1980 Annual Report

Columbia's spectrum: energy exploration, transmission, storage and distribution

COLUMBIA GAS System

Contents

1980 Highlights	**1980**	1979	% Change
Operating Revenues ($000)	**3,636,507**	2,851,733	27.5
Common Stock Data			
Earnings on Common Stock ($000)	**165,311**	143,113	15.5
Earnings per Share ($)	**5.02**	4.39	14.4
Dividends per Share ($)	**2.56**	2.44	4.9
Book Value per Share ($)	**35.96**	33.46	7.5
Financial Data ($000)			
Capital Expenditures	**442,825**	369,532	19.8
Total Assets	**3,861,861**	3,626,036	6.5
Capitalization	**2,438,288**	2,322,482	5.0
Operating Statistics			
Gas Customers	**1,841,810**	1,826,486	.8
Gas Sales (million cubic feet)	**1,158,781**	1,193,399	(2.9)
Degree Days (billing period)	**5,570**	5,703	(2.3)
Degree Days (calendar period)	**5,683**	5,678	—

Letter To The Stockholders

Columbia's record for the year 1980 shows continued improvement in earnings and dividends, and progress in programs to expand the System's energy production and market outlets.

Earnings

Earnings on Columbia's common stock in 1980 were $165.3 million, or $5.02 per share, as compared with earnings of $143.1 million, or $4.39 per share, in the previous year.

Primary factors contributing to the increase in earnings were (1) higher sales rates; (2) greater earnings related to sales of oil, propane and other hydrocarbons; (3) a colder weather pattern in the last 12 days of December 1980 as compared to the same period in 1979, causing deferral of a disproportionate amount of gas purchase expense in relation to recorded sales, and (4) increased investment tax credits. These improvements were partially offset by (1) a decrease in sales volumes due to warmer weather in the annual billing cycle and the business recession, particularly in the latter part of the year, and (2) increased operating costs related to inflation.

The 1979 earnings included $11.6 million, or 36 cents per share which resulted from the sale of most of Columbia's working interest in Canadian Beaufort Sea lands.

Dividends

On January 21, 1981, the Board of Directors declared a quarterly dividend of 67½ cents per share on the common stock of the Corporation, bringing the indicated annual dividend rate to $2.70 per share from the $2.56 paid in 1980. Columbia's common stock dividends have now been increased for 19 consecutive years. Regular quarterly dividends have been paid on Columbia common stock for more than 34 years.

Capital Expenditures

The System's capital expenditures in 1980 totaled $443 million, an increase of about 20 percent from the previous year. Of the 1980 total, $184 million was devoted to projects to develop supplies of natural gas and oil.

A record capital budget of $573 million has been approved for the year 1981, an increase of about 29 percent from the 1980 level. Approximately $257 million of the 1981 budget will be expended on supply projects.

The increase in supply project expenditures in 1981 is due primarily to projected higher outlays for Appalachian well drilling and investments in new supply related pipelines.

Financing

In August 1980, the Corporation sold $100 million principal amount of 12¾ percent 20-year debentures, and in December postponed the sale of an equal amount of debentures because of the System's strong cash position and high interest rates for long-term debt prevailing at that time.

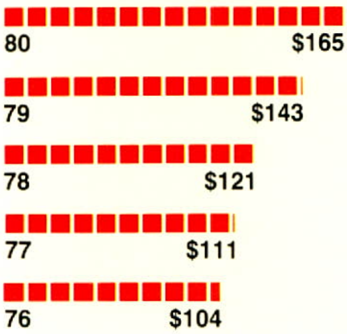
Additional financing will be required in 1981, the amount and timing to be determined later in the year.

Notable Developments

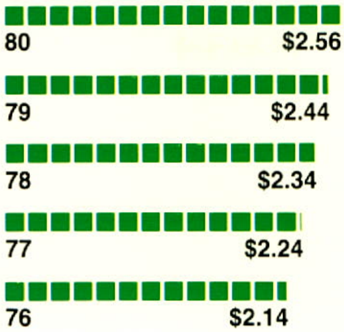
System progress, as reported in detail on the following pages of this report, was highlighted by these significant events:

- Columbia's seven affiliated distribution companies completed the first full year of new customer hookups since the sales moratorium of the 1970's, adding more than 25,700 new residential and commercial customers;
- Columbia continued to build its storage capacity and entered the 1980-81 heating season with a record 627 billion cubic feet in storage;
- Columbia Gas Development completed a gas discovery in the first well drilled in its Rocky Mountain exploration program;
- Columbia became a partner in the project to construct the Alaskan segment of the pipeline system that will deliver North Slope natural gas to consumers in the lower 48 states;
- Commercial production of coal began in the West Virginia mine being developed with an Exxon Corporation subsidiary, and a sales agreement with a European purchaser was concluded in February 1981;
- Columbia concluded an agreement with Commonwealth Natural Resources, Inc., a major gas marketer in central and eastern Virginia, under which that company would merge into Columbia through a tax-free exchange of 1.05 shares of Columbia common stock for each share of Commonwealth common stock. Approximately 1,222,000 shares of Columbia common stock will be issued under the agreement. The merger is awaiting

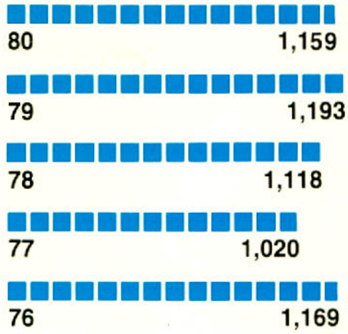
Earnings on Common Stock
(Millions of Dollars)



Dividends Paid per Common Stock
(Dollars)



Total Gas Sales
(Billions of Cubic Feet)



approval by the Securities and Exchange Commission and is expected to be completed early in 1981.

Industry Outlook

Columbia's progress mirrors the strong improvement in the outlook for the natural gas industry that was evidenced by these events in 1980:

- a record level of exploration and drilling activities in response to the Natural Gas Policy Act;
- Congressional veto of certain incremental pricing provisions of the Natural Gas Policy Act that could have adversely impacted industrial gas sales;
- the establishment and activation of the Federal Synthetic Fuels Corporation;
- an increased government and consumer awareness of the value of natural gas as an essential energy source, reversing the negative view prevailing only a few years ago.

Energy Policy

Continued progress for Columbia and the gas industry overall is keyed to government energy policies in the United States, Canada and other countries.

While Columbia generally supports less government regulation, it believes care must be taken to avoid actions which suddenly affect in a major way the cost of energy to the consumer. In this connection, Columbia opposes deregulation of prices for gas from wells drilled after passage of the Natural Gas Policy Act to the date of any new legislation.

The Canadian government late in 1980 announced proposals for sweeping changes in the tax on oil and gas producers and in the government's participation in production operations on federal crown lands, principally offshore and in frontier areas. While it is clear that these changes will have an adverse effect on Columbia, it is impossible to quantify the extent of this effect until Parliament acts on energy policy.

Management Change

On December 17, 1980, the Board of Directors accepted with regret the resignation of B. J. Clarke as Chairman of the Board and as a director for reasons of health. Mr. Clarke had relinquished his responsibilities as Chief Executive Officer in August upon the advice of his physician.

President W. F. Laird, who had been elected Chief Executive Officer in August, assumed the additional post of Chairman effective with Mr. Clarke's resignation. Mr. Laird has been President of the Corporation since April 1977 and a director since 1974. He joined the System in 1951 and at one time was Chairman and Chief Executive Officer of the System's seven retail distribution companies.

Mr. Clarke had served the Columbia System for more than 28 years and had been Chairman and Chief Executive Officer since August 1975. Beginning as an engineer with the Service Corporation in 1952, he filled engineering positions of increasing responsibilities over the next seven years and was elected vice president for engineering and research in 1959. He transferred to the Columbus Group Companies in 1963 as a senior vice president and director and became chairman of the boards of those companies in 1967. In 1970 he was elected President of the Corporation and in 1975 he was elected Chairman and Chief Executive Officer. His contributions and counsel will be missed by his fellow directors and associates.

The Columbia System began 1981 more firmly established than ever before as an organization operating successfully across the full spectrum of the gas industry from exploration to sales. Our capacity to explore for, produce, transport, store and distribute natural gas energy continues to expand. The dedication of employees and the support of stockholders are appreciated and are essential to continuing Columbia progress.

W. F. Laird
Chairman, President and Chief Executive Officer

February 24, 1981

COLUMBIA GAS
System

The Columbia Gas System is active across the full energy spectrum from exploration operations through production, transmission and storage to the distribution of energy to the consumer.

Energy Supply

Columbia's supply development program covers a broad range of activities including exploration and production in the United States and Canada, operation of a synthetic gas plant and importation of liquefied natural gas. The scope of the supply development efforts expanded in 1980.

Energy Transmission/Storage

Columbia's extensive network of transmission lines carry natural gas from the southwest and delivers it to 71 distribution companies serving eight states and the District of Columbia. Columbia also operates one of the largest gas storage systems in the country. 1980 programs added to both pipeline and storage capacity.

Energy Distribution

Columbia distributes natural gas at retail to more than 1,800,000 residential, commercial and industrial consumers in seven states that comprise the industrial heartland of America. Propane service reaches customers beyond the gas mains. Market interest in natural gas increased during 1980.

System Supply Companies

Columbia Gas Development Corporation (U.S. except Appalachian Basin)

Columbia Gas Transmission Corporation (Appalachian Basin)

Columbia Gas Development of Canada Ltd.

Columbia LNG Corporation

Columbia Coal Gasification Corporation

System Transmission Companies

Columbia Gas Transmission Corporation

Columbia Gulf Transmission Company (also participant in: Trailblazer Pipeline System Ozark Pipeline System)

Columbia Alaskan Gas Transmission Corporation

Columbia Retail Companies

Columbia Gas of Kentucky, Inc.

Columbia Gas of Maryland, Inc.

Columbia Gas of New York, Inc.

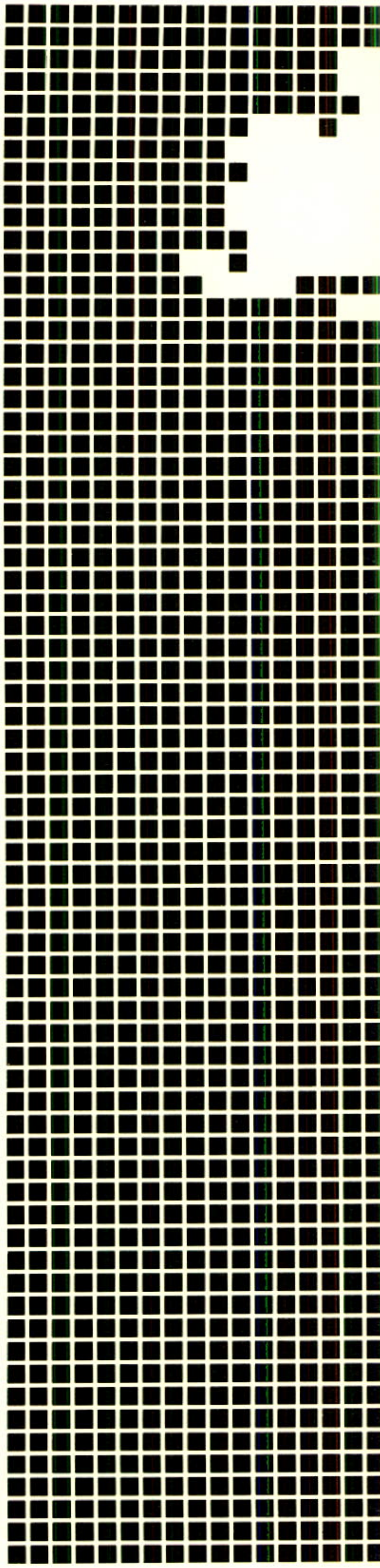
Columbia Gas of Ohio, Inc.

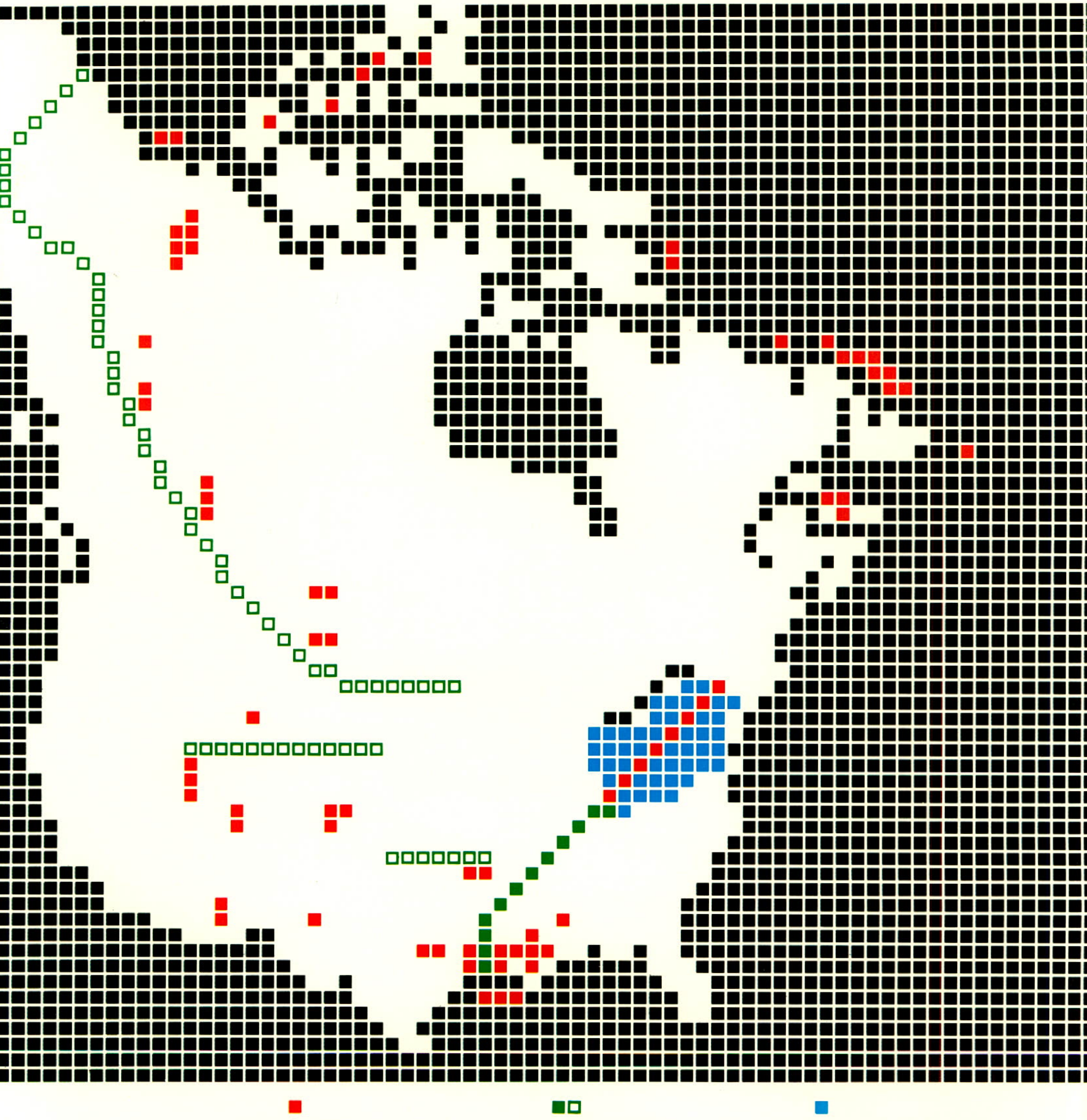
Columbia Gas of Pennsylvania, Inc.

