359.6
Accumulated depreciation and depletion	**(2,813.6)**	(2,690.2)
	3,200.5	2,669.4
Oil and gas producing properties, full cost method		
United States cost center	**1,130.7**	1,035.2
Canadian cost center	**260.2**	232.8
Accumulated depletion	**(540.8)**	(544.9)
	850.1	723.1
Net Property, Plant and Equipment	**4,050.6**	3,392.5
Investments and Other Assets		
Gas supply prepayments (Note 3)	**423.3**	474.8
Accounts receivable–noncurrent	**—**	106.8
Unconsolidated affiliates (less than 50% owned)	**51.6**	54.4
Other	**64.4**	44.0
Total Investments and Other Assets	**539.3**	680.0
Current Assets		
Cash and temporary cash investments	**7.9**	14.0
Accounts receivable		
Customers (less allowance for doubtful accounts of $8.3 and $8.1, respectively)	**500.3**	907.0
Other	**300.2**	259.8
Gas inventory	**435.5**	271.1
Other inventories–at average cost	**51.1**	48.1
Prepayments	**138.4**	117.8
Other	**28.2**	26.8
Total Current Assets	**1,461.6**	1,644.6
Deferred Charges	**144.8**	161.3
Total Assets	**$6,196.3**	$5,878.4

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

Capitalization and Liabilities as of December 31 (in millions)	1990	1989
Common Stock Equity		
Common stock, par value $10 per share–outstanding 50,471,568 and 45,642,566 shares, respectively	**$ 504.7**	$ 456.4
Additional paid in capital	**599.2**	422.2
Retained earnings	**738.3**	736.4
Accumulated foreign currency translation adjustment	**5.1**	5.3
Unearned employee compensation	**(89.5)**	—
Total Common Stock Equity	**1,757.8**	1,620.3
Long-Term Debt (Note 7)	**1,428.7**	1,196.0
Total Capitalization*	**3,186.5**	2,816.3
Current Liabilities		
Short-term debt (Note 8)	**735.5**	634.2
Current maturities of long-term debt	**35.2**	47.2
Accounts and drafts payable	**321.5**	324.3
Accrued taxes	**138.5**	125.2
Accrued interest	**61.7**	44.5
Estimated rate refunds	**180.8**	135.8
Estimated supplier obligations	**165.2**	238.8
Deferred income taxes	**48.7**	53.8
Other	**245.7**	282.2
Total Current Liabilities	**1,932.8**	1,886.0
Other Liabilities and Deferred Credits		
Income taxes–noncurrent	**964.5**	967.4
Estimated supplier obligations–noncurrent	**—**	107.8
Investment tax credits	**45.2**	47.9
Other	**67.3**	53.0
Total Other Liabilities and Deferred Credits	**1,077.0**	1,176.1
Commitments and Contingencies (Notes 2 and 9)		
Total Capitalization and Liabilities	**$6,196.3**	$5,878.4

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

Consolidated Statements of Cash Flows

Year Ended December 31 (in millions)	1990	1989	1988
Operations			
Cash received from customers	$2,829.8	$2,891.4	$2,863.8
Other operating cash receipts	161.2	155.3	191.2
Cash paid to suppliers	(1,319.2)	(1,351.9)	(1,481.0)
Interest paid	(172.5)	(176.1)	(147.9)
Income taxes paid	(58.4)	(24.7)	(96.3)
Other tax payments	(197.9)	(175.2)	(177.1)
Cash paid to employees and other employee benefits	(445.2)	(433.8)	(385.0)
Other operating cash payments	(377.7)	(484.5)	(338.3)
Net Cash from Operations	420.1	400.5	429.4
Investment Activities			
Capital expenditures*	(600.1)	(435.0)	(299.9)
Replacement of base gas inventory	(156.9)	—	—
Gas supply prepayments–net	(17.5)	10.2	23.1
Sale of Canadian properties	—	—	82.8
Other investments–net	8.1	20.8	7.2
Net Investment Activities	(766.4)	(404.0)	(186.8)
Financing Activities			
Dividends paid	(103.9)	(90.9)	(112.2)
Issuance (retirement) of revolving credit agreement	145.0	—	(300.0)
Retirement of long-term debt and preferred stock	(71.7)	(94.3)	(251.6)
Retirement of production loan	—	—	(75.0)
Issuance of common stock	225.3	8.5	10.4
Issuance of long-term debt	204.5	245.5	100.0
Increase (decrease) in short-term debt and other financing activities	(59.0)	(56.9)	387.6
Net Financing Activities	340.2	11.9	(240.8)
Increase (decrease) in cash and temporary cash investments	(6.1)	8.4	1.8
Cash and temporary cash investments at beginning of year	14.0	5.6	3.8
Cash and Temporary Cash Investments at End of Year**	$ 7.9	$ 14.0	$ 5.6
Net Income Reconciliation			
Net income	$ 104.7	$ 145.8	$ 119.0
Items not requiring (providing) cash:			
Depreciation and depletion	248.8	234.2	212.8
Deferred income taxes	(14.6)	94.2	(54.0)
Amortization of prepayments for producer contract modifications	72.3	72.0	47.8
Other–net	31.3	67.8	14.5
Net change in working capital (Note 12)	(22.4)	(213.5)	89.3
Net Cash from Operations	$ 420.1	$ 400.5	$ 429.4

*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, 1987	44,712	$447.1	$409.8	$675.2	$ —	$(8.4)
Net Income				119.0		
Dividends:						
Common ($2.295 per share)				(103.4)		
Preferred:						
10.96% Series B**				(1.0)		
10.24% Series C**				(3.9)		
Adjustable rate Series D (7.5%-8.35%)**				(3.0)		
Common stock issued:						
Lynchburg acquisition	379	3.8	(1.0)			
Dividend Reinvestment Plan	328	3.3	7.0			
Long-Term Incentive Plan	4		0.1			
Lynchburg retained earnings				4.4		
Preferred stock call premium				(5.7)		
Other						9.3
Balance at December 31, 1988	45,423	454.2	415.9	681.6	—	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	—	5.3
Net Income				**104.7**		
Common stock dividends ($2.20 per share)				**(103.9)**		
Common stock issued:						
Leveraged Employee Stock Ownership Plan	**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**

*100 million shares authorized at December 31, 1990, 1989 and 1988–$10 par value.

**Series B, C and D were redeemed on October 3, 1988 and dividends were paid through October 2, 1988.

***$601.5 million of retained earnings is not available for cash dividends and other capital stock distributions at December 31, 1990, under the terms of the indenture securing the Corporation's outstanding debentures.

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

Statements of Consolidated Taxes

Year Ended December 31 (in millions)	1990	1989	1988
Income Taxes			
Currently payable			
Federal	$ 68.1	$(28.0)	$ 98.4
State	4.4	3.8	4.7
Investment credits	—	(0.7)	1.5
Total Currently Payable	72.5	(24.9)	104.6
Deferred			
Federal	(15.5)	91.7	(52.5)
State	3.6	4.2	1.4
Total Deferred	(11.9)	95.9	(51.1)
Deferred Investment Credits–Net	(2.7)	(1.7)	(2.9)
Total Income Taxes	57.9	69.3	50.6
Other Taxes			
Property	69.1	67.2	64.9
Gross receipts	71.8	76.4	71.7
Payroll	25.3	23.9	23.0
Other	12.0	15.1	10.4
Total Other Taxes	178.2	182.6	170.0
Total Tax Expense	$236.1	$251.9	$220.6

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

Year Ended December 31 (in millions)	**1990**		1989		1988	
Computation of Income Taxes Total income taxes are different than the amount which would be computed by applying the statutory Federal income tax rate to book income before income tax. The major reasons for this difference are as follows:						
Book income before income taxes*	**$162.6**		$215.1		$169.6	
Tax expense at statutory Federal income tax rate	**$ 55.3**	**34.0%**	$ 73.1	34.0%	$ 57.7	34.0%
Increases (reductions) in taxes resulting from–						
State income taxes, net of Federal income tax benefit	**5.2**	**3.3**	5.3	2.5	3.7	2.2
Investment credits not deferred and amortization of credits deferred in prior years	**(2.7)**	**(1.7)**	(2.4)	(1.1)	(1.4)	(0.8)
Depreciation expense for accounting purposes over amounts claimed for income tax purposes	**4.1**	**2.5**	2.7	1.2	2.5	1.4
Effect of change in tax rates on certain deferred taxes previously provided	**(5.6)**	**(3.4)**	(2.8)	(1.3)	(7.3)	(4.3)
Loss carryforward utilized	**—**	**—**	(1.9)	(0.9)	—	—
Other	**1.6**	**0.9**	(4.7)	(2.2)	(4.6)	(2.7)
Total Income Taxes	**$ 57.9**	**35.6%**	$ 69.3	32.2%	$ 50.6	29.8%

*Includes income (loss) from foreign operations of $(21.8) million, $(2.9) million and $1.5 million, respectively.

Deferred Income Taxes Deferred income taxes result from timing differences in recognition of revenues and expenses for tax and accounting purposes. The source of these differences and tax effect of each is as follows:			
Acquisition, exploration and development costs	**$ 12.7**	$ 5.0	$ 4.3
Sale of Canadian properties	**—**	—	(26.9)
Depreciation expense	**26.8**	22.9	18.5
Gas purchased costs	**(45.2)**	32.6	1.5
Estimated rate refunds	**10.9**	58.9	(52.1)
Unbilled utility revenue	**1.2**	(11.9)	(15.3)
Alternative minimum tax	**6.6**	(23.2)	15.0
Capitalized inventory overheads	**(18.3)**	0.9	2.1
Other	**(6.6)**	10.7	1.8
Total Deferred Income Taxes	**$ (11.9)**	$ 95.9	$ (51.1)

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.

Certain reclassifications have been made to the 1989 and 1988 financial statements to conform to the 1990 presentation.

B. Basis of Accounting for Rate-Regulated Subsidiaries. Statement of Financial Accounting Standards No. 71 (SFAS No. 71) provides that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service, and if the competitive environment makes it reasonable to assume that such rates can be charged and collected. In 1985, it was determined that the Corporation's interstate transmission companies no longer met these criteria, and consequently, 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 (%)	**1990**	1989	1988
AFUDC	**9.4**	9.2	9.6
IDC	**9.5**	9.7	9.7

Improvements and replacements of retirement units are capitalized at cost. When units of property are retired, the accumulated provision for depreciation is charged with the cost of the units and the cost of removal, net of salvage. Maintenance, repairs and minor replacements of property are charged to expense.

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

Year Ended December 31 (%)	**1990**	1989	1988
Transmission property	**2.6**	2.9	3.0
Distribution property	**3.7**	3.3	3.4

D. Oil and Gas Producing Properties. The Corporation's subsidiaries engaged in exploring for and developing oil and gas reserves follow the full cost method of accounting. Under this method of accounting, all productive and nonproductive costs directly identified with acquisition, exploration and development activities are capitalized in 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 related to costs capitalized in the United States cost center is based upon the ratio of current year revenues to expected revenues, utilizing current prices, over the life of production. Depletion related to costs capitalized in the Canadian cost center is based upon the ratio of volumes produced to total reserves.

E. Futures Contracts. Futures transactions are used to hedge crude oil production in order to minimize the risk of market fluctuations. Positions can be taken for up to twelve months in the future, and for 80% of the expected uncommitted monthly Southwest and Canadian 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 in excess of carrying amounts for the distribution companies was approximately $58 million at December 31, 1990. 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. Gas inventory for Columbia Gas Transmission Corporation (Columbia Transmission) is carried at its 1990 weighted average cost of gas.

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's subsidiaries record income taxes to recognize full interperiod tax allocation which arise from timing differences in the recognition of revenues and expenses for income tax and accounting purposes, except when regulatory commissions do not recognize interperiod tax allocation for rate purposes. The cumulative amount of income tax timing differences for which deferred income taxes have not been provided was approximately $119 million at December 31, 1990, principally related to tax deductions for accelerated depreciation of the Corporation's gas distribution subsidiaries.

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.

Additional information related to the components of tax expense is contained in the Statements of Consolidated Taxes. Management's Discussion and Analysis of Financial Condition and Results of Operations provides information concerning the Financial Accounting Standards Board's pronouncement which currently requires the Corporation to adopt a new method of accounting for income taxes for fiscal years beginning after December 15, 1991. The Corporation plans to adopt the statement on January 1, 1992.

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. Regulatory Matters

A. Direct Billings of Take-or-Pay Payments and Contract Reformation Costs. In October 1990, the Supreme Court refused to consider an appeal of the United States Court of Appeals for the District of Columbia Circuit's rejection of the Federal Energy Regulatory Commission's (FERC) deficiency-based method for allocation by pipelines to their customers of take-or-pay and gas contract reformation costs. Under the deficiency-based method of allocation disallowed by the Court of Appeals, Columbia Transmission had expected to be billed approximately $400 million, including interest, which would, in turn, be collected from its customers as billed. Using a current or prospective allocation method, the amounts billed to Columbia Transmission would be significantly reduced. The effect should be reduced cost for Columbia Transmission's customers, including affiliated local distribution companies. The ultimate resolution of this issue will be decided by the FERC, which recently issued an order suggesting alternative current and prospective allocation methods for the parties to consider. Accordingly, Columbia Transmission has reduced its recorded liability to suppliers and anticipated billings to customers to reflect its reduced exposure. It is management's opinion that the Corporation's subsidiaries will ultimately be able to pass on substantially all such billings to their customers.

