Public Service

Public Service
Company of Colorado

16805 WCR 19 1/2; Platteville, Colorado 80651

April 7, 1993
Fort St. Vrain
Unit No. 1
P-93034

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

Docket No. 50-267

SUBJECT: **Annual Financial Report**

Gentlemen:

Enclosed are ten (10) copies of the 1992 Annual Report for Public Service Company of Colorado, including the certified financial statements for 1992. This document is submitted for your information and use in accordance with 10 CFR 50.71(b).

If you have any questions regarding this submittal, please contact Mr. M. H. Holmes at (303) 620-1701.

Sincerely,

Don W. Warembourg

Don W. Warembourg
Decommissioning Program Director

DWW/SWC

Enclosures

cc: Regional Administrator, Region IV

Mr. Ramon E. Hall, Director
Uranium Recovery Field Office

100062

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Creating Energy for Life

nnual Report 1992

Public Service

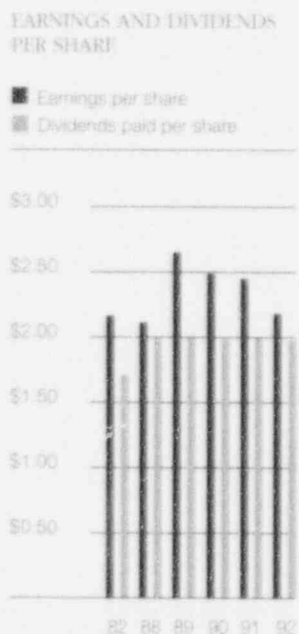
Public Service Company of Colorado

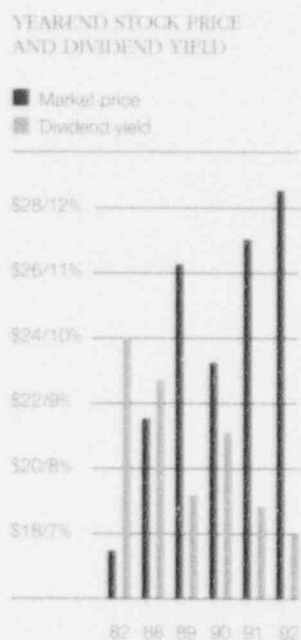
Contents

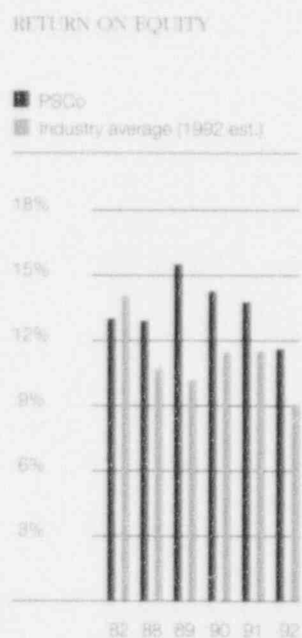
Financial and Operations Highlights

Financial	1992	1991	% Change
Earnings Per Weighted Average Share	**$2.16**	$2.48	(12.9)
Dividends Per Share	**$2.00**	$2.00	–
Return on Average Common Shareholder Equity	**11.7%**	13.8%	(15.2)
Common Shareholder Equity–% of Capitalization (year-end)	**40.2%**	42.8%	(6.1)
Operating Revenues (000)	**$1,862,273**	$1,794,904	3.8
Operating Expenses (000)	**$1,612,646**	$1,551,326	4.0
Net Income (000)	**$ 136,623**	$ 149,693	(8.7)
Construction Expenditures (000)	**$ 261,666**	$ 260,704	0.4
Colorado-Ute Asset Acquisition	**$ 265,385**	–	–
Gross Plant Investment (000)	**$4,814,204**	$4,273,744	12.6
Number of Employees	**6,568***	6,565	–
Common Stock Shareholders	**56,274**	56,038	0.4
Common Stock Shares Outstanding (000)	**58,477**	56,294	3.9
Operations			
Electric Revenues (000)	**$1,260,769**	$1,180,501	6.8
Kilowatt-Hour Sales (millions)	**21,815**	20,452	6.7
Electric Customers	**1,015,290**	1,000,662	1.5
Gas Revenues (000)	**$ 568,886**	$ 587,609	(3.2)
Mcf Deliveries (000)	**244,956**	232,702	5.3
Gas Customers	**895,338**	878,579	1.9

* Includes the addition of 157 Hayden power plant employees, due to the 1992 acquisition of Colorado-Ute assets.







Percentage of Male, Female and Minority Employees at Year-End 1991 and 1992

	Male		Female		Native American		Asian/Pacific Islanders		Hispanic		Black		Total Minorities		White		Total	
	1991	1992	1991	1992	1991	1992	1991	1992	1991	1992	1991	1992	1991	1992	1991	1992	1991	1992
Total Work Force*	4,922	4,960	1,643	1,608	25	49	87	87	871	874	366	369	1,349	1,379	5,216	5,189	6,565	6,568
% of Total	75.0	75.5	24.9	24.5	0.3	0.8	1.3	1.3	13.2	13.3	5.5	5.6	20.5	21.0	79.4	79.0	100	100
Management	780	683	138	109	2	3	13	11	52	46	27	21	94	81	824	711	918	792
% of Management	84.9	86.2	15.0	13.8	0.2	0.4	1.4	1.4	5.6	5.8	2.9	2.6	10.2	10.2	89.7	89.8	100	100
Non-Management	4,142	4,277	1,505	1,499	23	46	74	76	819	828	339	348	1,255	1,298	4,392	4,478	5,647	5,776
% of Non-Management	73.3	74.0	26.7	26.0	0.4	0.8	1.3	1.3	14.5	14.3	6.0	6.0	22.2	22.5	77.7	77.5	100	100

* Includes the addition of 157 Hayden power plant employees, due to the 1992 acquisition of Colorado-Ute assets.

To Our Shareholders

For the past few years we have been developing strategy to position our company for anticipated changes in the gas and electric industries. Beginning in the late 1980s we told our employees that we would have to move in a new direction; that business as usual would not be acceptable; that change was imminent. With the enactment of the National Energy Policy Act of 1992 and the issuance of the Federal Energy Regulatory Commission's Order 636, that time has arrived. I believe that 1992 clearly marks the beginning of a new era in our industries.

We anticipated that success in this dynamic environment would require a keener focus on our core business, and as we reported to you last year, we began that process in 1991. While I am confident that our strategy is correct, it did require some difficult but necessary decisions in 1992. We concluded that we needed to take the steps necessary to divest those non-core businesses which are not consistent with our strategy and do not meet our financial criteria.

In keeping with that conclusion, we sold a majority of the real estate properties owned by our Bannock Center Corporation subsidiary, and ended our involvement in a development project for the conversion of landfill methane gas into clean-burning diesel fuel. While I believe that these ventures hold promise for the future, they could not produce the near-term financial results that we require.

Even though this action resulted in a 44 cent per share reduction in earnings, the positive reaction of the financial markets confirmed that this was the right decision. In spite of these write-offs, we still had earnings for the year of $2.16 because of strong operating results. I attribute most of that success to our employees. Their commitment to the challenges we face is clearly evident through continuing improvements in productivity resulting in reduced costs.

At the same time we were working to refine our business focus and manage costs, we were active in growing our market through the successful joint acquisition of the Colorado-Ute Electric Association. Through a unique partnership with PacifiCorp and Tri-State Generation and Transmission, our company was able to add approximately half of Colorado-Ute's wholesale electric load to our system and acquire additional generating capacity. As a result, we increased our market, decreased our percentage of purchased power, and played a leadership role in resolving a difficult economic problem in the state of Colorado.

Another accomplishment in 1992 was the successful completion of the defueling of our Fort St. Vrain nuclear power plant ahead of schedule and under budget. Decommissioning is underway, and e anticipate converting the plant to a natural gas-fired facility.

The merger of our natural gas pipeline subsidiary, WestGas, with the parent company was in response to the changes which will result from FERC Order 636. Through increased synergies and the more efficient use of our resources, we will be better able to meet competitive challenges, and focus on market growth in the increasingly complex natural gas industry.

Regulation will continue to play a key role in our ability to meet the challenges of our competitive business environment. Much of 1992 was spent preparing for the January 20, 1993 filing of a rate case with the Colorado Public Utilities Commission. Our filing requests electric and natural gas rate increases based upon innovative regulatory principles, including the use of a forecasted test period and performance-based incentives.

In conjunction with our 1991 rate settlement agreement, the company has also been an active participant in the development of various energy conservation programs. These programs involve how we provide assistance to low-income customers, how we plan to meet our resource needs, how earnings can be separated from sales, and how we can recover costs and earn a fair return on efforts that reduce demand for our products. By working in partnership with our regulators and other interested parties, we believe we can effectively address these issues while balancing the interests of our stakeholders.

Forming partnerships with our customers remains a key component of our success, and 1992 saw new alliances created and existing ones strengthened. With increasing competition in the industrial and commercial segments of our business, we realize that our customers have energy options. We strive to understand their business needs and provide products and services to meet those needs. Helping our customers stay competitive in their industries helps our company stay competitive in its marketplace.

The energy services industry plays one of the most critical roles of any industry in America. It fuels our economy and, in turn, our quality of life. Because our company plays a key role in the well-being of the communities we serve, we will continue to pursue our goal of providing the highest quality products and services at competitive prices–creating energy for prosperity and growth in the Rocky Mountain region.

D. D. Hock

Chairman, President and Chief Executive Officer

Orchestrating the Forces

Delivering on a Commitment

Capitalizing on strengths is central to any success. Recognizing this axiom, Public Service Co. of Colorado made a commitment to doing what it does best, through a clearly defined strategy to focus on its core electric and natural gas businesses. At the same time, the company took a hard look at the changing utility marketplace and redefined and expanded its role from a traditional gas and electric company to an energy services provider. In 1991 the company positioned itself around this effort, setting the stage in 1992 for a year of considerable accomplishment. It was not, however, a year without its share of difficult decisions.

In keeping with this commitment, the company took action in 1992 to exit investments in the non-utility business sector. The company withdrew from the real estate development business through the sale of almost all of its Bannock Center Corporation's real estate properties, and it also took steps to end its involvement with a fuel conversion technology project. In addition, Public Service Co. is evaluating the divestiture of its oil and gas exploration investment.

At the forefront of the company's 1992 accomplishments was the completion of the joint acquisition of the bankrupt Colorado-Ute Electric Association. The company successfully integrated the newly acquired assets into its system during the year. Another significant achievement was the progress made at the Fort St. Vrain nuclear generating station. The company forged ahead with the defueling and decommissioning of the nuclear power plant, the first such undertaking of this scale in the country.

These efforts have enabled Public Service Co. to deliver on its core business commitment. As a result, the company can more readily position itself for a new emphasis in 1993, preparing for the dramatic forces that are impacting utilities nationwide. "Competition"– and how the company responds to it– is the critical element to building a successful future.

Changes resulting from increased competition are coming in a wide variety of forms including new regulatory approaches, shifting needs in the industrial and large commercial market segments, the effects of the continued deregulation of the natural gas business, the impact of the National Energy Policy Act of 1992, environmental compliance and concerns, and acquisition and market growth opportunities, to name a few. Rather than a "wait and see" approach, Public Service Co. has elected to actively participate in these changes and work to take advantage of opportunities which will bring measurable rewards to shareholders, customers, and the social and business environment of the West.

Charting a certain course for the future in this sea of variables is not easy. But the company enjoys the benefit of a visionary leadership and a dedicated work force. All of this has created a feeling of optimism at Public Service Co. and the confidence that the company is well prepared to handle the uncertainties of a changing utility industry.

Paving the Way

Public Service Co. faced difficult and complex decisions in 1992. In the fourth quarter, the company's Bannock Center Corp. subsidiary sold its downtown Denver-area properties, resulting in an after-tax loss of nearly $8.4 million. The company also made the decision to terminate its involvement in the Synhytech plant, which was a development project in the start-up phase for the production of clean-burning diesel from landfill methane gas. Although this technology still has promise, the project did not fit in with the company's core business focus. That decision resulted in an additional fourth-quarter loss of approximately $16.8 million after taxes. The company also is evaluating packaging the oil and gas exploration and production properties owned by its Fuel Resources Development Co. subsidiary for future sale.

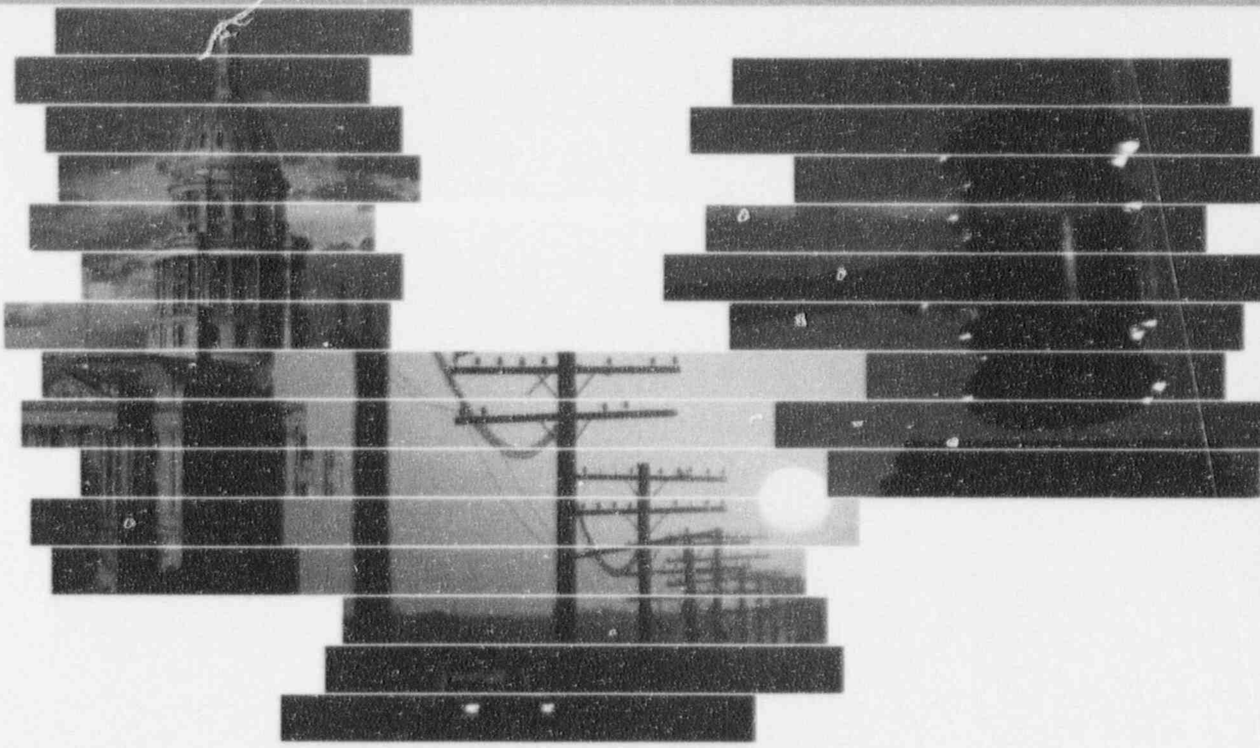
These actions will enable the company to disengage from those activities which were not making an adequate financial contribution. The validity of these decisions was confirmed by the positive reaction of the financial markets.

Closing a Chapter: Fort St. Vrain

Several complicated issues surrounding the closed Fort St. Vrain nuclear power plant also were successfully addressed during 1992. The spent fuel in the plant's core was removed and transferred to a licensed temporary storage facility on the plant site by June 1992, two months ahead of schedule. This temporary structure is specifically designed to house the fuel until a federal storage facility is available, or until the company is able to resume fuel shipments to the Department of Energy's storage site in Idaho.

Related litigation involving the Department of Energy, the state of Idaho and Public Service Co. continued throughout the year. As a result, the DOE agreed to prepare an environmental impact statement for the Idaho storage site, which would include the effects of the transfer of the plant's fuel from Colorado. The DOE plans to complete this environmental analysis in 1995. With a favorable outcome and barring further attempts to ban the transfer of fuel, Public Service Co. would be able to resume shipments to the designated Idaho repository at that time.