Columbia Gas of Virginia, Inc.

Columbia Gas of West Virginia, Inc.

Columbia Hydrocarbon Corporation





Supply Development

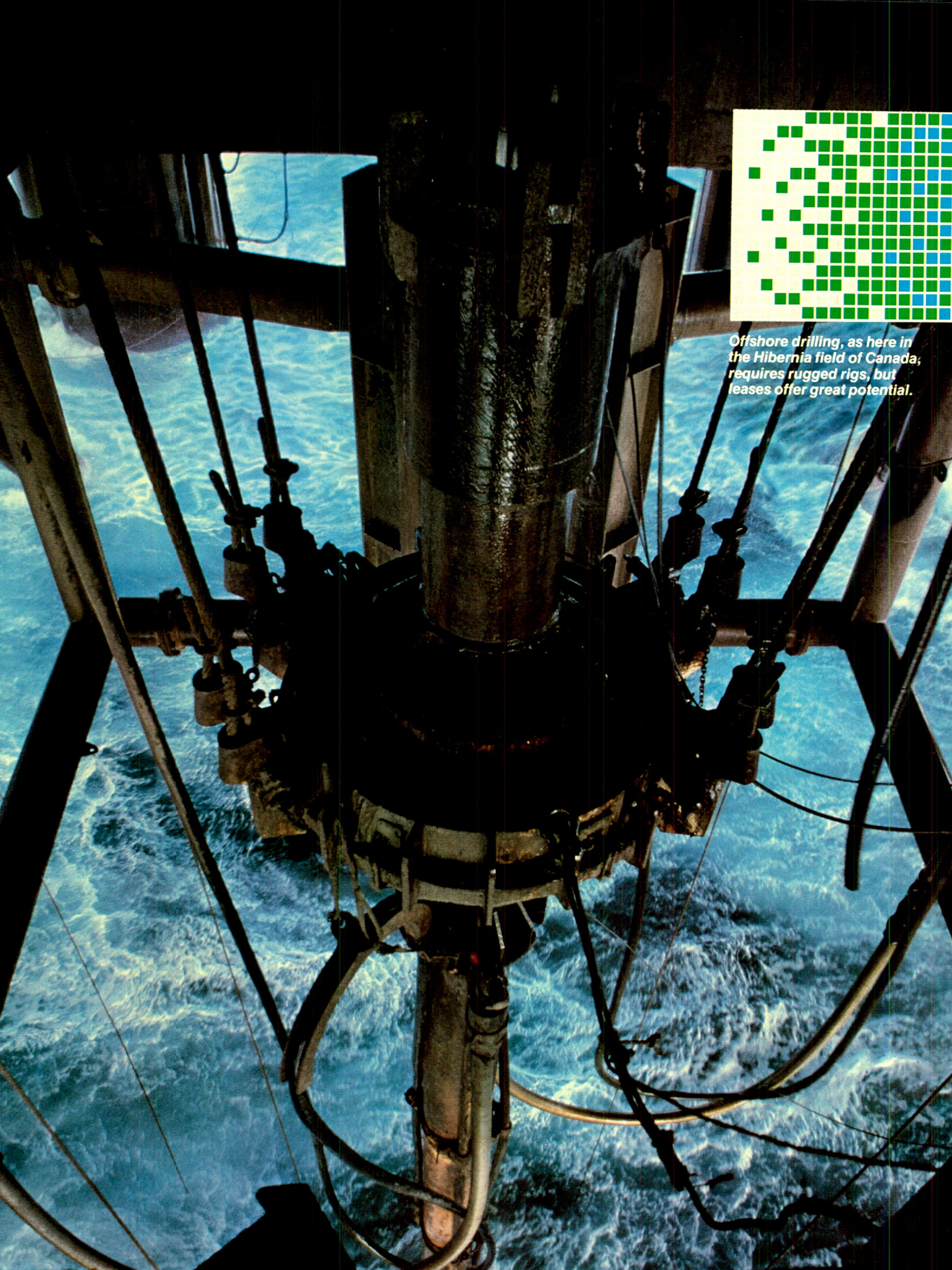
Columbia companies have lease holdings throughout the United States and Canada in areas indicated for gas and oil exploration and development.

Gas Transmission

Columbia operates a large diameter pipeline from the southwest to its service area (solid squares) and has interests in proposed Alaskan, Trailblazer and Ozark lines (outline squares). Not shown is Columbia's transmission network that serves distribution companies in the blue shaded area.

Columbia Service Area

Through seven affiliated and 64 non-affiliated distribution companies, Columbia supplies more than four million customers in eight midwest and Atlantic coast states and the District of Columbia.



Offshore drilling, as here in the Hibernia field of Canada, requires rugged rigs, but leases offer great potential.

Energy Supply Development

In 1980 Columbia expanded the scope of its energy supply development efforts—leasing new land for exploration, drilling more wells than in 1979, and securing additional future supply through purchase.

Overall, Columbia operating subsidiaries produced 157 billion cubic feet of natural and synthetic gas and 2 million barrels of oil and other liquids. They participated in drilling a total of 282 exploratory and development wells, compared with 252 in 1979.

Through drilling activity and gas purchase contracts concluded in 1980, Columbia companies dedicated more reserves to future System supplies than the volume of gas these sources provided for System needs in the year.

Gas reserves available to Columbia (through its own production, independent producers, non-affiliated pipelines and imported gas, including LNG) as of December 31, 1980 have been estimated by Ralph E. Davis Associates, independent consultants, to be 13,852 billion cubic feet. This is approximately 11.6 times the volume of gas used to meet System 1980 sales. This reserve estimate does not include up to 5.6 trillion cubic feet of Alaskan North Slope gas which Columbia has the right to purchase under agreements with Sohio Natural Resources Company and BP Alaska, Inc.

Southwest and Rocky Mountain Activities

Columbia Gas Development Corporation (Development), which conducts domestic exploration exclusive of the Appalachian Basin, increased its drilling activity in 1980 and added new acreage holdings in the west through its lease acquisition program. It participated in the drilling of 146 wells during the year, a significant increase from the 88-well program in 1979.

Columbia Development's working interest production during the year was 52 billion cubic feet of gas and 1,900,000 barrels of oil and other liquids. About a quarter of the liquids and virtually all of the gas were produced from offshore holdings.

The company's working interest reserves at year-end were estimated by Ralph E. Davis Associates to be 318 billion cubic feet of gas and 8,555,000 barrels of liquids.

Development's gas acquisition activities in 1980 resulted in the dedication of 693 billion cubic feet of new reserves to future System supply. The volume of new reserves dedicated in 1980 to future supply exceeds the volume of annual supply provided for the System's needs through Development's purchasing and drilling activities for the third consecutive year.

Offshore. Two exploratory and 57 development wells were drilled on 12 tracts in which Development holds an interest. Fifty-one of these wells contained commercial quantities of hydrocarbons. An additional 17 wells were still drilling or being completed at year-end.

Development's acreage holdings in the Gulf of Mexico on December 31, 1980, totaled 234,897 gross acres or 83,652 net acres on 54 oil and gas leases located offshore Louisiana and Texas.

Drilling was completed and production begun from three new platforms in the Gulf of Mexico in which Development holds an interest: the Vermilion 313B, West Cameron 643B and Ship Shoal 248D. The Ship Shoal 247F platform is also expected to be producing in the first quarter of 1981. Production from these platforms will bring to 42 the number of producing platforms in which Development holds an interest. It is the operator on four of those platforms.

System's synthetic gas plant at Green Springs, Ohio, processes imported liquids to provide steady supply source.

Commercial shipment of coal from new Columbia mine in West Virginia starts as first train moves out.

Drilling operations on four recently set platforms are expected to be completed before the end of 1981. These platforms are West Cameron 426A, on which Development is operator, South Marsh Island 143B, Vermilion 156A and Vermilion 144JA. One additional platform is planned to be set in 1981.

Onshore. Columbia Development participated in the drilling of 87 onshore wells, 78 of which were productive. In addition, 23 wells were still drilling at the end of 1980.

Development held an interest at year-end in 2.7 million gross acres and 820,000 net acres in Arkansas, Arizona, Colorado, Louisiana, Mississippi, Montana, New Mexico, North Dakota, Texas, Utah and Wyoming.

It acquired various interests in 50,332 gross or 19,871 net acres during 1980 in the Williston Basin, an active oil and gas exploration area in North Dakota and Montana. Several discoveries have been made recently in the vicinity of Development's holdings there, and the company is negotiating for the right to earn an interest in additional acreage there.

Oil Production. The expanding production activities in the East Giddings field in central Texas have made substantial contributions to Columbia Development's revenues, with nearly three-quarters of the liquids for the year being produced from this field. Development has participated in the drilling of 108 East Giddings wells. Plans for 1981 include continued development of the East Giddings leases.

Rocky Mountains. The first well in which Development has participated in this area resulted in a gas discovery at Moneta Hills, Fremont County, Wyoming, in May. The well is the second deepest producer ever drilled in the Rocky Mountains. Development has a 61.1 percent interest in this well and a 50 percent interest in 16,000 surrounding acres on which other wells will be drilled to determine the extent of gas reserves. Development is the operator in the Moneta Hills field.

Exploratory activity in the Rocky Mountains area will be expanded during 1981 with drilling continuing in Wyoming, Colorado and Utah, and beginning on the newly-acquired Williston Basin acreage.

Drilling in the Western Overthrust area by the industry continues at a record rate. Since the initial discovery in 1975, 250 total wells have been drilled resulting in 18 new field discoveries.

Development is active in purchasing gas in the Rocky Mountain Overthrust area for movement through the Trailblazer Pipeline System (see Transmission section on page 13).

Early in 1981 Columbia signed a contract with Chevron, Inc. for a volume of Overthrust gas that is expected to exceed 500 billion cubic feet. Production is expected to begin in mid-1982 and will be dedicated to the Trailblazer System.

Appalachian Activity

Columbia Gas Transmission Corporation, which conducts the System's exploration and production operations in the Appalachian area, drilled 42 wells in 1980, 25 of which were productive and 17 dry holes.

Columbia Transmission's lease holdings in the Appalachian region total 4.3 million net acres, exclusive of the acreage leased in conjunction with the 49 underground storage fields the company operates.

System proved reserves in the Appalachian area totaled 413 billion cubic feet at the end of 1980. Production from these reserves in 1980 totaled 43.5 billion cubic feet. In addition, other reserves committed to the System through purchase contracts in the Appalachian area totaled 431 billion cubic feet at year-end with 90.1 billion cubic feet produced from this source during 1980.

Columbia-Canada operates the Kotaneelee field in Yukon Territory, has a 22% interest. U.S. import permit is pending.

Eastern Overthrust. Two Oriskany Sandstone discovery wells completed in 1979 in Mineral County, West Virginia, in the heart of an extensive geologic area known as the Eastern Overthrust, have been tested and are being evaluated through on-line production. One other well completed in 1980 in the same area is being evaluated to determine its potential.

Columbia Transmission has acquired oil and gas lease rights to more than 200,000 acres in the eastern New York counties of Washington, Saratoga, Rensselaer and Albany, and is leasing additional acreage in the area prior to conducting tests to determine the potential for producing gas in this section of the Eastern Overthrust.

In Virginia, Columbia and seven other partners announced plans to explore 132,000 acres in Scott and Wise Counties, where proven and potential reserves of natural gas are estimated to total 78 billion cubic feet.

Project Penny. Approximately 500 wells were completed by independent producers during 1980 in Project Penny, Columbia's extensive gas development program in northwestern Pennsylvania and western New York. More than 3,500 wells are to be drilled on several hundred thousand acres over the next several years as part of this project. Columbia anticipates it will receive 60 million cubic feet of gas per day by 1984 from the area. Total reserves in the area are estimated at 700 billion cubic feet.

CO_2 Project. In November 1980, initial production began from a field in Kanawha County, West Virginia, that contains a mixture of one-third natural gas and two-thirds carbon dioxide. The carbon dioxide is removed from the natural gas at a separation plant. Full delivery of 10 million cubic feet of natural gas and 20 million cubic feet of carbon dioxide daily is projected to begin in the spring of 1981. The field is estimated to contain 56 billion cubic feet of natural gas and twice that much carbon dioxide. Carbon dioxide recovered from the field will be processed in a plant to be built at Marmet, West Virginia by Columbia Hydrocarbon Corporation. The plant will produce 600 tons daily of food grade carbon dioxide and 400 tons of non-food grade for use in enhanced oil recovery.

Canadian Operations

Columbia Gas Development of Canada Ltd. (Columbia-Canada) participated in the drilling of 39 exploratory and 55 development wells in 1980. Twenty-six of the exploratory and 46 of the development wells are considered to be commercial.

Columbia-Canada owns 132 billion cubic feet of proven Canadian gas reserves and 1.7 million barrels of oil and other liquids. (These data do not include projected reserves in the Hibernia field.) In addition, it has a call (subject to Canadian export approval) on 2.1 trillion cubic feet of additional reserves primarily in the Arctic Islands. The company holds an interest in approximately 37 million gross acres and 3.9 million net acres of oil and gas leases in Canada.

Columbia-Canada entered into an agreement with four independent Canadian oil and gas companies for a $60 million exploration program over a three-year period that began on January 1, 1980. The four companies committed $45 million to the program and will earn 25 percent of Columbia-Canada's interests in 18 million gross acres and in any new lands acquired under the program. Columbia-Canada is the program operator and will provide $15 million of the total exploration funds. A minimum amount of exploration has taken place on the acreage. No Columbia lands where oil and gas discoveries have been made prior to December 31, 1979 are included in the agreement. Under the program in 1980, 11 wells were drilled which resulted in 7 gas discoveries and 4 dry holes.

As operator of the Kotaneelee gas field in the Yukon Territory, Columbia-Canada ran production flow tests on two of the development wells in the field, from which absolute open flow rates were calculated for the Kotaneelee I-48 well at 450 million cubic feet per day and for the Kotaneelee H-38 well at 265 million cubic feet per day. Columbia-Canada has a 22 percent ownership interest in the field. This ownership is not expected to be affected by the new Canadian energy policy. Approval has been received from the National Energy Board of Canada for the export of up to 84.5 billion cubic feet over an eight-year period. Columbia Gas Transmission is awaiting approval of an application with the U.S. Department of Energy to import this gas.

