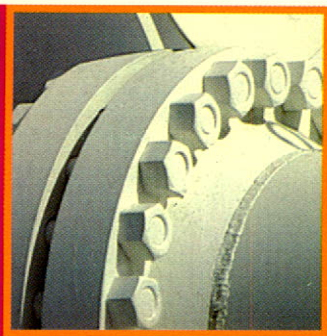
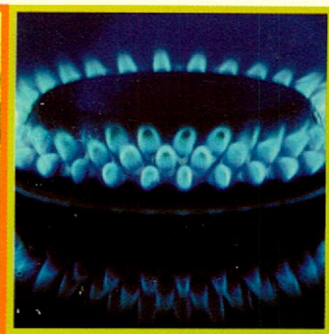
1981 Annual Report





A spectrum of operations, bringing energy efficiently and dependably to people.

COLUMBIA GAS
System

The Columbia Gas System is in the business of bringing energy to people, efficiently and dependably. We find, produce, purchase, transmit, store and deliver energy to homes, business and industry. At every step in the process—from wellhead to burner—we are guided by the needs of our customer and the concerns of our communities and equally by the interests of those who invest in Columbia.

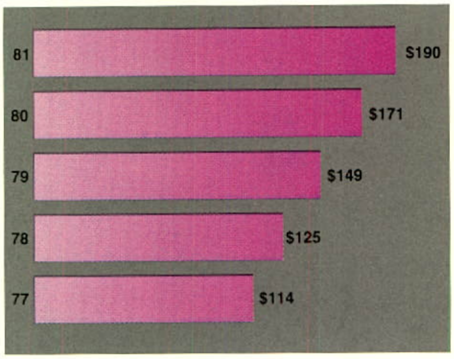
1981 Highlights

	1981	1980	% Change
Operating Revenues ($000)	**4,426,243**	3,719,921	19.0
Common Stock Data			
Earnings on Common Stock ($000)	**190,334**	171,346	11.1
Earnings per Share ($)	**5.50**	5.02	9.6
Dividends per Share ($)	**2.70**	2.56	5.5
Book Value per Share ($)	**38.50**	35.84	7.4
Financial Data ($000)			
Capital Expenditures	**592,002**	445,201	33.0
Total Assets	**4,616,781**	3,927,716	17.5
Capitalization	**2,707,614**	2,487,938	8.8
Operating Statistics			
Gas Customers	**1,901,802**	1,891,498	.5
Gas Sales (million cubic feet)	**1,204,549**	1,172,309	2.8
Degree Days (billing period)	**5,550**	5,570	(.4)
Degree Days (calendar period)	**5,474**	5,683	(3.7)

Contents

Letter to the Stockholders

Earnings on Common Stock
(In Millions of Dollars)



In 1981, Columbia's earnings and dividends per share maintained their record of steady increase, earnings rising for the 7th consecutive year, dividends for the 20th.

Earnings

Earnings on common stock were $190.3 million, an increase of 11 percent over 1980 and 28 percent over 1979. Per-share earnings totaled $5.50 in 1981 as compared to $5.02 in 1980 and $4.39 in 1979.

Primary factors contributing to the 1981 increased earnings were: (1) higher sales rates and a slight increase in volumes of gas sold; (2) improved earnings related to sales of oil, propane and other hydrocarbons; (3) greater gas production; and (4) increased investment tax credits. These improvements to earnings were partially offset by the loss of equity earnings on the Cove Point LNG terminal.

Dividends

On January 20, 1982, the Board of Directors declared a quarterly dividend of 71½ cents per share on the common stock of the Corporation, bringing the indicated annual dividend rate to $2.86 per share from the $2.70 paid in 1981. Regular quarterly dividends have been paid on Columbia common stock for more than 35 years.

Capital Expenditures

The System's capital expenditures in 1981 totaled $592 million, an increase of about 33 percent over the previous year. Of the 1981 total, $220 million was devoted to projects to develop supplies of natural gas and related hydrocarbons.

A record capital budget of $687 million is being projected for the year 1982, an increase of about 16 percent over the 1981 level. Approximately $320 million of the 1982 program is designated for supply projects. The increase in supply project expenditures in 1982 is due primarily to projected higher outlays for exploration and development activities and investments in new supply-related pipelines.

Financing

In May 1981, a proposed 20-year debenture issue was postponed because of the System's strong cash position and the high interest rates for long-term debt prevailing at that time. At year-end the Corporation had borrowed $180 million under its $200 million revolving credit agreement with eight commercial banks.

Additional external financing will be required in 1982, the amount and timing of which will be determined later in the year based on capital market conditions.

Notable Developments

1981 operations, which are described in detail on the following pages of this report, were highlighted by these developments:

- Major pipeline projects to reach large new gas sources moved forward as construction neared completion on the Ozark line from Oklahoma. Federal approval neared for the Trailblazer System from the Rockies. Prospects for financing the Alaskan Gas Transportation System improved following Congressional action.

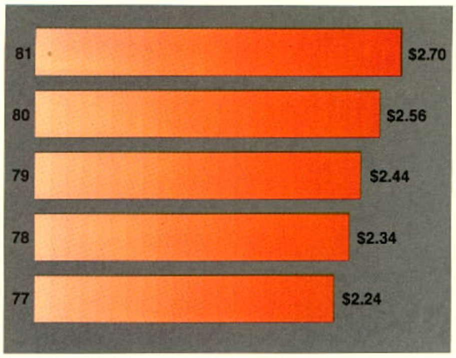
- Natural gas and oil production from Columbia properties increased.

- Columbia extended its acreage holding and exploration activity into Michigan and sections along the New York-Vermont border.

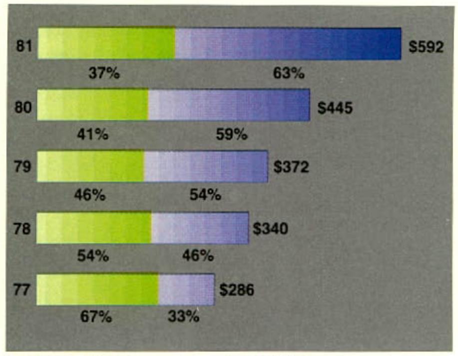
- Columbia's affiliated distribution companies connected more than 20,000 new residential and commercial customers in the year.

- Following approval by the Securities and Exchange Commission, Columbia completed a merger with Commonwealth Natural Resources, Inc., a major marketer in central and eastern Virginia.

Dividends Paid per Common Share
(In Dollars)



Total Capital Expenditures
(In Millions of Dollars)



Wellhead Price Regulation

Columbia's reports to stockholders for the last two years have discussed the dramatic improvement in gas supply that resulted from the freeing up of wellhead prices by passage of the Natural Gas Policy Act (NGPA).

The 1980 report also emphasized Columbia's opposition to proposals for deregulating so-called "old" gas. Columbia continues to believe such action would cause a sharp increase in consumer gas rates without necessarily enhancing gas supply.

At the present time it is uncertain if any proposals which have been made to change the NGPA will come up for active Congressional consideration in 1982.

Public Utility Holding Company Act

Columbia is one of three natural gas systems that continue to operate under the Public Utility Holding Company Act of 1935 (PUHCA). These three gas systems have a total of 13 utility subsidiaries out of more than 300 investor-owned gas distribution companies now operating in the United States. There are also nine electric holding companies under the Act. In 1935, when the Act was passed, more than 2,000 utilities were subject to it.

Much has been achieved under the PUHCA, but it no longer serves the purpose for which it was designed. Reflecting this obsolescence, several bills were introduced in the Senate in 1981 which would make dramatic changes in the PUHCA. In late 1981, in response to a Senate inquiry, the Securities and Exchange Commission expressed the judgment that the PUHCA should be repealed because there was no longer a need for it.

It is likely that Congress will consider legislation this year to repeal or substantially modify the Act. Columbia will support appropriate legislation.

Canadian Energy Policy

The Canadian government will undoubtedly adopt in 1982 the measures previously proposed which will establish financial disincentives for foreign-controlled oil and gas companies.

Columbia will continue to seek ways to maintain a presence in Canada. Effectuation of a restructuring of Columbia of Canada has been delayed because of weakness in Canadian financial markets for oil and gas securities.

Management Changes

On June 17, 1981, the Board of Directors elected John P. Cornell and John H. Croom Executive Vice Presidents of the Corporation and also elected Mr. Croom to serve on the board. Mr. Cornell has been a director since 1977 and is Chief Financial Officer of the Corporation. Mr. Croom has been a Senior Vice President of the Columbia Gas System Service Corporation.

Columbia's continuing investment in new facilities and ventures into new areas are evidence of its confidence in the future of natural gas as a premium energy source and in the ability of the System and its more than 12,000 employees to fulfill their responsibilities to customers and stockholders.

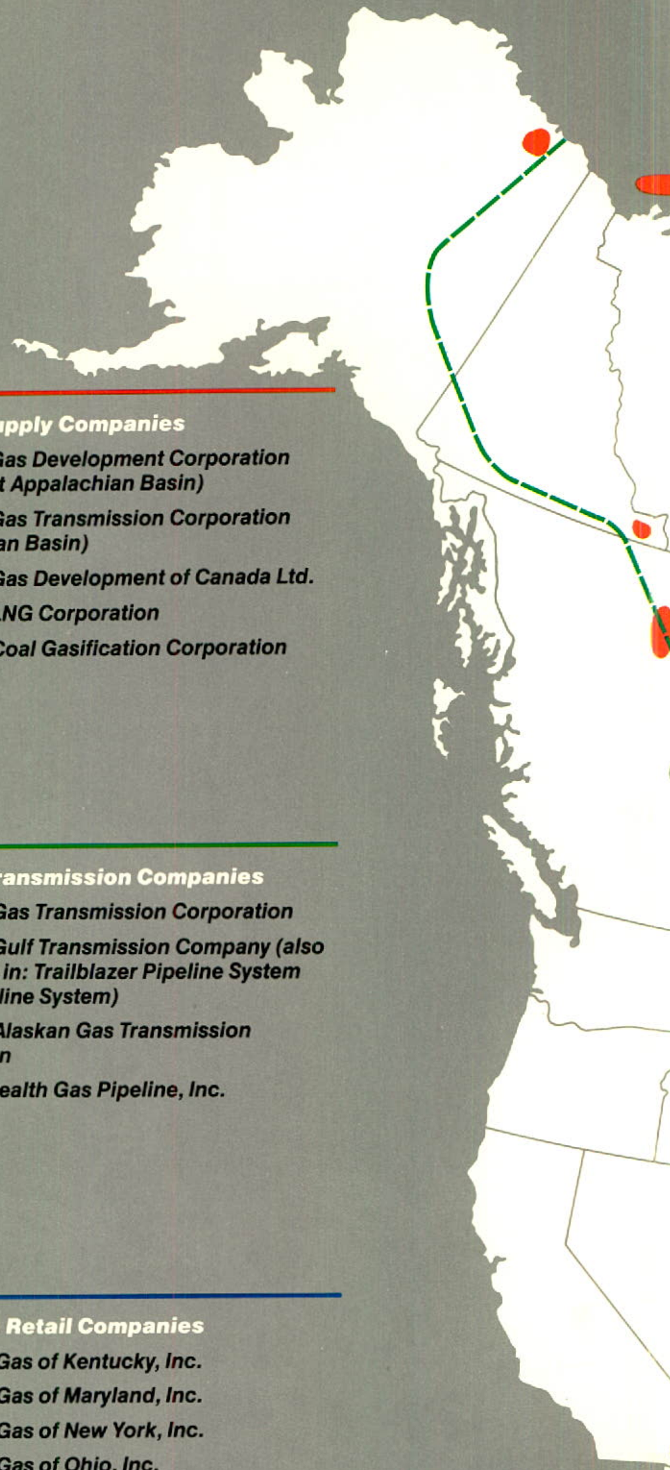
WF Laird

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

February 17, 1982

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.

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

Energy Transmission/Storage

Columbia's extensive network of transmission lines carry natural gas from the producing areas and delivers it to distribution companies serving eight states and the District of Columbia. Columbia also operates one of the largest gas storage systems in the country.