Considerable decommissioning progress also was made during the year, and Public Service Co. has contracted with Westinghouse and the M.K. Ferguson Group of Morrison Knudsen Corp. to decommission the plant. Preliminary activity began on August 1, 1992, and the company received final decommissioning authorization from the Nuclear Regulatory Commission on November 23. The project is scheduled for completion in 1995, and the company is evaluating a phased approach to convert the plant to a natural gas-fired facility. These accomplishments are very significant, considering the substantial shutdown costs and related financial issues facing most nuclear plants across the nation.



A Competitive Balance: Regulation

Regulation will play an integral role in the company's ability to meet the demands of a changing utility environment. With the reality of increasing competition, the traditional labeling of utilities as natural monopolies is no longer applicable. More energy services alternatives are available to the company's customers in the form of natural gas suppliers, independent power producers, and co-generation facilities, none of which currently operates under the same constraints of regulation.

It is with this balance in mind that the company approached its recent rate case filing with the Colorado Public Utilities Commission on January 20, 1993. In this filing, the company requested an electricity rate increase of 4.01 percent and a natural gas rate increase of 6.09 percent, which would result in an annual revenue increase of $81.6 million. Even with these proposed changes, the company's rates would continue to rank among the lowest in the nation. It is noteworthy that the proposed rates would still be less than they were 10 years ago, even though the U.S. Consumer Price Index has risen about 41 percent since that time.

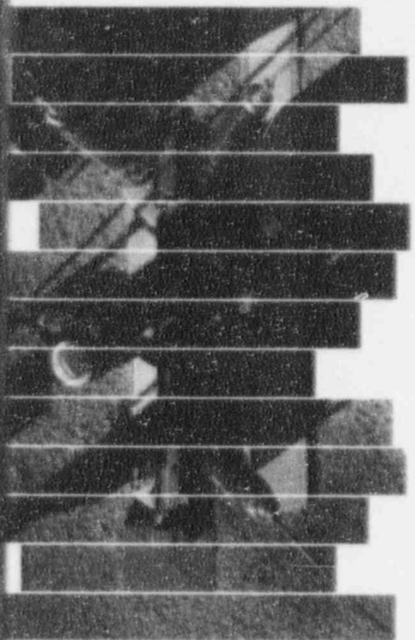
Clearly, an acceptable rate case outcome is an important element in contributing to the company's financial integrity. However, it is the non-traditional approach of this filing and the company's efforts to establish a partnership with its regulators that will be of vital importance. This will position the company to be an active participant in the increasingly competitive energy-services marketplace.

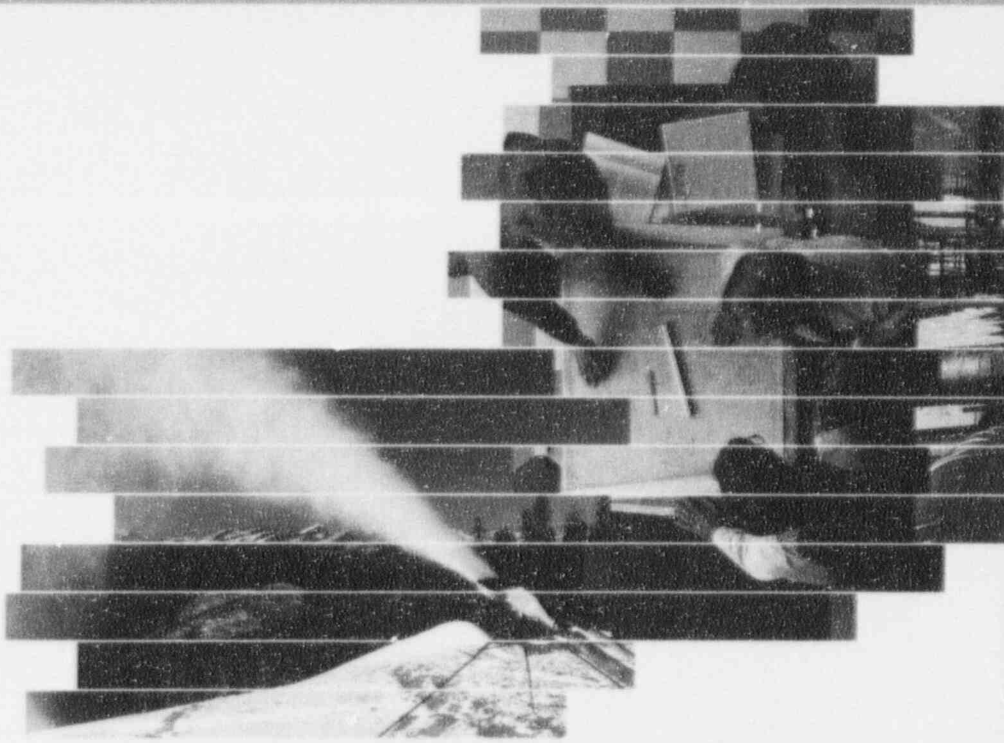
Innovative elements of the rate filing include the use of a forecasted test year instead of the customary method of basing rates on historical cost data, as well as an incentive plan designed to benefit the company and its customers. The forecasted test year would allow for improved matching of operating costs and revenues to enhance the financial health of the company, which will result in lower capital costs and long-term lower rates for customers. Through the proposed incentive program, the company and its customers would share a portion of any earnings that exceed the authorized return on common equity or any earnings deficiencies. This sharing concept, as well as incentive adjustments would be directly linked to the quality of service provided by the company.

It is anticipated that the company will receive a decision from the Colorado Public Utilities Commission in September 1993.

As part of the rate settlement agreement reached in 1991, Public Service Co. also is continuing to address specific energy efficiency proposals. These proposals– or regulatory dockets– are designed to equitably balance the interests of all parties.

The Low-Income Assistance docket, which provides weatherization upgrades to low-income residents in Public Service Co.'s service area, has received commission approval for an initial two-year program.





The program will examine the costs, eligibility, forms of assistance, and funding methods for various energy assistance options.

Another docket, Integrated Resource Planning, is intended to minimize electric rates, preserve reliable electricity service, and manage risks. On December 30, 1992, the Colorado Public Utilities Commission issued rules for preparing electric load forecasts and involving the public in assessing both supply and demand side options.

In addition, a separate docket established a collaborative process with public interest groups, consumers, and other industry participants to broaden demand-side management programs to all customer classes and review associated investments and implementation strategies. Through this collaborative process group, a series of demand-side management programs were proposed to the commission in February 1993. The programs may reduce the company's 1995 average electric peak by as much as 27 megawatts.

A final docket addressed the issue of separating the company's profits from its sales, as well as the incentive the company should be granted for programs to reduce peak electric demand. In a January 1993 order, the commission deferred a decision on separating earnings from sales, but it did establish satisfactory incentives to be applied to the demand-side management programs proposed as part of the collaborative process.

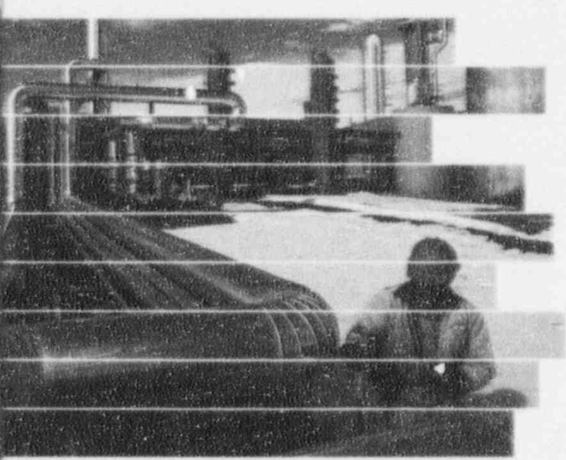
Partnering with Customers

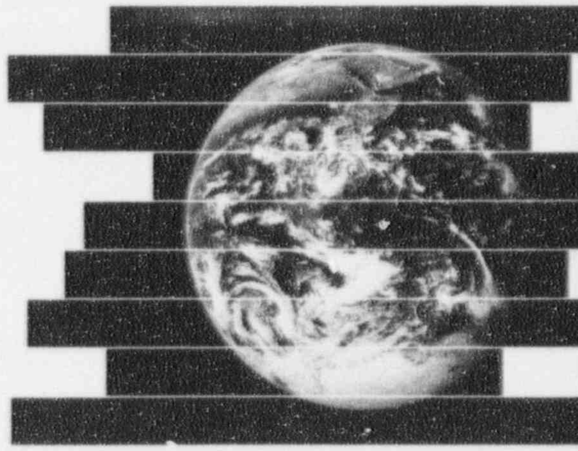
Today's utility can no longer escape the dynamics of market competition. Customers can no longer be thought of in terms of being "captive"– many have opportunities to make energy choices that could exclude Public Service Co.

This is increasingly evident in the commercial and industrial marketplace, where the company faces very real competition. These customers now have energy alternatives including self-generation of power, non-utility power producers and other natural gas suppliers. In addition, the potential relocation of businesses outside the company's service territory underscores the challenge of customer retention and growth.

To remain successful in this environment, the company must differentiate itself from its competition. It is no longer sufficient to simply serve as a gas and electricity provider, and recognizing this, the company is expanding its role to that of an energy services provider. In a consultative role, the company is able to jointly address customers' energy issues and provide individual solutions that will help these customers find greater success in their marketplaces.

During 1992, the company began to fill this new role by forming "partnerships" with many of its industrial and commercial customers who will be the ultimate decision makers regarding what technologies are commercially successful and what types of energy products and services they need. To be the





energy services provider of choice, the company is focusing on understanding the customer's business, identifying customer requirements and participating in customer decisions.

Responding to Competition: The Natural Gas Marketplace

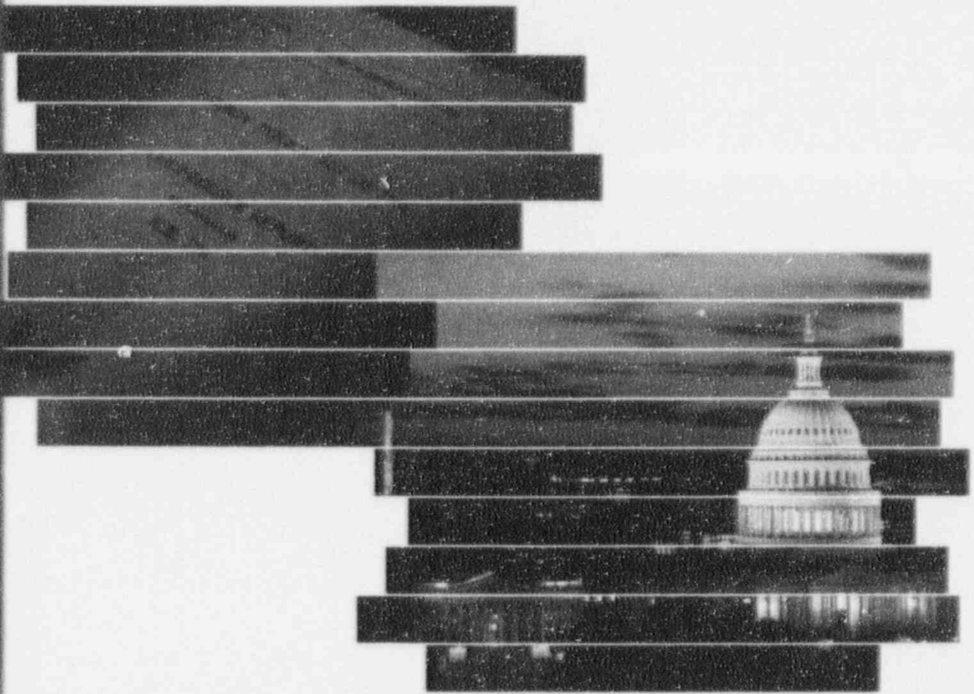
Tremendous change also has taken place in the natural gas arena during 1992, primarily stemming from the Federal Energy Regulatory Commission's issuance of Order 636. This ruling is generating a major restructuring of the entire natural gas industry, which is opening up competition and enabling all gas suppliers to compete on an equal basis.

The new ruling moves the responsibility for securing gas supplies from the pipeline companies – which traditionally provided this service – to local distribution companies, such as Public Service Co. The regulations also require that pipeline companies no longer package their services, but charge separately for activities such as gas transportation and storage.

Responding to these increasing complexities, Public Service Co. took a positive step in 1992 toward securing its position to benefit from the changes taking place in the natural gas marketplace. Central to this effort was the merger of WestGas, the company's natural gas pipeline subsidiary, with Public Service Co.

The formation of an integrated gas business unit through this merger complements the restructuring implications of FERC Order 636. Operating as a single unit, Public Service Co. will enjoy the benefits of newly created synergies, including more efficient use of the company's resources. Also, because the new regulations transfer the oversight responsibilities for all gas purchases from the federal level to the state level, the merger offers the added benefit of enabling the company to work as a single entity with the Colorado Public Utilities Commission.

Most importantly, the merger enhances the company's ability to address competition and market growth opportunities, particularly those situations which often require gas deliveries over both Public Service Co. and WestGas systems. As an integrated unit, customer negotiation with two parties is no longer necessary. The company will have the advantage of streamlining its service to customers, offering "one-stop" shopping.



Securing the Future: The Environment

As environmental issues escalate on a worldwide scale, Public Service Co. continues to take its corporate responsibility role very seriously, recognizing that its efforts in this arena are a vital component of securing a healthier, more livable environment.

Public Service Co. has a history of going beyond mere compliance in the environmental arena– taking an innovative leadership role of "environmental steward." As a long-standing corporate citizen in a region known for its natural beauty, the company has always recognized its obligation to protect and enhance the environment. For example, the company was recently recognized by the U.S. Forest Service as having one of the best utility tree-planting efforts in the country.

The newly enacted National Energy Policy Act of 1992 is the most recent example of legislation that delineates the future of energy demand and supply and sets guidelines related to environmental impact– well into the 21st century. One environmental aspect of the energy bill, which will benefit the company, is the increased emphasis on alternative fuels for vehicles. Through its Natural Fuels subsidiary, Public Service Co. is aggressively pursuing fleet conversions and building natural gas service and fueling stations to serve this growing market.

The act also addresses conservation and encourages demand-side management programs to reduce the growth of peak demand for electricity. Public Service Co. views demand-side management as a genuine resource to meet the future electricity needs of customers. The company has been a leader among utilities in implementing major demand-side management bid programs for electric demand reduction.

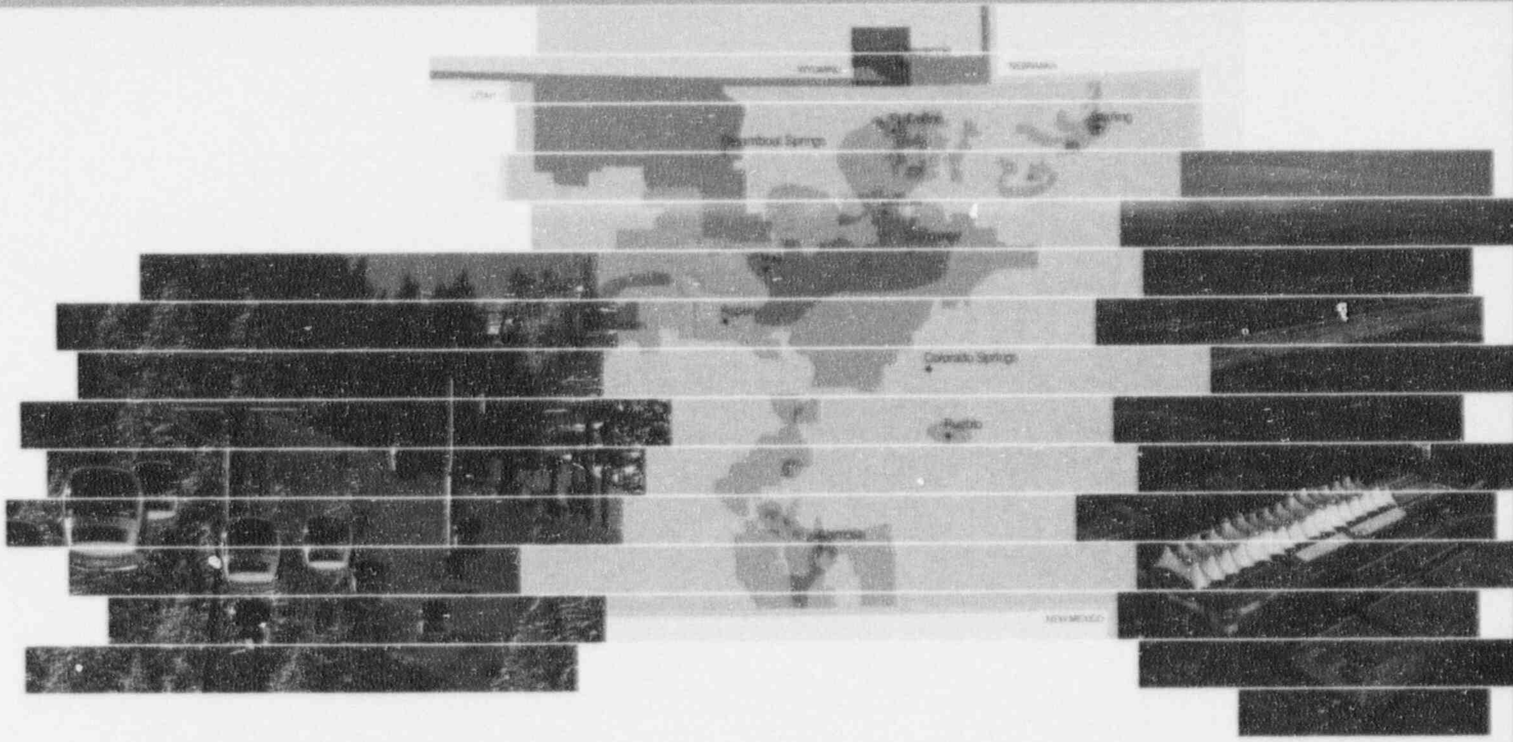
These programs will be an important part of the utility business of the future, when earnings may be partially based on meeting or surpassing demand-side management and other energy conservation goals.