Hibernia Wells. In drilling off the eastern coast of Canada, two successful confirmation wells offsetting the Hibernia P-15 oil discovery well have been completed and lend further encouragement for potential commercial production. The wells are located approximately 165 miles offshore east of the southern tip of Newfoundland.

The operating company, Mobil Oil Canada, Ltd., described the second confirmation well as the most productive yet tested, with oil or natural gas found in 10 of the 12 geologic zones tested. The Hibernia P-15 discovery well had earlier been estimated to be capable of producing over 20,000 barrels of oil daily and reserves in the field have been estimated at over one billion barrels. The third confirmation well, the Hibernia G-55, was drilling at year-end. Additional delineation wells and detailed seismic surveys will be required to determine the appropriate production system to be employed.

Columbia's interests in the Hibernia wells and the 524,748 gross acre block will be 6.09 percent if the lands are determined to be within the jurisdiction of the Province of Newfoundland. If the Canadian federal government has jurisdiction, Columbia's interest will be 5.47 percent, although this percentage may be reduced under the new Canadian energy policy.

Liquefied Natural Gas

The contribution of imported liquefied natural gas to Columbia's total 1980 supplies was substantially reduced by failure of the Algerian government to approve a price agreement reached in 1979 between the Algerian national company producing the LNG and the U.S. purchaser, the El Paso Company, from which Columbia buys LNG. Deliveries to Columbia LNG Corporation's Cove Point, Maryland terminal ended in April 1980 and in December the terminal was temporarily shut down. Negotiations on a new price directly between the United States and Algerian governments reached an impasse early in 1981, but it is hoped that discussions can be resumed on a commercial level, leading to an eventual resumption of deliveries. In 1980, LNG accounted for 24.8 billion cubic feet of gas to System supply. At full contract volume, deliveries from Cove Point would supply about 110 billion cubic feet to Columbia annually.

Columbia continues to investigate additional sources of LNG supplies.

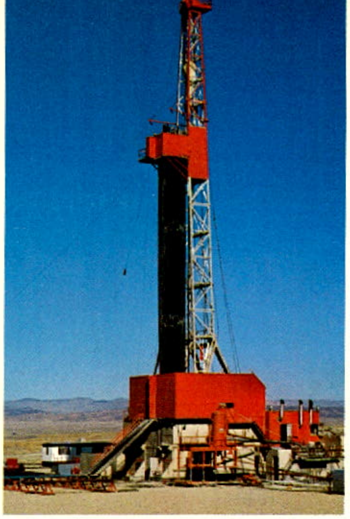
Synthetic Gas

Operations at Columbia LNG Corporation's plant at Green Springs, Ohio produced 69 billion cubic feet of pipeline quality synthetic gas, approximately 6 percent of the System's total 1980 supply. Feedstock for the plant is received from western Canada by pipeline.

Non-affiliated Pipelines

Columbia purchases about 45 percent of the gas it delivers from five non-affiliated pipeline companies from the Southwest. In 1980 these companies increased their deliveries over the previous year.

Unique new West Virginia plant separates natural gas and carbon dioxide, allowing useful recovery of both gases.



Rocky Mountain drill rig on Columbia lease explores promising new gas frontier, widening System supply search.

Coal Production

Commercial production began on a limited scale in 1980 at the Wayne County, West Virginia mine jointly owned by Columbia Coal Gasification Corporation and Monterey Coal Company, an Exxon affiliate. Columbia's first unit trainload of about 9,500 tons was shipped from the mine in December for a spot sale to a domestic utility.

Early in 1981, Columbia signed a three-year contract to sell a portion of its share of production from the mine over that period—40,000 tons annually—to a European purchaser.

The second coal mine planned under the Columbia-Exxon venture has been deferred until the coal market improves.

Over and above the 200 million tons dedicated to the mining venture, an additional 550 million tons of low sulfur coal reserves have been designated as proven and probable on Columbia lands in the same area of West Virginia. Some 300 million tons of these reserves are being offered for development to interested parties on a lease-royalty basis, and several small tracts have already been leased to coal operators.

Coal Gasification

Columbia's plans to participate with four other companies to construct the nation's first commercial-scale coal gasification plant to produce pipeline-quality gas were adversely affected by a federal court decision in late 1980 that reversed an FERC order authorizing the project.

The FERC order would have permitted costs of the Great Plains project to be passed through to consumers in the rates of the five sponsoring pipelines. This federal court decision renders it unlikely that the project can proceed promptly except on a basis not subject to continuing FERC regulation and approval. Columbia has withdrawn as a prospective investor in the project.

Columbia continues to conduct in-house basic, bench-scale level research directed at increasing the efficiency and reducing the cost of the coal gasification process. These projects include the pretreatment of coal, catalytic coal gasification, acid gas removal, and methanation. The project on catalytic coal gasification is co-funded by DOE.

Supply Research

Columbia conducts a broad supply research program through projects at its Columbus, Ohio laboratories and by supporting work by outside organizations.

Devonian Shale Studies. Potential gas reserves contained in the Devonian Shale formation of the Appalachian Basin are many trillions of cubic feet. Columbia is conducting cooperative programs with the U.S. Department of Energy, the Gas Research Institute and others to improve the production of natural gas through the evaluation of a number of stimulation techniques. Substantial progress has been made in these efforts. A 15-well program in Ohio, begun in 1979 in conjunction with another energy company, is nearing completion, and will provide additional research data.

Columbia's pipeline network, here adding New York link, provides market for producers, brings new gas to customers.

Transmission and Storage

Columbia operates one of the most extensive gas pipeline and gas storage systems in the United States. The capacity of this system to supply energy to consumers in eight states and the District of Columbia was increased by construction projects completed in 1980.

Offshore Pipelines

Columbia Gulf Transmission Company, which transports gas purchased and produced in the southwest to Columbia's market area, added new facilities to its lines in the Gulf of Mexico.

Improvements to the western shore pipeline of the Blue Water System, owned jointly with another company, allowed Columbia Gulf to increase its capacity by 200 million cubic feet per day.

Columbia Gulf also is participating in a pipeline project that will enable it to deliver 138 million cubic feet of gas per day from the South Pass offshore area.

Appalachian Pipelines

As part of its Project Penny, Columbia Gas Transmission Corporation began construction in 1980 of pipelines in Chautauqua County, New York, and in Erie, Warren, and Crawford Counties, Pennsylvania, to gather gas from wells being drilled by independent producers in those areas. Reserves in those counties are estimated to total 250 billion cubic feet.

Lines have also been constructed in Washington County, Ohio, and Indiana County, Pennsylvania, to connect reserves developed by other independent producers. Reserves in the two counties are estimated to total 250 billion cubic feet.

Transmission also carried out major construction projects in West Virginia to improve its delivery capacity.

Storage Operations

Transmission's network of storage fields in four Appalachian states contains more than 3,600 storage wells. Storage provides about one-third of all gas delivered in the heating season.

Transmission is engaged in a major expansion of its storage capacity through construction of the Crawford Storage field just south of Columbus, Ohio. When completed, the field will have the capacity to store 115 billion cubic feet of gas, increasing Transmission's total capacity to 705 billion cubic feet. Because of the expansion, gas in storage at the start of the 1980-81 heating season totaled a record 627 billion cubic feet.

New Pipeline Projects

Columbia is actively participating in plans to construct major pipeline systems which will give it access to new gas-producing areas.

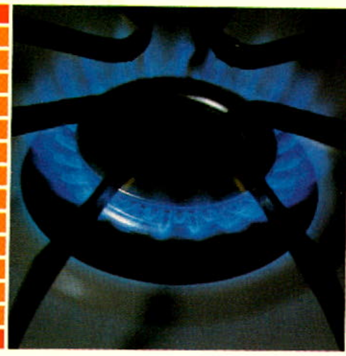
In 1980, Columbia joined ten other companies in developing plans for the 743-mile Alaskan segment of the 4,800-mile Alaskan Natural Gas Transportation System. Construction of the Alaskan segment of the system is planned to begin in 1983 and the entire Alaskan Natural Gas Transportation System is expected to be in operation by late 1985. Columbia has the right to purchase up to 5.6 trillion cubic feet of Alaskan gas from North Slope fields. Columbia is an equity participant only in the Alaskan segment of the system. In 1980, the FERC approved construction of portions of the eastern and western U.S. delivery legs of the system in the lower 48 states. Authorization was also received from the Canadian National Energy Board during the year to construct part of the Canadian segment of the system.

Federal hearings were held in 1980 on the application by Columbia and four other companies to build the Trailblazer Pipeline System from the Western Overthrust and other Rocky Mountain production areas to a connection in eastern Nebraska with existing interstate pipelines. The 800-mile line will initially deliver by displacement up to 665 million cubic feet of gas daily in certain segments of the Trailblazer System, of which Columbia's share could reach 175 million cubic feet daily.

A FERC Administrative Law Judge has recommended approval of an application by Columbia and three other companies to construct the Ozark Gas Transmission System, a 285-mile pipeline into the Arkoma Basin of Oklahoma and Arkansas. The pipeline is expected to be completed in late 1981 if FERC approval is received early in 1981. Columbia will receive its gas volumes through exchange with a project participant.

New convention center in Columbus, Ohio, selected gas for major energy needs as many large consumers are doing.

Energy Sales



Market interest in natural gas service increased during 1980 in areas served by both affiliated and non-affiliated retail distribution companies supplied by Columbia. Additionally, Columbia expects to acquire new retail and wholesale customers through the merger agreement with Commonwealth Natural Resources, Inc. This merger is expected to be completed early in 1981.

Total System sales of 1.159 trillion cubic feet in 1980 were about 3 percent less than the 1.193 trillion cubic feet sold in 1979. Of this total, 599 billion cubic feet were sold by affiliated distribution companies and 560 billion to non-affiliated companies supplied by Columbia. Sales volumes in 1980 reflected slightly warmer weather than in 1979 and lower industrial sales because of the nation's economic slowdown. These factors offset additional sales resulting from customer additions.

Retail Operations

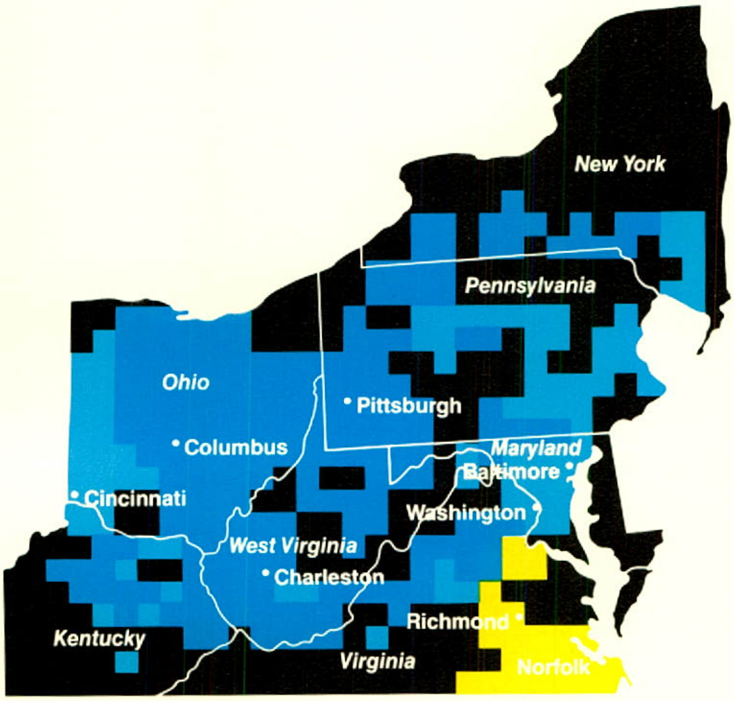
For Columbia's seven affiliated retail distribution companies, 1980 was the first complete calendar year of sales to new residential, commercial and high priority industrial customers since 1972. During the year, approximately 25,700 new residential and commercial customers were added to Columbia distribution lines. These customer additions were partially offset by service connections lost through such factors as highway relocations and urban renewal.

In addition, more than 5,000 customers who already had gas in their homes for other purposes became heating customers.

Industrial sales were encouraging through the early part of the second quarter but declined during the remainder of the year, reflecting national economic factors. While major industrial plant closings were experienced in some sections of the country, none occurred in Columbia's retail service area. Industrial development prospects in the area are encouraging and will reflect any overall improvement in national economic conditions.

Looking to continued growth, Columbia distribution companies began an aggressive marketing program aimed at new residential development areas, the conversion market, the appliance replacement market, energy systems in new commercial buildings, and increased emphasis on efficient use of natural gas for high priority industrial processes.

Columbia assisted in attracting and expanding industries within the seven-state retail area. Decisions during 1980 by three companies to locate major facilities with combined potential for more than 10,000 jobs in this area are indicative of growth potential.



Planned merger with Commonwealth Natural Resources will extend Columbia's direct marketing area.

Columbia Gas System Retail and Wholesale Service Areas

- Columbia Retail
- Columbia Wholesale
- Commonwealth

As natural gas costs continued to rise, the Columbia companies intensified efforts to develop better understanding by customers of increased costs. Advertising was reinstated to provide messages concerning conservation, higher gas costs and the benefits of the companies' budget payment plans. Customer forums, with the chief executive officer of the distribution companies as the principal participant, were held in a number of Columbia-served communities.

At year-end, approximately 40 percent of the companies' more than 1,690,000 residential customers were participating in budget payment plans. In addition, the companies completed plans to offer home energy audits and suggest needed conservation measures to customers in conjunction with the federal Residential Conservation Services program.

Wholesale Markets

Many of the 83 non-affiliated distribution companies supplied by Columbia, such as those in Washington, D.C., Baltimore, Maryland, Cincinnati and Dayton, Ohio, experienced new customer additions similar to those of Columbia's retail companies.

The advantages of gas energy attracted both new home builders and those home owners who previously used another fuel. Heating conversions from oil to gas were especially numerous in the eastern markets where gas heat saturation was lower than in other areas.

Columbia's retail companies set more than 25,700 meters to connect new residential and commercial customers.

Chairman Marvin White of System retail companies met with consumer groups to answer customer queries.

Commonwealth Merger

Commonwealth Natural Resources sells natural gas at both retail and wholesale in major central and eastern Virginia markets. (See map at left.) In 1980, Columbia supplied about 78 percent of the gas sold by Commonwealth.

Through a retail distribution company, Commonwealth serves about 48,000 customers directly and supplies another 200,000 customers through sales at wholesale to three non-affiliated utilities.

Another Commonwealth company supplies propane to an additional 31,000 customers.

Markets served by Commonwealth are judged to offer good growth potential in all customer categories.