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

Commonwealth Gas Pipeline, Inc.

Energy Distribution

Columbia distributes natural gas at retail to more than 1,900,000 residential, commercial and industrial consumers in seven states that comprise the industrial heartland of America. Propane service reaches customers beyond the gas mains.

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.

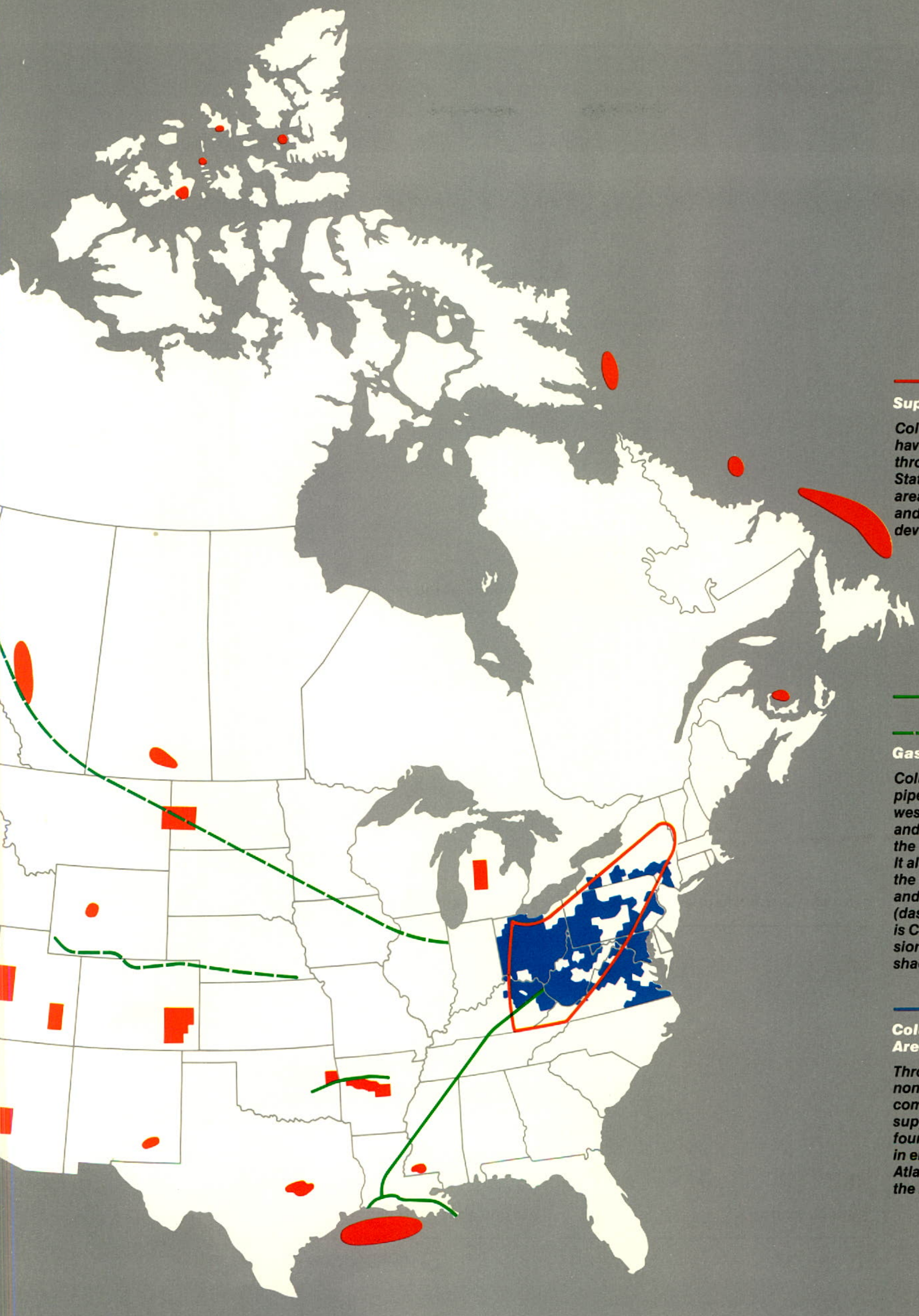
Columbia Gas of Virginia, Inc.

Columbia Gas of West Virginia, Inc.

Columbia Hydrocarbon Corporation

Commonwealth Gas Services, Inc.

Commonwealth Propane, Inc.



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 pipeline from the southwest to its service area and has an interest in the Ozark line (solid line). It also has interests in the proposed Alaskan and Trailblazer systems (dashed line). Not shown is Columbia's transmission network in the blue shaded area.

Columbia Service Area

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

Columbia geologist Mark Brand field tests rock samples for signs of hydrocarbons in part of expanded exploration program.

Exploration and Production

System energy exploration and production activities increased to record levels in 1981. Exploration programs were extended into several promising new regions. The overall progress reflects Columbia's efforts to expand the scope of operations in this non-utility phase of its energy business. Columbia produced 100 billion cubic feet of natural gas in 1981, an increase of 14 percent from the previous year. Total capital expenditures for exploration, production and other activities to develop new energy supplies were $220 million in 1981, compared to $184 million in the prior year.

Columbia companies participated in drilling of 269 exploratory and development wells, compared with 282 exploratory and development wells the year before. A major increase in drilling took place in the Appalachian region.

Columbia's total lease holdings of 9.0 million net acres in the United States and Canada are among the most extensive of major gas companies.

Gas reserves available to Columbia (through its own production, independent producers, non-affiliated pipelines and imported gas, including LNG) as of December 31, 1981, have been estimated to be 14.959 trillion cubic feet. This is approximately 11.8 times the volume of gas used to meet System sales in 1981. This reserve estimate includes the availability of 2.066 trillion cubic feet of liquefied natural gas from Algeria, but 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 Mountains

Columbia Gas Development Corporation (Development), which conducts all U.S. exploration for the System outside the eastern United States, continued to expand activities beyond the Gulf of Mexico holdings that first formed the base of Columbia operations in the southwest. During the year, Development participated in the drilling of 94 wells.

Development's reserves, exclusive of royalties, as of December 31, 1981, were estimated by Ralph E. Davis Associates, Inc. to be 243 billion cubic feet of gas and 8,779,000 barrels of oil and other liquids. Comparable figures for 1980 were 260 billion cubic feet and 6,934,000 barrels of oil and other liquids.

Development's gas production, exclusive of royalties, totaled 50.3 billion cubic feet during 1981, up from 42.7 billion cubic feet in 1980. Liquids production increased from about 1.9 million barrels in 1980 to over 2.4 million barrels in 1981.

During 1981, average prices received by Development were higher: $1.89 per Mcf for gas and $33.50 per barrel for oil and other liquids, compared with $1.44 per Mcf and $27.56 per barrel in 1980. Rising average gas prices reflect both the impact of price increases allowed under the NGPA and declining production from older properties.

Offshore. Six exploratory and nine development wells were drilled on 9 tracts in which Development holds an interest in the Gulf of Mexico. At year-end, 25 additional wells were being drilled.

Drilling into the earth is the only sure way to determine if gas or oil is present. In 1981 Columbia took part in drilling 269 wells in the United States and Canada.

Development's offshore holdings as of December 31, 1981, included 230,000 gross acres, 78,000 net acres, on 53 oil and gas leases located offshore Louisiana and Texas.

Drilling was completed and production begun from three platforms in the Gulf in which Development has an interest. Development now holds an interest in 44 producing platforms in the Gulf of Mexico, functioning as operator on four of these platforms. Production is expected to begin from three additional platforms during 1982. Construction of additional platforms contemplated for 1982 is contingent upon results of current exploration drilling.

Onshore. Development participated in the drilling of 79 wells onshore, 75 of which were productive. At the end of the year, six additional wells were still being drilled or being completed.

Development's onshore holdings at the end of 1981 included 1,998,000 gross acres, or 758,000 net acres, in Alaska, Arizona, Arkansas, Colorado, Louisiana, Mississippi, Montana, New Mexico, North Dakota, Oklahoma, Texas, Utah and Wyoming.

Drilling continued in the Giddings area of Texas. Development holds an interest in 72 oil wells drilled in the area during the year, all of which were productive. Production from the Giddings area amounted to about 52 percent of Development's oil production during 1981, reflecting the impact that this activity has had on Development's revenue. In 1982, and increasingly in the following years, development in the Giddings area will decline as prospective acreage is drilled.

Exploration on properties in the North Dakota portion of the Williston Basin began in 1981. Initial seismic exploration was completed, and mapping was carried out for additional seismic exploration. Development participated in two exploratory wells which indicated the presence of hydrocarbons but which were judged to be noncommercial. Development expects to take part in several exploratory wells in the Williston Basin during 1982.

Development's gas acquisition activities in 1981 resulted in the dedication of 1.348 trillion cubic feet of new reserves to future System supply. For the fourth consecutive year, the volume of new reserves dedicated to future supply exceeded the volume of annual supply required for the System's needs from Development's purchasing and drilling activities.

Early in 1981, Columbia signed a gas purchase contract with Chevron, Inc., for Overthrust reserves from its Whitney Canyon, Wyoming, field that are expected to exceed 500 billion cubic feet. Production is expected to begin in late 1982 and will be dedicated to the Trailblazer Pipeline System (see Transmission section on page 13). Development will continue gas purchase activity in 1982 for System supply for movement through the Trailblazer Pipeline System.

In the Arkoma Basin of Oklahoma and Arkansas, Development is increasing gas purchases to be dedicated to the Ozark Gas Transmission System. (See page 13) Sufficient reserves will be acquired to provide an estimated 85 million cubic feet of gas per day.

Columbia extended its exploration activity in 1981, including this well drilled from a barge on a lease in southern Louisiana, where promising deep horizons are being tested.

Gas production flow through Columbia's Louisiana-West Virginia pipeline is monitored from central control room in Houston, Texas.

Carbon dioxide recovered from a gas field will be processed by Columbia in this plant nearing completion in West Virginia. Plant's output will be sold for use in food manufacturing and enhanced oil recovery.

Appalachian Region

Columbia Gas Transmission Corporation (Transmission), which conducts the System's exploration and production operations in the Appalachian area, drilled 85 wells in 1981, 55 of which were productive and 30 were dry holes. Of the completed wells, 34 were classified as "wildcat" exploratory wells. Transmission drilled a total of 42 wells in 1980.

Columbia's lease holdings total 4.4 million net acres, exclusive of the acreage leased in conjunction with the 49 underground storage fields the company operates. New acreage obtained includes some 72,000 acres in the Michigan Basin and one-half interest in more than 300,000 acres in eastern New York and Vermont. Additional leasing is continuing in these areas.

System proved reserves in the Appalachian area totaled 408 billion cubic feet at the end of 1981. Production from these reserves in 1981 totaled 48.1 billion cubic feet, compared with 43.5 billion cubic feet in 1980.

Other reserves from the Appalachian area committed to the System through gas purchase contracts totaled 477 billion cubic feet at year-end, compared to 431 billion cubic feet at the end of 1980. During 1981, 104.5 billion cubic feet of gas were produced from this source.

Project Penny. Approximately 960 wells were completed during 1981 by independent producers. This project is being coordinated by Transmission in northwestern Pennsylvania and western New York. This brings to 1,460 the total number of wells completed in what has been recognized as the largest natural gas development project in the Appalachian Basin. Columbia anticipates it will receive up to 130 million cubic feet per day by 1984 from this area.

Eastern Overthrust. Transmission and Louisiana Land and Exploration conducted seismic tests on acreage in eastern New York and Vermont to test the northern potential of the geologic area known as the Eastern Overthrust. An exploratory well will be drilled during 1982.

Transmission and six partners are exploring 132,000 acres in Scott and Wise Counties, Virginia, where proved and potential reserves of natural gas are estimated to be 78 billion cubic feet. Eight wells have been drilled to an average depth of 5,500 feet, but none had been completed by year-end.