With an expanding awareness of the importance of ensuring an environmentally sound future, the company plans to continue to increase its environmental activities in 1993. Through the ongoing development of creative incentive plans designed in collaboration with regulators, the company's numerous energy-efficiency efforts will minimize environmental impact and provide mutual benefits to customers and shareholders.

A Growing Optimism

Despite the extraordinary changes taking place in the industry and the related uncertainties, Public Service Co. is moving ahead with a growing optimism.

The evolution of the utility marketplace has prompted the company to look for innovative ways to grow its market. The success of the Colorado-Ute asset acqui-



sition, completed in 1992, exemplifies this strategy. It provided a win/win outcome for all participants. The company reaped the added benefits of market growth, acquired low-cost assets for future needs, reduced the percentage of purchased power requirements and improved the company's load balance.

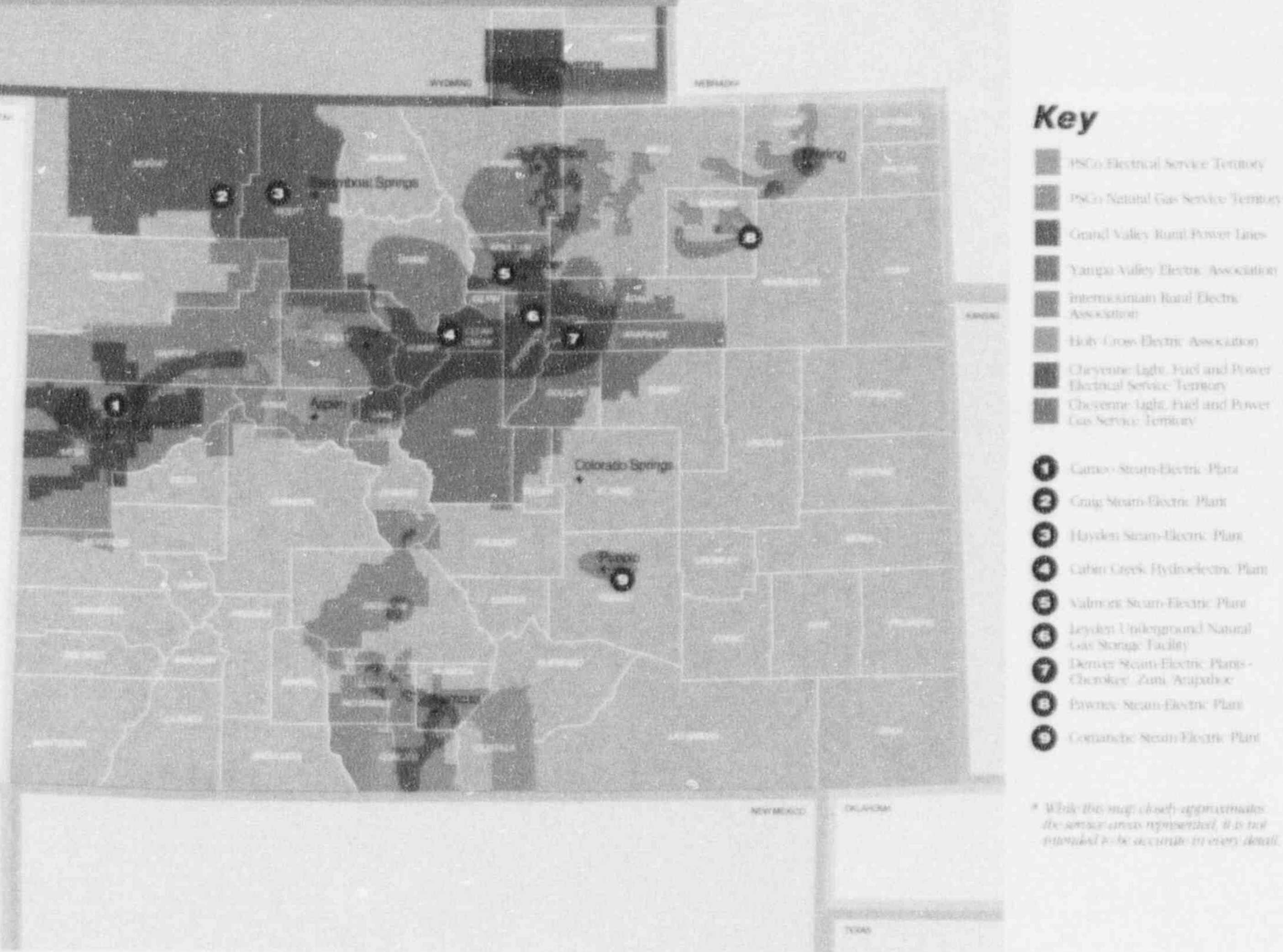
Another contributing factor to a positive outlook is an advantage unique to Public Service Co.– its area of operation. Colorado is strategically located, making it a central hub for interstate business opportunities. And, the natural beauty of the Rocky Mountain region and Colorado's quality of life continue to attract residents and businesses from throughout the country.

Having moved beyond the recession of the late 1980s, Colorado is experiencing renewed economic strength and growth at a time when the nation is struggling through a difficult economic period. Signs of this renewal range from the state's excitement over its own major-league baseball team to anticipation of the opening of the new Denver International Airport currently under construction. The airport, when completed, will be the largest airport site in the world and will become a key economic generator for the state in the years to come.

Last year brought the successful resolution of some difficult issues, paving the way for a new emphasis in 1993. There are a myriad of changes taking place in the industry as a whole– increasing competition, changing marketplace and customer dynamics, the need for regulatory reform and expanding environmental mandates, among others.

It is the united commitment of Public Service Co.'s management and employees that will equip the company to capitalize on its strengths to meet these dramatic changes head on. This singleness of purpose will furnish the energy and drive to effectively orchestrate these forces and nurture an environment of opportunity that will create added value for shareholders, customers and employees in 1993 and beyond.

About
Public Service Co. of Colorado



Public Service Co. of Colorado is an investor-owned electric, natural gas and thermal energy utility, which serves approximately 2.7 million people throughout Colorado and the Cheyenne, Wyoming area.

Headquartered in Denver, Colorado, the company operates eight steam-electric plants, six hydroelectric facilties, a downtown Denver thermal energy service and an extensive natural gas system that includes more than 13,300 miles of natural gas distribution piping.

The company's consolidated financial statements include the results of its subsidiary operations:

***Western Gas Supply Company**, one of the largest natural gas pipeline systems in the Rocky Mountain region (merged into Public Service Co. January 1, 1993);*

***Fuel Resources Development Co.**, an oil and natural gas exploration, development and production company with operations throughout the Rocky Mountain region;*

***Cheyenne Light, Fuel and Power Company**, an electric and natural gas company serving the Cheyenne area;*

***Natural Fuels Corporation**, a company that is building the infrastructure for natural gas vehicles and sells compressed natural gas as a transportation fuel;*

***Bannock Center Corporation**, a real estate investment company;*

***Welton Properties**, a company that owns and manages real estate for utility operations; and*

***P.S. Colorado Credit Corporation** and **P.S.R. Investment, Inc.**, two finance subsidiaries.*

Financial Information

OPERATING STATISTICS
Public Service Company of Colorado and Subsidiaries

Natural Gas Service Statistics

	1992	1991	1990	1989	1988	1987	1982
Bcf Gas Deliveries	**245.0**	232.7	210.9	202.2	194.5	179.3	189.8
% Change	**5.3%**	10.3	4.3	4.0	8.5	1.7	7.7%
Customers (000)	**895.3**	878.6	865.4	853.1	841.4	832.0	718.5
% Change	**1.9%**	1.5	1.4	1.4	1.1	1.5	2.4%
Average Annual Residential Mcf Usage	**109.5**	116.8	112.0	112.7	116.3	109.5	125.0
% Change	**(6.3)%**	4.3	(0.6)	(3.1)	6.2	3.7	10.7%
Annual Heating Degree Days	**5,359**	5,914	5,575	5,810	5,958	5,436	6,109
% Change	**(9.4)%**	6.1	(4.0)	(2.5)	9.6	2.2	33.7%
Average Residential Revenue Per Mcf	**$3.76**	3.74	3.78	3.81	3.82	3.88	$4.11
% Change	**0.5%**	(1.1)	(0.8)	(0.3)	(1.5)	(6.1)	18.1%
Average Annual Revenue Per Residential Customer	**$412**	437	420	430	441	425	$513
% Change	**(5.7)%**	4.0	(2.3)	(2.5)	3.8	(2.5)	30.7%
Daily Availability-(MMcf)	**1,596**	1,601	1,575	1,595	1,517	1,471	1,462
Maximum Peak-Day Sendout (MMcf)	**1,252**	1,258	1,575	1,497	1,170	1,094	1,302
% Change	**(0.5)%**	(20.1)	5.2	27.9	6.9	1.3	1.9%

Electric Service Statistics

	1992	1991	1990	1989	1988	1987	1982
Kilowatt-Hour Sales (millions)	**21,815**	20,452	20,148	19,716	19,194	18,357	15,433
% Change	**6.7%**	1.5	2.2	2.7	4.6	2.4	(0.3)%
Customers (000)	**1,015.3**	1,000.7	990.6	983.6	974.0	967.1	865.0
% Change	**1.5%**	1.0	0.7	1.0	0.7	0.9	2.2%
Average Annual Residential Kwh Usage	**6,533**	6,563	6,445	6,348	6,403	6,258	5,963
% Change	**(0.5)%**	1.8	1.5	(0.9)	2.3	1.7	4.0%
Average Residential Revenue Per Kwh	**7.20¢**	7.07	7.02	7.11	7.18	7.18	6.52¢
% Change	**1.8%**	0.7	(1.3)	(1.0)	–	(2.0)	13.6%
Average Annual Revenue Per Residential Customer	**$470**	464	453	451	460	449	$389
% Change	**1.3%**	2.4	0.4	(2.0)	2.5	(0.4)	18.2%
Net Dependable System Capability at Time of Peak-Megawatts	**4,658(s)**	4,168(s)	4,327(w)	3,912(s)	3,911(s)	3,672(s)	3,401(s)
Net Firm System Peak Load (Mw)	**3,757**	3,568	3,589	3,484	3,362	3,298	2,892
% Change	**5.3%**	(0.6)	3.0	3.6	1.9	1.9	2.6%
Reserve Margin at Time of Peak	**24.0%**	16.8	20.6	12.3	16.3	11.3	17.6%
Generation by Class of Fuel:							
Coal	**98.7%**	98.1	98.3	92.9	91.1	94.6	94.0%
Natural Gas	**1.3%**	1.7	1.6	2.9	3.5	3.8	1.4%
Oil	**–**	0.2	0.1	0.2	0.1	0.1	0.3%
Nuclear	**–**	–	–	4.0	5.3	1.5	4.3%
Average Cost Per Unit of Fuel:							
Coal–Ton	**$21.14**	22.40	21.44	21.41	22.39	25.05	$22.95
Natural Gas–Mcf	**$ 2.07**	1.98	2.07	2.16	2.27	2.19	$ 3.81
Oil–Barrel	**$26.84**	27.16	27.85	30.31	28.65	22.82	$38.01
Average Fuel Cost Per MMBTU	**$ 1.11**	1.20	1.17	1.17	1.25	1.34	$ 1.23

(s) summer peak load
(w) winter peak load

FINANCIAL AND STATISTICAL DATA

Public Service Company of Colorado and Subsidiaries

(Millions of Dollars Except as Noted)

	1992	1991	1990	1989	1988	1987	1982
Operating Revenues:							
Electric	$1,260.8	1,180.5	1,145.9	1,139.5	1,116.0	1,075.8	$ 843.4
Gas	568.9	587.6	561.7	577.3	591.4	563.3	732.3
Other	32.6	26.8	26.3	23.9	23.0	18.3	14.3
Total Revenues	$1,862.3	1,794.9	1,733.9	1,740.7	1,730.4	1,657.4	$1,590.0
Income Before Cumulative Effect of a Change in Accounting Method	$ 136.6	149.7	146.1	148.8	125.0	143.7	$ 116.5
Cumulative Effect to 1/1/87 of Accruing Unbilled Revenues	–	–	–	–	–	29.6	–
Net Income	136.6	149.7	146.1	148.8	125.0	173.3	116.5
Preferred Dividend Requirements	12.1	12.2	12.4	12.6	12.8	13.2	16.7
Earnings Available for Common Stock	$ 124.5	137.5	133.7	136.2	112.2	160.1	$ 99.8
Earnings Per Weighted Average Share:							
Before cumulative effect of a change in accounting method	$2.16	2.48	2.49	2.59	2.14	2.49	$2.17
Cumulative effect to 1/1/87 of accruing unbilled revenues	–	–	–	–	–	0.56	–
Total	$2.16	2.48	2.49	2.59	2.14	3.05	$2.17
Dividends Per Share:							
Paid	$2.00	2.00	2.00	2.00	2.00	2.00	$1.74
Declared	$2.00	2.00	2.00	2.00	2.00	2.00	$1.76
Common Stock Outstanding:							
Weighted average (000)	57,558	55,471	53,626	52,559	52,457	52,414	45,948
Year-end (000)	58,477	56,294	54,320	52,807	52,458	52,457	47,020
Total Assets	$3,760	3,463	3,234	3,054	2,995	2,945	$2,607
Common Equity	$1,101	1,034	964	905	865	858	$ 785
Preferred Stock:							
Subject to mandatory redemption at par	43	44	46	49	52	54	89
Not subject to mandatory redemption	140	140	140	140	140	140	140
Long-Term Debt	1,197	900	896	913	944	920	891
Short-Term Borrowings*	256	297	259	186	162	196	54
Total Capitalization	$2,737	2,415	2,305	2,193	2,163	2,168	$1,959
Capitalization Ratios–Year-End:							
Common equity	40.2%	42.8	41.8	41.2	40.0	39.6	40.1%
Preferred stock (Incl. due within 1 yr.)	6.8%	7.7	8.2	8.6	8.9	9.0	11.7%
Long-term debt (Incl. due within 1 yr.)	43.8%	41.2	40.7	41.7	43.6	42.4	45.6%
Notes payable and commercial paper	9.2%	8.3	9.3	8.5	7.5	9.0	2.6%
Construction Expenditures	$261.7	260.7	261.2	174.4	162.8	127.6	$230.0
% of Total capitalization	9.6%	10.8	11.3	8.0	7.5	5.9	11.7%
Cash Generated Internally**	$146.3	177.7	174.6	172.3	192.8	47.9	$145.0
% of Construction expenditures***	57.5%	69.4	67.7	99.7	118.8	38.0	64.9%
Rates of Return Earned:							
Total capitalization (Oper. income)	9.1%	10.1	10.3	11.3	10.2	10.7	9.9%
Avg. common equity before a change in accounting method (Net to common)	11.7%	13.8	14.3	15.4	13.0	15.7	13.1%
Avg. common equity (Net to common)	11.7%	13.8	14.3	15.4	13.0	19.3	13.1%
Pretax Coverage of Interest Expense	2.43x	2.94	3.07	3.02	2.81	3.91	3.67x
Effective Income Tax Rate	28%	32	34	31	33	46	47%
Payout Ratio on Dividends Paid	92.6%	80.6	80.3	77.2	93.5	65.6	80.2%
Book Value Per Share	$18.83	18.38	17.74	17.13	16.49	16.35	$16.69
Number of Employees–Year-End	6,568	6,565	6,611	6,636	6,559	6,476	6,794

* Includes debt due within one year, notes payable and commercial paper and preferred stock subject to mandatory redemption within one year.