Propane Sales

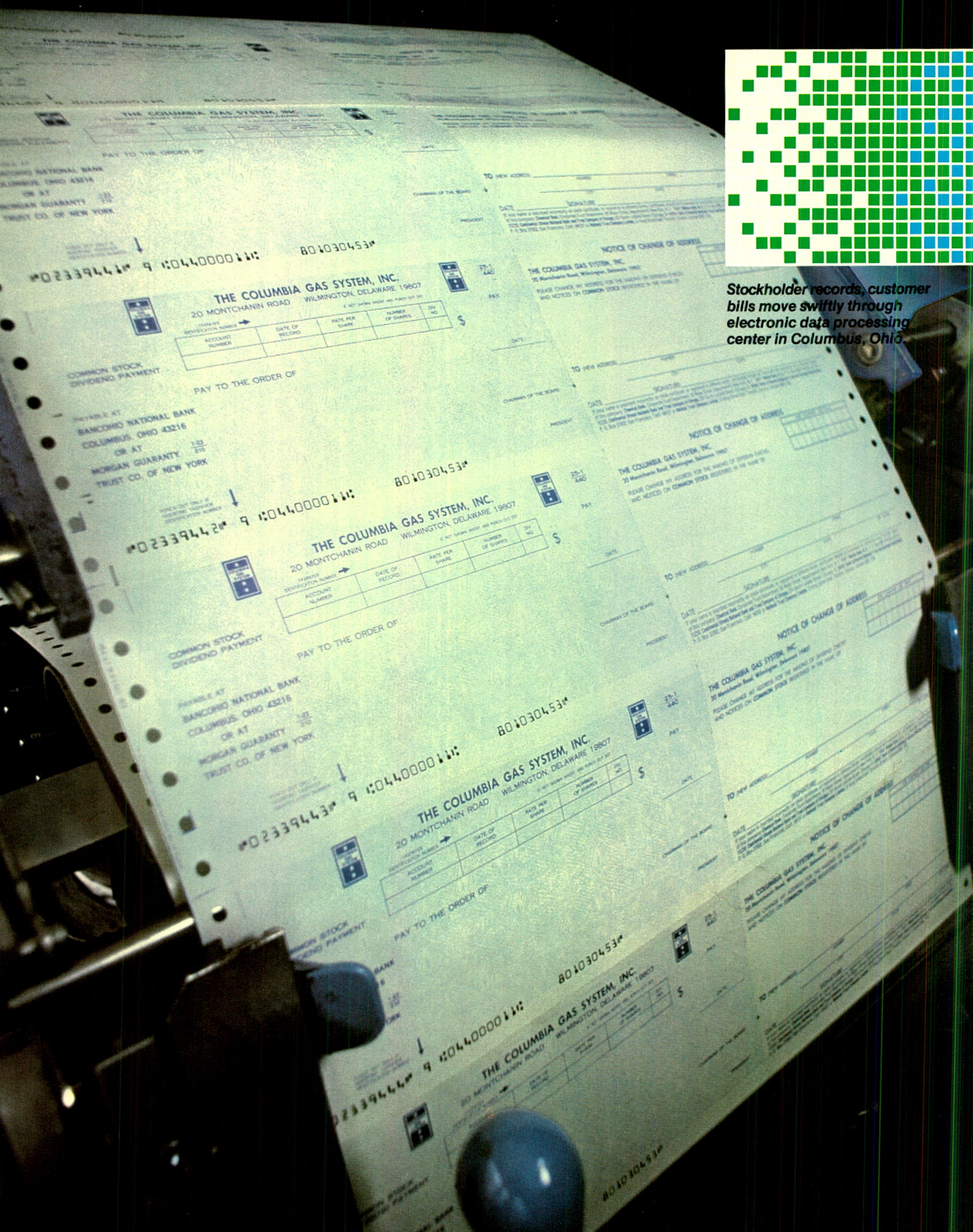
Through Columbia Hydrocarbon Corporation, the System offers propane service to residential, commercial and industrial customers beyond existing gas mains in parts of Columbia's retail service area. Additionally, it has begun test marketing of propane for fleet motor fuel use in certain areas. Propane sales in 1980 exceeded approximately 72 million gallons (equal to 66 million cubic feet of gas) as compared to 70 million gallons in 1979.

Energy Utilization Research

Columbia conducts a number of research projects, alone or with others, directed toward improved energy service to its customers.

Solar Projects. To supplement an existing project to test a combination gas/solar energy system for a commercial office building, Columbia in 1980 contracted to help construct an industrial solar energy system to process steam for a petrochemical plant in Ohio. Co-funded by the U.S. Department of Energy, the project is being conducted in association with the plant operator, the USS Chemicals Division of the United States Steel Corporation. The installation will be one of the largest solar energy systems in the world, utilizing 50,400 square feet of solar collectors. Columbia continues to monitor and evaluate all solar energy developments to determine how solar energy might relate to energy needs of Columbia's market areas in general and to measure solar's potential linkage with natural gas in particular.

Utilization. A second generation prototype of Columbia's gas residential heat pump is presently being fabricated. The Gas Research Institute is providing some of the funding as part of their research effort into gas heat pump systems. Columbia also has a number of other studies under way in its Columbus research center for improved residential and commercial gas utilization. A typical project is the development of a high efficiency combination space/water heater.



Stockholder records, customer bills move swiftly through electronic data processing center in Columbus, Ohio.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Results of Operations

Earnings on common stock for 1980 were $165.3 million or $5.02 per share, as compared with 1979 earnings of $143.1 million or $4.39 per share and 1978 earnings of $121.1 million or $3.72 per share.

Gas operating revenues for the current year increased $737 million due largely to increased sales rates which were partially offset by slightly lower sales volumes. Increased average rates of approximately 30% for retail and wholesale sales were necessary to recover increased gas purchased and other expenses. The decrease in volumes reflected warmer weather in the annual billing period, continued conservation and the effects of the recession. Industrial and wholesale volumes should increase when business conditions improve. Gas revenues in 1979 were influenced by higher average rates (up 9%) and a 7% increase in retail and wholesale volumes.

Other operating revenues rose $48.1 million or 60% over 1979 reflecting significant price increases during 1980 related to the sale of oil, propane and other hydrocarbons. The increase also reflected higher production volumes related to oil and other liquids.

Gas purchased costs continued to increase in 1980, as they did in 1979, reflecting the impact of the Natural Gas Policy Act, passed late in 1978, and the effects of inflation on supplier operating expenses. The System's rate regulated companies, both wholesale and retail, are able to pass along to customers increases in the cost of purchased gas through purchased gas adjustment clauses or similar provisions of the tariffs under which they operate. A nonrecurring adjustment to adopt accounting consistent with rate treatment was recorded in 1980 improving earnings for the year by approximately $0.13 per share.

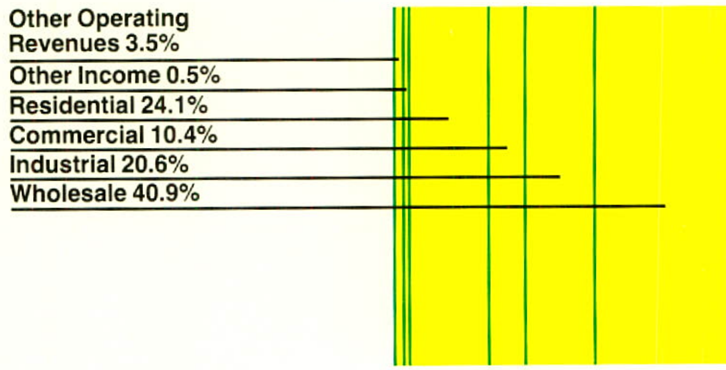
The System's business operations related to natural gas sales are greatly influenced by abnormal weather patterns which affect earnings and related components of revenue and expense. The year 1980 proved to be unique in that through December 19, 1980, the weather was warmer than for the same period a year ago. However, during the last twelve days of the year, the weather was 49% colder than for the comparable period in 1979. Since the Corporation's wholesale subsidiary expenses gas withdrawn from storage through the 19th of each month, this had the effect of deferring a portion of gas purchased expenses related to volumes sold and recorded in revenues through the end of December. This improved 1980 earnings by $.44 per share.

Other operation and maintenance expenses continued to reflect the effects of inflationary pressures. Depreciation and depletion increased in 1980 due to increased plant investment, higher revenues related to production and the downward adjustment recorded in 1979 in connection with a settled wholesale rate case, of which approximately $8,000,000 was applicable to 1978. The provision for income taxes includes an adjustment applicable to prior years which was recorded in 1980 to reflect current rate treatment. This adjustment increased 1980 earnings by approximately $0.17 per share. Gross receipts taxes continued to increase along with higher operating revenues. In addition, the increase in 1980 included approximately $7.8 million attributable to the "windfall profits" tax on decontrolled oil prices.

Investment tax credits increased $10.6 million and the allowance for equity funds increased $2.4 million, offsetting the gain of $11.6 million recorded in 1979 in connection with the sale of Canadian lands.

The preferred stock dividend accrual decreased $4.7 million due to the redemption of the 11.25% Series A preferred shares on November 1, 1979. The effect on 1980 earnings is tempered by the increase in interest expense related to the 11.75% debentures issued in October 1979.

1980 Source of Revenues



As noted in the 1980 Second Quarter Report to stockholders, regarding the importation of liquified natural gas from Algeria, implementation of the minimum bill provision under the tariff filed with the Federal Energy Regulatory Commission (FERC) provides for recovery of all costs except equity return resulting in a decrease in monthly earnings of approximately $.03 per share. At the cessation of deliveries on December 11, 1980, the minimum bill provision was invoked. However, complaints have been filed with the FERC alleging the minimum bill provision should have been invoked at an earlier date. The System is contesting these complaints, and no effect on reported 1980 earnings is anticipated.

Reference is made to the schedules on pages 22 and 23 entitled "Comparative Gas Operations Data" and "Selected Financial Data" for additional details.

Rate Activity

The System's transmission companies have filed a general rate increase with the FERC that would provide additional annual revenue of approximately $85.7 million over current rates now being collected. The increased rates will be placed in effect subject to refund on April 1, 1981.

During 1980, the System's distribution subsidiaries have received approvals for general rate increases amounting to approximately $35.3 million annually. Revenue increases of approximately $41.6 million annually have been filed and were awaiting action by state commissions at year-end.

Additional information regarding rate matters is contained in Note 2 of Notes to Consolidated Financial Statements.

Liquidity and Capital Resources

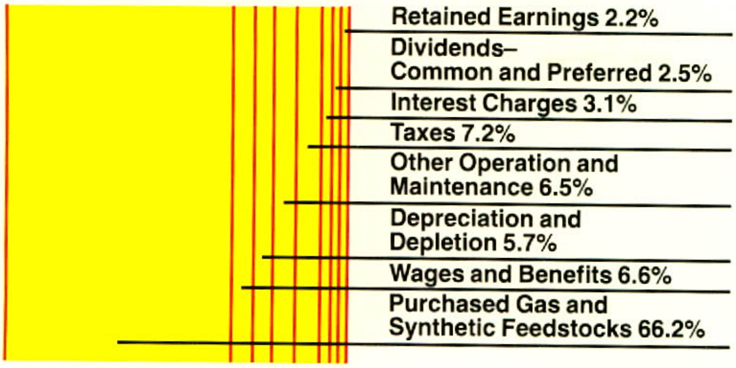
The Corporation does not anticipate any events that would materially change its present liquidity position which is adequate to satisfy known demands, even though the relative costs of obtaining new capital have increased significantly and projected capital expenditures for 1981 have increased to an estimated $573 million compared to $443 million in 1980.

The ability to generate cash adequate to meet short-term and long-term needs results from the collection of accounts receivable related to monthly billings to customers for sales of natural gas, propane and other hydrocarbons, short-term and long-term debt financing and equity financing. Demands for funds relate mostly to payments for gas purchased and other operating costs, taxes, debt obligations and capital expenditures.

With regard to short-term financing, the Corporation has lines of credit with major commercial banks sufficient to provide for short-term requirements either in the form of bank borrowings or as support for the issuance of commercial paper. Requirements are principally to finance gas purchases for storage until such gas is sold during the heating season. Recent increases in the credit line are due principally to escalating gas purchase prices.

As in the past, internally generated funds will provide a substantial portion of the capital expenditure requirements. In addition, the Corporation, during 1980, entered into a $200 million seven-year subordinated revolving credit agreement with a group of commercial banks. The revolving credit notes will be specifically subordinated to the Corporation's debentures, thereby conserving debenture financing capacity under indenture provisions, and providing considerable flexibility in the Corporation's financing program.

1980 Disposition of Revenues



Among the major projects described on page 13 of this report are the Alaska Natural Gas Transportation System, the Trailblazer Pipeline System and the Ozark Gas Transmission System. As presently contemplated, project financing will be used for these undertakings. As a result, the Corporation and other participants will provide their share of the equity investment, and the debt capital will be provided by lenders to the project on a non-recourse basis.

At December 31, 1980, the Corporation's material unused sources of liquidity consisted principally of credit lines related to short-term requirements of $182.4 million, $200 million available under the terms of the revolving credit agreement and available indenture capacity under the most restrictive of the Corporation's indenture tests, the amount of which is influenced by prevailing interest rates.

Impact of Inflation

The rate of inflation has continued to accelerate and it continues to be a matter of great concern. The Corporation's wholesale and retail subsidiaries have been successful in passing along to customers increases in the cost of gas. However, the Corporation's results of operations are adversely affected by the lag in recovering rising costs associated with operating expenses and interest rates. The Corporation has tried to minimize this impact by assuming an aggressive posture toward general rate filings. Note 12 of Notes to Consolidated Financial Statements contains additional information related to the effects of general inflation and changes in specific prices on the Corporation.

Common Stock Prices and Dividends

The common stock of The Columbia Gas System, Inc. is listed on the New York Stock Exchange, Philadelphia Stock Exchange and Toronto Stock Exchange under the symbol CG. At December 31, 1980, there were 143,946 shareholders.

Dividends paid and the price range of the Corporation's common stock by quarters for the last two years are provided below.