Michigan. Transmission has entered into a joint venture agreement with Sun Exploration and Marathon Oil to explore acreage in the Michigan Basin. Two wells were drilled in 1981 and three are scheduled for 1982. The 1981 wells in Cheboygan and Otsego Counties were both unsuccessful.

West Virginia. Approval has been received from the state to proceed with a carbon dioxide tertiary oil recovery project in Clay County, W. Va. Nearly 500,000 barrels of oil are expected to be recovered from the field.

The carbon dioxide will come from a field being developed by Transmission in Kanawha County which produces a gas stream that is one-third natural gas and two-thirds carbon dioxide. The carbon dioxide will be removed from the natural gas at a separation plant operated by Transmission.

The carbon dioxide will then be processed in a plant being built at Marmet 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. The plant is nearing completion and should be in operation in the spring of 1982.

Liquefied Natural Gas

Commercial negotiations are continuing between Sonatrach, the Algerian state-owned oil company, Columbia and two other liquefied natural gas importers on the terms of a new LNG contract. These talks began in May 1981 after an impasse was reached earlier in the year during direct negotiations between the U.S. and Algerian governments. Columbia believes that a final agreement can be concluded. Any accord reached by the U.S. companies and Sonatrach is subject to approval by both the United States and Algerian governments.

Acquisition of LNG supplies from additional sources is being considered.

Synthetic Gas

70 billion cubic feet of pipeline-quality synthetic gas were produced at Columbia LNG Corporation's Green Springs, Ohio, plant. This is approximately six percent of the System's total 1981 supply. Feedstock is supplied by pipeline from western Canadian sources.

Canadian Operations

Columbia Gas Development of Canada Ltd. (Columbia-Canada) participated in the drilling of 90 wells in 1981: 29 exploratory and 61 development. Twenty-two of the exploratory wells and 54 of the development wells are considered to be commercial.

Columbia-Canada owns 138 billion cubic feet of proved Canadian gas reserves and 1.9 million barrels of oil and other liquids. (This does not include the projected reserves in the Hibernia and Hebron fields.) In addition, it has a call (subject to Canadian export approval) on 2.1 trillion cubic feet of additional gas reserves, primarily in the Arctic Islands.

The company's interest in production from Canadian wells was 1.7 billion cubic feet of gas and 178,000 barrels of oil and other liquids, representing an increase over 1980 of 32 percent for gas and 93 percent for liquids.

Columbia-Canada, in association with four independent Canadian oil and gas companies, is conducting a $60 million exploration program over a three-year period that began on January 1, 1980. The four companies have 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. Under the program through 1981, 16 wells have been drilled which resulted in nine gas discoveries, two oil discoveries and five dry holes.

Although Columbia-Canada did not produce gas from the Kotaneelee gas field in the Yukon Territory during 1981, a significant Canadian federal action upheld the future value of these reserves; the field was declared "pioneer production" and, as a result, was exempted from any back-in ownership by the Crown. Since Columbia Gas Transmission's import application is still pending with the U.S. Department of Energy, Columbia-Canada is seeking other purchasers for the total authorized volume of 84.5 Bcf of natural gas through December 31 1987. Columbia-Canada is optimistic that sales from this field will commence late in 1982.

Offshore drilling. The Hebron I-13 well, located on a structure 23 miles southeast of the Hibernia discovery, flowed oil and natural gas from five of ten intervals tested in three principal geologic formations. The Hebron well was drilled to a depth of 15,500 feet. Further drilling will be necessary to determine the commercial significance of the find.

Columbia's capacity to transmit gas was increased by this 1981 project to install a larger pipeline across the Susquehanna River in Pennsylvania. Barrels support the pipe while it is pulled across, before lowering into river bottom trench.

Columbia biologist Donald Gartman checks water quality in operating area as part of an ongoing environmental monitoring program.

An additional exploratory well, Nautilus C-92, located eight miles northeast of the Hibernia discovery was drilling at year-end with a planned total depth of 19,000 feet.

Hibernia Wells. While the third delineation well in the Hibernia field, G-55, was dry, the fourth such well, Hibernia K-18, showed a significant northwest extension of the Hibernia field and confirmed productive zones previously found in the discovery well and the first two delineation wells. All nine zones tested at K-18 flowed oil and gas with oil as much as 4,642 barrels daily from sands corresponding to those in the P-15 discovery well. The results from this fourth delineation well tend to confirm the estimates of about 1.8 billion barrels of recoverable oil from the Hibernia structure. The fifth and final delineation well, Hibernia J-34, has been drilled to about 12,000 feet. Drilling has been suspended because of the loss of the platform in a storm on February 15, 1982. A detailed seismic survey of the Hibernia structure was completed during 1981; processing of the data should be completed by the spring of this year.

Columbia's interest in the 524,758 gross acre block encompassing the Hibernia, Hebron and Nautilus structures is 5.47 percent. This percentage will probably be reduced to 4.1 percent under the new Canadian energy policy.

Coal Production

Commercial production of coal continues on a limited basis at the Wayne County, West Virginia, mine owned jointly by Columbia Coal Gasification Corporation and Monterey Coal Company, an Exxon affiliate. Most of Columbia's half of the Wayne Mine production has been sold to a European purchaser under a three-year contract. Near year-end, one trainload was sold to a domestic utility under a spot order.

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

In addition to the 200 million tons dedicated to the mining venture, 550 million tons of low-sulfur coal reserves have been designated as proved 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.

Supply Research

The supply research program of the System included projects conducted both in the Columbia laboratories in Columbus, Ohio, and through support of projects conducted by outside agencies.

Laboratory work continued on coal gasification research seeking to reduce the cost and improve the efficiency of the gasification process. These projects included work on catalytic coal gasification funded in part by the Department of Energy.

Field work was concluded in 1981 on research seeking methods to improve gas flow from Devonian shale and similar impervious rock formations. The data are now being analyzed for evaluation with the Department of Energy and other organizations which helped fund the program.

Studies have been started in conjunction with the GEOSAT Committee, a consortium of 80 energy companies, on the possible use of remote sensing to detect factors which may indicate a potential gas reservoir.

Paul Beighle, utility man at Cobb Compressor, West Virginia, is one of 12,000 Columbia employees who keep energy moving to market.

Transmission and Storage

The Columbia System expanded its capacity to secure gas from new producing fields and to deliver gas to customers in its eight-state service area. Columbia's network of transmission pipelines is one of the most extensive in the nation and is coupled to an expanding complex of underground storage fields.

Offshore Pipelines

Columbia is a participant in the South Pass 77 Project, built in 1981 to connect with newly developed reserves in the eastern Louisiana offshore. It has a 37.5 percent share in the line's daily capacity of 550 million cubic feet. Columbia constructed pipelines to connect wells on three tracts in which Columbia Gas Development has an interest and is the operator: Ship Shoal 247, South Marsh Island 143, and West Cameron 426.

Appalachian Pipelines

Columbia Gas Transmission launched the largest pipeline construction program in its history in 1981, constructing more than 350 miles of new line and replacing almost 210 miles of its existing transmission and gathering network.

A substantial portion of the 1981 program was for facilities to transport gas to growing markets along the Eastern Seaboard. Another large part covered new pipelines and related compressor facilities in Ohio, New York, Pennsylvania and other states to gather gas from independent producers.

Storage Operations

Columbia Gas Transmission had a record 633 billion cubic feet of natural gas in its 49 underground storage fields located in four Appalachian states at the beginning of the 1981-82 winter heating season. It is continuing a major expansion of these facilities through construction of the Crawford Field in Ohio. When completed, the field will be capable of storing 115 billion cubic feet of gas, lifting Transmission's total storage capacity to 705 billion cubic feet.

Alaskan Gas Pipeline

Design and engineering work on the Alaskan Natural Gas Transportation System (ANGTS) is proceeding on schedule toward a project completion date of late 1986. The portion in which Columbia will have a financial interest consists of the 743-mile pipeline segment in Alaska and a gas conditioning plant to be located on the North Slope. The project is the largest venture ever to seek private financing, which has yet to be negotiated.

In December 1981, Congress approved a waiver of existing law to help achieve private financing for ANGTS. Provisions in the waiver will permit inclusion of the gas conditioning plant in the ANGTS, equity participation by the Prudhoe Bay producers in the Alaskan segment of the pipeline and the gas conditioning plant, and commencement of billing, under certain circumstances, prior to completion of all segments of the system.

Ozark Pipeline

Following Federal Energy Regulatory Commission (FERC) approval of the project, construction began late in 1981 on the Ozark Gas Transmission System in which Columbia is one of four partners. The 285-mile line will deliver gas reserves being acquired in the Arkoma Basin of Oklahoma and Arkansas to a connection in Arkansas with an existing interstate pipeline. Columbia has the right to use half the pipeline's daily capacity of 170 million cubic feet. The line will go into service early in 1982.

Trailblazer Pipeline

FERC authorization is expected shortly for construction of the Trailblazer Pipeline System which will run 800 miles from new Rocky Mountain production areas to a connection in Nebraska with an existing transmission line. Columbia is one of five companies building the line and will have the right to move 175 million cubic feet daily of the reserves which it is purchasing and developing in the Rockies. Assuming that construction of the system can be started early in 1982, first deliveries could be made before the end of the year.

Industrial sales planning takes utilization specialist Lezlie Struble into a metal forging plant in Binghamton, N.Y. to confer on customer requirements.

Energy Sales

Markets for natural gas continued to grow in 1981 as new customers were added in all sales categories by both affiliated and non-affiliated distribution companies.

The completion of Columbia's merger with Commonwealth Natural Resources, Inc. in August, 1981 extended Columbia's retail service areas to the Virginia Tidewater area.

Total System sales of 1.2 trillion cubic feet for 1981 were three percent above those in 1980. Of the total, 622 billion cubic feet were sold through the System's retail affiliates and 582 billion cubic feet were sold to non-affiliated distribution companies and others supplied by Columbia. Sales volumes in 1981 reflected weather that was slightly warmer than the previous year, and continuing conservation by residential customers.

Retail Operations

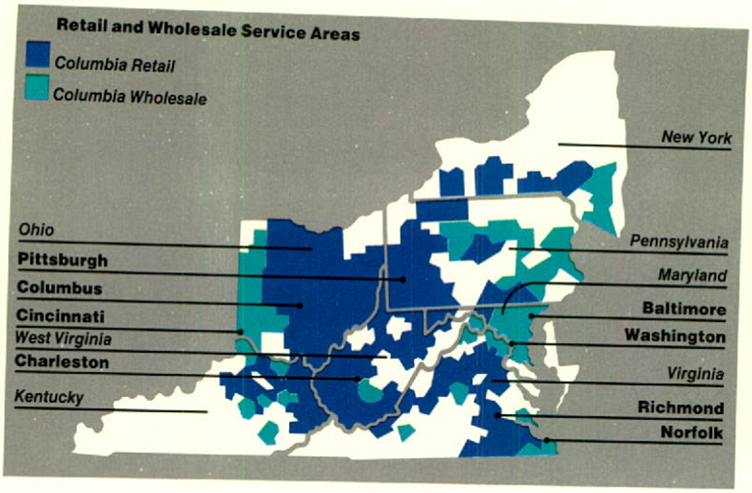
Columbia's affiliated retail distribution companies conducted an aggressive campaign in 1981 to enlarge their markets. Despite faltering home-building activity during the year, approximately 21,000 new residential and commercial customers were added. The increase was partially offset by service connections lost through such factors as highway relocations and urban renewal. The total number of Columbia retail customers is now approximately 1.9 million.

Increasing market interest in natural gas was evidenced by an announcement from a major appliance company that it is resuming manufacture of gas ranges after a 10-year halt.

Columbia's customers are showing increasing concern over higher natural gas costs. In order to mitigate the impact of higher bills, an intensified budget payment enrollment campaign was undertaken in late summer. Some 60,000 budget customers were added, raising the total number of customers on a budget plan to almost 700,000. This represents almost 40 percent of all residential users and it is the highest percentage of any of the 10 largest gas systems in the country.

Explanations of increased costs and the need for conservation were stressed at more than 750 public question-and-answer sessions, reaching some 35,000 people. Columbia personnel helped customers become more informed about federal and state programs designed to provide assistance for conservation measures and bill payments.