** Cash provided from operations net of cash used for dividends. 1982 calculated as funds generated internally.

*** Calculated as cash provided from operations net of cash used for dividends divided by construction expenditures net of AFDC-equity component. 1982 calculated as funds generated internally as a % of net construction expenditures.

Overview

In 1992, Public Service Company of Colorado (the Company) embarked on a program to focus its efforts on the core electric and natural gas businesses in an effort to become the premier energy company in the Rocky Mountain Region. Several significant events have occurred that the Company believes are key steps necessary to successfully implement this core business strategy.

In April 1992, the Company purchased approximately $265 million in electric generation, transmission and related assets from Colorado-Ute Electric Association, Inc. (Colorado-Ute), pursuant to Colorado-Ute's Chapter 11 bankruptcy reorganization. The highlights of the agreement include the purchase of low cost electric generation and related facilities and the addition of four wholesale customers. The customers are expected to add an estimated 1.8 billion annual electric Kwh sales (based on 1991 sales). These four wholesale customers are primarily winter peaking customers which serve the winter resort areas of the Rocky Mountains and, as such, create a desirable balance with the Company's existing summer peaking customers. As part of this asset acquisition, the Company entered into various purchase power agreements for the annual purchase of approximately 376 Mw of electric energy.

On January 20, 1993, the Company filed a general rate case with The Public Utilities Commission of the State of Colorado (CPUC). In its filing, the Company requested an increase in total annual revenues of approximately $81.6 million for its electric, natural gas and steam businesses. The rate filing also seeks, among other matters, an authorized return on equity of 13%, the use of a fully forecasted test year in the establishment of rates and the full normalization method of accounting for income taxes. The Company anticipates receiving a decision from the CPUC by September 1993.

On December 28, 1992, the CPUC approved the merger of Western Gas Supply Company (WestGas) into the Company. The Company had requested approval of this merger, which was effective January 1, 1993, to better position it to compete in the restructured natural gas business and to more effectively meet new regulatory requirements. The most significant regulatory issue being addressed by the Company is Federal Energy Regulatory Commission Order 636, which generally requires the unbundling of services offered within the gas industry.

Bannock Center Corporation (BCC), a real estate subsidiary, sold its downtown Denver-area properties resulting in an after-tax loss of approximately $8.4 million, or 15 cents per share. The sale, which included substantially all of BCC's investment in real estate, was completed because the Company does not expect significant near-term improvement in the Denver commercial real estate market.

The Company's oil and gas exploration and production subsidiary, Fuel Resources Development Co. (Fuelco), recorded an after-tax expense of approximately $16.8 million, or 29 cents per share, related to the termination of its involvement in the Synhytech project. The Synhytech plant, located near Pueblo, Colorado, has been in the start-up phase for the production of clean-burning diesel fuel, high grade wax and naphtha from landfill gases. The Synhytech plant never achieved commercial operation. The Company is exploring the feasibility of divestiture of some or all of Fuelco's remaining oil and gas exploration and production properties.

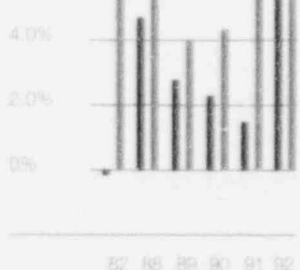
In summary, while the Company's operations in 1992 were generally favorable, net income reflects the negative impact of the BCC and Synhytech losses.

The subsequent discussions refer to the consolidated financial statements and related notes of the Company and should be read in conjunction with such statements and notes.

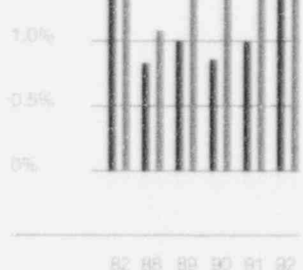
Earnings

Earnings per share were $2.16, $2.48 and $2.49 during 1992, 1991 and 1990, respectively. The positive effects in 1992 of increased revenues from higher sales, primarily associated with the four new wholesale customers, and decreased other operating expenses were to a large extent offset by the recognition of the two significant charges to earnings discussed above, which total approximately 44 cents per share, related to the divestiture of the Company's nonutility investments.

SALES GROWTH–
ELECTRIC AND GAS



CUSTOMER GROWTH–
ELECTRIC AND GAS



Electric Sales, Revenues and Energy Costs

Electric operating revenues increased $80.3 million in 1992, when compared to 1991, reflecting the net effects of rate changes and the Electric Cost Adjustments (ECA) mechanisms on prices of units sold as well as volume changes in unit sales. The following table details the annual changes in revenues when compared to revenues for the preceding year for these components.

	(Millions of Dollars) 1992	1991
Electric revenues:		
Base rate changes, net of required customer refunds	**$ (17.0)**	$ (13.7)
Electric cost adjustment	**37.8**	27.4
New wholesale customers	**43.0**	–
Sales volume and other changes	**16.5**	20.9
Net increase	**$ 80.3**	$ 34.6

Base rates are only changed through rate proceedings, either formal or informal, with the Company's regulatory agencies. Over the past several years, the Company has been involved in numerous settlement agreements with the CPUC and other parties which generally reduced electric revenues. There are currently two separate electric revenue reductions in place, a 1.41% reduction designed to adjust for an earnings imbalance between the electric and gas departments and a 3.38% reduction related to the settlement of the rate case filed in early 1991. Both reductions are to remain in effect until the completion of the rate case filed on January 20, 1993 and are discussed in more detail in Note 8. Commitments and Contingencies in the Notes to Consolidated Financial Statements along with other rate issues. During 1991, only the 1.41% reduction was in place as compared to three separate rate reductions in place during 1990. A 4.29% reduction was in effect from January through April 1990, a 1.11% reduction was in effect from May through November 1990, and the 1.41% reduction was in effect for December 1990. The difference between the 1990 reductions and the 1991 reduction resulted in higher revenues in 1991, when compared to 1990. This increase, however, was offset by the effects of the $22 million electric refund made in 1991, pursuant to the 1991 rate case settlement agreement.

Increased revenues from electric Kwh sales to the four new wholesale customers, resulting from the Colorado-Ute asset acquisition, amounted to $43 million in 1992. Such Kwh sales contributed significantly to the 6.7% increase in total electric Kwh sales in 1992, compared to a 1.5% increase in 1991 over 1990. In addition to these four large wholesale customers, the Company has continued to experience moderate growth in customers of 1.5% in 1992 and 1.0% in 1991, when compared to the respective preceding year. The Company anticipates customer growth to be in the 1.2% range in the near-term.

The Company and Cheyenne Light, Fuel and Power Company (Cheyenne) have in place ECA mechanisms which recognize the majority of the effects of increases in fuel used in generation and purchased power and allow recovery of such costs on a timely basis. As a result, the changes in revenues associated with these mechanisms in 1992 and 1991 had little impact on net income.

Total energy costs rose 10% in 1992 and 7% in 1991 when compared to the respective preceding year. The increase in fuel used in generation expense in 1992 was due to a 14% increase in generation at the Company's power plants partially offset by a lower per unit cost of fuel. The increase in 1991, however, was due to increases in the per unit cost of fuel along with a slight increase in generation. Purchased power costs increased in 1992 due to higher per unit costs for the power purchased, rather than increased purchases. The increase in purchased power costs was primarily associated with new contracts entered into in conjunction with the Colorado-Ute asset acquisition. The cost of electric energy purchased under these contracts is at a per unit cost in excess of spot market purchases which have been utilized to a greater degree in prior years. As a result of these agreements, short-term firm purchases have decreased.

Gas Sales, Revenues and Purchased Costs

Gas operating revenues declined $18.7 million in 1992, when compared to 1991, reflecting the net effects of the Gas Cost Adjustment (GCA) mechanisms on prices of units sold as well as volume changes in unit sales. The following table details the annual changes in revenues when compared to revenues for the preceding year for these components.

	(Millions of Dollars) 1992	1991
Gas revenues:		
Base rate changes	**$ –**	$ 14.2
Gas cost adjustment	**2.1**	(13.7)
Sales volume and other changes	**(20.8)**	25.4
Net increase (decrease)	**$ (18.7)**	$ 25.9

The decline in gas operating revenues in 1992 was primarily due to decreased gas sales. Gas sales (which exclude transportation services and gathering and processing activities) are sensitive to changes in the weather and declined 5.2% as it was 10.3% warmer than normal in 1992. Gas sales for 1991 increased 4.2%, when compared to 1990, as a result of colder than normal weather experienced during that year. Although gas sales have fluctuated in recent years, the Company continues to experience growth in transportation services and gathering and processing activities. The per unit fee charged for transportation services, while significantly less than the per unit fee charged for a sale to a similar customer, provides an operating margin equivalent to the margin earned on gas sold. In addition and similar to gas transportation services, the per unit fee charged for gathering and processing activities is also significantly less than the per unit amount charged for the sale of gas. Therefore, increases in such activities will not have as great an impact on gas revenues as increases in deliveries from the sale of gas but will have a positive impact on operating margin. Revenues were positively impacted in both 1992 and 1991 by the 2.77% positive gas revenue adjustment instituted in November of 1990, which was designed to rectify the earnings imbalance between the electric and gas departments.

The number of gas customers increased at a rate of 1.9% and 1.5% in 1992 and 1991, respectively, when compared to the preceding year, and the Company anticipates customer growth of approximately 1.6% during the near-term.

The Company and its regulated subsidiaries have in place GCA mechanisms for gas sales, which recognize the majority of the effects of changes in the cost of gas purchased for resale and adjust revenues to reflect such changes in cost on a timely basis. As a result, the changes in revenues associated with these mechanisms in 1992 and 1991 had little impact on net income. However, the fluctuations in gas sales affect the amount of gas the Company must purchase and, therefore, affect gas purchased for resale expense along with increases and decreases in the per unit cost of gas. The decline in 1992 purchased gas costs was due to lower sales offset by an increase in the per unit cost of gas when compared to 1991. The increase in gas purchased for resale expense in 1991, when compared to 1990, was due to higher gas sales.

Non-Fuel Operating Expenses
The decline in 1992 other operating expenses is primarily attributable to cost containment efforts instituted throughout the Company coupled with lower nuclear related costs. This decline was offset to a certain degree by costs incurred to operate assets acquired as part of the Colorado-Ute asset acquisition. The Company's nuclear power plant was shut down in 1989 and defueling commenced in 1990. Due to spent fuel shipping delays, the Company recognized $13.1 million in additional expenses in 1991. In addition, the Company recorded $7.9 million in present value adjustments in 1991 associated with the defueling and decommissioning liability. There were no such nuclear expenses recorded in 1992. The inclusion of the $13.1 million in expenses in 1991 was the primary reason for the increase in other operating expenses in 1991 when compared to 1990.

Other non-fuel operating expenses in 1992 also include the recognition of the charges to earnings associated with the Synhytech and BCC transactions of approximately $26.9 million and $11.4 million, respectively.

Higher depreciation and amortization expenses in 1992 compared to 1991 reflect the effects of the Colorado-Ute asset acquisition.

The decline in 1992 and 1991 income tax expense, when compared to the respective preceding year, is primarily attributable to lower pre-tax income. In addition, the recognition of higher tax deductions in the current period, for which no deferred taxes were provided, also contributed to the decline in 1992 income tax expense.

To finance the acquisition of Colorado-Ute assets, the Company issued $250 million in First Mortgage Bonds. The increased outstanding long-term debt as well as increased short-term debt resulted in a corresponding increase in interest expense in 1992. The increase in interest expense in 1991, when compared to 1990, was the result of increases in long-term debt issued throughout the year.

Recently Issued Accounting Standards Not Yet Adopted
In December 1990, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 106-"Employers' Accounting for Post-retirement Benefits Other Than Pensions" (SFAS 106) which establishes the accounting and reporting standards for postretirement benefits other than pensions. The statement requires the accrual, during the years that an employee renders service to the Company, of the expected cost of providing postretirement benefits to the employee and the employee's beneficiaries and covered dependents. The statement must be adopted in January 1993. Two recent rate settlement agreements address the accounting and regulatory treatment of such costs. The first agreement requires the Company to continue to recover such costs on an as paid basis until the effective date of new rates. At that time, the Company would be allowed to recover such costs according to a CPUC prescribed approach, which would also result in the recognition of a regulatory asset. The Emerging Issues Task Force (EITF) of the FASB, however, has recently issued guidance concerning what evidence is necessary to support the recognition of a regulatory asset when adopting SFAS 106. The Company's CPUC prescribed approach is not currently within this guidance (see Note 10. Employee Benefits in the Notes to Consolidated Financial Statements). Should the currently approved methodology not be modified to conform with the EITF consensus, the Company would be required to record as an expense the difference between the amounts allowed in rates and that required by SFAS 106. As a result, the Company has initiated discussions and negotiations focused on resolving this issue to the mutual acceptance of all parties to the settlement agreement without disrupting the overall agreement.

In February 1992, the FASB issued Statement of Financial Accounting Standards No. 109-"Accounting for Income Taxes" (SFAS 109). This statement must be adopted in January 1993. SFAS 109 establishes new financial accounting and reporting standards to recognize tax liabilities and assets that result from an enterprise's activities during the current and preceding years. The Company believes that application of the new standard will not have a material impact on the Company's results of operations or financial position.

In November 1992, the FASB issued Statement of Financial Accounting Standards No. 112-"Employers' Accounting for

Postemployment Benefits" (SFAS 112), which establishes accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement (postemployment benefits). SFAS 112 will be effective in January 1994. The Company is currently analyzing the provisions of SFAS 112 and believes that application of the new standard will not have a material impact on the Company's results of operations or financial position.

Commitments and Contingencies

The Company is in the process of defueling and decommissioning the Fort St. Vrain Nuclear Generating Station (Fort St. Vrain). As more fully discussed in Note 3. Fort St. Vrain Nuclear Generating Station in the Notes to Consolidated Financial Statements, uncertainties exist associated with the recovery of the remaining investment in the facility, the completion of decommissioning at currently estimated costs and the successful resolution of spent fuel storage and shipment issues. The ultimate resolution of these issues cannot be determined at this time.

Environmental issues are discussed in detail in Note 8. Commitments and Contingencies in the Notes to Consolidated Financial Statements.

The dividend level is dependent upon the Company's results of operations, financial position and other factors and is evaluated quarterly by the Board of Directors. The Company is subject to numerous uncertainties, particularly the rate case which was filed on January 20, 1993 and issues relating to Fort St. Vrain, the resolution of which could influence such evaluation.