Quarter Ended	High	Market Price Low	Close	Quarterly Dividends Paid
1980	$	$	$	¢
March 31	**47**	**33¾**	**37½**	**64**
June 30	**43½**	**34⅞**	**38⅛**	**64**
September 30	**41½**	**35½**	**35¾**	**64**
December 31	**42½**	**34¾**	**40¼**	**64**
1979				
March 31	28	25¼	26¼	61
June 30	28⅞	26	28⅜	61
September 30	40	28⅜	36⅜	61
December 31	40¾	30	37¾	61

Comparative Gas Operations Data

The Columbia Gas System, Inc. and Subsidiaries

	1980	1979	1978	1977	1976
Revenues (in thousands)					
Residential	**$ 878,524**	$ 731,908	$ 690,907	$ 610,076	$ 524,803
Commercial	**378,641**	302,183	274,158	226,497	209,006
Industrial	**753,882**	624,799	488,901	365,656	367,921
Wholesale	**1,492,132**	1,111,708	916,789	741,424	633,088
Other	**4,569**	498	447	12,546	616
Total revenues	**$3,507,748**	$2,771,096	$2,371,202	$1,956,199	$1,735,434
Sales (million cu. ft.)					
Residential	**240,330**	248,384	259,890	255,698	267,467
Commercial	**111,112**	111,792	112,725	103,491	119,241
Industrial	**247,623**	265,035	228,795	191,325	244,075
Wholesale	**557,634**	568,005	516,210	465,103	537,234
Other	**2,082**	183	230	4,211	577
Total sales	**1,158,781**	1,193,399	1,117,850	1,019,828	1,168,594
Customers at Year End					
Residential	**1,692,900**	1,680,349	1,674,016	1,682,875	1,693,226
Commercial	**146,439**	143,660	143,059	145,361	147,358
Industrial	**2,322**	2,298	2,329	2,383	2,443
Wholesale	**83**	84	85	84	84
Other	**66**	95	123	135	119
Total customers at year end	**1,841,810**	1,826,486	1,819,612	1,830,838	1,843,230
Degree Days—					
Billing period	**5,570**	5,703	5,983	5,669	5,663
Calendar period	**5,683**	5,678	5,958	5,588	5,769
Gas Available for Sale (million cu. ft.)					
Purchased—					
southwest	**934,009**	944,881	938,730	933,145	916,845
appalachian	**90,075**	70,186	68,167	65,283	65,882
LNG	**24,782**	75,432	29,523	—	—
Total gas purchased	**1,048,866**	1,090,499	1,036,420	998,428	982,727
Produced—					
natural	**87,524**	97,517	94,514	94,242	95,532
synthetic and LPG	**69,174**	68,951	75,553	63,869	57,440
Total gas produced	**156,698**	166,468	170,067	158,111	152,972
Exchange gas—net	**(5,601)**	2,979	(2,548)	6,102	7,486
Gas withdrawn from (delivered to) storage—net	**(1,065)**	(6,492)	(13,127)	(76,358)	77,456
Used in operations and other	**(40,117)**	(60,055)	(72,962)	(66,455)	(52,047)
Total gas available for sale	**1,158,781**	1,193,399	1,117,850	1,019,828	1,168,594

Selected Financial Data

The Columbia Gas System, Inc. and Subsidiaries

(in thousands except for per share amounts)	**1980**	1979	1978	1977	1976
Results of Operations					
Operating revenues	**$3,636,507**	$2,851,733	$2,444,171	$2,023,077	$1,770,586
Purchased gas and feedstocks	**2,418,185**	1,780,156	1,487,655	1,189,234	945,926
Other operating expenses	**840,454**	728,774	651,612	595,217	528,824
Income taxes	**130,777**	121,396	115,608	54,935	97,921
Operating income	**247,091**	221,407	189,296	183,691	197,915
Other income—net	**38,179**	37,930	29,447	36,715	22,765
Interest charges—net	**114,479**	106,056	86,542	98,514	105,823
Net Income	**170,791**	153,281	132,201	121,892	114,857
Preferred stock dividend accrual	**5,480**	10,168	11,105	11,105	11,105
Earnings on Common Stock	**$ 165,311**	$ 143,113	$ 121,096	$ 110,787	$ 103,752
Per share	**$5.02**	$4.39	$3.72	$3.41	$3.20
Average common shares	**32,948**	32,634	32,519	32,467	32,437
Dividends on Common Stock					
Per share	**$2.56**	$2.44	$2.34	$2.24	$2.14
Payout ratio (%)	**51.0**	55.6	62.9	65.7	66.9
Capitalization					
Common stock equity	**$1,191,455**	$1,097,886	$1,026,500	$ 978,891	$ 939,844
Redeemable preferred stock	**45,000**	50,000	100,000	100,000	100,000
Long-term debt, excluding current maturities	**1,201,833**	1,174,596	1,070,407	1,134,177	1,359,765
Total capitalization	**$2,438,288**	$2,322,482	$2,196,907	$2,213,068	$2,399,609
Book Value Per Common Share	**$35.96**	$33.46	$31.51	$30.13	$28.96
Property, Plant & Equipment	**$4,736,217**	$4,334,900	$4,078,740	$3,785,919	$3,583,056
Accumulated provision for depreciation and depletion	**(1,908,427)**	(1,715,962)	(1,594,904)	(1,449,030)	(1,342,425)
Net property, plant & equipment	**$2,827,790**	$2,618,938	$2,483,836	$2,336,889	$2,240,631
Total Assets	**$3,861,861**	$3,626,036	$3,427,222	$3,444,815	$3,173,785
Capital Expenditures for Year	**$ 442,825**	$ 369,532	$ 337,963	$ 284,034	$ 261,880

Managements Statement of Responsibility for Financial Statements

The accompanying consolidated financial statements and related notes have been prepared by the Corporation based on the appropriate 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 control system, and a comprehensive program of internal audits designed to reasonably assure the adequacy of internal controls and implementation of company policies and procedures. The internal audit staff is under the direction of the Vice President and General Auditor who reports directly to the Chairman of the Board.

An audit committee assists the board of directors in its oversight role and is composed of six directors who are not officers or employees of the Corporation. The audit committee meets with the Vice President and General Auditor periodically to review his work and to monitor the discharge of his responsibilities. The audit committee also meets periodically with the independent public accountants, who have free access to the audit committee of the board, to discuss internal accounting controls, auditing and financial reporting matters.

Auditors' Report

Arthur Andersen & Co.
1345 Avenue of the Americas
New York, New York 10105

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

We have examined the consolidated balance sheets of The Columbia Gas System, Inc. (a Delaware corporation) and subsidiaries as of December 31, 1980 and 1979 and the related statements of consolidated income, taxes, common stock equity and funds used for capital expenditures for each of the three years in the period ended December 31, 1980. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the consolidated financial statements referred to above present fairly the financial position of The Columbia Gas System, Inc. and subsidiaries as of December 31, 1980 and 1979, and the results of their operations and funds used for capital expenditures for each of the three years in the period ended December 31, 1980, in conformity with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen + Co.

February 10, 1981.

Statements of Consolidated Income

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31, (in thousands)	**1980**	1979	1978
Operating Revenues (Note 2)			
Gas	**$3,507,748**	$2,771,096	$2,371,202
Other	**128,759**	80,637	72,969
Total operating revenues	**3,636,507**	2,851,733	2,444,171
Operating Expenses			
Gas purchased for resale	**2,113,370**	1,513,362	1,225,953
Synthetic gas feedstocks	**304,815**	266,794	261,702
Other operation	**410,848**	364,903	317,962
Maintenance	**67,412**	60,194	55,250
Provision for depreciation and depletion	**209,719**	171,690	178,949
Provision for income taxes	**130,777**	121,396	115,608
Other taxes	**152,475**	131,987	99,451
Total operating expenses	**3,389,416**	2,630,326	2,254,875
Operating income	**247,091**	221,407	189,296
Other Income			
Investment credits, including amortization	**19,708**	10,523	15,655
Allowance for equity funds used during construction	**3,141**	693	7,033
Gain on sale of Canadian properties, less deferred income taxes of $2,060,000	**—**	11,590	—
Interest and other—net	**15,330**	15,124	6,759
Total other income	**38,179**	37,930	29,447
Income before interest charges	**285,270**	259,337	218,743
Interest Charges			
Long-term debt	**101,381**	89,045	88,325
Other—net	**20,573**	20,960	8,396
Allowance for borrowed funds used during construction	**(7,475)**	(3,949)	(10,179)
Total interest charges	**114,479**	106,056	86,542
Net Income	**170,791**	153,281	132,201
Preferred stock dividend accrual	**5,480**	10,168	11,105
Earnings on Common Stock	**$ 165,311**	$ 143,113	$ 121,096
Earnings Per Share of Common Stock (based on average shares outstanding)	**$5.02**	$4.39	$3.72
Dividends Per Share of Common Stock	**$2.56**	$2.44	$2.34
Average Common Shares Outstanding (thousands)	**32,948**	32,634	32,519

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

Consolidated Balance Sheets

The Columbia Gas System, Inc. and Subsidiaries

Assets

As of December 31, (in thousands)	1980	1979
Property, Plant and Equipment, at original cost—		
Gas utility and other plant	**$3,889,690**	$3,608,464
Accumulated provision for depreciation and depletion	**(1,666,574)**	(1,541,796)
	2,223,116	2,066,668
Oil and gas producing properties, full cost method—		
United States cost center	**747,224**	647,967
Canadian cost center ($42,466,000 and $34,050,000, respectively, not being amortized) (Note 3)	**99,303**	78,469
Accumulated provision for depletion	**(241,853)**	(174,166)
	604,674	552,270
Net property, plant and equipment	**2,827,790**	2,618,938
Gas Supply Advances and Investments	**124,021**	149,838
Current Assets		
Cash	**18,772**	32,729
Temporary cash investments, at cost which approximates market	**7,483**	196
Accounts receivable—		
Gas	**338,075**	281,299
Other	**78,743**	109,188
Accumulated provision for doubtful accounts	**(4,300)**	(3,654)
Gas supply advances—current	**40,690**	21,376
Gas in underground storage—current inventory, at cost	**261,140**	219,113
Materials and supplies, at average cost	**45,294**	38,383
Unrecovered gas costs—net	**—**	53,502
Other	**76,684**	62,559
Total current assets	**862,581**	814,691
Deferred Charges	**47,469**	42,569
Total Assets	**$3,861,861**	$3,626,036

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

Capitalization and Liabilities

As of December 31, (in thousands)	1980	1979
Common Stock Equity		
Common stock, $10 par value, authorized 50,000,000 shares, outstanding 33,131,265 and 32,807,246 shares, respectively	**$ 331,313**	$ 328,072
Balance of amounts paid in in excess of par value	**135,519**	126,275
Retained earnings	**724,623**	643,539
Total common stock equity (See Statements of Consolidated Common Stock Equity)	**1,191,455**	1,097,886
Redeemable Preferred Stock (Note 4)	**45,000**	50,000
Long-term debt (Note 5)	**1,201,833**	1,174,596
Total Capitalization	**2,438,288**	2,322,482
Current Liabilities		
Commercial paper	**42,600**	133,140
Current maturities of long-term debt and preferred stock	**41,595**	29,013
Accounts and drafts payable	**411,574**	312,320
Accrued taxes	**183,117**	82,065
Accrued interest	**42,915**	33,591
Estimated rate refunds	**168,301**	220,553
Over-recovered gas costs—net	**3,709**	—
Current deferred taxes—net	**8,995**	30,911
Other	**72,270**	59,173
Total current liabilities	**975,076**	900,766
Deferred Credits		
Accumulated provision for deferred income taxes—net	**357,723**	324,766
Accumulated deferred investment credits	**39,081**	34,144
Other	**51,693**	43,878
Total deferred credits	**448,497**	402,788
Commitments and Contingencies (Notes 2, 7, 8, and 9)		
Total Capitalization and Liabilities	**$3,861,861**	$3,626,036

Statements of Consolidated Common Stock Equity

The Columbia Gas System, Inc. and Subsidiaries

(in thousands)	1980	1979	1978
Common Stock			
Balance at beginning of year	**$ 328,072**	$ 325,802	$ 324,885
Sale of common stock*	**3,241**	2,270	917
Balance at end of year	**331,313**	328,072	325,802
Balance of Amounts Paid In in Excess of Par Value			
Balance at beginning of year	**126,275**	120,705	119,031
Sale of common stock*	**9,244**	5,570	1,674
Balance at end of year	**135,519**	126,275	120,705
Retained Earnings			
Balance at beginning of year	**643,539**	579,993	534,975
Net income	**170,791**	153,281	132,201
Cash dividends:			
Common stock	**(84,227)**	(79,567)	(76,078)
Redeemable preferred stock—			
11.25% Series A	**—**	(4,688)	(5,625)
10.96% Series B	**(5,480)**	(5,480)	(5,480)
Balance at end of year**	**724,623**	643,539	579,993
Total Common Stock Equity	**$1,191,455**	$1,097,886	$1,026,500

*In 1980, 1979 and 1978, the Corporation sold 76,681, 159,313 and 91,657 shares, respectively, of common stock to the trustee of the Tax Reduction Employee Stock Ownership Plan. In addition, during 1980 and 1979, the Corporation sold 247,338 and 67,707 shares, respectively, of common stock in connection with the Dividend Reinvestment Plan.

**$533,539,000 not available for cash dividends at December 31, 1980, under the terms of the Indentures securing the Corporation's outstanding debentures. In addition, restrictions on payment of cash dividends are also imposed by the Certificate of Incorporation as long as any preferred stock is outstanding. However, the provisions contained in the Indentures are presently more restrictive than those contained in the Certificate of Incorporation.

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

Statements of Consolidated Funds Used for Capital Expenditures

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31, (in thousands)	**1980**	1979	1978
Funds from Internal Sources			
Operations			
Net income	**$170,791**	$153,281	$132,201
Items not requiring (providing) funds:			
Depreciation and depletion	**210,058**	172,498	179,660
Deferred income taxes and investment credits—net	**19,991**	116,410	74,641
Allowance for equity funds used during construction	**(3,141)**	(693)	(7,033)
Accrued interest on gas supply advances	**(4,538)**	(997)	—
Total operations	**393,161**	440,499	379,469
Dividends on common and preferred stock	**(89,707)**	(89,735)	(87,183)
Other			
Cash and temporary cash investments	**6,670**	34,954	(31,160)
Accounts receivable	**(25,685)**	(125,697)	(10,776)
Gas in underground storage	**(42,027)**	8,571	(16,760)
Accounts and drafts payable	**99,254**	72,909	61,850
Accrued taxes	**101,052**	(23,195)	21,126
Rate refunds	**(52,252)**	(65,198)	37,019
Unrecovered/over-recovered gas costs—net	**57,211**	(100,079)	45,128
Repayments of gas supply advances and investments	**16,529**	57,152	179,580
Miscellaneous—net	**13,952**	44,992	38,273
Total other	**174,704**	(95,591)	324,280
Total funds from internal sources	**478,158**	255,173	616,566
Funds from Financing			
Issuance of capital stock	**12,485**	7,840	2,591
Retirement of capital stock	**—**	(50,000)	—
Issuance of long-term debt	**100,000**	175,000	—
Retirement of long-term debt	**(64,957)**	(67,811)	(222,145)
Short-term bank loans and commercial paper—			
Borrowed	**428,180**	465,110	253,725
Repaid	**(518,720)**	(417,470)	(319,807)
Total funds from financing (repaid)	**(43,012)**	112,669	(285,636)
Funds Used for Capital Expenditures	**$435,146**	$367,842	$330,930
Allowance for equity funds used during construction	**3,141**	693	7,033
Accrued interest on gas supply advances	**4,538**	997	—
Total Capital Expenditures	**$442,825**	$369,532	$337,963
Capital Expenditures for—			
Gas utility and other plant	**$301,065**	$211,887	$191,881
Oil and gas acquisitions, exploration and development	**128,287**	127,937	139,191
Gas supply advances and investments	**13,473**	29,708	6,891
Total Capital Expenditures	**$442,825**	$369,532	$337,963