B. Production-Related Costs. In February 1990, the United States Court of Appeals for the District of Columbia Circuit reversed portions of an order issued by the FERC which authorized certain pipeline companies to use a retroactive allocation methodology to directly bill their customers for production-related costs paid to producers by the pipelines under FERC Order No. 94. In October 1990, the Supreme Court refused to consider an appeal of the decision. Columbia Transmission had previously paid and expensed these costs pursuant to the allocation method declared illegal but did not pass them on to customers. These payments, plus interest, which total approximately $48.4 million, will be collected by Columbia Transmission and were reflected in income in 1990.

C. Direct Billings by Pipeline Supplier. The FERC issued an order on January 13, 1989, authorizing 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 direct bill its customers, including Columbia Transmission, for the price increase based on their levels of purchases during the period, reversing the FERC's long-standing position that the pipeline supplier should recover such costs through a prospective surcharge added to its commodity sales rate.

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 which provides, among other things, for payments by Columbia Transmission of approximately $21.3 million over an eight-year period, plus interest during the period, plus an additional $3.8 million to be paid at future dates. Under the settlement, these payments would be fully recovered by Columbia Transmission from its customers on an as-billed basis. The settlement is subject to FERC approval. The Company believes that the proposed settlement with Kentucky-West Virginia is consistent with the two Court of Appeals and Supreme Court rulings described in Notes 2A and 2B and that the Supreme Court's refusal to consider these matters enhances the prospects for timely FERC approval of this settlement. Various customers, other parties and the FERC staff have opposed the settlement. The ultimate outcome of this matter is uncertain.

3. Gas Supply Prepayments

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

At December 31 ($ in millions)	**1990**	1989
Prepayments for producer contract modifications	**356.6**	397.2
Take-or-pay prepayments	**66.7**	77.6
Total	**423.3**	474.8

A. Prepayments for Producer Contract Modifications. Payments are 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.

4. Accounting for Pension Costs and Other Postretirement Benefits

The Corporation has trusteed, noncontributory pension plans which, with minor exceptions, cover all regular employees, 21 years of age and over. The plans provide 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 plans 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 1990-1988 pension cost components for the plans, along with additional relevant data:

Pension Costs ($ in millions)	**1990**	1989	1988
Service cost	**20.3**	17.2	12.5
Interest cost	**59.2**	56.7	47.9
Actual return on assets	**10.6**	(132.3)	(72.9)
Net amortization and deferral	**(74.6)**	77.7	19.2
Net pension expense	**15.5**	19.3	6.7
Annual contribution	**17.3**	23.1	5.8
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 plans:

Plan Assets and Obligations at December 31 ($ in millions)	1990	1989
Plan assets at fair value	723.4	769.2
Actuarial present value of benefit obligations:		
Vested benefits	611.5	564.2
Nonvested benefits	41.3	39.6
Accumulated benefit obligation	652.8	603.8
Effect of projected future salary increases	152.2	139.3
Total projected benefit obligation	805.0	743.1
Plan assets in excess of (less than) projected benefit obligation	(81.6)	26.1
Unrecognized net (gain) loss	2.2	(78.4)
Unrecognized prior service cost	79.3	49.2
Unrecognized transition obligation	13.5	14.7
Prepaid pension cost	13.4	11.6
Discount rate assumption	8.0%	8.0%
Average age compensation growth rate	6.0%	6.0%

During 1990, the Corporation approved an increase in pension benefits paid to retired participants to become effective January 1, 1991. The cost of the amendment is approximately $33.1 million and is 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 employees upon their retirement. Medical care benefits for retirees are expensed as paid. Retiree life insurance benefits are paid through a substantially funded reserve. Expense is recognized and funded to the extent that the total plan assets will not exceed 80 percent of the actuarial present value of accrued benefits. The expense recognized for these postretirement benefits was $10.2 million in 1990, $6.5 million in 1989 and $6.7 million in 1988.

In December 1990, the Financial Accounting Standards Board issued a new standard (SFAS No. 106) on accounting for postretirement benefits other than pensions. This new standard requires that the expected cost of these benefits be fully accrued by the date that an employee first becomes eligible for the benefit. This is a significant change from the Corporation's current policy of recognizing these costs on a cash basis. The Corporation is required to adopt the new accounting and disclosure rules for fiscal years beginning after December 15, 1992. Management expects to adopt prospectively the new standard effective January 1, 1993, and plans to amortize the discounted present value of the obligation at that date to expense over a twenty-year period.

The impact of this standard has not been fully determined, but the adoption will result in significantly greater expense being recognized for these benefits. The Corporation expects that the increased benefits expense associated with its rate-regulated subsidiaries will either be recovered currently through rates or that a regulatory asset will be recorded to reflect amounts to be recovered through rates in the future as the costs are paid.

5. 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 280,555 shares remaining available for awards at December 31, 1990.

Stock options are granted at an exercise price equal to the fair market value on the date of the grant. The outstanding grants related to periods prior to 1989 provide that 50 percent of the options are exercisable beginning one year after the date of grant and 50 percent beginning two years from the date of grant. Stock options granted in 1989 and thereafter provide that 50 percent are exercisable beginning three years after the date of grant and 50 percent beginning four years from the date of grant. Options expire ten years from the date of grant.

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, 1990, are as follows:

	Options: Without Stock Appreciation Rights	Options: With Stock Appreciation Rights	Option Price Range
Outstanding 12/31/87	427,020	60,870	$37.74-$42.99
1988			
Granted	210,080	30,870	$34.30
Exercised	—	—	—
Cancelled	(9,435)	(9,790)	$37.74-$42.99
Converted	(11,980)	11,980	$37.74-$42.99
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**
Exercisable 12/31/90	**215,365**	**70,090**	**$34.30-$42.99**

In addition to the options, contingent stock awards have been granted to certain key executives in prior years. Shares of common stock have been issued for vested awards as follows: 1990–14,400 shares; 1989–3,000 shares; and 1988–4,000 shares. At December 31, 1990, there were no longer any awards outstanding as the remaining shares were issued during 1990. A new award program will be initiated in 1991.

During 1990, a minimal amount was expensed for the Long-Term Incentive Plan while amounts expensed in 1989 and 1988 were $1.4 million and $0.2 million, respectively.

6. Defined Contribution (Thrift) Plan

Eligible employees may participate in the Thrift Plan by contributing up to 16 percent of monthly basic earnings to any of four different investment funds. The Corporation will match the employee's contribution based upon the months of participation in the plan by the employee and ranges from 50% to 100% of the employee's contribution. However, the Corporation does not contribute on employee deposits over 6% of basic earnings. For a participant 55 years of age or older, the Corporation's matching contribution is made to the fund(s) designated by the participant. For all other participants, the Corporation's matching contribution is assigned to a fund which will invest in 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 Corporation's matching obligation under the terms of the Thrift Plan.

The LESOP Trust (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 has reflected the guaranteed LESOP borrowing as long-term debt and a corresponding entry to a contra-equity account. 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, will be used to repay the debt principal and interest. As the principal amount of the loan is repaid, the "Subordinated Guarantee of Leveraged Employee Stock Ownership Plan" debt will be reduced accordingly.

The two million shares held by the Trust will 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 100,198 shares of common stock was allocated in 1990.

Contributions to the Thrift Plan were $10.0 million, $9.2 million and $8.9 million in 1990, 1989 and 1988, respectively. Prior to 1990, contributions to the Thrift Plan were expensed as paid. Thrift Plan expense for 1990 was $13.1 million.

In 1990, the LESOP trust paid $8.1 million in debt service, including $2.2 million in principal and $5.9 million in interest. Of this amount, $4.8 million was provided by contributions and the remaining $3.3 million was provided by dividends on shares held by the Trust.

7. Long-Term Debt

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

At December 31 ($ in millions)	1990	1989
The Columbia Gas System, Inc.		
Debentures:		
6¼% Series due October 1991	—	12.0
6⅝% Series due October 1992	7.4	8.4
7¼% Series due May 1993	15.0	18.4
9% Series due August 1993	150.0	150.0
7% Series due October 1993	12.0	14.7
9% Series due October 1994	18.5	20.2
8¾% Series due April 1995	16.2	17.3
9⅛% Series due October 1995	20.3	22.0
10⅛% Series due November 1995	13.9	18.6
8⅜% Series due March 1996	33.0	35.5
9⅛% Series due May 1996	18.6	23.3
8¼% Series due September 1996	26.4	28.5
7½% Series due March 1997	23.7	25.1
7½% Series due June 1997	26.5	30.3
7½% Series due October 1997	28.4	30.6
7½% Series due May 1998	23.7	27.2
10¼% Series due May 1999	32.5	37.5
9⅞% Series due June 1999	21.8	23.2
10¼% Series due August 2011	100.0	100.0
10½% Series due June 2012	200.0	200.0
10³⁄₂₀% Series due November 2013	100.0	100.0
9⅕% to 9½% Series A Medium-Term Notes due 1998 through 2019	200.0	200.0
8¹⁹⁄₂₀% to 9⁴⁹⁄₅₀% Series B Medium-Term Notes due 1998 through 2020	200.0	45.5
9¹¹⁄₂₀% to 9³⁷⁄₅₀% Series C Medium-Term Notes due 2000 through 2020	50.0	—
	1,337.9	1,188.3
Unamortized debt discount, less premium	(7.8)	(7.2)
	1,330.1	1,181.1
Subordinated Guarantee of Leveraged Employee Stock Ownership Plan debt	87.0	—
Subsidiary debt:		
Miscellaneous	6.8	8.6
Capitalized lease obligations	4.8	6.3
Total long-term debt	1,428.7	1,196.0

The aggregate maturities of long-term debt, excluding the guarantee of the Leveraged Employee Stock Ownership Plan debt, for the five years ending December 31, 1995, are as follows:

($ in millions)

1991	32.7
1992	39.4
1993	219.4
1994	54.9
1995	63.5

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

8. Short-Term Debt

Certain working capital requirements of the Corporation and its subsidiaries are met through the sale of commercial paper, through notes sold directly to commercial banks and/or through borrowings under bank lines of credit. The commercial paper is sold through dealers for maturities ranging from one day to nine months.

The Corporation maintains a $500 million revolving short-term committed line of credit, for which participating banks are paid fees of ⅛% per annum on the total facility and 1⁄16% per annum on the unused portion of the facility. Additionally, the Corporation maintains a $750 million revolving subordinated committed line of credit. Participating banks are paid ⅜% per annum on the unused portion of the facility.

Loans under the lines of credit bear interest according to rate options based on prime, bank certificates of deposit, or the London InterBank Offered Rate. In addition, there is an auction provision included in the $500 million short-term facility which can be selected by the Corporation for various time periods. Outstanding commercial paper and notes are supported by unused bank lines of credit.

In 1990, the Corporation entered into a $100 million notional amount, two-year interest rate swap agreement, with a fixed interest rate obligation on the part of the Corporation of 8.12%, and in January, 1991, entered into another similar $100 million interest rate swap agreement with a fixed rate of 7.68%. In 1988, the Corporation entered into three interest rate swap agreements (each with a commitment of three years), based on a notional amount of $100 million each, with fixed interest payment obligations on the part of the Corporation of 8.24%, 8.94% and 9.03%. These agreements reduce the Corporation's exposure to interest rate fluctuations.

Year Ended December 31 ($ in millions)	1990	1989	1988
Outstanding at December 31:			
Commercial paper	177.0	374.2	385.0
Bank loans	558.5	260.0	312.1
Maximum day outstanding:			
Commercial paper	449.8	472.8	439.7
Bank loans	673.9	408.0	481.5
Aggregate peak	865.0	745.5	790.3
Daily average outstanding:			
Commercial paper	257.9	397.4	230.4
Bank loans	279.1	224.9	94.3
Interest rates:			
Commercial paper	7.3%-10.5%	8.2%-10.4%	6.6%-9.9%
Bank loans	7.3%-10.0%	8.4%-11.5%	7.7%-10.5%
Weighted daily average rate:			
Commercial paper	8.4%	9.4%	8.1%
Bank loans	8.6%	9.6%	9.1%
Weighted average rate at year end:			
Commercial paper	8.4%	8.6%	9.2%
Bank loans	8.7%	9.2%	9.8%
Weighted average maturity at year end (days):			
Commercial paper	24.4	25.3	31.2
Bank loans	19.1	74.4	27.8
Credit lines at year end	1,250.0	1,250.0	1,253.0
Unused credit lines at year end	513.5	613.7	553.0

9. Other Commitments and Contingencies

A. Capital Expenditures. Capital expenditures for 1991 are estimated at $525 million. Of this amount, $165 million is for oil and gas operations, $230 million for transmission operations, $110 million for distribution operations and $20 million for other energy operations.

B. Producer Contract Matters. Columbia Transmission began a program in 1985 to amend its high-cost gas purchase contracts with producers in the Southwest and Rocky Mountain areas. In connection with such contract renegotiations, Columbia Transmission agreed to indemnify producers against potential liabilities that may be incurred by them as a result of such contract modifications. Since 1986, several lawsuits have been filed by royalty owners challenging certain provisions of the contract modifications. In management's opinion, these indemnifications will not result in liabilities that will have material adverse effects on the consolidated financial position of the Corporation and its subsidiaries.