Liquidity and Capital Resources

Cash Flows

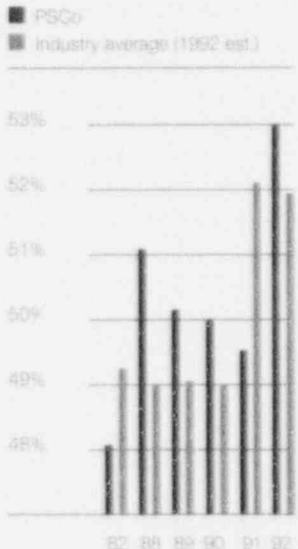
Net cash provided by operating activities in 1992 declined primarily due to the refund to gas customers of amounts received by the Company in 1991 from one of its gas suppliers. In addition, the Company continues to aggressively pursue defueling and decommissioning activities related to Fort St. Vrain and to incur expenditures related to such activities. Defueling and decommissioning expenditures of $50 million and $48.4 million were incurred in 1992 and 1991, respectively. In conjunction with these activities, the Company recognized a $124.4 million regulatory asset and a corresponding increase in the defueling and decommissioning liability in 1991. The regulatory asset will be recovered from customers, including a 9% carrying charge, in annual amounts of approximately $13.9 million over a 12 year period beginning July 1, 1993.

The 1992 acquisition of Colorado-Ute assets for approximately $265 million was primarily funded through the issuance of $250 million in First Mortgage Bonds.

In 1992, the Company received approximately $75 million in loan proceeds against company-owned insurance policies held by the Company's subsidiary, PSR Investments, Inc. (PSRI). In 1991, the Company funded corporately held insurance policies using long-term investments rather than short-term investments.

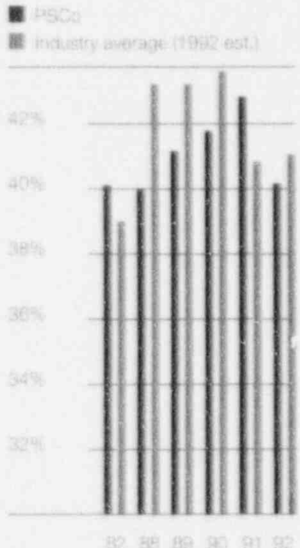
The Company also issued $50 million in medium-term notes and retired $83.8 million of long-term bonds in 1992. In addition, the Company engages in short-term debt activity to fund the normal day to day fluctuations in operating expenses.

DEBT RATIO



Proportion of borrowed funds to the total amount invested in the Company.

COMMON EQUITY RATIO



Shareholders' investment as a percent of the total amount invested in the Company.

Prospective Capital Requirements and Sources

At December 31, 1992, the Company and its subsidiaries estimated the cost of their construction programs, including AFDC and other capital requirements, in 1993, 1994 and 1995 to be as follows:

(Thousands of Dollars)	1993	1994	1995
Company:			
Electric			
Production*	$ 75,282	$ 76,158	$ 54,709
Transmission	23,092	17,110	54,232
Distribution	85,122	76,632	92,051
Gas	38,434	46,543	76,323
General**	63,269	48,247	43,058
Subtotal	285,199	264,690	320,373
Subsidiaries	20,425	9,072	45,664
Total construction	305,624	273,762	366,037
Less: AFDC	15,967	13,313	16,223
Add: Sinking funds and debt maturities	5,395	61,732	36,248
Add: Fort St. Vrain decomissioning***	54,612	41,717	44,901
Total capital requirements	$349,664	$363,898	$430,963

* Capital requirements for Electric Production include $0.9 million for Fort St. Vrain repowering. They are also net of Department of Energy funding of clean coal technology projects of $5.5 million for the 1993-1995 period.

** Capital requirements for General include assets leased under a leasing program.

*** Capital requirements for decommissioning are net of escrow funds available.

The construction programs of the Company and its subsidiaries are subject to continuing review and adjustment. In particular, actual construction expenditures for the electric system may vary from the estimates due to changes in projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting the Company's long-term energy needs. In addition, actual decommissioning and defueling expenses may exceed the estimates due to a variety of factors discussed in Note 3. Fort St. Vrain Nuclear Generating Station in the Notes to Consolidated Financial Statements.

At December 31, 1992, the Company and its subsidiaries estimated that their 1993-1995 capital requirements would be met principally with approximately $643 million from external sources and with funds from operations. The Company and its subsidiaries may meet their external capital requirements through the issuance of first mortgage bonds, preferred and/or common stock, by increasing the level of borrowing under PS Colorado Credit Corporation's (PSCCC) medium-term note program or through short-term borrowing under committed and uncommitted bank borrowing arrangements discussed below. The financing needs are subject to continuing review and can change depending on market and business conditions and changes, if any, in the construction plans of the Company and its subsidiaries.

The Company's Automatic Dividend Reinvestment and Common Stock Purchase Plan allows its shareholders to purchase additional shares of common stock of the Company through the reinvestment of cash dividends at a 3% discount for new issue shares and no price discount on open market shares. Additional shares of common stock may also be purchased with optional cash payments with no price discount. The 1993-1995 proceeds from the dividend reinvestment plan, estimated at approximately $102 million, will also provide funds to meet the capital requirements of the Company.

At December 31, 1992, the Company and its subsidiaries had temporary cash investments of $41.5 million.

As of December 31, 1992, PSCCC had borrowed $154.8 million in short-term debt, for use primarily in the purchase of the Company's customer accounts receivable and fossil fuel inventories. PSCCC may periodically convert short-term debt to medium-term notes. As of December 31, 1992, PSCCC had no medium-term notes outstanding. The level of financing of PSCCC is tied directly to daily changes in the level of the Company's outstanding customer accounts receivable and monthly changes in fossil fuel inventories. The Company expects that the amount of financing associated with PSCCC will vary minimally from year-to-year although seasonal fluctuations in the level of assets will cause corresponding fluctuations in the level of associated financing.

In 1990, the Company filed a registration statement with the Securities and Exchange Commission (SEC) for the issuance of $500 million principal amount of first mortgage bonds of which $200 million was designated for a secured medium-term note program. As of December 31, 1992, $141.5 million principal amount of medium-term notes had been issued. In addition to the medium-term notes, $250 million of first mortgage bonds had been issued for the acquisition of Colorado-Ute assets and to refund portions of the Company's short-term outstanding debt.

The Company's Indenture permits the issuance of additional first mortgage bonds to the extent of 60% of the value of net additions to the Company's utility property, provided net earnings before depreciation, taxes on income and interest expense for a recent twelve month period are at least 2.5 times annual interest requirements on all bonds to be outstanding. At December 31, 1992, the amount of net additions would permit (and the net earnings test would not prohibit) the issuance of approximately $121.1 million of new bonds (in addition to the $200 million principal amount of secured medium-term notes discussed above) at an assumed annual interest rate of 8.48%. The amount of net additions used for this calculation include property acquired prior to January 31, 1992, and consequently does not include the Colorado-Ute assets or other property additions acquired after January 31, 1992. Coverage under the net earnings test, at December 31, 1992, was 4.59.

The Company's Restated Articles of Incorporation prohibit the issuance of additional preferred stock without preferred shareholder approval, unless the gross income available for the payment of interest charges for a recent twelve month period is at least 1.5 times the total of (1) the annual interest requirements on all indebtedness to be outstanding for more than one year and (2) the annual dividend requirements on all preferred stock to be outstanding. At December 31, 1992, gross income available under this requirement would permit the Company, if allowed under the provisions of the Company's Restated Articles of Incorporation, to issue approximately $1.3 billion of additional preferred stock at an assumed annual dividend rate of 7.63%. Coverage of gross income to interest charges was 2.94 at December 31, 1992.

The Company's Restated Articles of Incorporation prohibit, without preferred shareholder approval, the issuance or assumption of unsecured indebtedness, other than for refunding purposes, greater than 15% of the aggregate of (1) the total principal amount of all bonds or other securities representing secured indebtedness of the Company, then outstanding, and (2) the total of the capital and surplus of the Company, as then recorded on its books. At December 31, 1992, the Company had outstanding unsecured indebtedness, including subsidiary indebtedness with the credit support of the Company, in the amount of $95.8 million. The maximum amount permitted under this limitation was approximately $364 million at December 31, 1992.

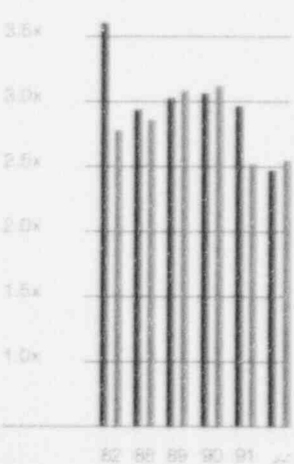
Arrangements for bank lines of credit totaled $300 million in committed lines and $20 million in uncommitted pre-approved lines at December 31, 1992, at which time $69.4 million was available to the Company and PSCCC. The Company could generally borrow under the uncommitted pre-approved lines of credit upon request; however, the banks have no firm commitment to make such loans.

On December 14, 1992, the Company and PSCCC extended the credit facility jointly entered into on February 8, 1991. The credit facility with several banks provides $300 million in bank lines of credit. The credit facility, which is used primarily to support the issuance of commercial paper by the Company and PSCCC, alternatively provides for direct borrowing thereunder. With this extension, BCC, Cheyenne, 1480 Welton, Inc., Fuelco, PSRI and WestGas were provided access to the credit facility under a $125 million aggregate sub-limit with direct borrowings guaranteed by the Company. Generally, the banks as participants in the credit facility would have no obligation to continue their commitments if there has been a material adverse change in the business or financial condition of the Company and its subsidiaries taken as a whole, that would prevent the Company and its subsidiaries from performing their obligation under the credit facility. The credit facility expires November 22, 1993 (see Note 7. Bank Lines of Credit and Compensating Bank Balances in the Notes to Consolidated Financial Statements).

Natural Fuels had arrangements on December 31, 1992 for a committed line of credit in the amount of $4 million. The unused amount of this committed line at December 31, 1992 was $3.9 million.

PRETAX COVERAGE OF INTEREST EXPENSE

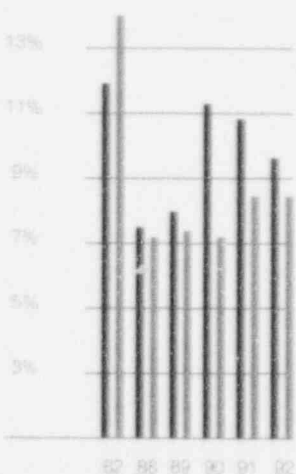
■ PSCo
■ Industry average (1992 est.)



Times interest earned, a measure of protection for bondholders.

CONSTRUCTION EXPENDITURES AS A % OF CAPITALIZATION

■ PSCo
■ Industry average (1992 est.)



New investment as a percent of existing investment.

Report of Management

The accompanying financial statements of Public Service Company of Colorado and subsidiaries have been prepared by Company personnel in conformity with generally accepted accounting principles consistent with the Uniform System of Accounts of the Federal Energy Regulatory Commission. The integrity and objectivity of the data in these financial statements are the responsibility of management. Financial information contained elsewhere in this Annual Report is consistent with that in the financial statements.

The Company maintains and enforces a system of internal controls, which is designed to provide reasonable assurance, on a cost effective basis, as to the integrity, objectivity and reliability of the financial records. This system includes a program of internal audits to assure management that proper procedures and methods of operation are used to implement the plans, policies and directives of management. Management has considered the internal auditor's and the independent public accountants' recommendations during the year concerning the Company's system of internal controls and has taken actions that we believe are cost effective in the circumstances. Management believes that, as of December 31, 1992, the Company's system of internal controls is adequate to accomplish the objectives discussed above. Furthermore, the accounting procedures and internal control system of the Company are reviewed by the Audit Committee of the Board of Directors.

The accompanying financial statements have been audited by Arthur Andersen & Co., independent public accountants. Management has made available to Arthur Andersen & Co. all the Company's financial records and related data, as well as representations we believe to be valid and appropriate.

W. Wayne Brown
Principal Accounting Officer

D. D. Hock
Chief Executive Officer

February 16, 1993

Report of the Audit Committee of the Board of Directors

The Board of Directors of the Company addresses its oversight responsibility for the consolidated financial statements through its Audit Committee. The Audit Committee meets regularly with the independent certified public accountants and the internal auditor to discuss results of their audit work and their evaluation of the adequacy of the internal controls and the quality of financial reporting.

In fulfilling its responsibilities in 1992, the Audit Committee recommended to the Board of Directors, subject to shareholder approval, the selection of the Company's independent certified public accountants. The Audit Committee reviewed the overall scope and specific plans of the independent certified public accountants' and internal auditor's respective audit plans, and discussed the independent certified public accountants' management letter recommendations, approved their general audit fees, and reviewed their non-audit services to the Company.

The committee meetings are designed to facilitate open communications between internal auditing, independent certified public accountants, and the Audit Committee. To ensure auditor independence, both the independent certified public accountants and internal auditor have full and free access to the Audit Committee.

J. Michael Powers

J. Michael Powers, Chairman
Audit Committee

February 16, 1993

Report of Independent Public Accountants

The Board of Directors and Shareholders of Public Service Company of Colorado

We have audited the accompanying consolidated balance sheets of Public Service Company of Colorado (a Colorado corporation) and subsidiaries as of December 31, 1992 and 1991, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1992. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Public Service Company of Colorado and subsidiaries as of December 31, 1992 and 1991, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1992, in conformity with generally accepted accounting principles.

As more fully discussed in Note 3 to the consolidated financial statements, realization of the Company's investment in its Fort St. Vrain Nuclear Generating Station (approximately $62.5 million at December 31, 1992), as well as the tax effects of previously recognized tax deductions associated with such investment for which no deferred taxes were required to be provided (approximately $7.5 million at December 31, 1992), is primarily dependent on the Company's ability to repower the facility as a natural gas fired plant, the eventual outcome of which cannot be determined at this time. In addition, as more fully discussed in Note 3 to the consolidated financial statements, the adequacy of the Company's recorded liability for defueling and decommissioning its Fort St. Vrain Nuclear Generating Station (approximately $141.0 million at December 31, 1992) is primarily dependent on assurances that the dismantlement and decommissioning of the Fort St. Vrain Nuclear Generating Station can be accomplished at currently estimated costs and that the spent fuel storage and shipment issues are successfully resolved. The outcome of the above issues cannot be determined at this time. The accompanying financial statements do not include any adjustments that might result from the outcome of these uncertainties.

Arthur Andersen & Co.

Arthur Andersen & Co.
Denver, Colorado

February 16, 1993

CONSOLIDATED STATEMENTS OF INCOME

Public Service Company of Colorado and Subsidiaries

Years ended December 31, 1992, 1991 & 1990

	(Thousands of Dollars Except Per Share Data)		
	1992	1991	1990
Operating Revenues:			
Electric	**$1,260,769**	$1,180,501	$1,145,915
Gas	**568,886**	587,609	561,712
Other	**32,618**	26,794	26,312
	1,862,273	1,794,904	1,733,939
Operating Expenses:			
Fuel used in generation	**182,832**	177,365	166,784
Purchased power	**366,949**	323,793	301,910
Gas purchased for resale	**343,188**	365,991	358,263
Other operating expenses	**346,368**	361,610	332,516
Maintenance	**72,540**	67,216	85,522
Termination of Synhytech project (Note 2)	**26,893**	–	–
Loss on sale of real estate investments (Note 2)	**11,370**	–	–
Depreciation and amortization	**127,317**	111,728	106,527
Taxes (other than income taxes) (Note 13)	**82,040**	74,335	70,033
Income taxes (Note 12)	**53,149**	69,288	73,978
	1,612,646	1,551,326	1,495,533
Operating Income	**249,627**	243,578	238,406
Other Income and Deductions:			
Allowance for equity funds used during construction (Note 1)	**7,378**	4,763	3,444
Miscellaneous income and deductions–net	**734**	2,889	1,590
	257,739	251,230	243,440
Interest Charges:			
Interest on long-term debt	**92,581**	81,666	75,075
Amortization of debt discount and expense less premium	**1,790**	1,827	1,543
Other interest	**30,669**	22,718	23,949
Allowance for borrowed funds used during construction (Note 1)	**(3,924)**	(4,674)	(3,271)
	121,116	101,537	97,296
Net Income	**136,623**	149,693	146,144
Dividend Requirements on Preferred Stock	**12,077**	12,234	12,439
Earnings Available for Common Stock	**$ 124,546**	$ 137,459	$ 133,705
Shares of Common Stock Outstanding (thousands):			
Year-end	**58,477**	56,294	54,320
Weighted average	**57,558**	55,471	53,626
Earnings Per Weighted Average Share of Common Stock Outstanding	**$2.16**	$2.48	$2.49
Dividends Per Share of Common Stock:			
Paid	**$2.00**	$2.00	$2.00
Declared	**$2.00**	$2.00	$2.00

The accompanying notes to consolidated financial statements are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS

Public Service Company of Colorado and Subsidiaries

December 31, 1992 & 1991

Assets	(Thousands of Dollars) 1992	1991
Property, Plant and Equipment, at Cost:		
Electric	**$3,231,876**	$2,784,646
Gas	**898,952**	871,843
Steam and other	**87,458**	95,324
Common to all departments	**280,416**	271,991
Construction in progress	**236,179**	171,698
	4,734,881	4,195,502
Less: Accumulated depreciation	**1,719,913**	1,511,162
	3,014,968	2,684,340
Fort St. Vrain related property (Note 3)	**79,323**	78,242
Less: Accumulated depreciation	**16,782**	16,782
	62,541	61,460
Total Property, Plant and Equipment	**3,077,509**	2,745,800
Investments, at Cost	**19,225**	111,572
Current Assets:		
Cash and temporary cash investments	**51,155**	36,274
Accounts receivable, less reserve for uncollectible accounts ($3,368 at December 31, 1992; $4,741 at December 31, 1991)	**151,643**	144,869
Accrued unbilled revenues (Note 1)	**72,795**	62,539
Recoverable purchased gas and electric energy costs-net (Note 1)	**45,640**	44,702
Materials and supplies, at average cost	**81,002**	78,367
Fuel inventory, at average cost	**33,573**	34,447
Gas in underground storage, at cost (LIFO)	**14,393**	14,803
Prepaid expenses	**20,984**	14,409
Current portion of recoverable nuclear decommissioning costs (Note 3)	**6,151**	–
Other	**2,191**	1,199
Total Current Assets	**479,527**	431,609
Deferred Charges:		
Unamortized debt expense	**20,361**	19,491
Recoverable nuclear decommissioning costs (Note 3)	**118,293**	124,444
Pension benefits (Note 10)	**15,629**	11,683
Other	**29,039**	18,069
	183,322	173,687
Total Assets	**$3,759,583**	$3,462,668

The accompanying notes to consolidated financial statements are an integral part of these financial statements.