Testing of the promising market potential for compressed natural gas fuel for fleet vehicles began during the year. Selected company vehicles were converted to dual-fuel capability as a forerunner to reaching a large prospective market of fleet conversions by a wide variety of businesses, industries and governmental groups. Interest in natural gas as a motor fuel has been increased by the Ford Motor Company's announcement that it is considering production of a natural gas-powered car.



It's official. A Commonwealth Gas employee affixes the Columbia tri-star emblem to the Commonwealth Gas headquarters to mark completion in August 1981 of the organizations' merger.

Columbia strengthened its economic development program, which is aimed at attracting new industries to its service area. Major new and expanded plant facilities in Columbus and Marysville, Ohio; Winchester, Ky, and Hagerstown, Md, will provide significant new gas sales as well as more than 11,000 new jobs. A number of smaller companies with substantial growth potential also located facilities in Columbia's territory.

Wholesale Markets

Deliveries to non-affiliated distribution companies served by Columbia Gas Transmission increased during 1981, although the downturn in the economy and increasing conservation held sales by these companies below anticipated levels.

The advantages of natural gas energy continued to attract new gas customers and to encourage homes, businesses and industries using other fuels to convert to natural gas in the wholesale markets. Heating conversions from oil to natural gas continued at a rapid pace in Transmission's eastern markets, resulting in increased deliveries in these areas.

Commonwealth Merger

The Columbia System gained three marketing subsidiaries in eastern and central Virginia in August 1981 through completion of the merger with Commonwealth Natural Resources, Inc.

Commonwealth Gas Pipeline is an intrastate wholesale transmission company supplying private and municipal distribution companies serving approximately 250,000 customers. The cities served include Richmond and Suffolk.

Commonwealth Gas Services serves about 50,000 customers in the Portsmouth, Fredericksburg and Petersburg areas.

Commonwealth Propane supplies liquefied petroleum gas at retail to more than 31,000 customers. Its markets include not only residential and commercial users, but a variety of industrial and agricultural applications throughout a large part of the state.

The territory served by the Commonwealth companies has good market growth potential among all classes of gas customers.

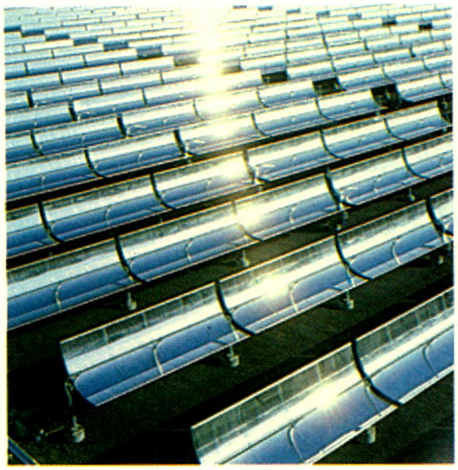
Propane Sales

Through Columbia Hydrocarbon Corporation, the System also offers propane service to residential, commercial and industrial customers beyond existing gas mains in other portions of Columbia's retail service area.

Additionally, Hydrocarbon is test marketing propane for fleet motor fuel use in certain areas. During the year over 800 vehicles were converted to the use of propane under this program.

Columbia Hydrocarbon propane sales in 1981 totaled 64 million gallons, compared to 72 million gallons in 1980.

In addition to propane, Columbia Hydrocarbon also produces and markets butanes and natural gasoline.



World's largest solar thermal energy facility will be operated by Columbia at an Ohio chemical plant to study possible application of combination gas/solar energy systems.

Energy Utilization Research

Primary Columbia research efforts are focusing on improved energy service and utilization. Projects are funded directly by Columbia or carried out in association with the Department of Energy (DOE), the Gas Research Institute (GRI) and other organizations.

Columbia completed construction late in 1981 of the world's largest solar thermal energy system at the Haverhill, Ohio complex of the USS Chemicals Division of United States Steel. The 50,400 square-foot array of solar collectors is expected to produce approximately eight billion Btu's per year of process steam for use in the production of phenol at the Haverhill plant. The design, construction and operation of this solar system is funded jointly by the DOE, Columbia and USS Chemicals. Columbia is also continuing to operate the 3,000 square-foot solar collector system on an office building in Columbus, Ohio. Both projects provide test data on the operation of combination gas and solar energy systems.

Columbia is one of 30 utility companies participating with the DOE and the Gas Research Institute in a planned field test of 45 forty-kilowatt fuel cell powerplants using natural gas. Columbia has selected 10 commercial customers' facilities to analyze the potential for on-site fuel cell energy service and it will select one of the 10 buildings for installation of two of the prototype fuel cell powerplants.

Columbia is continuing its research on an advanced absorption heat pump for the residential market. The objective of this program is to produce a gas heat pump which will provide heating and cooling for Columbia's residential customers, using the same amount of natural gas currently used to provide space heating alone. The prototype testing to date has produced results close to target performance objectives.

In cooperation with other gas utilities and equipment manufacturers, Columbia has an active industrial utilization research program directed at developing gas-fired industrial processes that result in cost savings for the user. Some developments will displace energy forms other than natural gas. The intent of this research is to ensure maintenance of position and offset encroachment by competition in the industrial market segment, thereby helping assure long-term growth.

Several of the programs have reached the point of industrial demonstration. These include improved equipment for producing special atmospheres for steel heat treatments, low metal loss aluminum melting, improved forging furnaces, preheating of steel scrap prior to electric melting, and several others. Equipment evolving from these demonstrations will be marketed by major heat processing equipment manufacturers.

Industrial concerns use more gas than any other class of retail customer. In this Toledo, Ohio plant rolls of metals are prefinished before fabrication, using clean-burning gas to bake and cure the coating.

Computer center in Ohio processes customer and stockholder accounts. Staff members shown are Raymond Black and Eileen Williams.

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

Results of Operations

Earnings on common stock, for 1981, increased to $190.3 million as compared with $171.3 million in 1980 and $148.6 million in 1979. Per share earnings were $5.50 in 1981, an increase of $0.48 over 1980 and $1.11 over 1979. This is the seventh consecutive year that per share earnings have increased.

Primary factors contributing to the 1981 increased earnings are: (1) higher sales rates and a slight increase in volumes of gas sold; (2) increased earnings contribution of oil and gas producing activities as a result of increased production and higher sales rates; and (3) increased investment tax credits. These improvements to earnings were partially offset by the loss of equity earnings on the Cove Point LNG terminal.

Gas Operating Revenues, for the year 1981, increased $648.3 million over 1980 reflecting a 15% increase in average sales rates and a 2.8% increase in sales volumes. System wholesale and retail companies placed into effect general rate increases, necessary to recover increased operating and interest costs, and recovered increases in the cost of purchased gas through purchased gas adjustment clauses or similar tariff provisions. Gas revenues were also improved during 1981 by a favorable decision in a state retail rate case, which permitted the recovery of costs previously denied (See Note 2A of Notes to Consolidated Financial Statements).

Gas sales volumes reflect the effects of warmer weather, continued conservation and the business recession, offset by customer growth, conversions from other fuels and greater wholesale sales. Industrial sales volumes increased slightly over 1980 but remained below 1979 levels due largely to the recession, particularly as related to the automobile industry.

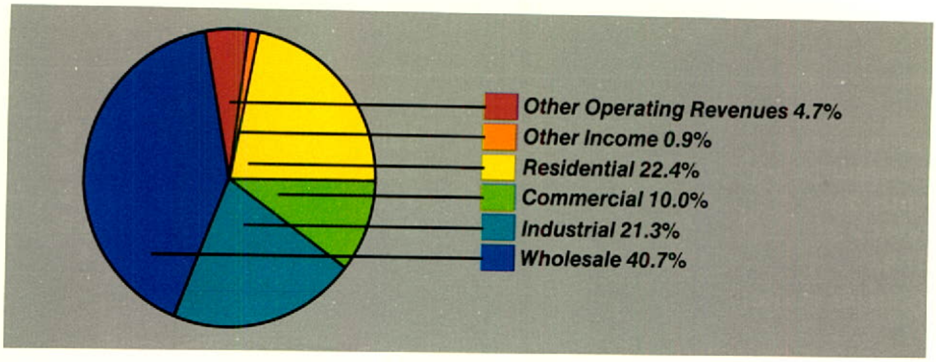
Gas operating revenues in 1980 were influenced by higher average rates (up 30%) and lower volumes related to warmer weather and the business slow-down.

Other Operating Revenues continued to rise, totaling $209.5 million, an increase of 38% over 1980 and 113% over 1979. The increases reflect significant price increases for sale of oil, propane and other hydrocarbons as well as continued higher production volumes.

Gas Purchased Costs continue to increase reflecting the impact of the Natural Gas Policy Act passed in late 1978 and the effects of inflation on supplier operating expenses. The average rate for gas purchased rose 20% in 1981 as compared to an increase of 45% in 1980. In addition, a nonrecurring gas purchased adjustment to adopt accounting consistent with rate treatment improved 1980 earnings by approximately $4 million.

Other Operation and Maintenance Expenses continued to increase due largely to the effects of inflation. The increase in depreciation and depletion reflected increased plant investment and greater revenues related to production, the same factors that influenced 1980 expense. In 1979, depreciation and depletion reflected a downward adjustment in connection with a settled wholesale rate case, of which approximately $8 million was applicable to 1978. Income taxes, as detailed on the Statements of Consolidated Taxes, decreased in 1981 despite a slight increase in taxable income principally due to an adjustment applicable to prior years. Income taxes for 1980 also reflected a nonrecurring downward adjustment to reflect rate treatment. Other taxes decreased as a result of recording effects of the Louisiana first use tax refund partially offset by significant increases in other gross receipt taxes reflecting the effect of higher retail revenues and the windfall profits tax on decontrolled oil prices.

1981 Source of Revenues



Other Income reflects increased investment tax credits due to the higher level of construction activity. Earnings for 1979 included a gain on the sale of Canadian properties. The increase in interest income is due primarily to interest accrued on deferred purchased gas costs.

Interest Expense on long-term debt reflects the full-year effect of the $100 million 12¾% debenture issue in August 1980, and 1981 borrowings related to the revolving credit agreement. Other interest expense increased due to greater short-term borrowings necessary to finance deferred purchased gas costs. Such interest expense is offset by interest accrued in Other Income, based on future recovery through rate tariff provisions. Also, average short-term borrowing rates increased to 16.3% in 1981 from 14.4% in 1980.

Rate Matters

During 1981, the System distribution subsidiaries received approvals for general rate increases amounting to approximately $73 million annually. Revenue increases of approximately $57 million annually have been filed and were awaiting action by state commissions at year-end.

On January 1, 1982, the transmission companies increased rates, subject to refund, that provide for additional annual revenues of $124.4 million.

On December 23, 1981, the United States Court of Appeals, Former Fifth Circuit, decided on appeal of two FERC rule-making orders that all pipeline production is governed by the Natural Gas Policy Act. Several parties have requested rehearing on this matter. However, should the court decision not be reversed, the Corporation's cost of service production would qualify for NGPA pricing which would increase revenues and improve future earnings, the amount of which cannot be reasonably determined until further FERC hearings are held. For additional information reference is made to Notes 2B and 10F of Notes to Consolidated Financial Statements.

Liquidity and Capital Resources

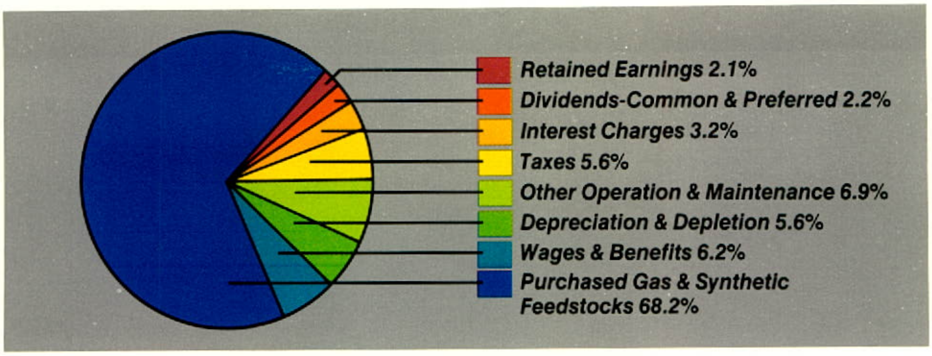
The Corporation does not anticipate any events that would materially change its present liquidity position which is adequate to satisfy known demands, even though the relative costs of obtaining new capital have increased significantly and projected capital expenditures for 1982 have increased to an estimated $687 million compared to $592 million in 1981.