Columbia Transmission is continually assessing whether its gas supply contracts are responsive to the market and is currently attempting to renegotiate certain Southwest producer contracts which were not included in the 1985 program, and in certain cases to resolve pending litigation.

Columbia Transmission's remaining renegotiation efforts could be concluded in 1991. The cost of these negotiations, if incurred, is not expected to exceed current reserves of approximately $11 million by more than $125 million. The Corporation expects to expense some of the costs as they are incurred, estimated to be up to $10 million, and to amortize the rest over the period of benefit. Such costs are subject to rate recovery under the terms of Columbia Transmission's gas inventory charge if customer purchases fall below established threshold levels and if Columbia Transmission's cost of gas meets a comparability test with competing pipeline companies. About $22 million of similar costs were recovered under the gas inventory charge in the fourth quarter of 1990. Management cannot estimate to what extent, if any, the remaining costs will be recovered in rates. However, any absorption of these costs should not have a material adverse effect on the consolidated financial position of the Corporation.

Among the unsettled claims against Columbia Transmission 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. Management is of the opinion that their resolution should not have a material adverse effect on the Corporation's consolidated financial position or results of operations.

The extremely warm weather experienced in Columbia Transmission's operating territory during 1990 and early 1991, significantly reduced sales volumes and, in turn, purchases from producers. Management currently expects that recoupable take-or-pay obligations of up to $100 million may be incurred in 1991.

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

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

E. Cove Point LNG Terminal. Deliveries of liquefied natural gas (LNG) to Columbia LNG Corporation's (Columbia LNG) Cove Point terminal ceased in April 1980 due to failure of the Algerian government to approve a price agreement reached in 1979 between the Algerian national company producing the LNG 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. The sale of the remaining 40.8 percent of the stock will be accomplished via a series of transactions expected to occur through 1992. Each transaction is subject to the satisfaction of certain conditions including negotiation of acceptable supply arrangements and receipt of required regulatory approvals. The initial agreement with Shell, which set a tentative sales price of approximately $110 million, has been amended and the sales price is now expected to approximate $90 million. However, the amended agreement also provides for the buyer to pay additional amounts to the Corporation, ranging from $12.5 million to $35.5 million, should certain volumetric and other conditions be met related to deliveries commencing on or before December 31, 1999. The parties contemplate forming a partnership to purchase LNG supplies and to market the regasified LNG at the Cove Point terminal.

F. Operating Leases. Payments made in connection with operating leases are charged to operation and maintenance expense as incurred. Such amounts were $54.2 million in 1990, $44.2 million in 1989 and $41.9 million in 1988.

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

($ in millions)

1991	7.7
1992	7.4
1993	7.4
1994	9.1
1995	9.5
After 1995	62.9

G. Environmental Matters. The Corporation's subsidiaries are subject to extensive federal, state and local laws and regulations related 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. In addition, certain subsidiaries have received notices from the Environmental Protection Agency (EPA) that they are one of several "potentially responsible parties" (PRP) under the Comprehensive Environmental Response Compensation and Liability Act and the Superfund Amendment and Reauthorization Act and may be required to share in the cost of the cleanup of certain sites. In management's opinion, current exposure related to such PRP notices is not material.

During 1989 and 1990, certain subsidiaries recorded liabilities to provide for estimated future clean-up costs primarily related to the cleanup of low levels of contamination from polychlorinated biphenyl (PCBs)-based lubricating oils in certain air compressors. At December 31, 1990, such recorded liabilities totaled $32.4 million. The cost of additional future environmental clean-up 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 designation as a PRP by the EPA and the difficulty in determining liability, if any, in proportion to other responsible parties; and (4) the effect of possible technological changes related to future cleanups. However, considering known facts, existing laws and possible insurance and rate recovery, management does not believe such matters will have a material adverse effect on the Corporation's financial position.

10. Interest Income and Other, Net

Year Ended December 31 ($ in millions)	**1990**	1989	1988
Interest income	**27.8**	37.7	33.9
Condemnation award, including interest	**47.9**	—	—
Write-down in coal mine investment	**(7.3)**	—	—
Write-down in coal terminal investment	**(5.3)**	—	—
Gain on sale of Columbia LNG stock	**—**	7.7	—
Income (loss) from equity investments	**0.9**	8.8	(4.3)
Miscellaneous	**6.3**	1.3	6.9
Total	**70.3**	55.5	36.5

11. Interest Expense and Related Charges

Year Ended December 31 ($ in millions)	**1990**	1989	1988
Interest on debt	**170.6**	159.7	148.8
Interest on rate refunds	**10.1**	16.4	14.7
Other interest charges	**0.4**	31.6	20.9
Allowance for borrowed funds used and interest during construction	**(11.3)**	(4.8)	(4.3)
Total	**169.8**	202.9	180.1

12. 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)	1990	1989	1988
Accounts receivable, net	**366.3**	(274.2)	(232.2)
Gas inventory	**(164.4)**	67.2	(6.3)
Accounts and drafts payable	**(2.8)**	65.0	25.8
Accrued taxes	**13.3**	13.7	11.0
Estimated rate refunds	**45.0**	(119.7)	10.1
Estimated supplier obligations	**(73.6)**	44.9	108.4
Deferred income taxes	**(5.1)**	53.8	—
Miscellaneous	**(44.3)**	58.5	68.2
Change in working capital	**134.4**	(90.8)	(15.0)
Reclassifications	**(156.8)**	(122.7)	104.3
Net change in working capital	**(22.4)**	(213.5)	89.3

13. Business Segment Information

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

Earnings reflect the allocation of certain corporate income and expenses. The basis for allocation or assignment to a specific segment is dependent on the nature of the item. Income or loss attributable to equity investments is assigned to specific segments. Corporate income, interest expense and preferred stock dividends are allocated in proportion to capital employed by identifiable segments. The provision for income taxes is allocated based upon each segment's pre-tax income adjusted for assignable statutory tax rate differences.

($ in millions)		1990	1989	1988
Revenues				
Oil and gas	–Unaffiliated	**195.4**	151.8	130.4
	–Intersegment	**19.6**	31.5	31.3
	Total	**215.0**	183.3	161.7
Transmission	–Unaffiliated	**626.6**	1,230.8	1,196.0
	–Intersegment	**316.0**	841.1	881.2
	Total	**942.6**	2,071.9	2,077.2
Distribution	–Unaffiliated	**1,425.2**	1,747.7	1,792.6
	–Intersegment	**—**	—	0.1
	Total	**1,425.2**	1,747.7	1,792.7
Other energy	–Unaffiliated	**110.7**	74.1	49.2
	–Intersegment	**76.3**	74.8	63.3
	Total	**187.0**	148.9	112.5
Adjustments	–Unaffiliated	**—**	—	—
and eliminations	–Intersegment	**(411.9)**	(947.4)	(975.9)
	Total	**(411.9)**	(947.4)	(975.9)
Consolidated		**2,357.9**	3,204.4	3,168.2

Identifiable assets related to other energy operations include the net assets of coal mining operations discontinued in 1984. Such amounts were $8.9 million in 1990, $11.2 million in 1989 and $11.9 million in 1988. The remaining coal mining assets are expected to be sold in the first quarter of 1991, and a write-down of $2.7 million was recorded in the fourth quarter of 1990 to reflect the anticipated selling price.

($ in millions)	1990	1989	1988
Operating Income (Loss)			
Oil and gas	**43.3**	30.2	31.5
Transmission	**128.2**	194.8	148.6
Distribution	**96.7**	146.1	140.7
Other energy	**5.5**	3.3	4.6
Corporate	**(11.6)**	(11.9)	(12.2)
Consolidated	**262.1**	362.5	313.2
Earnings (Loss)			
Oil and gas	**39.3**	2.0	8.7
Transmission	**47.2**	76.9	38.1
Distribution	**24.6**	68.6	63.1
Other energy	**(6.4)**	(1.7)	1.2
Consolidated	**104.7**	145.8	111.1
Depreciation & Depletion			
Oil and gas	**98.5**	84.2	70.7
Transmission	**86.9**	97.0	90.6
Distribution	**59.8**	50.4	48.5
Other energy	**3.6**	2.6	3.0
Consolidated	**248.8**	234.2	212.8
Identifiable Assets			
Oil and gas	**1,010.2**	913.5	709.1
Transmission	**3,288.9**	3,126.1	3,251.3
Distribution	**1,749.8**	1,916.6	1,576.9
Other energy	**140.3**	135.2	98.2
Adjustments and eliminations	**(55.4)**	(276.2)	(113.8)
Corporate and unallocated	**62.5**	63.2	119.3
Consolidated	**6,196.3**	5,878.4	5,641.0
Capital Expenditures			
Oil and gas	**229.0**	147.9	71.1
Transmission	**279.5**	189.5	102.6
Distribution	**107.0**	119.7	110.4
Other energy	**14.1**	16.4	23.8
Consolidated	**629.6**	473.5	307.9

14. Quarterly Financial Data (Unaudited)

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

Quarter Ended ($ in millions except per share data)	Operating Revenues	Operating Income	Earnings (Loss) on Common Stock	Earnings (Loss) Per Share
1990				
December 31	**645.9**	**102.2**	**60.8**[a][b][c]	**1.25**
September 30	**370.5**	**22.2**	**0.9**[d][e]	**0.02**
June 30	**458.8**	**23.8**	**(4.6)**	**(0.10)**
March 31	**882.7**	**113.9**	**47.6**	**1.04**
1989				
December 31	1,233.3	142.8	72.7[b][e][f]	1.60
September 30	425.8	12.9	(7.2)[g]	(0.16)
June 30	411.5	44.8	3.6	0.08
March 31	1,133.8	162.0	76.7	1.69

[a]Includes an improvement to earnings of $26.5 million related to the East Lynn condemnation settlement.

[b]Includes a decrease in earnings of $14.9 million in 1990 and $14.9 million in 1989 to record the write-down in the carrying value of Canadian oil and gas properties.

[c]Includes a decrease in earnings of $6.2 million to record a write-down in the carrying value of the Wayne Mine investment ($2.7 million) and the Glenhayes coal terminal ($3.5 million).

[d]Includes an improvement to earnings of $28.9 million related to FERC Order No. 94 (See Note 2B).

[e]Includes a decrease in earnings of $7.9 million in 1990 and $13.2 million in 1989 to record a liability for future environmental clean-up costs.

[f]Includes an improvement to earnings of $43.8 million related to the sale of storage inventory gas in connection with Columbia Transmission's and Columbia Gulf Transmission Company's 1989 Settlement with their customers.

[g]Includes an improvement to earnings of $8.0 million related to the recording of Columbia Transmission's and Columbia Gulf Transmission Company's 1989 Settlement with their customers.

15. 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. in 1990 and 1989 and by John R. Lacey International Ltd. in 1988. 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.

Capitalized Costs

	United States			Canada			Total		
($ in millions)	**1990**	1989	1988	**1990**	1989	1988	**1990**	1989	1988
Capitalized Costs at Year End									
Proved properties	**1,041.4**	962.8	887.1	**232.6**	192.6	175.0	**1,274.0**	1,155.4	1,062.1
Unproved properties[a]	**89.3**	72.4	61.7	**27.6**	40.2	27.7	**116.9**	112.6	89.4
Total capitalized costs	**1,130.7**	1,035.2	948.8	**260.2**	232.8	202.7	**1,390.9**	1,268.0	1,151.5
Accumulated depletion	**(422.0)**	(456.0)	(434.3)	**(118.8)**	(88.9)	(60.7)	**(540.8)**	(544.9)	(495.0)
Net capitalized costs	**708.7**	579.2	514.5	**141.4**	143.9	142.0	**850.1**	723.1	656.5
Costs Capitalized During Year									
Acquisition									
Proved properties	**29.4**	41.2	—	**0.3**	—	0.5	**29.7**	41.2	0.5
Unproved properties	**13.2**	9.9	5.2	**3.3**	3.9	5.3	**16.5**	13.8	10.5
Exploration	**53.3**	36.4	21.4	**13.6**	15.7	9.4	**66.9**	52.1	30.8
Development	**100.4**	34.8	24.7	**14.6**	5.0	4.0	**115.0**	39.8	28.7
Costs capitalized	**196.3**	122.3	51.3	**31.8**	24.6	19.2	**228.1**	146.9	70.5

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

Historical Results of Operations

	United States			Canada			Total		
($ in millions)	**1990**	1989	1988	**1990**	1989	1988	**1990**	1989	1988
Gross revenues									
Unaffiliated	**179.4**	139.2	119.0	**15.6**	12.3	11.2	**195.0**	151.5	130.2
Affiliated	**18.9**	24.7	30.9	**—**	—	—	**18.9**	24.7	30.9
Production costs	**36.0**	31.1	28.7	**4.3**	4.3	3.8	**40.3**	35.4	32.5
Depletion	**68.1**	56.6	58.5	**30.0**[a]	27.2[a]	11.8[a]	**98.1**	83.8	70.3
Income tax expense	**31.2**	25.9	21.3	**(6.4)**	(6.5)	(1.5)	**24.8**	19.4	19.8
Results of operations	**63.0**	50.3	41.4	**(12.3)**	(12.7)	(2.9)	**50.7**	37.6	38.5

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 tax credits.

[a]Includes write-down of the carrying value of $22.6 million for 1990, $22.6 million for 1989 and $6.9 million for 1988.