Capital and Liabilities	(Thousands of Dollars) 1992	1991
Common Equity:		
Common stock (Note 4)	**$ 853,322**	$ 795,718
Retained earnings	**247,725**	238,715
	1,101,047	1,034,433
Preferred Stock (Note 4):		
Not subject to mandatory redemption	**140,008**	140,008
Subject to mandatory redemption at par	**43,078**	43,792
Long-Term Debt (Note 5)	**1,196,959**	900,491
	2,481,092	2,118,724
Noncurrent Defueling and Decommissioning Liability (Note 3)	**88,124**	145,331
Current Liabilities:		
Notes payable and commercial paper (Note 6)	**250,626**	200,640
Long-term debt due within one year	**2,820**	93,474
Preferred stock subject to mandatory redemption within one year (Note 4)	**2,576**	2,576
Accounts payable	**182,690**	171,805
Dividends payable	**32,248**	31,171
Customers' deposits	**16,807**	15,842
Accrued taxes	**80,312**	76,343
Accrued interest	**31,032**	24,401
Gas refund liability	**909**	49,975
Current portion of defueling and decommissioning liability (Note 3)	**52,896**	47,034
Other	**53,603**	41,708
Total Current Liabilities	**706,519**	754,969
Deferred Credits:		
Customers' advances for construction	**59,867**	46,927
Unamortized investment tax credits	**129,248**	134,386
Accumulated deferred income taxes (Note 12)	**275,247**	251,481
Other	**19,486**	10,850
	483,848	443,644
Commitments and Contingencies (Notes 3 and 8)		
Total Capital and Liabilities	**$3,759,583**	$3,462,668

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Public Service Company of Colorado and Subsidiaries *Years ended December 31, 1992, 1991 & 1990*

			(Thousands of Dollars)
	1992	1991	1990
Retained Earnings at Beginning of Year	**$238,715**	$212,514	$186,284
Net Income	**136,623**	149,693	146,144
	375,338	362,207	332,428
Dividends:			
On cumulative preferred stock:			
$100 par value:			
4.20% series	**420**	420	420
4¼% series	**744**	744	744
4½% series	**293**	293	293
4.64% series	**742**	742	742
4.90% series	**735**	735	735
4.90% 2nd series	**735**	735	735
7.15% series	**1,787**	1,787	1,787
7.50% series	**1,620**	1,665	1,755
8.40% series	**2,051**	2,139	2,254
$25 par value:			
8.40% series	**2,940**	2,940	2,940
	12,067	12,200	12,405
On common stock:			
$2.00 per share in 1992, 1991 and 1990	**115,546**	111,292	107,509
	127,613	123,492	119,914
Retained Earnings at End of Year	**$247,725**	$238,715	$212,514

The accompanying notes to consolidated financial statements are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Public Service Company of Colorado and Subsidiaries

Years ended December 31, 1992, 1991 & 1990

		(Thousands of Dollars)	
	1992	1991	1990
Operating Activities:			
Net income	**$ 136,623**	$ 149,693	$ 146,144
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**134,335**	118,943	113,426
Termination of Synhytech project	**26,893**	–	–
Loss on sale of real estate investments	**11,370**	–	–
Amortization of investment tax credits	**(5,138)**	(5,230)	(4,982)
Deferred income taxes	**23,766**	26,122	34,287
Allowance for equity funds used during construction	**(7,378)**	(4,763)	(3,444)
Change in accounts receivable	**10,380**	(17,024)	8,378
Change in inventories	**6,024**	(8,579)	8,350
Change in other current assets	**(24,670)**	21,811	(17,964)
Change in accounts payable	**10,373**	(5,948)	13,319
Change in other current liabilities	**32,965**	(11,911)	31,002
Change in gas refunds–net	**(49,066)**	24,541	22,294
Change in deferred amounts	**23,011**	(121,665)	11,230
Change in noncurrent defueling and decommissioning liability	**(57,207)**	132,134	(71,903)
Other	**521**	2,134	3,385
Net Cash Provided by Operating Activities	**272,802**	300,267	293,522
Investing Activities:			
Construction expenditures	**(261,666)**	(260,704)	(261,221)
Colorado-Ute asset acquisition	**(265,385)**	–	–
Allowance for equity funds used during construction	**7,378**	4,763	3,444
Proceeds from (cost of) disposition of equipment	**(3,187)**	5,893	5,321
Purchase of other investments	**(6,348)**	(11,396)	(49,367)
Sale of other investments	**97,357**	15,002	25,798
Net Cash Used in Investing Activities	**(431,851)**	(246,442)	(276,025)
Financing Activities:			
Proceeds from sale of common stock (Note 1)	**48,914**	39,305	27,881
Proceeds from sale of long-term notes and bonds	**296,476**	97,204	83,684
Redemption of long-term notes and bonds	**(94,197)**	(42,918)	(94,008)
Proceeds from short-term borrowings	**831,290**	690,645	142,793
Repayment of short-term borrowings	**(781,304)**	(703,838)	(82,168)
Redemption of preferred stock	**(714)**	(2,576)	(2,576)
Dividends on common stock	**(114,454)**	(110,306)	(106,753)
Dividends on preferred stock	**(12,081)**	(12,251)	(12,456)
Net Cash Provided by (Used in) Financing Activities	**173,930**	(44,735)	(43,603)
Net Increase (Decrease) in Cash and Temporary Cash Investments	**14,881**	9,090	(26,106)
Cash and Temporary Cash Investments at Beginning of Year	**36,274**	27,184	53,290
Cash and Temporary Cash Investments at End of Year	**$ 51,155**	$ 36,274	$ 27,184

The accompanying notes to consolidated financial statements are an integral part of these financial statements.

1. Summary of Significant Accounting Policies

Consolidation

Public Service Company of Colorado (the Company) follows the practice of consolidating the accounts of its significant subsidiaries. All intercompany items and transactions have been eliminated. Effective January 1, 1993, Western Gas Supply Company (WestGas) was merged into the Company and its three subsidiaries, WestGas InterState, Inc., WestGas Gathering, Inc. and WestGas TransColorado, Inc. (WGT), became wholly-owned subsidiaries of the Company.

Revenue recognition

The Company and Cheyenne Light, Fuel and Power Company (Cheyenne) accrue for estimated unbilled revenues for services provided after the meters were last read on a cycle billing basis through the end of each year.

Statements of cash flows

The acquisition of assets from Colorado-Ute Electric Association, Inc. (Colorado-Ute) (see Note 9) involved various classes of assets and, as a result, affects numerous line items in the 1992 consolidated statement of cash flows.

For purposes of the consolidated statements of cash flows, the Company and its subsidiaries consider all temporary cash investments to be cash equivalents. These temporary cash investments are securities having original maturities of three months or less or having longer maturities but with put dates of three months or less.

Income taxes and interest
(excluding capitalized interest) paid:

	(Thousands of Dollars)		
	1992	1991	1990
Income taxes	**$ 38,624**	$44,418	$ 43,119
Interest	**$112,695**	$96,010	$95,236

Non-cash transactions:
Shares of common stock (333,418 in 1992, 242,674 in 1991 and 197,862 in 1990) valued at the market price on date of issuance (approximately $8.7 million in 1992, $5.3 million in 1991 and $5.0 million in 1990), were issued to the Employees' Savings and Stock Ownership Plan of Public Service Company of Colorado and Participating Subsidiary Companies. The estimated issuance values were recognized in other operating expenses during the respective preceding years. These stock issuances were not cash transactions and are not reflected as a source of cash in the consolidated statements of cash flows.

Depreciation

The Company and its subsidiaries use straight-line depreciation for financial accounting purposes. Composite rates are used for the various classes of depreciable assets. Depreciation rates include provisions for disposal and removal costs of property, plant and equipment. Total depreciation expense approximated an annual rate of 3.0%, 3.0% and 3.1% on the average cost of depreciable properties for the years ended December 31, 1992, 1991 and 1990, respectively.

Replacements and betterments representing units of property are capitalized. Items that represent less than units of property are charged to operations as maintenance. The cost of units of property retired, together with cost of removal, less salvage, is charged against accumulated depreciation.

Fuel Resources Development Co. (Fuelco) uses the unit-of-production depreciation method for producing oil and gas properties. For income tax purposes, the Company and its subsidiaries use accelerated depreciation and other elections provided by the tax laws.

Allowance for funds used during construction (AFDC)

AFDC, which does not represent current cash earnings, is defined in the system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and The Public Utilities Commission of the State of Colorado (CPUC) as the net cost during the period of construction of borrowed funds used for construction purposes, and a reasonable rate on funds derived from other sources. The Company capitalizes AFDC as a part of the cost of utility plant. The following range of AFDC rates were used for the years 1992, 1991 and 1990:

	1992	1991	1990
AFDC rates	**8.95%-10.21%**	8.76%-10.21%	8.76%-10.21%

Income taxes

The Company and its subsidiaries file consolidated state and Federal income tax returns. Income taxes are allocated to the subsidiaries based on separate company computations of taxable income or loss.

The Company and its regulated subsidiaries provide for deferred income taxes to the extent allowed by regulatory agencies, including deferred taxes arising from the use of accelerated depreciation, accelerated cost recovery, qualifying accelerated amortization and timing differences due to unbilled revenues which include deferred gas and electric costs. In addition, the Company currently provides for deferred taxes on book-tax timing differences arising from items associated with the Fort St. Vrain Nuclear Generating Station (Fort St. Vrain) (see Note 3), from certain customer refunds and for all book-tax timing differences included in FERC jurisdictional rates. The Company's non-regulated subsidiaries provide for deferred taxes arising from all book-tax timing differences.

As a result of the Tax Reform Act of 1986, the Company determines its income tax to be the greater of regular income tax or alternative minimum tax (AMT). Any excess of AMT over regular income tax becomes a credit which may be applied against future regular tax liabilities.

Investment tax credits are no longer available to the Company and its subsidiaries as a result of the Tax Reform Act of 1986. Previously recorded investment tax credits have been deferred and are being amortized to income over the productive lives of the related property.

Amortization of debt premium, discount and expense

Debt premium, discount and expense is being amortized to income over the respective original lives of the applicable issues or as directed by the CPUC.

Recoverable purchased gas and electric energy costs–net

The Company, Cheyenne and WestGas recover certain purchased gas and electric energy costs, in excess of amounts recovered through base rates, from their retail customers through various gas and electric cost adjustment tariffs. These cost adjustment tariffs, which include a provision for the collection of deferred purchased gas and electric energy costs, are revised periodically as prescribed by the appropriate regulatory agencies. The deferred costs are the difference between actual costs incurred and the amounts currently recovered from customers. A substantial portion of this deferred amount represents the costs incurred to provide gas and electric energy which customers have used but for which they have not yet been billed.

Reclassification

Certain items in the 1991 and 1990 consolidated financial statements have been reclassified to conform to the 1992 manner of presentation.

2. Divestiture of Nonutility Assets

As part of the Company's strategy to focus its efforts on the core electric and gas businesses, the following two events occurred in 1992 related to the Company's nonutility investments.

Bannock Center Corporation (BCC)

In December 1992, BCC sold its real estate properties located near downtown Denver for $6 million, resulting in a loss of approximately $11.4 million ($8.4 million after-tax or 15 cents per share). The sale, which included substantially all of BCC's investment in real estate, was completed because the Company does not expect significant near-term improvement in the Denver commercial real estate market.

Fuel Resources Development Co.

In December 1992, as part of the Company's strategy to divest Fuelco, the Company elected to terminate its involvement in Fuelco's Synhytech project. The Synhytech plant has been in the start-up phase to process biogas consisting of methane and carbon dioxide to produce clean-burning diesel fuel, high grade wax and naphtha. Commercial operation of the Synhytech plant has not been achieved. Fuelco recognized an expense of approximately $26.9 million ($16.8 million after-tax or 29 cents per share) associated with writing-off its entire investment in the Synhytech plant and recognizing certain additional costs expected to be incurred in the first half of 1993.

On February 3, 1993, the Company entered into a letter agreement with Rentech, Inc., resolving all claims between the Company and Rentech, Inc. that have been or could be asserted with respect to the Synhytech plant and related technology. Rentech, Inc. had been involved with various aspects of the Synhytech project since the project's inception. In exchange for the resolution of all such issues, the Company has agreed, among other things, to transfer all of the Synhytech assets to Rentech, Inc.

The Company is exploring the feasibility of the divestiture in one or more transactions of some or all of Fuelco's remaining oil and gas exploration and production properties which had a total net book value of approximately $67.9 million at December 31, 1992. Depending upon market conditions and other factors, it is possible that the Company would not recover all of its investment upon such divestiture. While the Company cannot predict market conditions or the timing of any such transactions, the Company does not currently believe that any losses incurred would have a material effect on the Company's results of operations or financial position.

3. Fort St. Vrain Nuclear Generating Station

Investment in Fort St. Vrain

In 1989, the Company announced its decision to end nuclear operations at Fort St. Vrain. The decision was based on the financial impact of an anticipated lengthy outage necessary to repair the plant's steam generator system coupled with the plant's history of reduced levels of generation. The Company has completed defueling from the reactor to the independent spent fuel storage installation (ISFSI) as discussed below in the section entitled "Defueling" and commenced the decommissioning process as described in the section entitled "Decommissioning".

During 1986, the Company entered into a Stipulation and Settlement Agreement with the CPUC, the Colorado Office of Consumer Counsel (OCC) and the other parties involved in litigation and administrative proceedings related to Fort St. Vrain's history of limited operations. As a result, the Company's investment in Fort St. Vrain was removed from rate base and certain charges were recognized including the write-down of a substantial portion of such investment and the recognition of the then estimated future unrecoverable defueling and decommissioning expenses.

The recovery of the remaining investment in Fort St. Vrain (approximately $62.5 million at December 31, 1992), as well as the tax effects of previously recognized tax deductions associated with such investment for which no deferred taxes were required to be provided (approximately $7.5 million at December 31, 1992), is primarily dependent on the Company's ability to repower the facility as a natural gas-fired plant. The Company has recently initiated an investigation which contemplates the repowering of Fort St. Vrain in a phased approach, with completion of the first phase in 1996 rather than completion of repowering in 1998, which was previously disclosed. The Company will be required to obtain a certificate of public convenience and necessity from the CPUC. If it becomes probable that all or a portion of such investment and/or the related taxes will not be recovered, the Company will recognize an expense equal to the unrecoverable amounts at the time such unrecoverable amounts can be reasonably estimated.