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 deferred purchased gas costs and 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.

Internally generated funds will provide a substantial portion of the capital expenditure requirements for 1982. Additional external financing is anticipated during 1982, the amount and form to be determined at a later date.

1981 Disposition of Revenues



Among the major projects described on page 13 of this report are the Alaskan Natural Gas Transportation System (ANGTS) and the Trailblazer Pipeline System. As presently contemplated, project financing will be used for these undertakings as it was for the Ozark Transmission System. 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. Columbia's participation in the ANGTS is contingent on several conditions related to the financing of this project. If these conditions are met, Columbia will have a $380 million equity position in the project, based on current estimates.

At December 31, 1981, the Corporation's unused sources of liquidity consisted principally of credit lines related to short-term requirements of $84.5 million, $20 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 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, 1981, there were 139,004 shareholders.

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

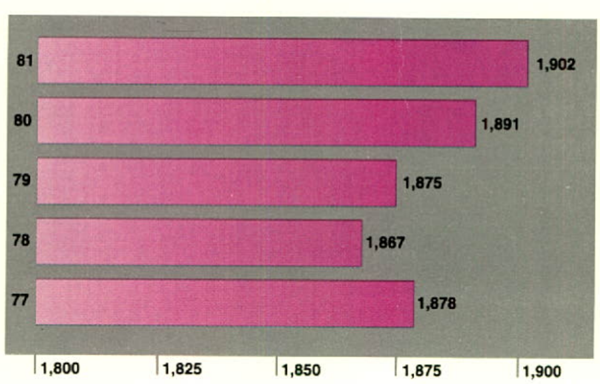
Quarter Ended	High	Market Price Low	Close	Quarterly Dividends Paid
1981	**$**	**$**	**$**	**¢**
March 31	**41½**	**34**	**37⅜**	**67.5**
June 30	**38¼**	**31½**	**33**	**67.5**
September 30	**35⅝**	**27⅞**	**29**	**67.5**
December 31	**34⅞**	**28⅛**	**32⅛**	**67.5**
1980				
March 31	47	33¾	37½	64
June 30	43½	34⅞	38⅛	64
September 30	41½	35½	35¾	64
December 31	42½	34¾	40¼	64

Comparative Gas Operations Data

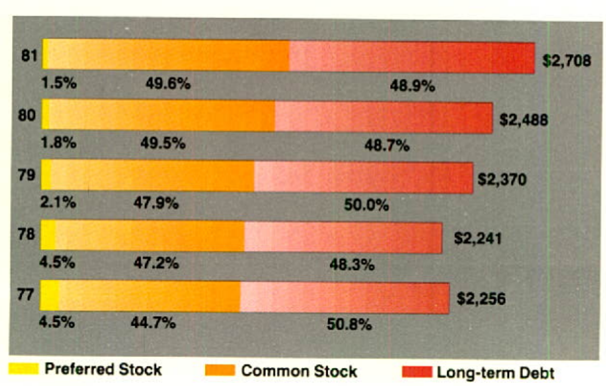
The Columbia Gas System, Inc. and Subsidiaries

	1981	1980	1979	1978	1977
Revenues (in thousands)					
Residential	$ 997,741	$ 896,541	$ 747,705	$ 707,671	$ 624,980
Commercial	448,179	385,723	308,225	280,117	231,696
Industrial	951,720	814,198	665,838	509,256	383,257
Wholesale	1,804,515	1,465,339	1,105,154	918,247	742,684
Other	14,578	6,673	1,379	1,784	13,726
Total revenues	$4,216,733	$3,568,474	$2,828,301	$2,417,075	$1,996,343
Sales (million cu. ft.)					
Residential	237,486	244,336	252,266	264,369	259,964
Commercial	114,481	112,962	113,625	114,641	105,272
Industrial	269,772	267,611	283,624	238,529	200,609
Wholesale	578,521	544,695	559,355	512,569	461,463
Other	4,289	2,705	734	838	4,783
Total sales	1,204,549	1,172,309	1,209,604	1,130,946	1,032,091
Customers at Year End					
Residential	1,746,774	1,738,815	1,725,151	1,718,115	1,727,058
Commercial	152,332	150,057	147,052	146,247	148,542
Industrial	2,546	2,473	2,446	2,386	2,473
Wholesale	85	86	87	88	87
Other	65	67	96	124	136
Total customers at year end	1,901,802	1,891,498	1,874,832	1,866,960	1,878,296
Degree Days					
Billing period	5,550	5,570	5,703	5,983	5,669
Calendar period	5,474	5,683	5,678	5,958	5,588
Gas Available for Sale (million cu. ft.)					
Total gas purchased	1,107,619	1,063,351	1,108,027	1,050,244	1,011,367
Total gas produced (natural and synthetic)	169,888	156,698	166,468	170,067	158,111
Exchange gas—net	1,601	(5,601)	2,979	(2,548)	6,102
Gas withdrawn from (delivered to) storage—net	(5,519)	(1,044)	(6,492)	(13,127)	(76,358)
Used in operations and other	(69,040)	(41,095)	(61,378)	(73,690)	(67,131)
Total gas available for sale	1,204,549	1,172,309	1,209,604	1,130,946	1,032,091

Number of Retail Customers Served-Year End
(In Thousands)



Capitalization and Capitalization Ratios
(In Millions of Dollars)



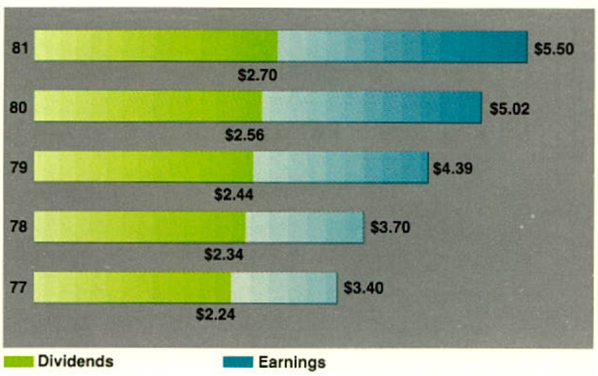
Selected Financial Data

The Columbia Gas System, Inc. and Subsidiaries

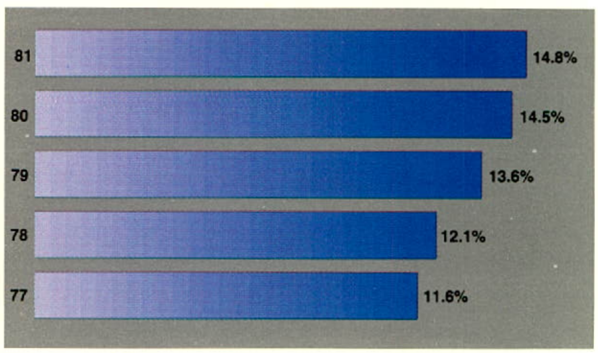
(in thousands except for per share amounts)	1981	1980	1979	1978	1977
Results of Operations					
Operating revenues	$4,426,243	$3,719,921	$2,926,524	$2,506,242	$2,079,674
Purchased gas and feedstocks	3,047,508	2,457,373	1,817,669	1,517,320	1,213,946
Other operating expenses	981,441	873,802	755,901	676,286	619,383
Income taxes	127,541	136,014	125,777	118,691	58,018
Operating income	269,753	252,732	227,177	193,945	188,327
Other income—net	66,461	39,728	38,783	29,916	37,300
Interest charges—net	140,720	115,584	107,176	87,883	99,986
Net income	195,494	176,876	158,784	135,978	125,641
Preferred stock dividend accrual	5,160	5,530	10,223	11,169	11,176
Earnings on Common Stock	$ 190,334	$ 171,346	$ 148,561	$ 124,809	$ 114,465
Per share	$5.50	$5.02	$4.39	$3.70	$3.40
Average common shares	34,597	34,142	33,820	33,699	33,641
Dividends on Common Stock					
Per share*	$2.70	$2.56	$2.44	$2.34	$2.24
Payout ratio (%)	49.1	51.0	55.6	63.2	65.9
Capitalization					
Common stock equity	$1,343,589	$1,231,091	$1,133,652	$1,058,818	$1,009,369
Preferred stock	40,000	45,000	50,269	100,290	100,349
Long-term debt, excluding current maturities	1,324,025	1,211,847	1,185,630	1,082,216	1,147,330
Total capitalization	$2,707,614	$2,487,938	$2,369,551	$2,241,324	$2,257,048
Return On Average Common Equity (%)	14.8	14.5	13.6	12.1	11.6
Book Value Per Common Share	$38.50	$35.84	$33.35	$31.36	$29.98
Property, Plant & Equipment	$5,310,253	$4,812,375	$4,408,723	$4,150,475	$3,855,510
Accumulated depreciation and depletion	(2,134,605)	(1,941,623)	(1,747,052)	(1,623,999)	(1,476,063)
Net property, plant & equipment	$3,175,648	$2,870,752	$2,661,671	$2,526,476	$2,379,447
Total Assets	$4,616,781	$3,927,716	$3,692,491	$3,489,256	$3,508,886
Capital Expenditures for Year	$ 592,002	$ 445,201	$ 371,604	$ 340,107	$ 286,013

*Excludes Commonwealth

Earnings And Dividends Per Share of Common Stock



Return on Average Common Equity



Management's 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, 1981 and 1980 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, 1981. 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, 1981 and 1980, and the results of their operations and funds used for capital expenditures for each of the three years in the period ended December 31, 1981, in conformity with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen + Co.

February 9, 1982.

Statements of Consolidated Income

The Columbia Gas System, Inc. and Subsidiaries

Year Ended December 31, (in thousands)	**1981**	1980	1979
Operating Revenues			
Gas	**$4,216,733**	$3,568,474	$2,828,301
Other	**209,510**	151,447	98,223
Total operating revenues	**4,426,243**	3,719,921	2,926,524
Operating Expenses			
Gas purchased for resale	**2,699,401**	2,152,558	1,550,875
Synthetic gas feedstocks	**348,107**	304,815	266,794
Other operation	**508,702**	437,572	385,444
Maintenance	**75,599**	67,895	61,256
Depreciation and depletion	**248,407**	212,126	174,000
Income taxes	**127,541**	136,014	125,777
Other taxes	**148,733**	156,209	135,201
Total operating expenses	**4,156,490**	3,467,189	2,699,347
Operating income	**269,753**	252,732	227,177
Other Income			
Investment credits, including amortization	**27,275**	19,709	10,523
Allowance for equity funds used during construction	—	3,141	693
Gain on sale of Canadian properties, less related income taxes of $2,060,000	—	—	11,590
Interest and other—net	**39,186**	16,878	15,977
Total other income	**66,461**	39,728	38,783
Income before interest charges	**336,214**	292,460	265,960
Interest Charges			
Long-term debt	**113,355**	102,347	90,032
Other—net	**39,447**	20,712	21,093
Allowance for borrowed funds used during construction	**(12,082)**	(7,475)	(3,949)
Total interest charges	**140,720**	115,584	107,176
Net Income	**195,494**	176,876	158,784
Preferred stock dividend accrual	**5,160**	5,530	10,223
Earnings on Common Stock	**$ 190,334**	$ 171,346	$ 148,561
Earnings Per Share of Common Stock (based on average shares outstanding)	**$5.50**	$5.02	$4.39
Dividends Per Share of Common Stock*	**$2.70**	$2.56	$2.44
Average Common Shares Outstanding (thousands)	**34,597**	34,142	33,820