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

Statements of Consolidated Taxes

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31, (in thousands)	1980	1979	1978
Provision for Income Taxes			
Included in operating expenses			
Currently payable—			
Federal	**$ 78,199**	$ (4,173)	$ 17,029
State	**12,879**	696	8,283
Total	**91,078**	(3,477)	25,312
Deferred, net—			
Federal	**9,023**	99,279	68,665
State and foreign	**1,804**	9,001	2,205
Total	**10,827**	108,280	70,870
Investment credits—			
Provision	**31,957**	18,304	21,557
Provision not deferred	**(2,492)**	(989)	(1,542)
Amortization	**(593)**	(722)	(589)
Total	**28,872**	16,593	19,426
Total included in operating expenses	**130,777**	121,396	115,608
Included in other income			
Deferred—			
Federal	**—**	(2,168)	—
Foreign	**—**	4,228	—
Total	**—**	2,060	—
Investment credits—			
Provision not deferred	**(17,797)**	(8,623)	(13,741)
Amortization	**(1,911)**	(1,900)	(1,914)
Total	**(19,708)**	(10,523)	(15,655)
Total included in other income	**(19,708)**	(8,463)	(15,655)
Total provision for income taxes	**111,069**	112,933	99,953
Other Taxes			
Property	**38,764**	37,605	33,467
Gross receipts	**94,320**	79,908	53,307
Payroll	**12,367**	10,763	8,402
Other	**7,024**	3,711	4,275
Total other taxes	**152,475**	131,987	99,451
Total Tax Expense	**$263,544**	$244,920	$199,404

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

Year Ended December 31, (in thousands)	1980		1979		1978	
Computation of Income Taxes— The total provision for income taxes is less 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 provision for income taxes	**$281,860**		$266,214		$232,154	
Tax expense at statutory Federal income tax rate	**$129,656**	**46.0%**	$122,458	46.0%	$111,434	48.0%
Increases (reductions) in taxes resulting from—						
State and foreign income taxes, net of Federal income tax benefit	**8,518**	**3.0**	5,195	1.9	5,606	2.4
Investment credits not deferred and amortization of credits deferred in prior years	**(22,793)**	**(8.1)**	(12,234)	(4.6)	(17,786)	(7.7)
Depreciation expense for accounting purposes over amounts claimed for income tax purposes—net	**4,792**	**1.7**	4,452	1.7	6,073	2.6
Gain on sale of Canadian properties taxed at less than the statutory rate	**—**	**—**	(4,220)	(1.6)	—	—
Other	**(9,104)**	**(3.2)**	(2,718)	(1.0)	(5,374)	(2.2)
Total provision for income taxes	**$111,069**	**39.4%**	$112,933	42.4%	$ 99,953	43.1%

	1980	1979	1978
Deferred Income Taxes— Deferred income taxes result from timing differences in the recognition of revenues and expenses for tax and accounting purposes. The source of these differences and tax effect of each is as follows:			
Acquisitions and exploration and development costs	**$ 14,304**	$ 26,445	$ 34,015
Depreciation expense	**14,002**	11,846	9,306
Unrecovered/over-recovered gas costs	**(32,338)**	27,386	(17,579)
Estimated rate refunds	**19,473**	39,754	35,380
Other	**(4,614)**	4,909	9,748
Total provision for deferred income taxes	**$ 10,827**	$110,340	$ 70,870

1. Summary of Significant Accounting Policies

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

B. Property, Plant and Equipment, and Related Depreciation and Depletion. Property, plant and equipment of the Corporation's rate regulated subsidiaries is stated at the historical cost of construction. Such costs include payroll and related taxes, administrative and general costs, and allowance for funds used during construction.

Allowance for funds used during construction is defined in the applicable regulatory system of accounts as the net cost, during the period of construction, of borrowed funds used and a reasonable rate upon other funds when so used. The rate for such allowance was 12.0% in 1980, 11.25% in 1979 and 10.5% in 1978.

The Corporation's subsidiaries provide for depreciation on a composite straight-line basis. The annual provisions for depreciation as related to the average of depreciable property at the beginning and end of each year result in composite rates of 2.8% in 1980, 2.9% in 1979 and 3.0% in 1978 for distribution properties and 4.5% in 1980, 3.8% in 1979 and 5.3% in 1978 for other properties.

The Corporation's subsidiaries engaged in exploring for and developing reserves of hydrocarbons (principally natural gas) follow the full cost method of accounting. Under this method of accounting, all productive and nonproductive costs directly identified with acquisition, exploration and development activities are capitalized in country-wide cost centers.

Provisions for depletion related to costs capitalized in the United States cost center are based upon gross revenues. Provisions for depletion related to costs capitalized in the Canadian cost center, exclusive of Canadian frontier areas as described in Note 3, are based upon physical units produced.

C. Gas in Underground Storage. Current inventory is carried at cost on a last-in, first-out basis (LIFO). The excess of current cost over carrying value was approximately $168,800,000 and $132,300,000 at December 31, 1980 and 1979, respectively. Under present regulatory practice, liquidation of the LIFO layers would be reflected in future purchased gas adjustments in customer rates.

D. Income Taxes and Investment Tax Credits. The Corporation's subsidiaries follow interperiod tax allocation with respect to timing differences in the recognition of revenues and expenses for tax and accounting purposes except when regulatory commissions do not recognize interperiod tax allocation for rate purposes.

Investment tax credits are being recorded in income currently except for credits of the gas distribution subsidiaries, which are being deferred and amortized generally over the life of the related property to conform with regulatory policy.

Reference is made to Statements of Consolidated Taxes for the components of and additional information relating to taxes.

E. Provisions for Estimated Rate Refunds. Provisions for estimated rate refunds are based upon management's current judgement as to the ultimate disposition of pending rate proceedings. No provisions are made in instances where a reasonable estimate of the ultimate outcome cannot be made.

F. Unrecovered Gas Costs. The Corporation's gas wholesale and 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.

G. Unbilled Revenues. The Corporation's gas distribution subsidiaries recognize revenue from meters read or calculated on a monthly cycle basis, thereby resulting in unbilled revenue from the cycle ending date through month-end. The effect of not recording unbilled revenue is substantially offset by the policy of a gas wholesale subsidiary of expensing gas withdrawn from underground storage only to the 20th of each month and the deferral by the gas distribution subsidiaries of the cost of gas associated with unbilled revenues.

H. Pension Costs. The Corporation has a trusteed, noncontributory Retirement Income Plan which, with certain minor exceptions, covers all regular employees, 25 years of age and over. The Corporation's policy is to fund pension costs accrued, which amounted to $21,900,000 in 1980, $19,600,000 in 1979 and $16,800,000 in 1978, including amortization of unfunded prior service costs.

A comparison of accumulated plan benefits and plan assets is presented below:

At December 31, (in thousands)	**1980**	1979
Actuarial present value of accumulated plan benefits:		
Vested	**$252,300**	$240,700
Nonvested	**4,600**	5,000
Total	**$256,900**	$245,700
Net Assets Available for Benefits	**$270,800**	$214,500

The average assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 8.5% as of December 31, 1980, and 7.8% as of December 31, 1979. These rates represent those available through insurance company annuity contracts.

Effective January 1, 1980, the Corporation authorized supplemental payments to retired employees and surviving beneficiaries of employees who retired prior to January 1, 1980. These payments are being made from the general funds of the Corporation. The total actuarial liability of approximately $9,200,000 at December 31, 1980, is being amortized over a period ending in 1989.

2. *Regulatory Matters*

A. Wholesale Rate Order. On February 12, 1980, the Federal Energy Regulatory Commission (FERC) issued an order which reversed a 1977 Administrative Law Judge's decision approving a gas wholesale subsidiary's request to price new Appalachian gas production on a cost-of-service basis beginning December 15, 1975. Refunds totaling $51,600,000 were made during 1980. Such refunds had no effect on reported earnings since adequate provisions were previously recorded.

B. Other Rate Matters. In July 1979, the FERC issued an order which confirmed existing FERC policy that, in determining wholesale rates, statutory income tax rates should be used to compute cost-of-service. The order also found that the income tax allowance in rates collected by the Corporation's wholesale subsidiaries since December 15, 1975, was just and reasonable. An application for rehearing requested by an opposing intervenor was denied by the FERC whereupon the opposing intervenor filed a petition for review in the United States Court of Appeals for the District of Columbia circuit. The Court has scheduled oral argument for March 2, 1981. In the opinion of management, the favorable decision of the FERC will be upheld by the Court.

During 1979, The Public Utilities Commission of Ohio modified its rules by adopting a gas cost recovery clause to provide for a monthly matching of gas purchased costs and the recovery of such costs in revenues. Due to the timing of the implementation of the new rule, the Corporation's Ohio gas distribution company was denied the recovery of a substantial amount of gas purchased costs, previously expensed, which was associated with unbilled revenues at the transition date. The company, and other affected Ohio companies, filed for a transitional adjustment and the Commission ordered hearings on the issue. Late in January 1981, a small Ohio gas distribution company received an order from the Commission allowing an adjustment in rates to recover a portion of the filed for transitional adjustment. If the company receives and accepts a similar rate order, the Corporation's 1981 earnings would be improved.

As discussed under "Management's Discussion" on page 20, on December 11, 1980, Columbia LNG Corporation invoked the minimum bill provision of its tariff filed with the FERC at the termination of deliveries to its customer. The minimum bill provision specifically allows recovery of operation and maintenance expenses, taxes and costs associated with debt. In management's opinion, the investment associated with the Cove Point terminal will be recovered through the resumption of deliveries or appropriate rate recovery.

C. Rate Increase Filings. Certain subsidiaries have increased their rates and are collecting the increase in revenue subject to refund. In the opinion of management, the provisions for estimated rate refunds charged to income are adequate to cover the ultimate disposition of pending rate proceedings.

Reference is made to the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information.

3. *Investment in Canadian Frontier Areas*

Costs capitalized in the Canadian cost center, net of accumulated provision for depreciation and depletion, amounted to $97,800,000 and $77,600,000 at December 31, 1980, and 1979, respectively. Investments by Columbia Gas Development of Canada Ltd. (Columbia-Canada) in certain Canadian frontier areas, as shown in the accompanying table, have been excluded from this cost center for purposes of calculating depletion pending determination of proved reserves and/or valuation attributable to the properties. Such properties are subject to periodic assessment (at least annually), and any impairment below cost is included in costs being amortized.

At December 31, (in thousands)	**1980**	1979
Arctic Islands and Northwest Territories	**$23,100**	$21,800
Offshore East Coast	**19,400**	12,300
	$42,500	$34,100

Arctic Islands and Northwest Territories. Columbia-Canada owns varying interests in 10.6 million gross acres (.8 million net acres). Costs were initially incurred in 1971 and consist principally of exploration costs. Exploration drilling by Columbia-Canada and others is proceeding to evaluate lands in which Columbia-Canada has interests. Management estimates that development of gas reserves attributable to these properties will occur in the mid to late 1980's.

Offshore East Coast. Columbia-Canada owns varying interests in 14.2 million gross acres (2.1 million net acres) offshore Labrador and Newfoundland, 490,000 gross acres (245,000 net acres) offshore Baffin Island, and 3.5 million gross acres (517,000 net acres) offshore Prince Edward Island. Costs were initially incurred in 1972 and consist principally of exploration costs. Gas discoveries have been made offshore along the eastern coasts of Newfoundland and Baffin Island. The Chevron Hibernia well 200 miles east of St. Johns, Newfoundland, in which Columbia-Canada has an interest, is a potentially significant discovery, and two successful follow-up wells drilled in 1980 have added weight to the commercial significance of the area. Follow-up drilling, additional exploration activities and development feasibility studies are underway or planned for the immediate future. Development of the east coast offshore area is estimated by management for the mid-1980's.

4. Redeemable Preferred Stock

As of December 31, 1980, the Corporation had authorized 10,000,000 shares of preferred stock $50.00 par value and had outstanding 1,000,000 shares of 10.96% Series B Preferred Stock. The 1,000,000 shares of 11.25% Series A Preferred Stock were redeemed on November 1, 1979. The Series B preferred stock is subject to a mandatory sinking fund which requires that the Corporation redeem 100,000 shares ($5,000,000) per year beginning May 31, 1981, resulting in a maximum aggregate cash requirement of $25,000,000 over the next five years. Shares are redeemable for the sinking fund, in 1981 and thereafter, at a price of $50.00 per share, or otherwise, at the optional redemption price of $55.32 on or before May 31, 1985, and $53.95 thereafter.

Dividends are cumulative and if four quarterly dividends remain unpaid, the holders of the preferred stock have the right to elect a majority of the Board of Directors. In addition, for the protection of the preferred stockholders, the Corporation's Certificate of Incorporation limits the ability of the Corporation to create a class of stock equal to or higher in preference than the preferred stock.

5. Long-Term Debt

The outstanding long-term debt of the Corporation and subsidiaries is as follows:

At December 31, (in thousands)	**1980**	1979
The Columbia Gas System, Inc. Debentures—		
3⅞% Series F due 1981	**$ —**	$ 11,250
4¾% Series G due 1981	**—**	7,520
5 % Series I due 1982	**7,492**	8,195
4⅜% Series J due 1983	**9,980**	10,190
4⅞% Series K due 1983	**8,228**	9,004
5⅛% Series O due 1985	**11,800**	12,710
5⅛% Series due June 1986	**12,636**	13,372
4½% Series due June 1987	**11,875**	12,126
4⅝% Series due August 1987	**9,492**	10,066
4⅜% Series due November 1987	**14,200**	15,113
4⅜% Series due January 1988	**11,788**	12,620
4⅝% Series due May 1989	**27,219**	27,845
4⅝% Series due October 1989	**21,690**	23,180
9⅝% Series due November 1989	**60,000**	67,500
4⅝% Series due May 1990	**23,026**	23,115
4⅞% Series due October 1990	**23,200**	24,412
6¼% Series due October 1991	**24,600**	26,000
6⅝% Series due October 1992	**16,239**	17,125
7¼% Series due May 1993	**34,215**	36,000
7 % Series due October 1993	**27,400**	28,800
9 % Series due October 1994	**36,000**	37,750
8¾% Series due April 1995	**30,104**	31,600
9⅛% Series due October 1995	**37,750**	38,574
10⅛% Series due November 1995	**65,600**	70,300
8⅜% Series due March 1996	**59,250**	61,827
9⅛% Series due May 1996	**70,300**	75,000
8¼% Series due September 1996	**47,400**	49,500
7½% Series due March 1997	**41,221**	42,357
7½% Series due June 1997	**49,500**	51,600
7½% Series due October 1997	**49,500**	51,600
7½% Series due May 1998	**42,963**	44,488
10¼% Series due May 1999	**75,000**	75,000
9⅞% Series due June 1999	**35,728**	37,015
11¾% Series due October 1999	**100,000**	100,000
12¾% Series due August 2000	**100,000**	—
	$1,195,396	$1,162,754
Unamortized debt discount, less premium	**(8,172)**	(7,948)
	1,187,224	1,154,806
Term bank loans(a)	**10,000**	15,000
Miscellaneous debt of subsidiary companies	**4,609**	4,790
Total long-term debt(b)	**$1,201,833**	$1,174,596

(a) The term bank loans are due in semi-annual installments through 1983 and bear interest at the prime bank rate through October 1981, and at the rate of 105% of the prime bank rate thereafter, with no compensating balance requirements.