Other Oil and Gas Production Data

	United States			Canada		
	1990	1989	1988	**1990**	1989	1988
Average sales price per Mcf of gas ($)	**2.03**	1.92	1.74	**1.21**	1.16	1.15
Average sales price per barrel of oil and other liquids ($)	**24.13**	17.57	13.66	**18.69**	14.88	12.10
Production (lifting) cost per dollar of gross revenue ($)	**0.18**	0.19	0.19	**0.28**	0.35	0.34
Depletion rate per dollar of gross revenue ($)	**0.34**	0.35	0.39	**—**	—	—
Depletion rate per equivalent Mcf ($)	**—**	—	—	**1.09**	0.73	0.74

Reserve Quantity Information

	United States		Canada[a]	
Proved Reserves	Gas (Bcf)	Oil and Other Liquids (000 Bbls)	Gas (Bcf)	Oil and Other Liquids (000 Bbls)
Reserves as of December 31, 1987	732.7	7,732	149.4	6,401
Revisions of previous estimate	68.1	1,577	3.4	127
Extensions, discoveries and other additions	14.8	502	3.5	743
Production	(72.2)	(1,637)	(2.4)	(691)
Purchase/(sale) of minerals-in-place	(1.2)	71	1.7	79
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**
Proved developed reserves as of December 31				
1988	697.6	6,706	154.4	6,298
1989	702.8	7,160	111.7	4,763
1990	**730.1**	**11,210**	**113.2**	**4,250**

[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 economical.

Standardized Measure of Discounted Future Net Cash Flows

	United States			Canada			Total		
($ in millions)	1990	1989	1988	1990	1989	1988	1990	1989	1988
Future cash inflows	2,420.2	2,193.7	1,880.9	226.4	219.9	280.3	2,646.6	2,413.6	2,161.2
Future production costs	(508.8)	(425.3)	(351.0)	(61.1)	(59.0)	(55.5)	(569.9)	(484.3)	(406.5)
Future development costs	(165.4)	(139.9)	(102.0)	(12.2)	(13.3)	(10.0)	(177.6)	(153.2)	(112.0)
Future income tax expense	(514.3)	(498.0)	(439.7)	(29.3)	(27.4)	(54.0)	(543.6)	(525.4)	(493.7)
Future net cash flows	1,231.7	1,130.5	988.2	123.8	120.2	160.8	1,355.5	1,250.7	1,149.0
Less 10% discount	562.0	537.5	471.9	46.5	49.7	78.5	608.5	587.2	550.4
Standardized measure of discounted future net cash flows	669.7	593.0	516.3	77.3	70.5	82.3	747.0	663.5	598.6

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.

The price of crude oil and natural gas has declined since December 31, 1990. Although many factors influence the calculation of the Standardized Measure of Discounted Future Net Cash Flows, if this price reduction remains, there could be a significant reduction in this calculation and a negative impact on the carrying value of the Corporation's Canadian oil and gas assets.

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, 1990, follows:

	United States			Canada			Total		
($ in millions)	**1990**	1989	1988	**1990**	1989	1988	**1990**	1989	1988
Beginning of year	**593.0**	516.3	457.3	**70.5**	82.3	77.3	**663.5**	598.6	534.6
Oil and gas sales, net of production costs	**(162.3)**	(132.8)	(121.2)	**(11.3)**	(8.0)	(7.4)	**(173.6)**	(140.8)	(128.6)
Net changes in prices and production costs	**(11.6)**	53.9	76.0	**6.1**	3.5	(8.1)	**(5.5)**	57.4	67.9
Extensions, discoveries and other additions, net of related costs	**109.8**	98.6	20.8	**11.4**	7.5	6.6	**121.2**	106.1	27.4
Revisions of previous estimates, net of related costs	**35.7**	5.7	80.1	**(2.3)**	(39.3)	2.3	**33.4**	(33.6)	82.4
Purchases of reserves	**30.3**	34.0	2.5	**—**	—	1.2	**30.3**	34.0	3.7
Accretion of discount	**84.4**	73.6	64.0	**8.6**	11.0	10.7	**93.0**	84.6	74.7
Net change in income taxes	**(14.5)**	(31.9)	(37.2)	**(2.4)**	11.2	2.8	**(16.9)**	(20.7)	(34.4)
Other	**4.9**	(24.4)	(26.0)	**(3.3)**	2.3	(3.1)	**1.6**	(22.1)	(29.1)
End of year	**669.7**	593.0	516.3	**77.3**	70.5	82.3	**747.0**	663.5	598.6

The estimated discounted future net cash flows increased during 1990 primarily due to changes in extensions, discoveries and other additions (net of related costs), revisions of previous estimates (net of related costs) and purchases of reserves.

Statements of Income from Oil and Gas Operations (Unaudited)

Year Ended December 31 (in millions)	1990	1989	1988
Operating Revenues			
Gas	**$153.9**	$151.5	$131.2
Oil and liquids	**61.1**	31.8	30.5
Total Operating Revenues	**215.0**	183.3	161.7
Operating Expenses			
Operation and maintenance	**62.6**	54.4	50.7
Depreciation and depletion	**98.5**	84.2	70.7
Other taxes	**10.6**	14.5	8.8
Total Operating Expenses	**171.7**	153.1	130.2
Operating Income	**43.3**	30.2	31.5
Other Income (Deductions)			
Interest income and other, net	**49.1**	1.1	5.8
Interest expense and related charges	**(30.4)**	(30.2)	(23.2)
Total Other Income (Deductions)	**18.7**	(29.1)	(17.4)
Income before Income Taxes	**62.0**	1.1	14.1
Income Taxes	**22.7**	(0.9)	4.2
Net Income	**39.3**	2.0	9.9
Preferred Stock Dividends	**—**	—	1.2
Earnings on Common Stock	**$ 39.3**	$ 2.0	$ 8.7

Oil and Gas Operations

In 1990, a significant portion of the Corporation's capital budget was allocated to the oil and gas segment reflecting the commitment to expand this segment of the business. Half of the program was devoted to development drilling, with the remainder going to exploration and lease acquisition. In mid-December 1990, the Corporation announced that oil and gas expenditures are expected to be $195 million in 1991. However, the impact of extremely warm weather in 1990 and early 1991 has significantly depressed natural gas prices. With gas prices not expected to increase in the near future and oil prices uncertain, capital expenditures for 1991 oil and gas operations have been reduced to $165 million. Of the total, $90 million will be spent for oil and gas activities in the Southwest and Rocky Mountain areas, $50 million in the Appalachian Basin and $25 million in Canada.

Market Conditions

Average gas prices received by Columbia have risen each year since 1987, however, the warm weather has caused a significant drop in current natural gas prices. Oil prices continue to be volatile due largely to the unsettled conditions in the Persian Gulf. Should oil and gas prices remain at currently depressed levels, future cash inflows would be significantly reduced, and could adversely impact the carrying value of the Corporation's Canadian oil and gas assets. In 1990, Columbia received an average price of $22.86 per barrel of oil and $2.00 per thousand cubic feet of gas which is an increase from 1989 levels of 37% and 6%, respectively.

Reserves

Total proved gas reserves increased 23 Bcf in 1990 to 925.7 Bcf. Proved oil reserves increased 14% to 19 million barrels.

Acquisitions, which added nearly 12 Bcf of new gas reserves in 1990, included an additional interest in the West Cameron 485/507 Field, located offshore Louisiana in the Gulf of Mexico. A mineral interest, primarily oil, was purchased in the Austin Chalk Trend in Dimmitt County, Texas, where further development is currently underway. Also acquired in 1990 was an interest in the Main Pass 30 Field located offshore in the Gulf of Mexico which was principally oil. These acquisitions added both producing and potentially productive reserves. Due to the expanded development drilling program, Columbia's 1990 Appalachian-developed reserve additions exceeded production of existing reserves for the first time in several years.

Southwest

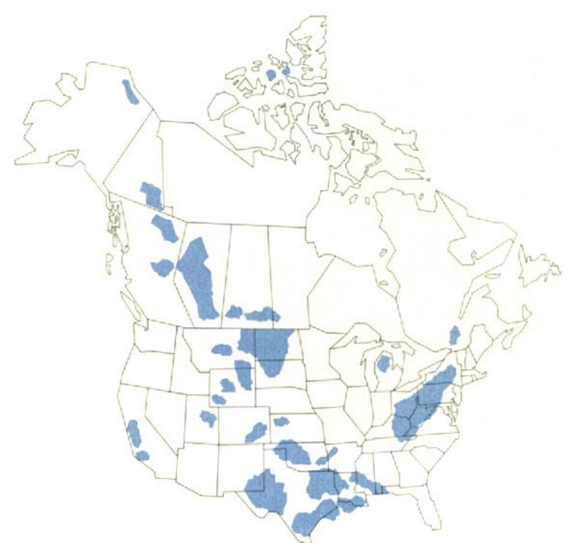
Columbia Gas Development Corporation's (Columbia Development) 1990 drilling activity in the Southwest reached the highest level in the company's history with successful results achieved in both its exploration and development programs. Columbia Development participated in 26 net exploratory wells drilled in 1990 with a 25% success rate. The company also participated in the drilling of 33 net development wells with a success rate of 94%. The 59 net wells drilled in 1990, including 11 horizontal wells, reflected a 195% increase over the 1989 level.

The exploratory program was highlighted by four large onshore discoveries in North Dakota, Louisiana and Texas. The development program included six wells drilled in the West Cameron 485/507 complex offshore Louisiana in the Gulf of Mexico. Columbia Development plans to design a platform and begin production on block 507 during 1992. A second production platform was set on Eugene Island block 309 with gas production starting in December 1990 and oil production beginning in January 1991.

Columbia Development's successful 1990 horizontal drilling program added significant liquids production in 1990. Columbia Development's participation in 11 net horizontal wells drilled during 1990 included 5 in the Giddings and Pearsall fields of Texas, 5 in the Ash Coulee Field in North Dakota and a 44% interest in a wildcat well in South Texas. Ninety-six percent of these wells were successful.

Appalachia

Columbia Natural Resources, Inc. (CNR) completed 144 net wells, with a 95% success rate. CNR concentrated on proven undeveloped prospects and gave special emphasis to Devonian Shale prospects that qualify for Section 29 tax credits under the Internal Revenue Code. CNR in cooperation with the Department of Energy drilled a horizontal well into Devonian Shale in Kentucky. Successful application of horizontal drilling techniques could significantly increase the value of Devonian Shale acreage, which comprises one-third of CNR's 2.3 million net acres of oil and gas leases in the Appalachian Basin. CNR's marketing strategy focuses on a mix of long-term contracts and one-year, fixed-price contracts at prices above the spot market.



North American Acreage Holdings

Canada

Columbia Gas Development of Canada Ltd. (Development Canada) made a significant gas and condensate discovery in the deeper Hamburg-Milligan area of northwestern Alberta. With the acquisition of additional acreage, Development Canada plans a geophysical program and additional delineation wells in the area during 1991. Disappointing results in British Columbia from a deep well drilled on the Crow River prospect and unsuccessful results in the Grizzly area contributed to a fourth quarter write-down of Development Canada's assets.

Gas production from the Kotaneelee reserves in the Yukon began in early 1991 at an initial annual rate of approximately 4 Bcf. However, regulatory delays and pipeline capacity constraints continue to delay the company's planned sale of 5 Bcf annually of other Canadian gas for use by cogeneration plants in the northeast United States.

Volumes

In 1990, gas production declined by 3% due to pipeline capacity limitations caused by maintenance activities and unfavorable summer market conditions, after increasing 4% in 1989. The added emphasis on exploration and development activities, together with the anticipated improvement in market conditions related to environmental concerns, should result in significant increases in future gas production.

Oil and liquids production increased 40% from 1989 due partly to the success of the exploration and drilling program. Oil and liquids production in 1989 decreased as a result of not stripping natural gas liquids from the gas stream due to depressed market conditions and the temporary shut-in of a Wyoming oil production field. These conditions contributed to a 17% decrease in oil and liquids production compared to 1988.

Oil and Gas Operating Highlights

	1990	1989	1988	1987	1986
Capital Expenditures ($ Millions)	**229.0**	147.9	71.1	81.5	66.8
Proved Reserves					
Gas (Bcf)	**925.7**	902.7	897.8	882.1	884.9
Oil and Liquids (000 Barrels)	**18,991**	16,731	14,904	14,133	12,699
Production					
Gas (Bcf)	**75.3**	77.7	74.6	75.8	68.1
Oil and Liquids (000 Barrels)	**2,688**	1,924	2,328	2,199	2,170
Average Prices					
Gas ($ per Mcf)	**2.00**	1.89	1.72	1.67	2.09
Oil and Liquids ($ per Barrel)	**22.86**	16.71	13.20	15.63	14.35

Operating Revenues

1990 gas revenues increased to $153.9 million, up $2.4 million from 1989, as higher gas prices more than offset the reduction in gas production.

Oil and liquids revenues for 1990 increased to $61.1 million, up $29.3 million over 1989. The improvement reflects the 40% increase in oil production and 37% increase in average prices.

1989 operating revenues of $183.3 million were higher by $21.6 million, or 13%, compared to 1988 as a result of higher gas and oil prices and increased gas production. The average prices of gas and oil increased by 10% and 27%, respectively. These factors more than offset the significant decline in oil and liquids production.