*Excludes Commonwealth

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

Consolidated Balance Sheets

The Columbia Gas System, Inc. and Subsidiaries

Assets

As of December 31, (in thousands)	1981	1980
Property, Plant and Equipment, at original cost—		
Gas utility and other plant	**$4,339,814**	$3,964,660
Accumulated depreciation and depletion	**(1,824,822)**	(1,699,770)
	2,514,992	2,264,890
Oil and gas producing properties, full cost method—		
United States cost center	**848,990**	748,412
Canadian cost center ($40,438,000 and $42,466,000, respectively, not being amortized) (Note 3)	**121,449**	99,303
Accumulated depletion	**(309,783)**	(241,853)
	660,656	605,862
Net property, plant and equipment	**3,175,648**	2,870,752
Gas Supply Advances and Investments	**135,016**	126,949
Current Assets		
Cash	**24,540**	23,264
Temporary cash investments, at cost which approximates market	**1,938**	7,483
Accounts receivable—		
Gas	**474,770**	347,512
Other	**84,107**	78,742
Allowance for doubtful accounts	**(5,348)**	(4,618)
Federal income tax refund	**32,235**	—
Gas supply advances—current	**23,462**	40,690
Gas in underground storage—current inventory, at cost	**276,258**	261,431
Materials and supplies, at average cost	**64,906**	49,260
Deferred purchased gas costs—net	**130,963**	—
Prepaid taxes	**32,403**	21,851
Other	**84,061**	55,926
Total current assets	**1,224,295**	881,541
Deferred Charges	**81,822**	48,474
Total Assets	**$4,616,781**	$3,927,716

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

Capitalization and Liabilities

As of December 31, (in thousands)	1981	1980
Common Stock Equity		
Common stock, $10 par value, authorized 50,000,000 shares, outstanding 34,898,081 and 34,353,202 shares, respectively	$ 348,981	$ 343,532
Balance of amounts paid in in excess of par value	148,140	135,339
Retained earnings	846,468	752,220
Total common stock equity (See Statements of Consolidated Common Stock Equity)	1,343,589	1,231,091
Redeemable Preferred Stock (Note 4)	40,000	45,000
Long-term debt (Note 8)	1,324,025	1,211,847
Total capitalization	2,707,614	2,487,938
Current Liabilities		
Commercial paper	314,030	42,600
Current maturities of long-term debt and preferred stock	53,010	42,757
Accounts and drafts payable	583,516	418,023
Accrued taxes	80,878	183,906
Accrued interest	41,066	43,131
Estimated rate refunds	120,146	168,301
Current deferred taxes—net	69,470	9,173
Other	117,108	77,888
Total current liabilities	1,379,224	985,779
Deferred Credits		
Accumulated deferred income taxes—net	422,852	361,701
Accumulated deferred investment credits	43,931	40,522
Other	63,160	51,776
Total deferred credits	529,943	453,999
Commitments and Contingencies (Notes 2, 5, and 6)		
Total Capitalization and Liabilities	$4,616,781	$3,927,716

Statements of Consolidated Common Stock Equity

The Columbia Gas System, Inc. and Subsidiaries

(in thousands)	No. of Shares	Par Value	Balance of Amounts Paid In in Excess of Par Value	Retained Earnings
Balance at December 31, 1978	33,764	$337,643	$120,802	$600,374
Net income	—	—	—	158,784
Dividends:				
Common stock	—	—	—	(81,588)
Redeemable preferred stock				
11.25% Series A	—	—	—	(4,688)
10.96% Series B	—	—	—	(5,480)
Convertible preferred stock	—	—	—	(55)
Sale of common stock:				
Dividend reinvestment plan	68	677	1,484	—
Tax reduction employee stock ownership plan	159	1,593	4,086	—
Other	3	31	(12)	—
Balance at December 31, 1979	33,994	339,944	126,360	667,347
Net income	—	—	—	176,876
Dividends:				
Common stock	—	—	—	(86,473)
Redeemable preferred stock				
10.96% Series B	—	—	—	(5,480)
Convertible preferred stock	—	—	—	(50)
Sale of common stock:				
Dividend reinvestment plan	247	2,473	7,048	—
Tax reduction employee stock ownership plan	77	767	2,196	—
Other	35	348	(265)	—
Balance at December 31, 1980	34,353	343,532	135,339	752,220
Net Income	—	—	—	**195,494**
Dividends:				
Common stock	—	—	—	**(92,596)**
Redeemable preferred stock				
10.96% Series B	—	—	—	**(5,160)**
Write-off of capital stock expense previously deferred	—	—	—	**(3,490)**
Sale of common stock:				
Dividend reinvestment plan	**378**	**3,778**	**9,025**	—
Tax reduction employee stock ownership plan	**168**	**1,680**	**3,799**	—
Other	**(1)**	**(9)**	**(23)**	—
Balance at December 31, 1981*	**34,898**	**$348,981**	**$148,140**	**$846,468**

*$560,260,000 of retained earnings not available for cash dividends at December 31, 1981, 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)	**1981**	1980	1979
Funds from Internal Sources			
Operations			
Net income	**$195,494**	$176,876	$158,784
Items not requiring (providing) funds:			
Depreciation and depletion	**249,136**	212,165	174,493
Deferred income taxes and investment credits—net	**123,880**	16,005	111,535
Allowance for equity funds used during construction	**—**	(3,141)	(693)
Accrued interest on gas supply advances	**(6,307)**	(4,538)	(997)
Total operations	**562,203**	397,367	443,122
Dividends on common and preferred stock	**(97,756)**	(92,003)	(91,811)
Other			
Cash and temporary cash investments	**4,269**	10,236	27,617
Accounts receivable	**(131,893)**	(28,805)	(125,560)
Federal income tax refund	**(32,235)**	—	—
Gas in underground storage	**(14,827)**	(42,076)	8,505
Accounts and drafts payable	**165,493**	99,627	75,663
Accrued taxes	**(103,028)**	99,658	(22,242)
Estimated rate refunds	**(48,155)**	(52,252)	(65,198)
Deferred purchased gas costs—net	**(132,612)**	55,248	(99,212)
Repayments of gas supply advances and investments	**36,813**	16,529	57,152
Miscellaneous—net	**(29,403)**	18,015	51,319
Total other	**(285,578)**	176,180	(91,956)
Total funds from internal sources	**178,869**	481,544	259,355
Funds from Financing			
Issuance of capital stock	**18,282**	12,484	7,840
Retirement of capital stock	**(5,000)**	—	(50,000)
Issuance of long-term debt	**180,000**	100,055	175,350
Retirement of long-term debt	**(57,886)**	(66,021)	(69,171)
Short-term debt—net	**271,430**	(90,540)	46,540
Total funds from financing (repaid)	**406,826**	(44,022)	110,559
Funds Used for Capital Expenditures	**$585,695**	$437,522	$369,914
Allowance for equity funds used during construction	**—**	3,141	693
Accrued interest on gas supply advances	**6,307**	4,538	997
Total Capital Expenditures	**$592,002**	$445,201	$371,604
Capital Expenditures for—			
Gas utility and other plant	**$405,690**	$303,441	$213,959
Oil and gas producing properties	**156,533**	128,287	127,937
Gas supply advances and investments	**29,779**	13,473	29,708
Total Capital Expenditures	**$592,002**	$445,201	$371,604

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)	**1981**	1980	1979
Income Taxes			
Included in operating expenses			
Currently payable—			
Federal	**$ (30,341)**	$ 82,924	$ 234
State	**1,268**	13,252	943
Total	**(29,073)**	96,176	1,177
Deferred, net—			
Federal	**114,749**	9,028	98,920
State and foreign	**5,731**	1,788	9,004
Total	**120,480**	10,816	107,924
Investment credits—			
Provision*	**41,874**	32,208	18,525
Provision not deferred	**(2,440)**	(2,514)	(1,054)
Amortization	**(3,300)**	(672)	(795)
Total	**36,134**	29,022	16,676
Total included in operating expenses	**127,541**	136,014	125,777
Included in other income			
Deferred—			
Federal	—	—	(2,168)
Foreign	—	—	4,228
Total	—	—	2,060
Investment credits—			
Provision not deferred	**(25,377)**	(17,798)	(8,623)
Amortization	**(1,898)**	(1,911)	(1,900)
Total	**(27,275)**	(19,709)	(10,523)
Total included in other income	**(27,275)**	(19,709)	(8,463)
Total income taxes	**100,266**	116,305	117,314
Other Taxes			
Property	**42,633**	39,320	38,165
Gross receipts	**79,786**	96,997	82,124
Payroll	**15,258**	12,796	11,136
Other	**11,056**	7,096	3,776
Total other taxes	**148,733**	156,209	135,201
Total Tax Expense	**$248,999**	$272,514	$252,515

* Includes Tax Reduction Employee Stock Ownership Plan provisions of $5,459,000, $4,124,000 and $4,602,000, respectively.

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

Year Ended December 31, (in thousands)	**1981**		1980		1979	
Computation of Income Taxes— Total income taxes are 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 income taxes	**$295,760**		$293,181		$276,098	
Tax expense at statutory Federal income tax rate	**$136,050**	**46.0%**	$134,863	46.0%	$127,005	46.0%
Increases (reductions) in taxes resulting from—						
State and foreign income taxes, net of Federal income tax benefit	**3,648**	**1.2**	8,710	3.0	5,333	1.9
Investment credits not deferred and amortization of credits deferred in prior years	**(33,015)**	**(11.2)**	(22,895)	(7.8)	(12,372)	(4.5)
Depreciation expense for accounting purposes over amounts claimed for income tax purposes—net	**3,594**	**1.2**	4,792	1.6	4,452	1.6
Gain on sale of Canadian properties taxed at less than the statutory rate	**—**	**—**	—	—	(4,220)	(1.5)
Other	**(10,011)**	**(3.3)**	(9,165)	(3.1)	(2,884)	(1.0)
Total income taxes	**$100,266**	**33.9%**	$116,305	39.7%	$117,314	42.5%

	1981	1980	1979
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	**$ 13,552**	$ 14,278	$ 26,462
Depreciation expense	**41,260**	14,107	11,972
Deferred purchased gas costs—net	**60,805**	(32,293)	26,968
Estimated rate refunds	**4,827**	19,473	39,754
Other	**36**	(4,749)	4,828
Total deferred income taxes	**$120,480**	$ 10,816	$109,984

Notes to Consolidated Financial Statements

1. *Summary of Significant Accounting Policies*

A. Principles of Consolidation. The Consolidated Financial Statements include the accounts of the Corporation and all subsidiaries. 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 before tax rate for such allowance was 17.75% in 1981, 12.0% in 1980 and 11.25% in 1979.

Interest during construction is also capitalized in connection with certain non-rate regulated activities at a before tax rate of 9.3% in 1981, 8.5% in 1980 and 5.0% in 1979.

The Corporation's subsidiaries provide for depreciation on a composite straight-line basis. The annual depreciation as related to the average of depreciable property at the beginning and end of each year results in composite rates of 2.8% in 1981, 2.8% in 1980 and 2.9% in 1979 for distribution properties and 4.2% in 1981, 4.4% in 1980 and 3.8% in 1979 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.

Depletion related to costs capitalized in the United States cost center is based upon gross revenues. Depletion related to costs capitalized in the Canadian cost center, exclusive of Canadian frontier areas described in Note 3, is based upon volumes 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 $245,900,000 and $168,800,000 at December 31, 1981 and 1980, 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. Estimated Rate Refunds. Provisions for estimated rate refunds are based upon management's current judgment 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. Deferred Purchased 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 offset by the deferral of gas purchased costs applicable to such revenue.

H. Pension Costs. The Corporation has trusteed, noncontributory pension plans which, with certain minor exceptions, cover all regular employees, 25 years of age and over. The Corporation's policy is to fund pension costs accrued, which amounted to $24,700,000 in 1981, $22,300,000 in 1980 and $20,000,000 in 1979, including amortization of unfunded prior service costs.