During the first quarter of 1991, as a result of spent fuel shipment delays and a higher probability of utilization of the on-site ISFSI (discussed below under "Defueling"), the Company recognized an additional $13.1 million in defueling and decommissioning expenses. Other operating expenses also included present value adjustments of approximately $7.9 million and $10.9 million to the defueling and decommissioning liability for 1991 and 1990, respectively. Since the Company has adopted an early dismantlement/decommissioning approach as discussed below, such present value adjustments are no longer required.

Decommissioning

On December 27, 1991, the CPUC approved a Supplemental Settlement Agreement (the Agreement) to the 1986 Fort St. Vrain Stipulation and Settlement Agreement, allowing the Company to continue with the early dismantlement/decommissioning of Fort St. Vrain. Early dismantlement/decommissioning assumes that following the removal of the spent fuel segments from the reactor (defueling), the radioactive components of the reactor will be dismantled and removed over an approximate three year period. Pursuant to the Agreement, the Company will recover from customers approximately $124.4 million, plus a 9% carrying cost, which represents the inflation adjusted estimated remaining cost of the early dismantlement/decommissioning activities not previously recognized as expense, over a twelve year period, beginning July 1, 1993. The annual amount recovered from customers each year will be approximately $13.9 million. As a result, a $124.4 million regulatory asset and a corresponding increase in the defueling and decommissioning liability have been recognized in the consolidated balance sheets. In consideration for authorization to charge this annual amount to customers, the Agreement stipulates that the Company will adhere to certain ratemaking principles during the twelve year period.

On November 23, 1992, the Nuclear Regulatory Commission (NRC) approved the Company's early dismantlement/decommissioning plan. The Company has contracted with Westinghouse Electric Corporation and MK-Ferguson, a division of Morrison Knudsen Corporation, for the early dismantlement/decommissioning of Fort St. Vrain. The contract stipulates a fixed price, based on a defined work scope; however, such price could be revised due to changes in work scope or applicable regulations. Since defueling has been completed from the reactor to the ISFSI (discussed below) and the decommissioning order has been received, the Company and the contractors have proceeded with decommissioning activities. The Company anticipates completion of the decommissioning activities during 1995.

Following is a reconciliation of the recorded defueling and decommissioning cost estimate from September 30, 1986, when the plant was removed from rate base, to December 31, 1992:

	(Thousands of Dollars)
Defueling and decommissioning liability–9/30/86	$ 95,404
Revision in estimate–9/30/88	63,764
Revision in estimate–3/31/91	13,099
Present value adjustments accrued through 9/30/91	36,428
CPUC approved additional cost recovery–12/31/91	124,444
Revision in estimate–12/31/92	(1,350)
	331,789
Defueling expenditures through 12/31/92	(146,089)
Decommissioning expenditures through 12/31/92	(44,680)
Defueling and decommissioning liability–12/31/92	$ 141,020*
*Defueling	$ 11,146
Decommissioning	129,874
	$ 141,020

Because of the possibility of changes in the decommissioning work scope, changes in applicable regulations and/or the uncertainties related to the final disposal of spent fuel, there can be no assurance that the actual cost of defueling and decommissioning will not exceed the estimated liability. The Company could be required to revise the estimated cost of defueling and decommissioning as a result of any such matters.

Defueling

In 1965, the Company, the Atomic Energy Commission (now the Department of Energy (DOE)) and General Dynamics entered into an agreement to construct Fort St. Vrain. The 1965 agreement, as amended and modified, requires the DOE to designate a facility for the temporary storage and reprocessing of Fort St. Vrain's first eight spent fuel segments and additional spent fuel segments at the DOE's discretion. Pursuant to the terms of an agreement dated

April 1, 1980, among the Company, the DOE and General Dynamics, the DOE designated the Idaho National Engineering Laboratory (INEL) for receipt and temporary storage and reprocessing of the Fort St. Vrain first eight spent fuel segments. On June 24, 1983, the Company and the DOE entered into a contract for the disposal of spent nuclear fuel and/or high level radioactive waste from Fort St. Vrain beginning with fuel segment 9, in the event the DOE does not accept segment 9 under the provisions of the 1965 agreement, as amended and modified. The Company intends to pursue with the DOE the storage/reprocessing of the equivalent spent fuel elements of segment 9 at the INEL in conjunction with the storage/reprocessing of the first eight segments.

In addition to its contractual obligations to provide for temporary storage and reprocessing of Fort St. Vrain spent fuel segments, the DOE is required by Federal statute to provide a repository for the permanent storage and disposal of spent nuclear fuel beginning in 1998. However, the DOE currently estimates that such a repository will not be available until 2010. Absent other arrangements with the DOE as discussed above, the equivalent spent fuel elements of segment 9 will be stored at the ISFSI.

While the plant was operating and as part of routine refueling procedures, three spent fuel segments were transported to the INEL. After cessation of operations at Fort St. Vrain, defueling activities were initiated and authorization from the DOE to commence the shipment of the spent nuclear fuel to the INEL was received in February 1991.

Despite the Company's arrangements with the DOE, several parties contested the shipment of Fort St. Vrain spent nuclear fuel to the State of Idaho. As a result, several lawsuits were filed during 1991 by and among the Company, the DOE, the State of Idaho and the Shoshone-Bannock Indian Tribes, whose reservation is located near the INEL. While the Company was able to ship some fuel elements to the INEL following the initiation of litigation, no shipments have been made since October 1991. Initially, this was because of an injunction, which was subsequently set aside, that precluded the DOE from receiving spent fuel at the INEL. Most recently, the DOE determined it necessary to prepare an Environmental Impact Statement (EIS) relative to, among other things, the receipt and storage of spent fuel at the INEL. Accordingly, the Company believes that the DOE will not accept any more shipments of spent fuel until the EIS is completed, which the DOE anticipates to occur in 1995.

The Company constructed the ISFSI for the interim storage of spent fuel segments 4 - 9 in order to safeguard against any potential future delays in the defueling process. Accordingly, on December 26, 1991, the Company began defueling the reactor to the ISFSI and completed such activities on June 10, 1992. Recognition of the additional $13.1 million in defueling and decommissioning expenses during the first quarter of 1991 allows for the utilization of this facility for an interim period of time without the recognition of additional expense. The Company believes the defueling and decommissioning liability currently recorded on the books is adequate assuming that shipment of the spent fuel to the INEL is completed in 1997.

While the Company intends to pursue all available legal actions to enable it to ship the spent fuel to Idaho, the eventual outcome of this issue, and its timing, are uncertain. If, because the litigation discussed above is not resolved or because of other uncertainties, it becomes probable that storage of the spent fuel in the ISFSI will be required until 2020 (which the Company assumes is the earliest that a Federal repository could take such fuel), the Company would be required to recognize an additional incremental expense of approximately $20 million, determined on a present value basis. These expenditures have been escalated at an average annual rate of 5.3% and discounted to present value at a rate of 9%. The Company has assumed that costs associated with the shipment of the fuel from the ISFSI to the Federal repository in 2020 are to be the responsibility of the DOE and such costs are, therefore, excluded from this estimate. At this time, the Company cannot predict the likelihood, timing of recognition, or the amount of such additional costs to be recognized, if any.

Funding

Under NRC regulations, the Company is required to make filings with, and obtain the approval of, the NRC regarding certain aspects of the Company's decommissioning proposals. On January 27, 1992, the NRC accepted the Company's funding aspects of the decommissioning plan. The Company has also obtained an unsecured irrevocable letter of credit totaling $125 million that meets the NRC's stipulated funding guidelines including those proposed on August 21, 1991 that address decommissioning funding requirements for nuclear power reactors that have been prematurely shut down.

The Company had previously set aside approximately $30 million in trust accounts for decommissioning the reactor. During the fourth quarter of 1992, since decommissioning activities have commenced, the Company began withdrawing funds from the trust accounts and plans to exhaust the funds in such accounts during the first quarter of 1993. In addition, the Company has established a separate decommissioning trust for the ISFSI which had funds of approximately $1.5 million at December 31, 1992. It is anticipated that this amount, together with the expected earnings on the funds, will be sufficient to decommission the ISFSI in 1997.

Costs for maintaining the ISFSI and defueling from the ISFSI, which the Company is not required to prefund, will be paid from a combination of operating funds of the Company and its subsidiaries and/or the issuance of securities.

Nuclear insurance

The Price Anderson Act, as amended, limits the public liability of a licensee for a single nuclear incident at its nuclear power plant to the amount of financial protection available through liability insurance and deferred premium assessment charges, currently approximately $7.8 billion, which includes a 5% surcharge. Financial protection for this exposure is provided by private insurance and an indemnity agreement with the NRC. Effective July 1, 1989, the Company maintains approximately $200 million of private insurance, the amount required by the NRC. In the event of a nuclear incident involving a licensed commercial power plant in the United States that results in damages in excess of the private liability insurance, each reactor licensee, including the Company, is responsible to share in the liability up to the maximum amount through a deferred premium assessment. The maximum amount the Company would be required to pay in respect of each incident at a United States nuclear plant would be approximately $66 million (which includes a 5% surcharge), indexed every five years for inflation, provided that not more than $10 million would be payable per incident in any one year.

In addition to the Company's liability insurance, Federal regulations require the Company to maintain $1.06 billion in nuclear property insurance. Effective February 1, 1991, however, the NRC granted the Company's exemption request to reduce the nuclear property insurance coverage from $1.06 billion to a minimum of $169 million. This lower limit would cover stabilization and decontamination expenses resulting from a worst case defueling accident. The Company currently maintains $281 million in property insurance coverage. The additional insurance coverage above the $169 million is necessary to provide coverage for the estimated depreciated replacement value of the plant assets that will be used in the repowering of Fort St. Vrain.

4. Capital Stock

Common Stock

	1992		1991	
	Shares	**Amount**	Shares	Amount
		(Thousands of Dollars)		(Thousands of Dollars)
Common stock, $5 par value:				
Authorized	**140,000,000**		140,000,000	
Issued and outstanding	**58,476,805**	**$292,384**	56,293,525	$281,468
Premium on common stock		**560,938**		514,250
		$853,322		$795,718

Changes in common stock and premium on common stock for the three years ended December 31, 1992 are as follows:

		(Thousands of Dollars)	
	Average Price Per Share	**Common Stock**	**Premium on Common Stock**
Balance, January 1, 1990		$264,036	$454,260
197,862 shares issued under the Employees' Savings Plan	$25.13	989	3,983
1,315,163 shares issued under the Dividend Reinvestment Plan	$21.20	6,576	21,305
Balance, December 31, 1990		271,601	479,548
242,674 shares issued under the Employees' Savings Plan	$21.69	1,214	4,050
1,730,603 shares issued under the Dividend Reinvestment Plan	$22.71	8,653	30,652
Balance, December 31, 1991		281,468	514,250
333,418 shares issued under the Employees' Savings Plan	$26.06	1,667	7,022
1,849,862 shares issued under the Dividend Reinvestment Plan	$26.44	9,249	39,666
Balance, December 31, 1992		$292,384	$560,938

On December 7, 1992, the Company filed a registration statement with the Securities and Exchange Commission (SEC) relating to the registration of 1,000,000 common stock shares, $5 par value, and 1,000,000 common share purchase rights. These shares and rights are associated with the Company's Omnibus Incentive Plan discussed in Note 10.

During 1991, the Company's Board of Directors declared a dividend of one common share purchase right (right) on each outstanding share of the Company's common stock. All future common shares issued will contain this right. Each right stipulates an initial purchase price of $55 per share and also prescribes a means whereby the resulting effect is such that, under the circumstances described below, shareholders would be entitled to purchase additional shares of common stock at 50% of the prevailing market price at the time of exercise. The rights are not currently exercisable, but would become exercisable if certain events occurred related to a person or group acquiring or attempting to acquire 20% or more of the outstanding shares of common stock of the Company.

In the event a takeover results in the Company being merged into an acquiror, the unexercised rights could be used to purchase shares in the acquiror at 50% of market price. Subject to certain conditions, if a person or group acquires 20% but no more than 50% of the Company's common stock, the Company's Board of Directors may exchange each right held by shareholders other than the acquiring person or group for one share of common stock (or its equivalent).

If a person or group successfully acquires 80% of the Company's common stock for cash, after tendering for all of the common stock, and satisfies certain other conditions, the rights would not operate. The rights expire on March 22, 2001, however, each right may be redeemed by the Board of Directors for one cent at any time prior to the acquisition of 20% of the common stock by a potential acquiror.

Preferred Stock

	1992		1991	
	Shares	**Amount**	Shares	Amount
		(Thousands of Dollars)		(Thousands of Dollars)
Cumulative preferred stock, $100 par value:				
Authorized	**3,000,000**		3,000,000	
Issued and outstanding:				
Not subject to mandatory redemption:				
4.20% series	**100,000**	**$ 10,000**	100,000	$ 10,000
4¼% series (includes $7,500 premium)	**175,000**	**17,508**	175,000	17,508
4½% series	**65,000**	**6,500**	65,000	6,500
4.64% series	**160,000**	**16,000**	160,000	16,000
4.90% series	**150,000**	**15,000**	150,000	15,000
4.90% 2nd series	**150,000**	**15,000**	150,000	15,000
7.15% series	**250,000**	**25,000**	250,000	25,000
Total	**1,050,000**	**$105,008**	1,050,000	$105,008
Subject to mandatory redemption:				
7.50% series	**216,000**	**$ 21,600**	216,000	$ 21,600
8.40% series	**240,545**	**24,054**	247,680	24,768
	456,545	**45,654**	463,680	46,368
Less: Preferred stock subject to mandatory redemption within one year	**(25,760)**	**(2,576)**	(25,760)	(2,576)
Total	**430,785**	**$ 43,078**	437,920	$ 43,792
Cumulative preferred stock, $25 par value:				
Authorized	**4,000,000**		4,000,000	
Issued and outstanding:				
Not subject to mandatory redemption:				
8.40% series	**1,400,000**	**$ 35,000**	1,400,000	$ 35,000

The preferred stock may be redeemed at the option of the Company upon at least 30, but not more than 60, days' notice in accordance with the following schedule of prices, plus an amount equal to the accrued dividends to the date fixed for redemption:

$100 par value:

Not subject to mandatory redemption:
All series: $101.

Subject to mandatory redemption:

7.50% series: $102.75 on or prior to August 31, 1993, reducing each year thereafter by $0.25 per share until August 31, 2003, after which the redemption price is $100; 8.40% series: $103 on or prior to July 31, 1993, and reducing each year thereafter by $0.25 per share until July 31, 2004, after which the redemption price is $100.

In 1993 and in each year thereafter, the Company must offer to repurchase 12,000 shares of the 7.50% series subject to mandatory redemption at $100 per share, plus accrued dividends to the date set for repurchase, and 13,760 shares of the 8.40% series subject to mandatory redemption at $100 per share, plus accrued dividends to the date set for repurchase. Consequently, this preferred stock to be redeemed is classified as preferred stock subject to mandatory redemption within one year in the December 31, 1992 consolidated balance sheets. In 1992, the Company repurchased 7,135 shares of the 8.40% cumulative preferred series subject to mandatory redemption. During both 1991 and 1990, the

Company repurchased 13,760 shares of the 8.40% cumulative preferred series and 12,000 shares of the 7.50% cumulative preferred series subject to mandatory redemption. No other changes in preferred stock occurred in the three years ended December 31, 1992.

$25 par value:

Not subject to mandatory redemption: 8.40% series: $25.25.