Operating Income

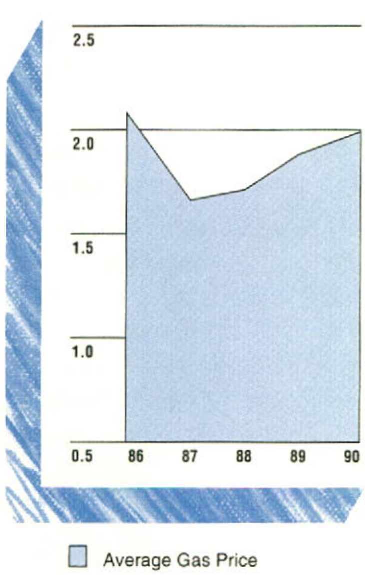
Operating income for 1990 improved to $43.3 million, an increase of $13.1 million or 43%. The substantial increase in operating revenues was partially offset by higher operating expenses. Operation and maintenance costs increased as a result of higher production expense related to expanded operations and an increase in well rehabilitation projects in the Appalachian area.

Depletion expense in each of the last three years includes the impact of write-downs of Canadian oil and gas assets. The 1990 write-down of $22.6 million was due largely to unsuccessful results at the Crow River and Grizzly prospects and a reduction in reserves related to revisions of prior year estimates. Downward revisions of proved reserve estimates caused the $22.6 million write-down in 1989 while depressed oil and gas prices resulted in a $6.9 million write-down in 1988. The write-down recorded in 1989 coupled with higher operating expenses, more than offset the increase in revenue and caused a $1.3 million decline in operating income compared to 1988.

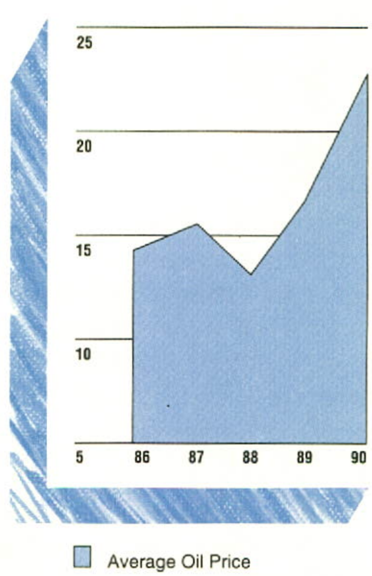
Earnings

Oil and gas earnings of $39.3 million were $37.3 million higher than in 1989 as other income was up $47.8 million in addition to the improvement in operating income. A settlement on the value of land condemned by the Army Corps of Engineers for use in creating the East Lynn Reservoir in West Virginia increased other income by $47.9 million. Income taxes increased due to the improvement in operating income and the effect of the East Lynn settlement.

Average Gas Price
$/Mcf



Average Oil Price
$/Bbl



Statements of Income from Transmission Operations (Unaudited)

Year Ended December 31 (in millions)	1990	1989	1988
Net Revenues			
Sales revenues	$479.9	$1,538.1	$1,747.9
Less: Cost of gas sold	195.0	1,253.2	1,416.8
Net Sales Revenues	284.9	284.9	331.1
Transportation revenues	396.8	524.7	329.3
Less: Associated gas costs	100.3	119.6	87.3
Net Transportation Revenues	296.5	405.1	242.0
Storage Revenues	65.9	9.1	—
Net Revenues	647.3	699.1	573.1
Operating Expenses			
Operation and maintenance	384.4	354.8	285.8
Depreciation	86.9	97.0	90.6
Other taxes	47.8	52.5	48.1
Total Operating Expenses	519.1	504.3	424.5
Operating Income	128.2	194.8	148.6
Other Income (Deductions)			
Interest income and other, net	22.1	43.0	17.9
Interest expense and related charges	(74.7)	(113.5)	(106.1)
Total Other Income (Deductions)	(52.6)	(70.5)	(88.2)
Income before Income Taxes	75.6	124.3	60.4
Income Taxes	28.4	47.4	18.1
Net Income	47.2	76.9	42.3
Preferred Stock Dividends	—	—	4.2
Earnings on Common Stock	$ 47.2	$ 76.9	$ 38.1

Transmission Operations

Expanding to Serve New Markets

In 1990, Columbia Gas Transmission Corporation (Columbia Transmission) constructed the majority of the facilities agreed to under the 1989 comprehensive customer settlement (1989 Settlement). It completed construction on 51.5 miles of pipeline and necessary compression facilities related to this project in 1990, and 14.5 miles of pipeline and compression facilities will be constructed in 1991.

A 59-mile, 20-inch diameter pipeline, started in 1987, which provides natural gas service to New Jersey Natural Gas Company, Elizabethtown Gas Company in New Jersey and Providence Gas Company in Rhode Island, was also completed in 1990. Total sales and firm transportation service to be rendered to the three distribution companies is 24 Bcf a year.

In the Southeast, Columbia Transmission began service to Piedmont Natural Gas in Tennessee, North Carolina and South Carolina. Awaiting regulatory approval is a project which includes firm transportation service to Virginia Power's Chesterfield Station which began receiving interruptible transportation in June 1990. Together these projects will provide annual service of 17 Bcf by late 1991.

In the Northeast, Columbia Transmission is constructing facilities to provide a cogeneration facility in Gloucester County, New Jersey, with firm annual transportation service of 20 Bcf. A portion of the service began December 1, 1990, with the remaining scheduled to begin in 1991. Columbia Transmission will also complete facilities to provide firm transportation service to New England Power Company's generating plants in Massachusetts and Rhode Island in 1992.

Regulatory Matters

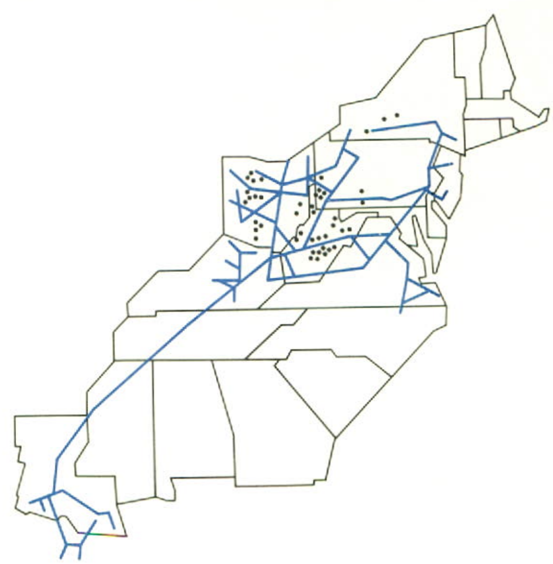
In September 1989, Columbia Transmission and Columbia Gulf Transmission Company (Columbia Gulf) filed concurrent general rate cases to implement a number of agreements reached in the 1989 Settlement. The proposed rates were accepted and suspended by the Federal Energy Regulatory Commission (FERC) in October 1989 and became effective, subject to refund, in April 1990. The filings include provisions for a revised cost allocation and rate design methodology consistent with the 1989 Settlement, new service levels and rates for new services, including a storage service. A settlement agreement with customers and the FERC staff was approved by the FERC in February 1991.

Columbia Transmission and Columbia Gulf made new general rate filings in April 1990, with a proposed effective date of November 1, 1990. The filings were necessary to recover the costs associated with approximately $115 million of new construction required in order for Columbia Transmission to provide the incremental services agreed to under the 1989 Settlement, and to reflect the impact on Columbia Transmission's rates of rolling in the costs associated with the merger of Commonwealth Gas Pipeline Corporation, an affiliated company, into Columbia Transmission. In May 1990, the FERC issued its order accepting and suspending these rates, subject to refund and conditions, effective November 1, 1990. A procedural schedule has been established calling for a hearing in late 1991. Settlement discussions commenced in January 1991.

In November 1990, the FERC issued Order No. 528 in response to the Supreme Court's denial to rehear the Court of Appeals' decision that pipeline direct billing of the costs of producer contract disputes (Order No. 500 costs) based upon a purchase deficiency direct billing mechanism violates the filed rate doctrine. With certain exceptions, Order No. 528 directs pipelines which utilized the purchase deficiency direct billing mechanism to file new allocation mechanisms consistent with the Court's decision. Pipelines with final settlements governing the recovery of such costs (including Columbia Transmission's own take-or-pay and contract reformation costs) were exempted from the Order.

On November 16, 1990, the pipeline supplier which has made the largest direct billings to Columbia Transmission under the purchase deficiency mechanism, made a new recovery filing purportedly to comply with Order No. 528. While this filing would provide Columbia Transmission with substantial refunds and rate reductions, Columbia Transmission and a number of its customers have protested this filing on the basis that it is not consistent with the Court's decision and Order No. 528. The final outcome is anticipated to result in reduced costs to Columbia Transmission, which has reduced its recorded liability to suppliers and anticipated billings to customers. Filings by other pipeline suppliers are expected to further reduce the previously estimated $400 million in billings from pipeline suppliers. Refer to Note 2A of the Notes to Consolidated Financial Statements for additional information.

The FERC has yet to take action responding to the Supreme Court's denial of petitions for rehearing of the Court of Appeals' decision which held that pipeline direct billing of costs to compensate producers for compression and gathering (Order Nos. 94/473 costs)



— Columbia's Major Pipeline Network

• Underground Storage

on the basis of past purchases violates the filed rate doctrine. However, since Columbia Transmission previously paid and expensed these costs, but did not pass them on to customers, it is entitled to retain amounts refunded. The refunds, including interest, improved 1990 pre-tax earnings by $48.4 million.

As discussed in Note 2C of the Notes to Consolidated Financial Statements, Columbia Transmission has reached a settlement with Kentucky-West Virginia Gas Company (Kentucky-West Virginia) concerning Kentucky-West Virginia's filings to retroactively collect higher prices for gas it produced and sold between 1979 and 1983. The settlement provides, 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. Under the terms of the settlement, these costs would be fully recovered by Columbia Transmission from its customers on an as-billed basis. Columbia Transmission's customers and other parties have opposed this settlement on the grounds that Columbia Transmission is barred by a 1985 customer settlement from recovering any of these costs. The Kentucky-West Virginia settlement is subject to FERC approval and is specifically conditioned upon Columbia Transmission being authorized to recover the costs from its customers.

Gas Supply Matters

The extremely warm weather experienced in Columbia Transmission's operating territory during 1990 and early 1991 has significantly reduced sales volumes and, in turn, purchases from producers. As of February 14, 1991, storage was 100 Bcf over planned levels, more than at any time in Columbia Transmission's history. Management currently expects that recoupable take-or-pay obligations of up to $100 million may be incurred in 1991. Should warmer than normal temperatures continue through the remainder of the current heating season, supply issues will become more severe as Columbia Transmission's merchant function would continue to be adversely affected by higher storage balances, lower spot gas prices and increased gas supply costs. Management is pursuing alternatives to minimize further contractual exposure, including short-term contract releases which may require cash payments, and increased use of storage facilities.

In 1990, Columbia Transmission announced that recent factors, including increased gas available under some older high-cost contracts, the anticipated effects of gas deregulation legislation passed in 1989 which will remove all remaining controls on pricing, and Columbia Transmission's dramatic decline in sales volumes in the late 1980's (primarily due to customers' switching from sales to transportation service), made it evident that several of the Southwest contracts not previously renegotiated will present future marketability problems if not renegotiated. During 1990, some of these contracts were amended and certain producer disputes were settled. Columbia Transmission is discussing the renegotiation of other such contracts and, in some cases, the settlement of related litigation with other Southwest producers,

Transmission Operating Highlights

	1990	1989	1988	1987	1986
Capital Expenditures ($ Millions)	**279.5**	189.5	102.6	100.9	60.7
Throughput (Bcf)					
Sales	**89.2**	408.2*	369.3	394.2	496.8
Transportation					
Firm	**319.4**	195.6	108.3	159.9	—
Interruptible	**480.1**	627.7	504.3	372.3	371.1
Short-haul	**497.4**	387.4	268.5	286.4	195.5
Total	**1,296.9**	1,210.7	881.1	818.6	566.6
Throughput	**1,386.1**	1,618.9*	1,250.4	1,212.8	1,063.4
Net Storage Activity (Bcf)					
Withdrawals (injections)	**(175.6)**	184.6	(19.2)	17.8	(45.4)

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

and such negotiations could be concluded in 1991. However, due to the uncertainties inherent in the situation, it is impossible to predict the ultimate outcome or the timing of the renegotiation efforts. The cost of these remaining renegotiations, if incurred, is not expected by the Corporation to exceed current reserves of approximately $11 million by more than $125 million. The Corporation expects that up to approximately $10 million of the $125 million could be expensed as incurred, with the remainder being amortized over several years depending upon the extent to which costs are incurred for prospective price relief. Such costs are subject to rate recovery under the terms of Columbia Transmission's gas inventory charge (GIC) if customer purchases fall below established threshold levels and if Columbia Transmission's cost of gas meets a comparability test with competing pipeline companies. About $22 million of similar costs were recovered under the GIC in the fourth quarter of 1990. Management cannot estimate to what extent, if any, the remaining costs will be recovered in rates. However, any absorption of these costs should not have a material adverse effect on the consolidated financial position of the Corporation.

Additionally, several royalty owner lawsuits related to the 1985 renegotiation of Southwest producer contracts were settled during the year and efforts to resolve Appalachian price disputes are ongoing. Liabilities provided in the consolidated financial statements reflect management's judgment as to the ultimate outcome of these various gas supply matters. (See Note 9B of the Notes to Consolidated Financial Statements for additional information.)