(b) The composite annual interest rate on long-term debt outstanding at December 31, 1980 is 8.6%, and the current annual interest requirement on such long-term debt is $107,200,000.

The aggregate annual sinking fund requirements and the aggregate maturities of long-term debt for the five years ended December 31, 1985, amount to $36,595,000 in 1981 (excluding $42,131,000 previously satisfied), $65,869,000 in 1982 (excluding $847,000 previously satisfied), $74,416,000 in 1983, $58,747,000 in 1984, and $78,412,000 in 1985. The Corporation has from time to time satisfied sinking fund requirements by purchases of debentures other than through operation of the respective sinking funds.

During 1980, the Corporation entered into a "Revolving Credit and Term Loan Agreement" with eight commercial banks in order to provide the Corporation with greater flexibility with regard to long-term financing decisions. Under the terms of this agreement, a $200 million commitment is available to the Corporation through April 1, 1985, with any borrowings outstanding at the end of that period being converted to term loans due April 1, 1987. All borrowings under this agreement would be subordinated to the Corporation's debentures. Interest rates on borrowings are equal to the prime commercial lending rate through March 31, 1983, 103% of the prime commercial lending rate through March 31, 1985, and 105% of the prime commercial lending rate through April 1, 1987. In addition, the Corporation pays a commitment fee of ½% per annum of the unused portion of the commitment, and 2% per annum of the prime commercial lending rate applied to the aggregate amount of the commitment. Under the agreement, the Corporation may reduce the amount of the commitment or cancel it entirely, without penalty. There were no borrowings outstanding under this agreement at December 31, 1980.

6. Compensating Balances and Short-Term Borrowings

Short-term requirements are met through the use of bank loans and/or commercial paper. Typically, these obligations remain outstanding for periods of one to seven months at or below the prime commercial lending rate.

The Corporation maintains compensating balances in connection with certain bank lines of credit in accordance with a formula calling for the greater of 10% of such lines of credit or 20% of the annual average borrowings. There are no legal restrictions regarding the withdrawal of these compensating balances. Also, during 1980, the Corporation maintained other lines of credit with certain banks on a fee basis with no compensating balances.

Certain information relating to lines of credit and compensating balances is as follows:

At December 31, (in thousands)	**1980**	1979
Credit lines	**$225,000**	$195,000
Outstanding commercial paper	**(42,600)**	(133,100)
Unused credit lines	**$182,400**	$ 61,900
Approximate compensating balances	**$ 8,000**	$ 15,600

7. Lease Rentals

In accordance with the current ratemaking practice of the regulatory commissions having jurisdiction over the Corporation's rate regulated subsidiaries, payments made in connection with noncapitalized financing and operating leases are charged to expense or clearing accounts, which are substantially charged to expense, as incurred. Such amounts were $31,200,000 in 1980, $25,900,000 in 1979, and $22,700,000 in 1978. If the Corporation had capitalized financing leases, the effect on total assets, liabilities and expenses would not be material.

Minimum rental commitments under "noncancellable" leases are as follows:

Period	(in thousands)
1981	$17,900
1982	14,100
1983	10,200
1984	6,600
1985	4,900
After 1985	19,500

8. Acquisition of Commonwealth Natural Resources, Inc.

On September 29, 1980, the Corporation and Commonwealth Natural Resources, Inc. of Richmond, Virginia, announced that agreement in principle had been reached for the merger of Commonwealth into the Corporation on the basis of a tax-free exchange of 1.05 shares of the Corporation's common stock for each share of Commonwealth common stock. The agreement has subsequently been approved by the Board of Directors of both corporations and an application has been filed with the Securities and Exchange Commission (SEC) for approval. The merger is expected to be completed early in 1981.

Approximately 1,222,000 common shares of the Corporation will be issued in exchange for all outstanding shares of Commonwealth common. Commonwealth's operating revenues for the 12 months ended December 31, 1980 were $211,232,000, and its net income for the same period was $6,085,000. Net assets at December 31, 1980 amounted to $39,637,000.

9. Commitments

Capital expenditures for 1981 are estimated at $573,000,000. Reference is made to the foregoing report to stockholders for additional information relating to capital expenditures and commitments including those applicable to gas supply.

10. Oil and Gas Producing Activities

A. Introduction. Reserve information contained in the following tables was supplied by the independent consulting firms of Ralph E. Davis Associates, Inc. for U.S. properties and by John R. Lacey International Ltd. for the Canadian properties. The Corporation's oil and gas producing properties subject to cost-of-service rate regulation are excluded from the disclosures in the accompanying tables.

U.S. reserves are reported as net working interest while Canadian reserves are working interest reserves since royalties related to Canadian leases generally provide for payment on a basis other than a percent of production.

Gross revenues are reported after deduction of royalty interest payments. Average sales rates are computed using such revenues and net working interest production for U.S. reserves and working interest production for Canadian reserves.

Production (lifting) cost rates related to the U.S. cost center are expressed per dollar of net working interest revenue. Canadian production (lifting) cost rates are expressed per equivalent Mcf working interest production.

The U.S. cost center depletion rate is expressed as the rate, per dollar of net working interest revenues, necessary to amortize capitalized costs over the life of U.S. reserves. The Canadian depletion rate is expressed as the equivalent Mcf unit of production rate, based on working interest reserves, necessary to amortize capitalized costs over the life of Canadian reserves.

Certain information included in the "Other Oil and Gas Production Data" table applicable to prior years has been adjusted for conformity to the current method of calculation.

B. Production Revenues, Costs and Statistics

	U.S.			Canada		
(in thousands)	**1980**	1979	1978	**1980**	1979	1978
Capitalized Costs at Year End						
Proved properties	**$599,169**	$524,648	$482,532	**$40,281**	$27,329	$21,495
Unproved properties	**148,055**	123,319	92,891	**59,022**	51,140	66,975
Total capitalized costs	**747,224**	647,967	575,423	**99,303**	78,469	88,470
Accumulated depletion	**(240,333)**	(173,249)	(152,809)	**(1,520)**	(917)	(722)
Net capitalized costs	**$506,891**	$474,718	$422,614	**$97,783**	$77,552	$87,748
Net Production Revenues						
Inter-company sales and transfers	**$ 76,111**	$ 73,625	$ 49,386	**$ —**	$ —	$ —
Unaffiliated sales	**59,575**	21,817	11,212	**2,808**	2,114	980
Gross revenues	**135,686**	95,442	60,598	**2,808**	2,114	980
Production (lifting) costs	**(24,246)**	(16,371)	(9,724)	**(949)**	(564)	(301)
Net revenues	**$111,440**	$ 79,071	$ 50,874	**$ 1,859**	$ 1,550	$ 679
Costs Capitalized During Year						
Property acquisitions	**$ 16,452**	$ 7,643	$ 18,030	**$ 227**	$ 1,730	$ 2,784
Exploration	**43,231**	44,114	38,676	**11,964**	8,925	7,352
Development	**47,770**	57,643	65,203	**8,643**	7,882	7,146
Costs capitalized	**$107,453**	$109,400	$121,909	**$20,834**	$18,537	$17,282
Other Oil and Gas Production Data						
Depletion expense (000)	**$ 72,252**	$ 55,968	$ 40,604	**$ 603**	$ 557	$ 270
Average sales price per Mcf of gas produced	**$ 1.54**	$ 1.27	$ 0.93	**$ 1.48**	$ 1.12	$ 0.92
Average sales price per barrel of oil and other liquids produced	**$ 28.07**	$ 15.30	$ 11.82	**$ 9.50**	$ 7.82	$ 7.57
Average production (lifting) cost	**$ 0.18**	$ 0.17	$ 0.16	**$ 0.52**	$ 0.31	$ 0.30
Average depletion rate	**$ 0.53**	$ 0.59	$ 0.67	**$ 0.33**	$ 0.31	$ 0.27

C. Company-Owned Proved Reserves (Unaudited)

As of December 31,	1980		1979		1978	
	Total	Developed	Total	Developed	Total	Developed
Gas (MMcf @ 14.73 psia)						
U.S.	**365,309**	**241,991**	390,342	268,532	441,393	311,294
Canada	**132,445**	**118,394**	105,298	89,624	101,686	88,304
Total	**497,754**	**360,385**	495,640	358,156	543,079	399,598
Oil and Other Liquids (000 Bbls.)						
U.S.	**9,856**	**5,636**	6,089	4,021	6,957	4,635
Canada	**1,695**	**1,603**	1,114	1,019	866	771
Total	**11,551**	**7,239**	7,203	5,040	7,823	5,406

D. Changes in Company-Owned Proved Reserves (Unaudited)

	U.S.		Canada	
	Gas @ 14.73 psia (MMcf)	Oil and Other Liquids (000 Bbls.)	Gas @ 14.73 psia (MMcf)	Oil and Other Liquids (000 Bbls.)
Reserves as of December 31, 1977	426,140	6,748	105,610	625
Revisions of previous estimate	15,668	144	(3,107)	44
Extensions, discoveries, and other additions	53,709	954	—	227
Production	(54,124)	(889)	(817)	(30)
Reserves as of December 31, 1978	441,393	6,957	101,686	866
Revisions of previous estimate	(45,117)	(981)	(5,527)	59
Extensions, discoveries, and other additions	52,913	1,480	10,574	253
Production	(58,847)	(1,367)	(1,435)	(64)
Reserves as of December 31, 1979	**390,342**	**6,089**	**105,298**	**1,114**
Revisions of previous estimate	**14,713**	**2,519**	**—**	**—**
Extensions, discoveries, and other additions	**12,500**	**3,225**	**28,453**	**674**
Production	**(52,246)**	**(1,977)**	**(1,306)**	**(93)**
Reserves as of December 31, 1980	**365,309**	**9,856**	**132,445**	**1,695**

E. Future Net Revenue Data (Unaudited)

The Estimated Future Net Revenues are computed by applying year-end prices of oil and gas to estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the reserves.

Estimated Future Net Revenues	U.S.		Canada	
(in thousands)	Total	Developed	Total	Developed
1981	$130,092	$114,769	$ 11,093	$ 11,311
1982	129,333	92,780	12,063	11,924
1983	121,225	75,362	9,542	9,230
After 1983	570,334	268,837	148,820	133,796
Future Net Revenues as of December 31, 1980	**$950,984**	**$551,748**	**$181,518**	**$166,261**
Future Net Revenues as of December 31, 1979	$766,328	$473,513	$116,330	$102,511
Future Net Revenues as of December 31, 1978	$683,823	$458,850	$ 72,250	$ 60,664

The Present Value of Future Net Revenues is derived by applying a 10% discount factor, as required by SEC rules, to the Estimated Future Net Revenues. The Corporation believes that this data does not adequately reflect the current economic value of the oil and gas producing properties since no economic value is attributed to potential reserves and the use of a 10% discount rate is arbitrary.

Present Value of Estimated Future Net Revenues	U.S.		Canada	
(in thousands)	Total	Developed	Total	Developed
As of December 31, 1980	**$637,207**	**$387,313**	**$ 84,186**	**$ 78,195**
As of December 31, 1979	$481,903	$326,504	$ 57,648	$ 51,795
As of December 31, 1978	$420,651	$304,819	$ 30,968	$ 26,712

F. Information Related to Excluded Cost-of-Service Properties
Certain oil and gas producing assets are subject to cost-of-service rate making. Net capitalized costs of these properties at December 31, 1980, amounted to $5,300,000. Proved gas reserves related to these properties, as supplied by Ralph E. Davis Associates, Inc., amounted to 297,631 MMcf. Production for the year amounted to 33,972 MMcf.

11. Reserve Recognition Accounting Data (Unaudited)

Introduction: The SEC requires disclosures of the effects of a proposed new method of accounting for oil and gas producing operations called Reserve Recognition Accounting (RRA). Under RRA, the value of proved reserves is recognized as an asset and changes in reserve valuations, net of related costs, are included in earnings as they occur. Under the full cost method of accounting presently used in historical financial statements, revenues and expenses are recognized in earnings when the related reserves are produced and sold.

The Corporation cautions that the data presented herein should not be used to project future results. Estimates of proved reserves are inherently imprecise and will be revised on the basis of new information as it becomes available from development drilling and production performance. Years elapse between incurrence of costs and final determination of the economic results of the expenditures. Also, the valuation procedure does not necessarily yield the best estimate of the fair market value of a company's oil and gas properties. An estimate of fair market value should also take into account, among other factors, the possibility of future recoveries of oil and gas in excess of proved reserves, and inflationary effects on future prices and related development and production costs. Finally, the SEC may modify its rules with respect to RRA as experience is gained, which could result in changes in the RRA accounting method.

A reconciliation of the changes in present value of estimated future net revenues of proved oil and gas reserves, from the beginning to the end of the years ending December 31, 1980 and 1979 follows:

Year Ended December 31, (in thousands)	**1980**	1979
Net present value at beginning of year	**$539,551**	$451,619
New field discoveries and extensions, net	**99,173**	80,091
Revisions to reserves discovered in prior years	**179,799**	51,830
Projected development costs incurred	**16,169**	36,632
	834,692	620,172
Less: production, net of lifting costs	**(113,299)**	(80,621)
Net present value at end of year	**$721,393**	$539,551

The accompanying summary of RRA operations measures income resulting from current year activities. It should be noted that an analysis of RRA income should not place undue emphasis on the results of any one year.

Year Ended December 31, (in thousands)	1980	1979
Summary of RRA Operations		
Additions to proved reserves:		
New field discoveries and extensions, net	**$ 99,173**	$ 80,091
Revisions to reserves discovered in prior years resulting from—		
Increases in prices of oil and gas	**139,024**	92,960
Accretion of discount (Note 1)	**53,955**	45,162
Other revisions (Note 2)	**(13,180)**	(86,292)
Total additions to proved reserves	**278,972**	131,921
Less related costs (Note 3):		
Incurred during the year—		
Acquisition	**16,679**	9,373
Exploration	**55,195**	53,039
Development	**56,413**	65,525
Projected development costs incurred	**(16,169)**	(36,632)
Change in deferred costs	**(19,344)**	(8,004)
Total related costs	**92,774**	83,301
Results of RRA operations, before income taxes and gain from sale of Canadian properties	**186,198**	48,620
Gain from sale of Canadian properties before income taxes	**—**	23,930
Results of RRA operations, before income taxes	**186,198**	72,550
Less provision for income taxes	**85,651**	26,624
Results of RRA operations	**$100,547**	$ 45,926

Notes: 1. Represents the approximate increase in value of reserves attributable to the passage of time.

2. Includes the net impact of all other changes affecting the RRA valuation, including changes to previously estimated reserve quantities and the expected timing and cost of producing reserves.