A comparison of accumulated benefits and assets of the plans is presented below:

At December 31,	**1981**	1980
Actuarial present value of accumulated benefits:		
Vested	**$253,700**	$255,300
Nonvested	**4,500**	4,700
Total	**$258,200**	$260,000
Net Assets Available for Benefits	**$297,700**	$277,900

The average assumed rate of return used in determining the actuarial present value of accumulated benefits was 10.5% as of December 31, 1981 and 8.5% as of December 31, 1980. These rates represent those available through insurance company annuity contracts.

Effective January 1, 1980, the Corporation authorized supplemental payments from the general funds of the Corporation, to retired employees and surviving beneficiaries of employees who retired prior to January 1, 1980. Effective January 1, 1982, the Corporation authorized that these payments be made from plan assets.

2. Regulatory Matters

A. Retail. 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. A favorable order on this matter was issued by the Commission during April 1981, thereby improving earnings for 1981 approximately $13,428,000 or $0.39 per share.

B. Wholesale. 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. The United States Court of Appeals for the District of Columbia circuit, after hearing oral arguments, remanded this case to the FERC for additional findings. In the opinion of management, the FERC will reaffirm its existing policy.

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. The loss of equity earnings in 1981 amounted to approximately $0.36 per share. In management's opinion, the investment associated with the Cove Point terminal of approximately $175,000,000, will be recovered through the resumption of deliveries or appropriate rate recovery.

On December 23, 1981, the United States Court of Appeals, Former Fifth Circuit, decided on appeal of two FERC rulemaking orders that pricing of all pipeline production is governed by the Natural Gas Policy Act. The Court stated that Congress intended for pipeline production to be treated no differently from production by independent producers or by pipeline affiliates. The Court's decision would only affect cost-of-service pipeline production. Several parties have requested rehearing. Whatever the outcome of the request for rehearing, it is expected that petitions for writ of certiorari to the Supreme Court of the United States will be filed, and that a considerable period of time could be involved before this matter is finally resolved. If the initial decision of the Court is not reversed, wellhead prices for the Corporation's own Appalachian production presently priced on a cost-of-service basis could significantly increase. At the present time, the effect of this order on the Corporation's earnings, from December 1, 1978 (the effective date of the Act) through December 31, 1981, cannot be reasonably determined until further FERC hearings are held. Reference is made to Note 10F for additional information related to capitalized costs, gas reserves and current production associated with the Corporation's cost-of-service properties.

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.

3. Investment in Canadian Frontier Areas

Costs capitalized in the Canadian cost center, net of accumulated depletion, amounted to $118,900,000 and $97,800,000 at December 31, 1981 and 1980, 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)	**1981**	1980
Arctic Islands and Northwest Territories	**$13,800**	$23,100
Offshore East Coast	**26,600**	19,400
	$40,400	$42,500

Arctic Islands and Northwest Territories. Columbia-Canada owns varying interests in 8.6 million gross acres (.7 million net acres). Costs were initially incurred in 1971 and consist principally of exploration costs accumulated since that time. 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 14.1 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, Labrador and Baffin Island. The Chevron Hibernia oil discovery well 200 miles east of St. Johns, Newfoundland, in which Columbia-Canada has an interest, has been followed up with four successful delineation wells which have added to the potential commercial significance of the area. Additional drilling 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, 1981, the Corporation had authorized 10,000,000 shares of preferred stock $50.00 par value and had outstanding 900,000 shares of 10.96% Series B Preferred Stock. The preferred stock is subject to a mandatory sinking fund which requires that the Corporation redeem 100,000 shares ($5,000,000) per year, resulting in a maximum aggregate cash requirement of $25,000,000 over the next five years. Shares are redeemable for the sinking fund at a price of $50.00 per share, or otherwise, at the optional redemption price of $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. 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 $41,600,000 in 1981, $32,700,000 in 1980, and $27,600,000 in 1979. 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)
1982	$21,400
1983	17,100
1984	12,500
1985	8,600
1986	6,800
After 1986	25,200

6. Commitments

Capital expenditures for 1982 are estimated at $687,000,000. Reference is made to the foregoing report to stockholders for additional information relating to capital expenditures and commitments including those applicable to gas supply.

7. Acquisition of Commonwealth Natural Resources, Inc.

On August 21, 1981, The Columbia Gas System, Inc. issued 1,221,000 shares of its common stock for the outstanding common stock of Commonwealth Natural Resources, Inc. This acquisition has been accounted for as a pooling of interests and, accordingly, prior period financial statements have been combined to reflect this acquisition. The effect of this merger is not significant to the Consolidated Financial Statements.

8. Long-Term Debt

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

At December 31, (in thousands)	**1981**	1980
The Columbia Gas System, Inc. Debentures—		
5 % Series I due 1982	$ —	$ 7,492
4⅜% Series J due 1983	9,035	9,980
4⅞% Series K due 1983	7,520	8,228
5⅛% Series O due 1985	10,890	11,800
5⅛% Series due June 1986	11,800	12,636
4½% Series due June 1987	10,926	11,875
4⅝% Series due August 1987	8,558	9,492
4⅜% Series due November 1987	13,150	14,200
4⅜% Series due January 1988	10,730	11,788
4⅝% Series due May 1989	25,475	27,219
4⅝% Series due October 1989	20,400	21,690
9⅝% Series due November 1989	52,500	60,000
4⅝% Series due May 1990	21,777	23,026
4⅞% Series due October 1990	21,800	23,200
6¼% Series due October 1991	23,200	24,600
6⅝% Series due October 1992	15,375	16,239
7¼% Series due May 1993	32,475	34,215
7 % Series due October 1993	26,000	27,400
9 % Series due October 1994	34,250	36,000
8¾% Series due April 1995	28,800	30,104
9⅛% Series due October 1995	36,000	37,750
10⅛% Series due November 1995	60,900	65,600
8⅜% Series due March 1996	56,588	59,250
9⅛% Series due May 1996	65,600	70,300
8¼% Series due September 1996	45,300	47,400
7½% Series due March 1997	39,489	41,221
7½% Series due June 1997	47,400	49,500
7½% Series due October 1997	47,400	49,500
7½% Series due May 1998	41,250	42,963
10¼% Series due May 1999	75,000	75,000
9⅞% Series due June 1999	34,400	35,728
11¾% Series due October 1999	100,000	100,000
12¾% Series due August 2000	100,000	100,000
	1,133,988	1,195,396
Unamortized debt discount, less premium	(7,855)	(8,172)
	1,126,133	1,187,224
Revolving credit agreement(a)	180,000	—
Term bank loans(b)	5,000	10,000
Miscellaneous debt of subsidiary companies	12,892	14,623
Total long-term debt(c)	$1,324,025	$1,211,847

(a) Under the terms of the agreement with eight commercial banks, 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 are 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 rate through March 31, 1985 and 105% of the prime rate through April 1, 1987. The Corporation pays a commitment fee of ½% per annum of the unused amount and 2% per annum of the prime rate applied to the aggregate amount of the commitment. The Corporation may reduce the amount of the commitment or cancel it entirely, without penalty.

(b) The term bank loans are due in semi-annual installments through 1983 and bear interest at the prime bank rate, with no compensating balance requirements.

(c) The composite annual interest rate on long-term debt outstanding at December 31, 1981, is approximately 9.5% and the current annual interest requirement on such long-term debt is approximately $130,000,000.

The aggregate annual sinking fund requirements and the aggregate maturities of long-term debt for the five years ended December 31, 1986, amount to $48,010,000 in 1982 (excluding $19,720,000 previously satisfied), $74,794,000 in 1983 (excluding $796,000 previously satisfied), $59,966,000 in 1984, $79,107,000 in 1985 and $78,613,000 in 1986. The Corporation has from time to time satisfied sinking fund requirements by purchases of debentures other than through operation of the respective sinking funds.

9. *Compensating Balances and Short-Term Borrowings*

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

The Corporation and several subsidiary companies maintained compensating balances in connection with certain bank lines of credit. Balances so maintained were equal, on average, to 7% of the line of credit. There are no legal restrictions regarding the withdrawal of these compensating balances. Also, during 1981, the Corporation and several subsidiary companies maintained lines of credit with certain banks on a fee basis with no compensating balances.

Selected information relating to lines of credit, compensating balances and commercial paper is as follows:

At December 31, (in thousands)	**1981**	1980	1979
Maximum commercial paper outstanding	**$350,000**	$138,600	$138,000
Daily average outstanding	**$147,600**	$ 25,800	$ 34,400
Range of interest rates	**11.1%-20.3%**	12.3%-20.3%	10.1%-14.4%
Weighted daily average rate	**16.3%**	14.4%	12.6%
Weighted average rate at year-end	**12.7%**	18.8%	13.8%
Credit lines at year-end	**$398,500**	$225,000	$199,000
Less outstanding commercial paper	**314,000**	42,600	133,100
Unused credit lines	**$ 84,500**	$182,400	$ 65,900
Approximate compensating balances at year-end	**$ 10,200**	$ 8,000	$ 16,000

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.

B. Production Revenues, Costs and Statistics.

U.S. Cost Center (in thousands)	**1981**	1980	1979	1978
Capitalized Costs at Year End				
Proved properties	**$687,678**	$600,357	$525,877	$483,747
Unproved properties	**161,312**	148,055	123,319	92,891
Total capitalized costs	**848,990**	748,412	649,196	576,638
Accumulated depletion	**(307,260)**	(240,333)	(173,249)	(152,809)
Net capitalized costs	**$541,730**	$508,079	$475,947	$423,829
Net Production Revenues				
Inter-company sales and transfers	**$112,134**	$ 76,111	$ 73,625	$ 49,386
Unaffiliated sales	**96,518**	59,575	21,817	11,212
Gross revenues	**208,652**	135,686	95,442	60,598
Production (lifting) costs	**(37,474)**	(24,246)	(16,371)	(9,724)
Net revenues	**$171,178**	$111,440	$ 79,071	$ 50,874
Costs Capitalized During Year				
Acquisitions	**$ 7,950**	$ 16,452	$ 7,643	$ 18,030
Exploration	**63,914**	43,231	44,114	38,676
Development	**62,523**	47,770	57,643	65,203
Costs capitalized	**$134,387**	$107,453	$109,400	$121,909
Other Oil and Gas Production Data				
Depletion expense	**$100,039**	$ 72,252	$ 55,968	$ 40,604
Average sales price per Mcf of gas	**$ 2.01**	$ 1.54	$ 1.27	$ 0.93
Average sales price per barrel of oil and other liquids	**$ 33.60**	$ 28.07	$ 15.30	$ 11.82
Production (lifting) cost per dollar of gross revenue	**$ 0.18**	$ 0.18	$ 0.17	$ 0.16
Depletion rate per dollar of gross revenue	**$ 0.48**	$ 0.53	$ 0.59	$ 0.67

B. Production Revenues, Costs and Statistics.

Canadian Cost Center (in thousands)	**1981**	1980	1979	1978
Capitalized Costs at Year End				
Proved properties	**$ 47,402**	$40,281	$27,329	$21,495
Unproved properties	**74,047**	59,022	51,140	66,975
Total capitalized costs	**121,449**	99,303	78,469	88,470
Accumulated depletion	**(2,523)**	(1,520)	(917)	(722)
Net capitalized costs	**$118,926**	$97,783	$77,552	$87,748
Net Production Revenues				
Gross revenues (unaffiliated)	**$ 4,717**	$ 2,808	$ 2,114	$ 980
Production (lifting) costs	**(2,949)***	(949)	(564)	(301)
Net revenues	**$ 1,768**	$ 1,859	$ 1,550	$ 679
Costs Capitalized During Year				
Acquisitions	**$ 909**	$ 227	$ 1,730	$ 2,784
Exploration	**13,597**	11,964	8,925	7,352
Development	**7,640**	8,643	7,882	7,146
Costs capitalized	**$ 22,146**	$20,834	$18,537	$17,282
Other Oil and Gas Production Data				
Depletion expense	**$ 1,003**	$ 603	$ 557	$ 270
Average sales price per Mcf of gas	**$ 1.48**	$ 1.48	$ 1.12	$ 0.92
Average sales price per barrel of oil and other liquids	**$ 12.18**	$ 9.50	$ 7.82	$ 7.57
Production (lifting) cost per equivalent Mcf	**$ 1.07***	$ 0.52	$ 0.31	$ 0.30
Depletion rate per equivalent Mcf	**$ 0.36**	$ 0.33	$ 0.31	$ 0.27

* Includes maintenance costs associated with the Kontaneelee field, which was not in production.