Cove Point LNG Terminal

During 1990, progress continued toward returning the Cove Point, Maryland, liquefied natural gas (LNG) terminal to service. This terminal, which can deliver a billion cubic feet of natural gas daily by regasifying LNG, is expected to help meet the growing gas demand in the eastern United States. As discussed in Note 9E of the Notes to the Consolidated Financial Statements, a subsidiary of Shell Oil Company (Shell) has now purchased approximately 9% of the Corporation's stock in Columbia LNG Corporation (Columbia LNG). Under an agreement, which was recently amended, Shell can purchase 50% of Columbia LNG's stock for $90 million. However, the amended agreement also provides for the buyer to pay additional amounts to the Corporation, ranging from $12.5 million to $35.5 million, should certain volumetric and other conditions be met related to deliveries commencing on or before December 31, 1999. Shipping arrangements were secured during the year when a dispute regarding LNG tankers was resolved. A supply agreement for Algerian LNG was signed in February 1991 and an agreement for Nigerian LNG is expected to be finalized in March 1991. Completion of the supply agreements will clear the way for filings seeking regulatory approvals to permit the importation of LNG. Recommissioning of the terminal will begin once these regulatory approvals are received. The terminal is expected to resume operations early in 1993. As now planned, the gas will be marketed by a partnership of Columbia and Shell subsidiaries.

Volumes

Transmission's 1990 throughput of 1,386 Bcf was down 233 Bcf, or 14%, from 1989. Weather during the year was 20% warmer than in 1989 causing decreased throughput of over 100 Bcf. In addition, in 1989, 116 Bcf of storage gas was sold in place to Columbia Transmission's customers, of which 70 Bcf was delivered in 1990. These storage deliveries replaced transportation volumes that would have otherwise been reflected in 1990 throughput under previous circumstances. Sales in 1990 were also reduced by 60 Bcf due to the timing of deliveries for heating season prepaid gas. Increased short-haul transportation volumes of 110 Bcf, resulting from additional construction of new facilities, helped to mitigate the decrease in throughput.

Throughput for 1989 of 1,619 Bcf increased 369 Bcf, or 29%, over 1988. This improvement included the one-time effect of the 116 Bcf sale of storage gas pursuant to the 1989 Settlement, timing of heating season deliveries of prepaid sales volumes, increased deliveries to new and existing customers and slightly colder weather. Also improving throughput was Columbia Gulf's short-haul transportation which increased 119 Bcf primarily reflecting the construction of new facilities.

Net Revenues

Net revenues (revenues less associated gas costs) in 1990 of $647.3 million decreased $51.8 million from 1989. Net transportation revenues were lower by $108.6 million and net sales revenues were unchanged from the 1989 level despite reduced sales volumes. Storage service revenues increased $56.8 million reflecting the full year effect of a new storage service initiated as part of the 1989 Settlement. Previously, storage costs were recovered through sales and transportation rates.

In 1990, Columbia Transmission recorded the $30.5 million beneficial effect on net revenues of a court ruling that allows it to recoup costs previously paid to other pipelines for expenses related to natural gas production which were not previously paid by its customers. In addition, Columbia Transmission received $22 million of GIC revenues. These improvements to 1990 net sales revenues were offset by the loss of sales volumes.

Net transportation revenues in 1990 were lower by $108.6 million due to the delivery in 1990 of storage gas purchased by customers in 1989, the benefit in 1989 of lower transportation rate refund requirements recorded as part of the 1989 Settlement, reduced margins on interruptible transportation and customers switching to lower margin firm transportation services.

Transmission's 1989 net revenues totaled $699.1 million, an increase of $126.0 million over 1988. The improvement is due primarily to the aggregate effect of recording the 1989 Settlement, and to a lesser extent, increases in throughput related to deliveries to new customers and the effect of slightly colder weather.

Net transportation revenues increased $163.1 million in 1989 due to greater deliveries of long-haul and short-haul volumes along with the effect of lower rate refund reserve requirements related to the 1989 Settlement.

Net sales revenues decreased $46.2 million from 1988 reflecting lower volumes and the terms of the 1989 Settlement which included, among other things, a $21.5 million absorption of inventory costs. These decreases were partially offset by a $69.7 million gain on Columbia Transmission's sale of 116 Bcf of storage gas to its customers, also a part of the 1989 Settlement.

Operating Income

For 1990, operating income of $128.2 million decreased $66.6 million, or 34%, from last year. This lower level reflects reduced net revenues together with increased operating expenses of $14.8 million. Operation and maintenance expense increased $29.6 million. A major component was increased expenses associated with Columbia Transmission's efforts to renegotiate certain Southwest producer contracts and the settlement of take-or-pay and other producer disputes. Labor and benefit costs also increased. These increases were partially offset by reduced provisions for future environmental costs. Depreciation expense decreased $10.1 million in 1990 due to lower rates offset in part by increased plant in service. Other taxes decreased $4.7 million principally due to lower property tax accruals related to reduced gas inventory as a result of 1989's storage sale and a lower level of gas in storage because of the cold weather in December 1989.

Operating income in 1989 of $194.8 million was $46.2 million over the 1988 level. Higher net revenues of $126.0 million were mitigated in part by higher operating expenses of $79.8 million. These higher expenses reflect the recording of a reserve in 1989 for estimated future environmental clean-up costs, together with higher operation and maintenance expense, which included payments made to producers for the temporary release of gas supply.

Earnings

Transmission earnings of $47.2 million declined $29.7 million, or 39%, from 1989. The decrease in earnings reflected the effect of lower operating income partially offset by the net effect of certain items in other income and interest expense. Absent the offsetting effects of upstream pipeline take-or-pay on interest income of $26.7 million and interest expense of $27.5 million, interest income improved $5.8 million and interest expense was down $11.3 million. The improvement in other income reflects interest income associated with the refund on previously paid producer costs partially offset by lower income from pipeline equity investments. The reduction in interest expense is related to lower interest on rate refunds.

Statements of Income from Distribution Operations (Unaudited)

Year Ended December 31 (in millions)	1990	1989	1988
Net Revenues			
Sales revenues	$1,380.0	$1,672.4	$1,703.7
Less: Cost of gas sold	819.9	1,101.4	1,161.4
Net Sales Revenues	560.1	571.0	542.3
Transportation revenues	45.2	75.3	89.1
Less: Associated gas costs	(17.1)	14.9	37.0
Net Transportation Revenues	62.3	60.4	52.1
Net Revenues	622.4	631.4	594.4
Operating Expenses			
Operation and maintenance	351.0	323.5	296.3
Depreciation	59.8	50.4	48.5
Other taxes	114.9	111.4	108.9
Total Operating Expenses	525.7	485.3	453.7
Operating Income	96.7	146.1	140.7
Other Income (Deductions)			
Interest income and other, net	0.8	0.8	(1.2)
Interest expense and related charges	(59.2)	(54.0)	(46.7)
Total Other Income (Deductions)	(58.4)	(53.2)	(47.9)
Income before Income Taxes	38.3	92.9	92.8
Income Taxes	13.7	24.3	27.4
Net Income	24.6	68.6	65.4
Preferred Stock Dividends	—	—	2.3
Earnings on Common Stock	$ 24.6	$ 68.6	$ 63.1

Distribution Operations

Market Conditions

Extremely warm weather during 1990 contributed to the disappointing 1990 financial results. The continuation of warm weather into 1991 is also expected to adversely impact 1991 earnings.

During 1990, the distribution companies (Distribution) added approximately 40,000 new residential and commercial customers, equaling the strong results achieved in 1989. In addition, efforts to promote baseload-enhancing appliances such as gas grills and ranges, gaslights and commercial appliances are increasing baseload usage per customer. New customer growth in 1991 is not expected to match the level achieved during the past two years due to the impact of the current recession.

Increases in industrial throughput can be attributed to competitive rates and targeted marketing programs which are designed to capture customers using other fuels. Environmental concerns and energy security considerations together with renewed interest in natural gas to comply with the Clean Air Act and increased industrial activity also contributed to industrial throughput. During the year, major increases in natural gas deliveries were experienced in electric power generation and cogeneration.

Although still vulnerable to economic downturns to some extent, the major metropolitan areas in the Distribution operating territory now have diversified economies that are no longer overly reliant on heavy industry as in the past.

Regulatory Matters

In 1990, each of the distribution subsidiaries resolved rate cases that will increase annual base rate revenues by $36.8 million, exclusive of changes in gas costs. These rate increases are needed to recover costs associated with capital spending activities and normal increases in operating expenses. The results in Ohio were less than expected as the Ohio commission approved only 24% of the rate increase requested. The Ohio subsidiary comprises approximately one-half of the Corporation's distribution operations.

Notably, Distribution has now received final regulatory approvals from each of the state commissions to recover take-or-pay costs from pipeline suppliers. These approvals will allow Distribution to recover approximately 97% of these costs. As previously discussed, Columbia Transmission's reduced exposure to upstream pipeline billings for these costs has significantly decreased Distribution's exposure.

The increased investment required to satisfy growth along with current levels of inflation are combining to bring back the regulatory lag problem which was evident in the early eighties. The distribution companies are working with state commissions to address inadequate regulations for permitting timely recovery of the capital costs involved with adding new customers, or in keeping up to date with inflationary impacts on operating expenses.

Considerable progress has been made in two states where 1990 rate settlements provided for more current pricing and more flexible operating practices. Another priority is to establish flexible pricing mechanisms and services to enable the distribution subsidiaries to respond to dynamic market conditions.

Sale of New York Subsidiary

In August 1990, the Corporation agreed to sell Columbia Gas of New York, Inc. to New York State Electric & Gas Corporation of Binghamton, New York. The net proceeds from this sale, including the repayment of debt owed by the subsidiary to the Corporation, are expected to be $50 million after taxes and will result in a minor increase to net income. The sale is now awaiting approval of the New York Public Service Commission. In management's opinion, the investment in the subsidiary can be more effectively utilized in states where Distribution has a greater market share.

Volumes

Total throughput for Distribution decreased to 466 Bcf, down 22 Bcf, or 5%, from last year. 1990 was nearly 20% warmer than 1989, largely accounting for a 37 Bcf decrease in sales volumes. The negative impact of weather on sales was partially offset by new residential and commercial customers plus increased

Distribution Operating Highlights

	1990	1989	1988	1987	1986
Capital Expenditures ($ Millions)	**107.0**	119.7	110.4	105.8	101.0
Throughput (Bcf)					
Sales					
Residential	**173.5**	201.5	195.0	175.1	178.8
Commercial	**76.8**	85.0	85.6	79.8	87.2
Industrial	**16.6**	16.4	25.0	22.0	40.7
Other	**0.2**	1.1	0.7	0.7	0.8
Total	**267.1**	304.0	306.3	277.6	307.5
Transportation	**198.6**	184.4	163.1	143.8	108.1
Throughput	**465.7**	488.4	469.4	421.4	415.6
Customers					
Residential	**1,724,281**	1,693,914	1,665,135	1,625,458	1,598,099
Commercial	**165,144**	161,864	157,440	152,071	147,493
Industrial	**2,400**	2,334	2,329	2,177	2,167
Other	**20**	26	29	28	28
Total	**1,891,845**	1,858,138	1,824,933	1,779,734	1,747,787
Degree Days	**4,893**	6,083	6,014	5,470	5,521

customer usage. Per customer usage is now gradually increasing, after several years of decline due to conservation and higher equipment efficiencies. Marketing programs encouraging customers to purchase additional load-enhancing gas appliances helped to increase customer usage. Industrial throughput was 13.7 Bcf higher due to increased transportation services that stem from the continued availability of lower cost spot supplies and successful marketing efforts.

Throughput for 1989 of 488 Bcf increased 19 Bcf, or 4%, over the prior year. Transportation volumes increased 21 Bcf while tariff sales were lower by 2 Bcf. Industrial throughput increased 10 Bcf reflecting deliveries to a new cogeneration facility and the effect of marketing programs which have been successful in attracting customers who previously used alternative fuels. Higher residential sales of 7 Bcf resulted from the addition of new customers and slightly colder weather in 1989 compared with 1988.

Net Revenues

Distribution's 1990 net revenues (operating revenues less associated gas costs) of $622.4 million were $9 million, or 1%, lower than in 1989. Net sales revenues decreased $10.9 million while net transportation revenues improved $1.9 million.

The decrease in net sales revenues attributable to the weather-related reduction in sales volumes was only partially offset by rate increases during the year. The higher net transportation revenues primarily reflect the increased industrial transportation throughput.

Net revenues of $631.4 million for 1989 were $37 million over the 1988 level. This improvement reflected higher throughput and base rate increases.