3. The costs of acquiring unproved properties and drilling exploratory wells are deferred until the properties are evaluated and determined to be either productive or nonproductive, at which time they are charged to expense.

Following is an analysis of Summary of RRA Operations:

1980

RRA net income amounted to $100.5 million principally reflecting upward price and volume revisions applicable to reserves discovered in prior years. The increase in prices, brought about by the Natural Gas Policy Act of 1978 and partial decontrol of oil, were partially offset by the first time inclusion of windfall profits tax. Previously estimated reserve quantities were upwardly revised by 14,713 MMcf of natural gas and 2.5 million Bbls of oil and other liquids.

The revenue effect of new field discoveries (40,953 MMcf and 3.9 million Bbls of oil and other liquids) was mostly offset by costs incurred during the year. At year end, costs deferred amounted to $126 million (which is net of a $10 million valuation allowance) pending evaluation of potential reserves associated with unproved properties, principally the Rocky Mountain area and the Canadian frontier.

The provision for income taxes reflects the current federal statutory rate. The pre-tax profit contribution in the 1980 primary financial statements, related to oil and gas producing activities utilizing full cost accounting, amounted to $40.4 million as compared to $186.2 million under RRA.

1979

RRA net income amounted to $45.9 million despite a downward revision in previously estimated reserves of 50,644 MMcf of gas and 0.9 million Bbls of oil and other liquids. Substantial upward revisions relating to price ($93 million) brought about principally by the Natural Gas Policy Act of 1978, more than offset the downward revisions of reserves. In addition, a gain was recognized ($23.9 million, before income taxes) in connection with the sale of certain Canadian properties.

The provision for income taxes reflects an effective tax rate of 37 percent. The principal reasons for the difference from the current statutory rate of 46 percent are the effects of a reduction in the statutory rate from 48 percent used to compute the prior year's provision and the gain on sale of the Canadian properties taxed at less than the statutory rate.

The pre-tax profit contribution in the primary financial statements related to oil and gas producing activities utilizing full cost accounting, amounted to $37.7 million as compared to $72.6 million under RRA.

12. Effects of General Inflation and Specific Price Changes (Unaudited)

The following supplementary information is supplied in accordance with requirements of the Financial Accounting Standards Board (FASB) and is intended to illustrate the effects of inflation on the Corporation in terms of general inflation (constant dollars) and in terms of specific prices of resources used by the Corporation (current cost). The computations should be viewed as estimates of the effects of inflation rather than as a precise measure.

The Corporation believes that the assumptions and methodology used in preparing these estimates, and the presentation of these effects, are reasonable under the circumstances; however, the procedures require many subjective judgments. The FASB recognizes that preparers and users of financial statements have not reached a consensus on the general and practical usefulness of supplementary cost-adjusted information, and that the measurement and analysis of information on changing prices will continue to require substantial experimentation.

Present rate-making practices do not provide for immediate cost recovery of increases caused by price changes. Also, the historical cost depreciation expense which is presently recoverable in rates, is inadequate for purposes of maintaining the purchasing power invested by the common stockholders. The impact of these ratemaking limitations on the common stockholders, along with the purchasing power loss on monetary assets, is mitigated to the extent that depreciable property and other non-monetary assets are financed with debt which can be repaid with dollars of less purchasing power.

The presentation included herein reconciles income reported in the financial statements, by adjusting components, to income under both constant dollar and current cost reporting methods. These statements show that the shareholders' return on their investment is reduced when measured in terms of general purchasing power but increased in terms of specific price changes affecting the Corporation during 1980. The increase resulting from changes in specific prices is primarily attributable to non-rate regulated oil and gas properties.

Statement of Income Adjusted for Changing Prices

Year Ended December 31, 1980 (in thousands of average 1980 dollars)	Stated in terms of General Inflation	Stated in terms of Specific Prices
Income as reported	$165,311	$165,311
Effect on earnings of changing prices:		
Operating revenues	17,841	17,841
Purchased gas and feedstocks expense	(13,027)	(13,027)
Depreciation and depletion expense	(194,624)	(302,004)
Adjusted income (loss) from continuing operations	(24,499)	(131,879)
Other adjustments:		
Excess of specific price increases of non-monetary assets ($1,088,257) over increases due to general inflation ($869,281)*	—	218,976
Reduction to recoverable cost	(79,312)	(71,125)
Reduction in purchasing power loss through debt financing	184,799	184,799
Income adjusted for changing prices	$ 80,988	$200,771

*At December 31, 1980, the current cost of property, plant and equipment, net of accumulated depreciation and depletion, approximated $3,505,753,000 at recoverable cost.

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

Year Ended December 31, (in thousands of average 1980 dollars except as noted)	**1980**	1979	1978	1977	1976
Operating revenues	**$3,654,348**	$3,257,089	$3,109,953	$2,760,966	$2,569,253
Historical cost information adjusted for general inflation:					
Income from continuing operations	**$ (24,499)**	$ 11,682			
Income from continuing operations per common share	**(0.74)**	0.36			
Income after other adjustments	**80,988**	91,325			
Income per common share after other adjustments	**2.46**	2.80			
Net assets at recoverable cost	**1,477,870**	1,454,481			
Reduction in purchasing power loss through debt financing	**184,799**	212,405			
Historical cost information adjusted for changes in specific prices:					
Income from continuing operations	**$ (131,879)**	$ (103,622)			
Income from continuing operations per common share	**(4.00)**	(3.18)			
Income after other adjustments	**200,771**	125,966			
Income per common share after other adjustments	**6.09**	3.86			
Excess of specific price increases of non-monetary assets over increases due to general inflation after reduction to recoverable cost	**147,851**	17,183			
Net assets at recoverable cost	**1,784,743**	1,659,238			
General information:					
Cash dividend per common share— at historical cost	**$2.56**	$2.44	$2.34	$2.24	$2.14
in average 1980 dollars	**2.56**	2.77	2.96	3.05	3.10
Market price per common share at year-end— at historical cost	**40¼**	37¾	25½	29	30⅜
in average 1980 dollars	**38⅜**	40½	31	38½	43
Average consumer price index	**246.8**	217.4	195.4	181.5	170.5

( ) indicates loss

Methods and Assumptions

Constant dollar amounts represent the effects of adjusting dollars recorded in actual transactions (historical cost) at different times to dollars of equal purchasing power. As required by the FASB, the adjustment is made by using the Consumer Price Index for all Urban Consumers, a broad-based measure of the general inflation rate.

The current cost amounts reflect the changes in specific prices and differ from constant dollar amounts to the extent that specific prices have increased more or less rapidly than the general rate of inflation. The current cost of property, plant and equipment represents an estimated cost of replacing existing plant assets and was primarily determined by indexing the historical cost of existing plant by the Handy-Whitman Index of Public Utility Construction Costs. Land and oil and gas producing properties were converted using other indices as deemed appropriate. Since the assets are not expected to be replaced precisely in kind, current cost does not necessarily represent the replacement cost of the Corporation's productive capacity.

Operating revenues and purchased gas and feedstocks expense have been adjusted to average current year dollars since these transactions do not occur evenly throughout the year.

The change in depreciation expense related to constant dollar and current cost is the difference between the indexed depreciation and historical cost depreciation.

The effect of specific price changes on non-monetary assets represents an unrealized holding gain, principally attributable to oil and gas producing assets. The excess of the cost of regulated plant stated in terms of constant dollars and current cost over the historical cost of plant is not presently recoverable in rates, and is reflected as a reduction to net recoverable cost.

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

13. Quarterly Financial Data (Unaudited)

Quarter Ended (Thousands except per share data)	Operating Revenues	Operating Income	Earnings on Common Stock	Earnings Per Share
March 31, 1979	$ 992,432	$95,415	$77,649	$2.38
June 30, 1979	532,483	46,964	27,230	.84
September 30, 1979	454,129	15,846	(4,217)	(.13)
December 31, 1979	872,689	63,182	42,451	1.30
March 31, 1980	**1,302,382**	**99,517**	**82,478**	**2.51**
June 30, 1980	**739,542**	**45,957**	**30,629**	**.93**
September 30, 1980	**557,405**	**21,468**	**(4,030)**	**(.12)**
December 31, 1980	**1,037,178**	**80,149**	**56,234**	**1.70**

Comparison of results of operations among quarters during the year may be misleading in obtaining an understanding of the trend of the Corporation's business operations since gas sales are predominantly influenced by seasonal weather patterns which in turn affect earnings and related components of operating revenues and operating expenses.

Columbia Gas System Companies

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

Columbia Gas System Service Corporation
Columbia LNG Corporation
Columbia Alaskan Gas Transmission Corporation

Ashland Group Companies
340-17th Street, Ashland,
KY 41101

Columbia Coal Gasification Corporation
Columbia Hydrocarbon Corporation
The Inland Gas Company, Inc.

Columbia Distribution Companies
99 North Front Street,
Columbus, OH 43215

Columbia Gas of Kentucky, Inc.
Columbia Gas of Maryland, Inc.
Columbia Gas of New York, Inc.
Columbia Gas of Ohio, Inc.
Columbia Gas of Pennsylvania, Inc.
Columbia Gas of Virginia, Inc.
Columbia Gas of West Virginia, Inc.

Columbia Gas Transmission Corporation

Big Marsh Oil Company
1700 MacCorkle Ave., SE,
Charleston, WV 25314

Columbia Gulf Transmission Company
3805 West Alabama Ave.
Houston, TX 77027

Columbia Gas Development Corporation
1700 West Loop, South
Houston, TX 77027

Columbia Gas Development of Canada Ltd.
639-5th Avenue, S.W.
Calgary, Alberta,
Canada T2P 0M9

Stockholder Information

Dividend Disbursement and Certificate Inquiries
Corporate Secretary
The Columbia Gas System, Inc.
20 Montchanin Road
Wilmington, DE 19807

Common Stock Listed:
New York Stock Exchange
Philadelphia Stock Exchange
Toronto Stock Exchange

Ticker Symbol: CG

Preferred Stock Listed:
New York Stock Exchange

Dividend Reinvestment Plan
P. O. Box 4020
Wilmington, DE 19807

Transfer Agents—Common Stock
Chemical Bank
55 Water Street
New York, NY 10041

Mellon Bank, N.A.
P. O. Box 926
Pittsburgh, PA 15320

Continental Illinois National Bank and Trust Company of Chicago

231 South LaSalle Street
Chicago, IL 60690

Bank of America National Trust and Savings Association
P. O. Box 37002
San Francisco, CA 94137

National Trust Company, Ltd.
21 King Street East
Toronto, Canada M5C 1B3

Registrars—Common Stock
Morgan Guaranty Trust Company of New York
30 West Broadway
New York, NY 10015

Pittsburgh National Bank
P. O. Box 340746P
Pittsburgh, PA 15230

The First National Bank of Chicago
One First National Plaza
Chicago, IL 60670

Wells Fargo Bank N.A.
420 Montgomery St.
San Francisco, CA 94144

Crown Trust Company
302 Bay Street
Toronto, Canada M5H 2P4

Transfer Agent and Registrar—Preferred Stock
Chemical Bank
55 Water Street
New York, NY 10041

Trustee and Paying Agent for Debentures
Morgan Guaranty Trust Company of New York
30 West Broadway
New York, NY 10015

Additional Information

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

Directors and Officers —Parent Company

Directors

Thomas S. Blair[1,2]
President, Blair Strip Steel Company
New Castle, Pa.

Warren W. Clute, Jr.[2,3]
Chairman, Glen Bank and Trust Company
Watkins Glen, New York

John P. Cornell
Senior Vice President and Chief Financial Officer

Frank J. Durzo[3,4]
Former Chairman and Chief Executive Officer
Jeffrey Galion, Inc.
Acquired by Dresser Industries, Inc.
Industrial Equipment, Supplies and Services
Columbus, Ohio

J. Robert Fletcher[2,3]
Chairman
J. H. Fletcher & Co.
Manufacturer of Mining Equipment
Huntington, W.Va.

Elizabeth V. Hallanan[3,4]
Member,
Dodson, Deutsch and Hallanan
Attorneys-at-Law
Charleston, W.Va.

Robert H. Hillenmeyer[3,4]
Chairman, Hillenmeyer Nurseries, Inc.
Lexington, Kentucky

W. Frederick Laird[1]
Chairman, President and Chief Executive Officer

George P. MacNichol, III[2,3]
Private Investor
Former Vice President, Libbey-Owens-Ford Company,
Glass and Plastics Business
Toledo, Ohio

John W. Partridge[1]
Former Chairman of the Board

Ernesta G. Procope[2,4]
President
E. G. Bowman Co., Inc.
Insurance Brokerage Firm
New York, N.Y.

John P. Roche[1,4]
Of Counsel, Reed Smith Shaw & McClay
Attorneys-at-Law
Washington, D.C.

Arch A. Sproul[2,4]
President, Virginia International Co.
Foreign Investments
Staunton, Va.

1. Member of the Executive Committee
2. Member of the Audit Committee
3. Member of the Compensation Committee
4. Member of the Long-Range Planning Committee

Officers

W. Frederick Laird
Chairman, President and Chief Executive Officer

John P. Cornell
Senior Vice President and Chief Financial Officer

Philip W. Frick
Secretary and Treasurer

Hart T. Mankin
Michael J. Prylucki
Assistant Secretaries

Alexander P. McCann
Assistant Treasurer

Columbia Gas System Service Corporation

W. Frederick Laird
Chairman, President and Chief Executive Officer

John P. Cornell
Senior Vice President and Chief Financial Officer

Daniel L. Bell
John H. Croom
Robert P. Rowen
Senior Vice Presidents

Philip W. Frick
Vice President and Secretary

Stanley C. Kauffman
Vice President and General Auditor

William T. Lynam
Vice President and Assistant Chief Financial Officer

Hart T. Mankin
Vice President and General Counsel

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John W. F. Faircloth
William C. Hart
George P. Marquis
Robert A. Oswald
Bruce Quayle
C. Ronald Tilley
Charles W. Uhlinger
Robert W. Welch
Vice Presidents

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Treasurer

Robert G. Smith
Controller

Leslie A. Field, Jr.
Assistant Secretary and Assistant Treasurer

Michael J. Prylucki
Assistant Secretary

Larry J. Bainter
Lawrence J. Doyle
Michael W. O'Donnell
Assistant Treasurers

James T. Connors
William J. Forsythe
Kenneth P. Murphy
Assistant Controllers

Operating Company Executives

Joseph A. Brake
President
Ashland Group Companies

John H. Croom
President
Columbia Alaskan Gas Transmission Corporation

Marvin E. White
Chairman
John D. Daly
President
Columbia Distribution Companies

Edward D. Callahan
President
Columbia Gas Development Corporation

Rollin W. Prather
President
Columbia Gas Development of Canada Ltd.

William W. Ferrell
Chairman
James D. Little
President
Columbia Gas Transmission Corporation

Charles W. Morrow
President
Columbia Gulf Transmission Company

John E. Towle
President
Columbia LNG Corporation

COLUMBIA GAS
System

20 Montchanin Road, Wilmington, Delaware 19807