C. Company-Owned Proved Reserves (Unaudited).

As of December 31,	U.S. Gas @ 14.73 psia (MMcf)	U.S. Oil and Other Liquids (000 Bbls.)	Canada Gas @ 14.73 psia (MMcf)	Canada Oil and Other Liquids (000 Bbls.)	Total Gas @ 14.73 psia (MMcf)	Total Oil and Other Liquids (000 Bbls.)
1981						
Total	**350,095**	**12,839**	**138,320**	**1,923**	**488,415**	**14,762**
Developed	**292,485**	**8,142**	**127,186**	**1,844**	**419,671**	**9,986**
1980						
Total	365,309	9,856	132,445	1,695	497,754	11,551
Developed	241,991	5,636	118,394	1,603	360,385	7,239
1979						
Total	390,342	6,089	105,298	1,114	495,640	7,203
Developed	268,532	4,021	89,624	1,019	358,156	5,040
1978						
Total	441,393	6,957	101,686	866	543,079	7,823
Developed	311,294	4,635	88,304	771	399,598	5,406

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

	U.S. Gas @ 14.73 psia (MMcf)	U.S. Oil and Other Liquids (000 Bbls.)	Canada Gas @ 14.73 psia (MMcf)	Canada 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**
Revisions of previous estimate	**16,271**	**2,868**	**(22)**	**(13)**
Extensions, discoveries and other additions	**29,531**	**2,643**	**7,622**	**419**
Production	**(61,016)**	**(2,528)**	**(1,725)**	**(178)**
Reserves as of December 31, 1981	**350,095**	**12,839**	**138,320**	**1,923**

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
1982	$ 173,072	$ 147,789	$ 4,276	$ 4,542
1983	190,342	129,212	15,401	15,882
1984	164,155	93,746	13,283	14,070
After 1984	626,892	298,803	227,067	216,336
Future Net Revenues as of December 31, 1981	**$1,154,461**	**$669,550**	**$260,027**	**$250,830**
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 Estimated 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, 1981	**$797,587**	**$477,877**	**$113,170**	**$110,568**
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 located in the Appalachian area are presently subject to cost-of-service rate making. Net capitalized costs of these properties at December 31, 1981, were insignificant. Proved gas reserves related to these properties, as supplied by Ralph E. Davis Associates, Inc., amounted to 289,150 MMcf. Production for the year amounted to 37,413 MMcf.

11. Reserve Recognition Accounting Data (Unaudited)

Introduction: The SEC requires the accompanying disclosures utilizing a method of accounting for oil and gas producing operations called Reserve Recognition Accounting (RRA). The SEC has indicated that it will withdraw this requirement upon resolution of the Financial Accounting Standards Board's current project on financial disclosures by oil and gas producers.

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 the Corporation's financial statements, revenues and expenses are recognized in earnings during the production cycle.

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.

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, 1981 1980 and 1979 follows:

Year Ended December 31, (in thousands)	**1981**	1980	1979
Net present value at beginning of year	**$ 721,393**	$ 539,551	$ 451,619
New field discoveries and extensions, net	**174,398**	99,173	80,091
Revisions to reserves discovered in prior years	**176,021**	179,799	51,830
Projected development costs incurred	**11,891**	16,169	36,632
	1,083,703	834,692	620,172
Less: production, net of lifting costs	**(172,946)**	(113,299)	(80,621)
Net present value at end of year	**$ 910,757**	$ 721,393	$ 539,551

The accompanying summary of RRA operations measures income resulting from each year's 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)	**1981**	1980	1979
Summary of RRA Operations			
Additions to proved reserves:			
New field discoveries and extensions, net	**$174,398**	$ 99,173	$ 80,091
Revisions to reserves discovered in prior years resulting from—			
Increases in prices of oil and gas	**64,152**	139,024	92,960
Accretion of discount (Note a)	**72,139**	53,955	45,162
Other revisions (Note b)	**39,730**	(13,180)	(86,292)
Total additions to proved reserves	**350,419**	278,972	131,921
Less related costs (Note c):			
Incurred during the year—			
Acquisition	**8,859**	16,679	9,373
Exploration	**77,511**	55,195	53,039
Development	**70,163**	56,413	65,525
Projected development costs incurred	**(11,891)**	(16,169)	(36,632)
Change in deferred costs	**(3,518)**	(19,344)	(8,004)
Total related costs	**141,124**	92,774	83,301
Results of RRA operations, before income taxes and gain from sale of Canadian properties	**209,295**	186,198	48,620
Gain from sale of Canadian properties before income taxes	**—**	—	23,930
Results of RRA operations, before income taxes	**209,295**	186,198	72,550
Less provision for income taxes	**96,276**	85,651	26,624
Results of RRA operations	**$113,019**	$100,547	$ 45,926

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

b. 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.

c. 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:

1981

RRA net income amounted to $113 million reflecting the combined effects of new field discoveries and the upward price and volume revisions applicable to reserves discovered in prior years. The new field discoveries reflect additions of 37,153 MMcf (principally the Vermilion area offshore Louisiana) and 3.1 million Bbls of oil and other liquids (primarily the Giddings area in East Texas). The increase in gas prices, brought about by the Natural Gas Policy Act of 1978, were somewhat offset by declining oil prices at year-end. Previously estimated reserve quantities were upwardly revised by 16,249 MMcf and 2.9 million Bbls of oil and other liquids.

Costs incurred during the year amounted to $141.1 million. Costs deferred at year end were $129 million (which is net of a $14 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 1981 primary financial statements, related to oil and gas producing activities utilizing full cost accounting, amounted to $71.9 million as compared to $209.3 million under RRA.

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 earnings on common stock reported in the financial statements, to income under both constant dollar and current cost reporting methods.

Since the subsidiaries are principally engaged in rate regulated activities, the Corporation believes that income adjusted for the effects of general inflation or specific price changes as required by the FASB is incomplete. Therefore, additional effects occurring as a result of reduction in purchasing power loss due to debt financing, gains resulting from oil and gas producing assets and write-down of utility assets should be included in the measure of income. These effects are provided in the Statement of Income and the Five Year Comparison as "Income after all adjustments."

Statement of Income Adjusted for Changing Prices **Year Ended December 31, 1981** (in thousands of average 1981 dollars)	Stated in terms of General Inflation	Stated in terms of Specific Prices
Earnings on common stock, as reported	$190,334	$190,334
Effect on earnings of changing prices:		
Operating revenues	11,964	11,964
Purchased gas and feedstocks expense	(7,238)	(7,238)
Depreciation and depletion expense	(231,740)	(289,748)
Income (loss) after required adjustments	(36,680)	(94,688)
Reduction in purchasing power loss through debt financing	150,025	150,025
Other adjustments:		
Excess of specific price increases of non-monetary assets ($1,232,166) over increases due to general inflation ($735,477)*	—	496,689
Reduction to recoverable cost	(4,562)	(419,616)
Other adjustments—net	(4,562)	77,073
Income after all adjustments	$108,783	$132,410

*At December 31, 1981, the current cost of property, plant and equipment, net of accumulated depreciation and depletion, approximated $3,966,549 at recoverable cost.

Five-Year Comparison of Selected Supplementary Financial Data Adjusted for Changing Prices Year Ended December 31, (in thousands of average 1981 dollars except as noted)	**1981**	1980	1979	1978	1977
Operating revenues	**$4,438,207**	$4,124,485	$3,689,225	$3,517,713	$3,131,519
Historical cost information adjusted for general inflation:					
Income (loss) after required adjustments	**$ (36,680)**	$ (23,653)	$ 12,420		
Income (loss) after required adjustments per common share	**(1.06)**	(0.69)	0.37		
Income (loss) after all adjustments	**108,783**	96,916	100,775		
Income (loss) after all adjustments per common share	**3.14**	2.84	2.98		
Net assets at recoverable cost	**1,696,077**	1,676,847	1,650,436		
Reduction in purchasing power loss through debt financing	**150,025**	206,745	235,674		
Historical cost information adjusted for changes in specific prices:					
Income (loss) after required adjustments	**$ (94,688)**	$ (140,745)	$ (109,329)		
Income (loss) after required adjustments per common share	**(2.74)**	(4.12)	(3.23)		
Income (loss) after all adjustments	**132,410**	229,635	138,347		
Income (loss) after all adjustments per common share	**3.83**	6.73	4.09		
Excess of specific price increases of non-monetary assets over increases due to general inflation after reduction to recoverable cost	**77,073**	163,635	12,003		
Net assets at recoverable cost	**2,064,692**	2,016,685	1,875,292		
General information:*					
Cash dividend per common share—					
at historical cost	**$2.70**	$2.56	$2.44	$2.34	$2.24
in average 1981 dollars	**2.70**	2.82	3.06	3.26	3.36
Market price per common share at year-end—					
at historical cost	**32⅛**	40¼	37¾	25½	29
in average 1981 dollars	**31**	44⅜	47¼	35½	43½
Average consumer price index	**272.3**	246.8	217.4	195.4	181.5

*Excludes Commonwealth

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 (in thousands except per share data)	Operating Revenues	Operating Income	Earnings on Common Stock	Earnings Per Share
March 31, 1980	$ 1,327,954	$ 102,513	$ 85,602	$ 2.52
June 30, 1980	761,496	46,953	31,670	.92
September 30, 1980	573,331	21,905	(3,583)	(.10)
December 31, 1980	1,057,140	81,361	57,657	1.68
March 31, 1981	**1,471,553**	**99,022**	**86,369**	**2.51**
June 30, 1981	**889,937**	**48,533***	**32,690***	**.95**
September 30, 1981	**713,683**	**28,219**	**(148)**	**—**
December 31, 1981	**1,351,070**	**93,979****	**71,423****	**2.04**

*Includes one-time adjustment to earnings as discussed in Note 2A.

**Includes an improvement to earnings of approximately $6,000,000 related to an adjustment of the 1981 effective tax rate.

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, Delaware 19807

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

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

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

Columbia Distribution Companies
99 North Front Street
Columbus, Ohio 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
1700 MacCorkle Ave., SE,
Charleston, West Virginia 25314

Big Marsh Oil Company

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

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

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

Commonwealth Group Companies
200 South Third Street
Richmond, Virginia 23219

Commonwealth Gas Services, Inc.
Commonwealth Gas Pipeline Corporation
Commonwealth Propane, Inc.

Stockholder Information

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

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

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

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

Trustee and Paying Agent for Debentures
Morgan Guaranty Trust
Company of New York
30 West Broadway
New York, New York 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[2,3]
President, Blair Strip Steel Company
New Castle, Pennsylvania

Warren W. Clute, Jr.[1,2]
Chairman, Glen Bank and Trust Company
Watkins Glen, New York

John P. Cornell
Executive Vice President and
Chief Financial Officer

John H. Croom
Executive Vice President

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

Elizabeth V. Hallanan[2,3]
Member, Dodson, Deutsch and Hallanan
Attorneys-at-Law
Charleston, West Virginia

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, New York

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

Arch A. Sproul[3,4]
Chairman, Virginia International Co.
Foreign Investments
Staunton, Virginia

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

Officers

W. Frederick Laird
Chairman, President and
Chief Executive Officer

John P. Cornell
Executive Vice President and
Chief Financial Officer

John H. Croom
Executive Vice President

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
Executive Vice President and Chief Financial Officer

John H. Croom
Executive Vice President

Daniel L. Bell
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

Robert C. Austin
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

Alexander P. McCann
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 Corporation

John E. Towle
President
Columbia LNG Corporation

Paul H. Riley
Chairman
Commonwealth Group Companies

COLUMBIA GAS
System

COLUMBIA GAS SYSTEM

20 Montchanin Road, Wilmington, Delaware 19807