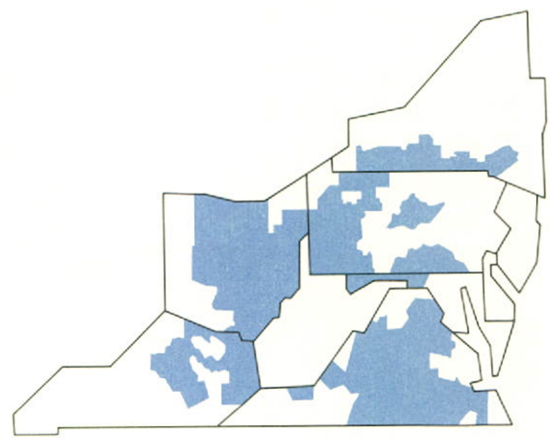
Operating Income

Operating income for 1990 declined to $96.7 million which was $49.4 million, or 34% below 1989. This decrease is due to lower net revenues and an 8% increase in operating expenses. Higher operation and maintenance costs, including increased labor and benefits expense, continue to reflect rising inflation and customer growth. Because of regulatory lag, these expenses are not always being recovered in a timely manner through current rates. Other taxes are higher by $3.5 million reflecting higher property taxes related to the 1989 purchase of storage inventory.

The 1989 operating income of $146.1 million was an increase of $5.4 million over the 1988 level. The effect of higher net revenues was reduced by a 7% rise in operating expenses. Increased labor and benefit costs largely contributed to the increase.

Earnings

Distribution earnings of $24.6 million declined $44.0 million, or 64% from 1989. This decrease primarily reflects the lower operating income caused by warm weather and the effect of regulatory lag together with an increase in interest expense and related charges of $5.2 million primarily related to rate refunds.



Columbia's Retail Service Area

Statements of Income from Other Energy Operations (Unaudited)

Year Ended December 31 (in millions)	1990	1989	1988
Net Revenues			
Sales revenues	**$110.1**	$75.7	$49.1
Less: Products purchased	**85.8**	54.8	29.2
Net Sales Revenues	**24.3**	20.9	19.9
Other revenues	**76.9**	73.2	63.4
Net Revenues	**101.2**	94.1	83.3
Operating Expenses			
Operation and maintenance	**87.4**	84.1	71.7
Depreciation and depletion	**3.6**	2.6	3.0
Other taxes	**4.7**	4.1	4.0
Total Operating Expenses	**95.7**	90.8	78.7
Operating Income	**5.5**	3.3	4.6
Other Income (Deductions)			
Interest income and other, net	**(13.3)**	(1.2)	1.7
Interest expense and related charges	**(5.5)**	(5.2)	(4.0)
Total Other Income (Deductions)	**(18.8)**	(6.4)	(2.3)
Income (Loss) before Income Taxes	**(13.3)**	(3.1)	2.3
Income Taxes	**(6.9)**	(1.4)	0.9
Net Income (Loss)	**(6.4)**	(1.7)	1.4
Preferred Stock Dividends	**—**	—	0.2
Earnings (Loss) on Common Stock	**$ (6.4)**	$ (1.7)	$ 1.2

Other Energy Operations

Columbia is actively engaged in diverse energy markets related to the natural gas business. These ventures serve to either complement existing natural gas markets or expand opportunities for natural gas usage.

Cogeneration

TriStar Ventures Corporation made several cogeneration investments during 1990 and has several other projects in the planning stage. TriStar Ventures is an equity partner in Cogeneration Partners of America, a partnership which designs, builds, owns and operates on-site cogeneration plants throughout the United States. The partnership currently has four small gas-fired cogeneration facilities. During 1990, Cogeneration Partners began construction of a 117-megawatt cogeneration project in Pedricktown, N.J., and neared completion of financing for a 50-megawatt plant in Binghamton, N.Y. Columbia's participation in cogeneration provides attractive equity investment opportunities as well as opportunities for increased throughput for the transmission and distribution companies and new sales for Columbia's oil and gas operations.

Propane

In 1990, Columbia merged the managements of its two propane companies, Columbia Propane, Inc. and Commonwealth Propane, Inc. to promote more efficient operations. The propane companies sold approximately 74 million gallons of propane, a slight decrease from 1989. Retail sales decreased 9% in 1990 reflecting warmer weather while wholesale sales increased 24%. Customers served reached a total of 63,500 in 1990. Pursuing opportunities to build market share and profitability, especially in the residential and commercial areas, has been a primary focus for the propane companies.

Coal

Columbia owns 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. In 1990, the value of a coal loading facility was written down to reflect current market conditions.

In 1990, Columbia also recorded a write-down in its investment in discontinued coal mining operations to reflect its current value as determined by ongoing negotiations to sell the Corporation's interest in the mine. The sale is expected to be completed in the first quarter of 1991.

Net Revenues

Net revenues for 1990 were $101.2 million which was $7.1 million higher than in 1989. Net sales revenues increased $3.4 million reflecting improved margins on propane sales partially offset by the effect of lower sales volumes. Other revenues were up 5% due to higher coal leasing revenues, which included a first quarter adjustment of $1.6 million for prior period advance royalty payments, and higher billings to affiliated companies for professional services.

Operating Income

Operating income of $5.5 million for 1990 increased $2.2 million from last year. Coal leasing operations increased operating income while increased net revenues from propane operations were offset by higher operating expenses. Operating income for 1989 declined $1.3 million due largely to the loss of revenue from the 1988 sale of a fractionation plant.

Earnings (Loss)

Other energy operations had a loss of $6.4 million, which was $4.7 million larger than the loss incurred in 1989. The improvement in operating income was more than offset by write-downs recorded for the mine and coal loading facility of $2.7 million and $3.5 million, respectively.

Other Energy Highlights

	1990	1989	1988	1987	1986
Capital Expenditures ($ Millions)	**14.1**	16.4	23.8	10.6	3.8
Propane					
Gallons sold (Millions)	**74.4**	75.2	73.3	75.8	64.0
Customers	**63,546**	62,707	50,016	44,421	42,629
Coal Reserves (Million tons)	**550**	550	650	650	650

Consolidated Earnings Review

Earnings on Common Stock

Earnings on common stock for 1990 were $104.7 million, or $2.21 per share, compared to 1989 earnings of $145.8 million or $3.21 per share, and 1988 earnings of $111.1 million or $2.46 per share. Record-setting warm temperatures significantly reduced earnings from Transmission and Distribution, while earnings from oil and gas operations were improved by higher oil and gas prices, increased oil production and a one-time favorable adjustment related to a land condemnation settlement with the Federal government. Earnings from other energy operations were hurt by asset write-downs related to coal operations.

Earnings for oil and gas operations of $39.3 million were $37.3 million over 1989. The favorable outcome of the condemnation proceeding contributed $29 million to the increase in earnings. The effects of higher oil and gas prices and increased oil production were partially offset by a drop in gas production and higher operating expenses. Earnings were reduced $14.9 million due to write-downs of Canadian oil and gas assets in both 1990 and 1989.

Transmission earnings of $47.2 million were lower in 1990 by $29.7 million, or 39%. The decrease in earnings reflects a 233 Bcf, or 14%, decline in throughput, of which an estimated 100 Bcf is attributable to warmer weather. The decrease also reflects the improvement to 1989 throughput from the sale of 116 Bcf of storage gas volumes by Columbia Transmission to its customers. Another 70 Bcf is attributable to the delivery of those storage gas volumes in 1990 as these deliveries replaced transportation volumes which would have otherwise been reflected in 1990 throughput. Sales volumes in 1990 were also reduced by 60 Bcf due to the timing of deliveries for heating season prepaid gas while 1989 sales volumes were benefitted by a like amount. In addition to throughput, both 1990 and 1989 earnings were affected by one-time occurrences. Earnings in 1990 were improved by $30.4 million due to a court ruling that allows Columbia Transmission to recoup costs previously paid to other pipelines for natural gas production-related costs. Earnings in 1989 were improved $44 million by the sale of storage gas and $8 million from recording the 1989 Settlement. Earnings in 1990 were reduced $9.1 million by additional charges to the $13.2 million after-tax reserve for future environmental clean-up costs established in 1989.

Distribution earnings of $24.6 million declined $44 million or 64% from 1989. The substantial decrease is attributable to the warm weather and to regulatory policies in certain states which preclude the distribution companies from reflecting current cost levels in rates.

Other energy operations incurred a loss of $6.4 million in 1990 compared to a loss of $1.7 million in 1989. The loss is due primarily to the write-down of assets related to coal operations totaling $6.2 million.

The lingering effects of 1990's warm weather, coupled with continued warm weather through mid-February 1991, have reduced the Corporation's earnings outlook for 1991.

Revenues

Operating revenues of $2,357.9 million, decreased $846.5 million from 1989 reflecting lower gas sales revenues of $789.1 million and reduced transportation revenues of $139.1 million. Other revenues increased by $81.7 million. The sales revenue decline reflects lower sales volumes in the current period caused by the record warm weather, the effect of a 1989 storage sale to wholesale customers and the timing of heating season prepaid gas sales. Also, reducing sales revenues was a reduction for upstream pipeline supplier take-or-pay costs of $238.5 million which is largely offset by lower associated gas purchased expense. Depressing 1990 transportation revenues was the delivery during the year of storage gas purchased by customers in 1989 from Columbia Transmission, which replaced volumes that normally would have provided transportation revenues in the current period.

Total operating revenues of $3,204.4 million in 1989 increased $36.2 million from 1988. Higher transportation and other revenues offset lower gas sales revenues due to reduced sales prices reflecting lower cost gas and a decrease in the recording of receivables for the recovery of upstream pipeline supplier take-or-pay and contract reformation costs.

Expenses

Products purchased expense in 1990 was $846.8 million, a decrease of $822.2 million from 1989. This decrease reflects reduced volumes purchased for resale offset in part by a higher unit cost of gas which resulted from selling lower priced storage gas in 1989. When compared to 1988, products purchased expense decreased $153.3 million in 1989, despite higher sales volumes as a result of withdrawing lower cost gas from storage. Additionally, expense associated with the passthrough of upstream pipeline supplier take-or-pay costs decreased in 1989 by $160.7 million.

Operation and maintenance expense increased in 1990 and 1989 by 9% and 16%, respectively. Labor and benefit costs, primarily related to medical costs, were higher in 1990 by $29.6 million and $31.8 million in 1989. Also increasing 1990 operation and maintenance expense was higher take-or-pay and producer settlement expense. Reserves were established in 1990 and 1989 of $14.4 million and $21.2 million, respectively, for Transmission's environmental clean-up costs.

Depreciation and depletion expense was higher by 6% in 1990 and 10% for 1989. Included in all three years were write-downs of the carrying value of Canadian oil and gas properties of $22.6 million for 1990 and 1989 and $6.9 million for 1988. Increased depreciation resulting from the increased investment in plant was mitigated by lower depreciation rates for Transmission effective April 1990.

Other Income (Deductions)

Interest income and other-net of $70.3 million was up $14.8 million over 1989. This increase included $47.9 million for a settlement on the value of land condemned by the Army Corps of Engineers for use in creating the East Lynn Reservoir in West Virginia and interest income of $17.9 million associated with recent court rulings on production-related costs. These increases were reduced by lower interest income of $26.7 million relating to the flow-through of upstream pipeline supplier take-or-pay payments which are offset in interest expense and the effect of a 1989 gain on the sale of Columbia LNG stock to Shell Oil. During 1990, write-downs were recorded for the coal mine and coal loading facility of $7.3 million and $5.3 million, respectively, to reflect market value. The 1989 increase over the prior year reflected the Columbia LNG stock sale and a $13.2 million increase for the flow-through of upstream take-or-pay interest.

Interest expense and related charges in 1990 of $169.8 million were lower by $33.1 million compared to 1989. Reduced interest expense for upstream pipeline supplier take-or-pay payments coupled with lower interest rates and decreased average short-term borrowings were the principal reasons for the decrease. The 1989 increase over 1988 is due to upstream pipeline supplier take-or-pay and the funding of the increased capital expenditure program.

Income Taxes

Income taxes, as detailed on the Statements of Consolidated Taxes, decreased $11.4 million primarily due to a decrease in pre-tax income of $52.5 million. In 1989, income taxes increased due to greater pre-tax income.

In December 1987, the Financial Accounting Standards Board (FASB) issued Financial Accounting Standard No. 96 regarding accounting for income taxes. Among other things, this pronouncement requires the impact on deferred taxes be recognized in income whenever tax rates change. The FASB has delayed implementation until fiscal years beginning after December 15, 1991. Columbia plans to adopt this statement on January 1, 1992.

This pronouncement also requires that the cumulative effects on deferred tax liabilities of tax rate and other tax law changes be recorded in current earnings except for rate-regulated entities which follow the accounting and reporting requirements of Statement of Financial Accounting Standards No. 71, such as Distribution.

If adopted as currently required on January 1, 1992, Columbia's net income will increase approximately $160 million since no restatement of prior periods is planned.

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 1990, the Corporation paid dividends of $2.20 per share on its common stock. On January 16, 1991, the Board of Directors increased the quarterly common stock dividend from $.55 per share to $.58 per share.

Columbia's common stock is listed on the New York, Philadelphia and Toronto stock exchanges under the symbol CG. At December 31, 1990, there were approximately 79,300 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
	$	$	$	¢
1990				
December 31	**54¾**	**44¾**	**46⅞**	**55**
September 30	**52½**	**43**	**50⅝**	**55**
June 30	**49**	**41½**	**44¼**	**55**
March 31	**52⅛**	**44¼**	**44½**	**55**
1989				
December 31	52¾	43	52	50
September 30	50	43½	45½	50
June 30	47¼	34⅛	46¾	50
March 31	37	33¾	34½	50

Liquidity and Capital Resources

Cash from Operations

Net cash from operations of $420.1 million improved $19.6 million compared with 1989. Other operating cash payments were down $106.8 million due primarily to 1989 rate refund payments made by Columbia Transmission under the terms of the 1989 Settlement. Other operating cash receipts increased $5.9 million due largely to income tax refunds.

Cash received from customers declined $61.6 million reflecting the effect of reduced sales volumes due to the much warmer weather in 1990. The decrease in cash paid to suppliers of $32.7 million principally reflects reduced gas purchases partially offset by increased producer and pipeline settlement payments. The increase in income taxes paid in 1990 is due to higher taxable income as 1989 payments were reduced by deductions attributable to rate refunds made by Transmission in 1989.

Net cash from operations was $400.5 million in 1989, a decrease of $28.9 million from 1988. A rate refund payment primarily related to Transmission's 1989 Settlement, together with higher operating expenses were the major contributors to the increased operating cash payments. Decreasing cash payments were reduced supplier payments due to a reduction in gas volumes purchased and lower income taxes paid reflecting deductions attributable to 1989 rate refunds.

Investment Activities

Investment activities were $766.4 million in 1990, which was $362.4 million higher than last year. Capital expenditures increased substantially, reflecting the large capital program undertaken in 1990. A significant portion of the program was targeted for new business activities for Transmission and Distribution and expanded exploration and development programs for oil and gas operations. Also in 1990, 50 Bcf of capitalized base gas inventory, at a cost of $156.9 million, was replaced after being withdrawn during the extremely cold weather in December 1989. The increase in gas supply prepayments reflects a $32 million payment to a producer to renegotiate a gas supply contract.

Although the original 1991 capital program of $600 million has been reduced to $525 million, it continues Columbia's aggressive growth in historic and non-historic markets and the expansion of its oil and gas exploration and development activities. Total oil and gas expenditures are expected to be $165 million of which $90 million will be spent for oil and gas activities in the Southwest and Rocky Mountain areas, $50 million in the Appalachian Basin and $25 million in Canada. Approximately $90 million of the total oil and gas program will be spent on development activities. Transmission capital expenditures are expected to be $230 million with $114 million, or 50%, allocated to business expansion. Distribution expenditures for 1991 are expected to be $110 million of which 35% is targeted toward new business, including the addition of new residential and commercial customers. Expenditures of $20 million on other capital programs will be devoted primarily to developing cogeneration projects and to the expansion of Columbia's retail propane markets.

Financing Activities

In 1990, the Corporation issued $204.5 million of senior debt in the form of Medium-Term Notes. Maturities ranged from 10 to 30 years with an average cost of approximately 9.78 percent.

In April 1990, the Corporation established a Leveraged Employee Stock Ownership Plan (LESOP) and issued 2 million shares of common stock to the Employees' Thrift Plan of Columbia Gas System Trust (Trust) for proceeds of $91.75 million. The purchase of this common stock was financed by the issuance of an equal amount of debt by the Trust. The LESOP debt is guaranteed on a subordinated basis by the Corporation.

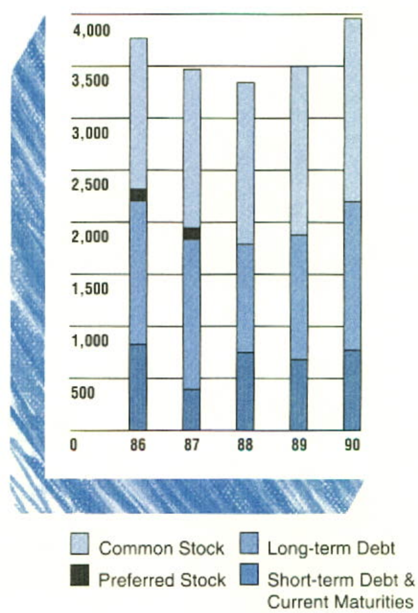
In December 1990, the Corporation sold 2,600,000 shares of common stock, raising $123.5 million. An additional $10 million was raised during 1990 through the issuance of 228,912 shares to the Corporation's Dividend Reinvestment Plan (DIP) and Long-Term Incentive Plan (LTIP).

External financing requirements for 1991 are currently projected to be approximately $460 million. In addition to an approximate $305 million increase in bank loans and commercial paper, the Corporation expects to raise $5 million from the sale of stock through its DIP and LTIP and $150 million of additional senior long-term debt. The Corporation's 1991 external financing requirements are intended to fund the capital expenditure programs of its subsidiaries and to retire modest amounts of maturing debt.

The Corporation believes that it will have sufficient resources to meet its known cash requirements. The Corporation's resources to meet these cash requirements include: (1) internally generated cash, (2) the additional $513.5 million available at year-end 1990 under committed bank credit facilities and (3) senior debt capacity available under the indenture applicable to the Corporation's senior debt. The Corporation plans to file a shelf registration with the Securities and Exchange Commission early in 1991 for $300 million of debt securities.

The Corporation maintains two committed bank credit facilities totaling $1.25 billion. One facility is a $750 million subordinated five-year revolving credit agreement, entered into in October 1988. The other facility is a $500 million short-term revolving credit agreement which is renewed annually. The unused portions of these facilities are used to support the Corporation's borrowings in the commercial paper and bank note markets. As of December 31, 1990, the Corporation had $736.5 million of commercial paper and bank loans outstanding.

Capitalization
(in millions of dollars)



Directors

Thomas S. Blair
A director since 1962, Thomas S. 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 Chairman: Finance
Committee Membership: Audit and Executive

John H. Croom
John H. 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 also serves as first vice chairman of the American Gas Association and as a director of the National Petroleum Council. He is a director and former board chairman of the Gas Research Institute.
Committee Chairman: Executive

John D. Daly
John D. Daly was elected executive vice president and a director of the Columbia Gas System in September 1990. He currently serves as chairman of the Interstate Natural Gas Association of America, an association representing the nation's pipeline industry.

Dr. Sherwood L. Fawcett
A director since 1984, Dr. Sherwood L. Fawcett is a trustee and former chairman of the board of trustees of Battelle Memorial Institute in Columbus, Ohio. Battelle helps industry and government develop technologies for commercialization. He currently serves as chairman of Transmet Corporation.
Committee Chairman: Long-Range Planning
Committee Membership: Finance

Robert H. Hillenmeyer
Robert H. Hillenmeyer was first elected to the board in 1970. He is chairman and chief executive officer of Hillenmeyer Nurseries, Inc., in Lexington, Kentucky.
Committee Membership: Compensation and Long-Range Planning

Malcolm T. Hopkins
A director since 1982, Malcolm T. Hopkins is former vice chairman, chief financial officer and director of 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 Life Insurance Company Series Fund, Inc.; MAPCO, Inc.; Wangner Systems Corporation; and Kinder-Care Learning Centers, Inc.
Committee Chairman: Audit
Committee Membership: Compensation and Finance

W. Frederick Laird
W. 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. William E. Lavery was elected to Columbia's board in 1985. He is a professor at, and was the president of, Virginia Polytechnic Institute and State University in Blacksburg, Virginia. He currently serves as a director of Dominion Bankshares Corporation.
Committee Membership: Compensation and Long-Range Planning

George P. MacNichol, III
George P. MacNichol was first elected to the board in 1971. He has been a private investor since 1979, when he retired as vice president of Libbey-Owens-Ford Company, the glass and plastics manufacturer in Toledo, Ohio. He also serves as a director of Fifth Third Bank of Toledo.
Committee Membership: Audit and Finance

Robert A. Oswald
Robert A. 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 G. Procope is president and chief executive officer of E. G. Bowman Co., Inc., an insurance brokerage firm in New York City. She also serves as a director of Avon Products, Inc., and Chubb Corporation.
Committee Membership: Audit and Finance

Dr. Ronald W. Skeddle
Dr. Ronald W. 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, Federal Mogul Corporation and Therma-Tru Corporation.
Committee Membership: Compensation and Long-Range Planning

John W. Snow
John W. Snow, elected to the board in 1990, is chairman, president and chief executive officer of CSX Corporation, a diversified transportation company, in Richmond, Virginia. He is also a director of Bassett Furniture Industries, Inc.; C&S/Sovran Corporation; and the Richmond, Fredericksburg and Potomac Railroad Co.
Committee Membership: Audit and Long-Range Planning

James R. Thomas, II
Elected to the board in 1990, James R. Thomas serves as president of the Charleston Renaissance Corporation, a public/private partnership formed to revitalize the business and commercial core of Charleston, West Virginia. Mr. Thomas is also on the board of directors of One Valley Bank, NA; Camcare, Inc.; Healthnet, Inc.; Strategic Ventures Incorporated; and Shoney's Inc.
Committee Membership: Audit and Long-Range Planning

William R. Wilson
William R. Wilson, a director since 1987, is chairman of the board and chief executive officer of Lukens, Inc., manufacturer of steel and industrial products, located in Coatesville, Pennsylvania.
Committee Chairman: Compensation
Committee Membership: Finance

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 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 Gas Development of Canada Ltd.
Lawrence J. Macdonald
President and Chief Executive Officer

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

TRANSMISSION

COLUMBIA TRANSMISSION COMPANIES

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 DISTRIBUTION COMPANIES

C. Ronald Tilley
Chairman and Chief Executive Officer

James R. Lee
Executive Vice President

Robert C. Skaggs, Jr.
Executive Vice President

Columbia Gas of Kentucky, Inc.
Columbia Gas of New York, Inc.
Columbia Gas of Ohio, Inc.
Richard J. Gordon
President and Chief Operating Officer

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

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

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

Stockholder Information

Common Stock Data

The Columbia Gas System, Inc.

Year	Number of Shares Traded (000)	Market Price High $	Market Price Low $
1990	**31,777**	**54¾**	**41½**
1989	39,132	52¾	33¾
1988	47,906	44¾	26⅞
1987	31,491	56½	35½
1986	26,311	46	34¾
1985	29,135	40	26¾
1984	14,624	37½	27
1983	14,191	35½	27⅞
1982	7,414	33⅞	26⅞
1981	6,692	41½	27⅞

Dividend Reinvestment–Columbia offers a Dividend Reinvestment Plan to its common stockholders which provides a convenient and economical method of acquiring additional shares of Columbia Common Stock through the reinvestment of quarterly cash dividends and optional cash payments.

Participation in the Plan may be discontinued at any time, in which case you will receive a stock certificate or, if you prefer, cash for shares credited to your account. Participants will be treated for federal income tax purposes as having received a cash dividend and will be taxed on the full amount of the dividend utilized to purchase additional shares. There is a small brokerage commission on shares purchased or sold through the Plan.

Common stockholders desiring a complete description of the Plan should request a copy of the Prospectus by writing to: Columbia Dividend Reinvestment, Stockholder Services Department, P.O. Box 2318, Columbus, Ohio 43216-2318.

Additional Information–A supplementary report containing more detailed operating, financial, and statistical data on the Columbia Gas System is prepared each year for stockholders and others interested in such information. A copy of Form 10-K filed annually with the Securities and Exchange Commission is also available. A copy of either document may be obtained by writing to: Secretary, The Columbia Gas System, Inc., 20 Montchanin Road, Wilmington, Delaware 19807-0020.

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

Stockholder Inquiries–Columbia's Stockholder Services Department maintains a toll-free number during business hours, 8 a.m. to 4:45 p.m. (1-800-245-4588). Stockholder correspondence should be addressed to: The Columbia Gas System, Inc., Stockholder Services Department, P.O. Box 2318, Columbus, Ohio 43216-2318.

Annual Meeting–The Corporation's 1991 Annual Meeting of Stockholders will be held at the Hotel du Pont, 11th and Market Streets, Wilmington, Delaware on April 17, 1991 at 1 p.m. Proxy material will be mailed on or about March 25, 1991.

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

COMMON STOCK LISTED:
New York Stock Exchange
Philadelphia Stock Exchange
Toronto Stock Exchange

TICKER SYMBOL: CG

DIVIDEND REINVESTMENT PLAN:
The Columbia Gas System, Inc.
Stockholder Services Dept.
P.O. Box 2318
Columbus, Ohio 43216-2318

TRANSFER AGENTS AND REGISTRARS:
Harris Trust Company of New York
Corporate Trust Department
77 Water Street, 4th Floor
New York, New York 10005

National Trust Company
Corporate Trust Services
555 Wilson Avenue
Downsview, Ontario, Canada M3H 5Y6

TRUSTEE AND PAYING AGENT FOR DEBENTURES:
Morgan Guaranty Trust Company of New York
Security Holder Relations
60 Wall Street
New York, New York 10260

Glossary

Defined below are some common natural gas industry terms.

Bcf
Billion cubic feet.

Cofiring
The process of burning natural gas in conjunction with another fuel to reduce air pollutants.

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

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

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

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.

Fuel Cell
A technology that converts natural gas to electricity and thermal energy without combustion and with a high overall energy efficiency.

Horizontal Drilling
A form of directional drilling deviating from the vertical that is used primarily to expose a greater portion of a formation to the well bore and improve productivity.

Interruptible Service
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. In volume, it occupies 1/600 the space of the gas in its vapor state. LNG can be transported in insulated tankers and stored in insulated tanks. It returns to a vaporous state when warmed.

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

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

Merchant Function
Buying and selling natural gas.

MMcf
Million cubic feet.

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 in 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 rates do not adequately reflect the current level of operating costs, investment or throughput.

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.

COLUMBIA GAS
System

20 Montchanin Road
Wilmington, Delaware
19807-0020

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