5. Long-Term Debt

	(Thousands of Dollars) 1992	1991
Public Service Company of Colorado:		
First mortgage bonds:		
4⅜% series, paid March 1, 1992	**$ –**	$ 8,800
8.95% series, paid May 1, 1992	**–**	75,000
4½% series, due June 1, 1994	**35,000**	35,000
5⅜% series, due May 1, 1996	**35,000**	35,000
5¾% series, due July 1, 1997	**35,000**	35,000
6¾% series, due July 1, 1998	**25,000**	25,000
8½% series, due September 1, 2000	**35,000**	35,000
7¼% series, due February 1, 2001	**40,000**	40,000
7½% series, due August 1, 2002	**50,000**	50,000
7⅜% series, due June 1, 2003	**50,000**	50,000
8¼% series, due March 1, 2004	**100,000**	–
9⅜% series, due October 1, 2005	**49,500**	49,500
8½% series, due November 1, 2007	**50,000**	50,000
9¼% series, due October 1, 2008	**50,000**	50,000
9⅜% series, due July 1, 2020	**75,000**	75,000
8⅜% series, due March 1, 2022	**150,000**	–
Pollution Control Series A,		
5¾%, due March 1, 2004	**24,000**	24,000
Pollution Control Series B:		
7⅜%, due December 1, 1995	**2,500**	2,500
8%, due December 1, 2004	**35,000**	35,000
Pollution Control Series C:		
7¼%, due October 1, 2004	**15,000**	15,000
7⅜%, due October 1, 2005	**1,960**	1,960
7⅜%, due October 1, 2006	**2,105**	2,105
7⅜%, due October 1, 2007	**2,260**	2,260
7⅜%, due October 1, 2008	**2,425**	2,425
7⅜%, due October 1, 2009	**26,250**	26,250
Pollution Control Series E,		
9⅞%, due May 1, 2013	**42,000**	42,000
Pollution Control Series F,		
7⅜%, due November 1, 2009	**27,250**	27,250
Secured Medium-Term Notes, Series A:		
8.38%, due January 12, 1994	**10,000**	10,000
8.375%, due January 17, 1994	**10,000**	10,000
8.55%, due January 11, 1995	**20,000**	20,000
8.82%, due January 15, 1996	**15,000**	15,000
8.90%, due August 1, 1997	**5,000**	5,000
8.90%, due August 15, 1997	**5,000**	5,000
6.66%, due October 30, 1997	**20,000**	–
6.66%, due October 30, 1997	**5,000**	–
9%, due April 1, 1998	**5,000**	5,000
9.08%, due March 15, 1999	**10,000**	10,000
8.90%, due August 10, 1999	**5,000**	5,000
7.23%, due November 1, 1999	**10,000**	–

	(Thousands of Dollars)	
	1992	1991
Public Service Company of Colorado: *(continued)*		
First mortgage bonds: *(continued)*		
Secured Medium-Term Notes, Series A: *(continued)*		
9.25%, due March 27, 2001	**$ 6,500**	$ 6,500
7.28%, due October 22, 2002	**5,000**	–
7.28%, due October 22, 2002	**5,000**	–
7.65%, due October 30, 2002	**5,000**	–
Unsecured promissory notes:		
7⅞%, due December 1, 1997	**20,000**	–
10.35%, due in installments through December 1, 1999	**2,667**	–
11.60%, due May 1, 2015	**5,000**	–
12.875%, due May 1, 2025	**10,000**	–
Unamortized premium	**485**	545
Unamortized discount	**(2,136)**	(1,039)
Capital lease obligations, 8.40%-14.65%, due in installments through April 1, 1995	**1,649**	2,230
	1,139,415	887,286
Cheyenne Light, Fuel and Power Company:		
First mortgage bonds:		
7⅞% series, due April 1, 2003	**4,000**	4,000
Industrial Development Revenue Bonds, 7.25%, due September 1, 2021	**7,000**	7,000
10.70 % unsecured notes, due September 1, 1995	**8,000**	8,000
Western Gas Supply Company:		
Unsecured promissory notes:		
7⅞%, due December 1, 1997	**–**	20,000
10.35%, due in installments through December 1, 1999	**–**	4,000
11.60%, due May 1, 2015	**–**	5,000
12.875%, due May 1, 2025	**–**	10,000
Unamortized discount	**–**	(292)
1480 Welton, Inc.:		
12.50% secured promissory note, due in installments through March 1, 1998	**7,903**	8,906
13.25% secured promissory note, due in installments through October 1, 2016	**32,527**	32,708
Fuel Resources Development Co.:		
Unsecured note, paid June 30, 1992, interest rate fluctuates with the New York Federal Funds rate (4.49% at December 31, 1991)	**–**	7,000
Capital lease obligations, 7.09% due in installments through May 1, 1996	**781**	–
Bannock Center Corporation:		
8% mortgage note, paid in installments through January 1, 1992	**–**	200
Natural Fuels Corporation:		
12.25% secured note, due in installments through May 23, 1994	**6**	9
Capital lease obligations, 8¾% due in installments through August 31, 1996	**147**	148
	1,199,779	993,965
Less: Maturities due within one year	**2,820**	93,474
	$1,196,959	$900,491

In October 1990, the Company filed a registration statement with the SEC relating to a $500 million principal amount of First Mortgage Bonds of which $200 million was subsequently designated for offering pursuant to a secured medium-term note program. During 1992, $250 million of First Mortgage Bonds (other than medium-term notes) were issued in connection with the acquisition of Colorado-Ute assets. As of December 31, 1992, the Company has issued $141.5 million under the secured medium-term note program. The Company will continue from time to time to offer such secured medium-term notes and bonds based on market conditions and other factors.

On October 7, 1992, the CPUC approved the refinancing of certain outstanding bonds with new issue lower cost debt securities at the Company's discretion prior to December 31, 1995. The Company will continue to evaluate and consider refinancing long-term debt, depending on current market rates and other related factors.

At December 31, 1992, PS Colorado Credit Corporation (PSCCC) had in place a program to sell its private medium-term notes, with maturities from nine months to ten years, up to an amount of $100 million outstanding at any one time. There were no amounts outstanding under this program at December 31, 1992 or 1991.

On December 31, 1992, WestGas assigned its unsecured promissory notes totaling $37.7 million to the Company in anticipation of the merger of WestGas into the Company, effective January 1, 1993.

Substantially all properties of the Company and its subsidiaries, other than expressly excepted property, are subject to the liens securing the Company's First Mortgage Bonds or the mortgage bonds and notes of subsidiaries.

The aggregate annual maturities and sinking fund requirements during the five years subsequent to December 31, 1992 are (in thousands of dollars):

Year	Maturities	Sinking Fund Requirements	Total
1993	$ 2,820	$4,605	$ 7,425
1994	58,306	4,755	63,061
1995	33,172	4,755	37,927
1996	51,602	5,505	57,107
1997	90,821	5,155	95,976

The Company expects to satisfy its sinking fund obligations through the application of property additions, and Cheyenne expects to satisfy $60,000 of its sinking fund obligations annually through the application of property additions.

6. Notes Payable and Commercial Paper

Information regarding notes payable and commercial paper for the years ended December 31, 1992 and 1991 is as follows:

	1992 (Thousands of Dollars)	1991
Notes payable to banks (weighted average interest rates of 4.05% at December 31, 1992 and 5.58% at December 31, 1991)	**$ 95,800**	$ 12,100
Commercial paper (weighted average interest rates of 4.09% at December 31, 1992 and 5.55% at December 31, 1991)	**154,826**	188,540
	$ 250,626	$200,640
Maximum amount outstanding at any month-end during the period	**$ 259,811**	$200,640
Weighted average amount (based on the daily outstanding balance) outstanding for the period (weighted average interest rates of 4.24% for the year ended December 31, 1992 and 6.47% for the year ended December 31, 1991)	**$ 231,770**	$179,494

7. Bank Lines of Credit and Compensating Bank Balances

Arrangements by the Company and its subsidiaries for committed lines of credit are maintained entirely by fee payments in lieu of compensating balances. Arrangements for uncommitted lines of credit have no fee or compensating balance requirements.

On January 15, 1992, the Company and PSCCC extended a credit facility with several banks providing $300 million in bank lines of credit. This facility, which is used primarily to support the commercial paper issuance of the Company and PSCCC, alternatively provides for direct borrowings thereunder. In addition, BCC, Cheyenne, 1480 Welton, Inc., Fuelco and WestGas have access to $100 million under the facility which has been guaranteed by the Company. This facility replaced the $300 million individually arranged bank lines of credit in effect at the time it was entered into. On December 14, 1992, the facility's maturity date was extended to November 22, 1993. Effective January 1, 1993 with this extension, the amount guaranteed by the Company was increased to $125 million and PSR Investments, Inc. was added as an additional obligor.

At December 31, 1992 and 1991, there were $300 million in available commitments of which $49.4 million and $111.5 million remained unused, respectively. Generally, the banks as participants in the facility would have no obligation to continue their commitments if there has been a material adverse change in the consolidated financial condition, operations, business or otherwise, that would prevent the Company and its subsidiaries from performing their obligations under the facility.

Natural Fuels Corporation (Natural Fuels) had arrangements for a committed line of credit in the amount of $4 million of which $3.9 million was unused at December 31, 1992 and 1991.

At December 31, 1991, WestGas and Cheyenne had individual arrangements for committed bank lines of credit of $25 million and $2 million, respectively. The unused amounts of these committed lines of credit at December 31, 1991 were $12.9 million and $2 million, respectively.

Individual arrangements for uncommitted bank lines of credit totaled $20 million at December 31, 1992 and $60 million at December 31, 1991, of which all remained unused for each of the respective years. The Company and its subsidiaries generally may borrow under uncommitted preapproved lines of credit upon request; however, the banks have no firm commitment to make such loans.

8. Commitments and Contingencies

Rate filings

On January 20, 1993, the Company filed a general rate case with the CPUC. In its filing, the Company seeks increases in electric, gas, and steam rates designed to produce an increase in total annual revenues of $81.6 million on the basis of a rate of return on rate base of 10.5%, including a rate of return on common equity of 13%. The Company is seeking the use of a fully forecasted test year ended June 30, 1994 in establishing revenue requirements, the full normalization method of accounting for income taxes and modifications to the calculation of the Electric Cost Adjustment (ECA). In accordance with an agreement with the CPUC staff, the Company will file with the CPUC in early March 1993 supplemental information demonstrating the effect on the requested rate increase of the use of an historical test year ended September 30, 1992. While this information has not been finalized, the Company believes that the use of such historical test year, without any other change in ratemaking principles from those requested, would have the effect of reducing the increase in annual revenues by more than 50%. The submission of the supplemental information does not affect the Company's request for the use of a forecasted test year. The Company anticipates receiving a decision from the CPUC by September 1993. The Company cannot predict the amount of the rate increase, if any, which the CPUC will ultimately authorize.

The Company advised in its rate case filing that it may seek modifications to the Supplemental Settlement Agreement to the 1986 Fort St. Vrain Stipulation and Settlement Agreement so as to recover costs of postretirement benefits consistent with Statement of Financial Accounting Standards No. 106-"Employers' Accounting for Postretirement Benefits Other Than Pensions" (SFAS 106) (see Note 10).

On January 31, 1991, the Company filed a rate case with the CPUC requesting an increase in revenue levels, among other things. During June 1991, the Company, the OCC and other parties signed two Settlement Agreements and filed a joint motion to dismiss the Company's rate case. The terms of the Settlement Agreements and the dismissal of the rate case were approved by the CPUC on July 17, 1991. The first Settlement Agreement, addressing revenue requirements, provided, among other things: (1) for a $22 million refund to electric customers in August 1991; (2) that the Company would not request an increase in base rates prior to November 2, 1992 and it would not seek an increase in base rates to be effective prior to July 1, 1993; and (3) for a reduction in electric rates of 3.38%, or approximately $3 million per month, for the period beginning January 1, 1992 and ending June 30, 1993, or until the effective date of new rates.

A separate agreement, related to the first Settlement Agreement, established a procedure by which the CPUC can monitor the Company's financial results until new rates become effective. For monitoring purposes, the CPUC will use the regulatory principles from the Company's last rate case which became effective in May 1984 and a rate of return on regulated equity range of 12.5% to 13.5% as a benchmark against which the Company's future financial performance would be measured.

The second Settlement Agreement resulted in the opening of four new dockets with the CPUC. The first docket, initiated on July 15, 1991, addressed the issues of decoupling the revenues of the Company from its sales, and reviewed and established regulatory incentives to encourage Demand Side Management (DSM) programs. On January 14, 1993, the CPUC issued a decision adopting cost recovery and incentive mechanisms. The cost recovery and incentive mechanisms apply only to the DSM programs developed through the DSM Collaborative Process discussed below. The CPUC specified that the matters of decoupling revenues from sales and of providing a long-term mechanism that encourages DSM investments would be addressed in the Company's 1993 general rate case filing discussed above.

In regard to DSM programs, the second docket, the DSM Collaborative Process (also opened on July 15, 1991), established a collaborative process among the Company, public interest groups, consumers, and industry to examine the potential for DSM investment, the potential of DSM for all customer classes and the implementation of such DSM programs. Through the collaborative process group, DSM programs were proposed to the CPUC on February 16, 1993. These DSM programs are scheduled to be implemented over a three year period. The Company is uncertain whether a similar collaborative process will be pursued beyond this initial three year period.

The third docket, opened October 1, 1991, addressed Integrated Resource Planning (IRP) which takes into account energy demand, supply and environmental matters. On December 30, 1992, the CPUC issued a decision that adopts the rules for the state's utilities to follow in preparing electric load forecasts and in securing broad public participation for assessing both supply- and demand-side options. The IRP is intended to minimize electric rates while preserving reliable electric service and managing risks. The Company is required to file its first IRP by August 1, 1993. Subsequent IRPs are to be filed every three years with an application requesting CPUC approval of IRP.

On December 2, 1991, the fourth docket was opened to examine low income energy assistance options, including, among other issues, costs, eligibility plans, forms of assistance and methods of funding assistance. On December 2, 1992, the CPUC issued an order that provides for an initial two year program that may be extended after determining its cost effectiveness. The two year program may not exceed total expenditures of $7.2 million. The CPUC decision provides for a cost recovery mechanism.

Rate adjustments currently in effect

On February 4, 1988, the Company, the OCC and the staff of the CPUC reached an electric rate reduction agreement in response to the Company's earnings being in excess of regulatory authorization. Subsequently, these reductions were adjusted and extended to November 27, 1990. As a result of these negotiated rate settlements and in anticipation of the 1993 rate case discussed above, the Company implemented, following CPUC approval, various rate adjustments designed to rectify the earnings imbalance which exists between the electric and gas departments. Such rate adjustments between the electric and gas departments are achieved through a negative 1.41% electric adjustment and a positive 2.77% gas adjustment. These rate adjustments were implemented on November 27, 1990 and will remain in effect until the effective date of new rates pursuant to the rate case discussed above.

As a consequence of the first Settlement Agreement approved in 1991 and the rate adjustments discussed above, electric revenues were reduced by approximately $46.9 million, $14.9 million and $24.0 million for the twelve month periods ending December 31, 1992, 1991 and 1990, respectively. Gas revenues, as a result of the adjustments discussed above, were increased by approximately $14.8 million and $13.8 million for the years 1992 and 1991, respectively. There were no corresponding gas rate adjustments in effect during 1990.

Environmental issues

The Lowry Landfill in southeast metropolitan Denver has been designated by the Environmental Protection Agency (EPA) as a Superfund hazardous waste site pursuant to the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). Under CERCLA, the EPA has notified Potentially Responsible Parties (PRPs) of their potential joint and several liability for the cleanup of the site. The Company, which had used the site for disposal of trash and neutralized liquids generated in its boiler cleaning process, was named, along with many others, as a PRP at the Lowry Landfill.

In September 1991, the EPA submitted a draft Consent Decree to the Lowry Landfill De Minimis Group (De Minimis Group), of which the Company is a member, and initiated negotiations on the terms and conditions of a settlement. The draft Consent Decree provided for a total cleanup cost of $536 million.

In November 1991, Chemical Waste Management, Inc. offered to assume all liabilities for, and indemnify and defend the individual parties within the De Minimis Group based on their proportionate share of a cleanup cost of $500 million. On March 23, 1992, the Company entered into a settlement and indemnification agreement with Chemical Waste Management, Inc. under which the Company's cleanup cost is approximately $1.3 million. Chemical Waste Management, Inc. has agreed to indemnify, assume the liability of, defend, and hold harmless the Company from any and all claims of third parties, including the United States and the State of Colorado.

The proposed Elitch Gardens Amusement Park site near downtown Denver has revealed low level, widespread contamination. The Company had used the site in the past as a manufactured gas plant site and is one of three PRPs. An agreement has been signed releasing the Company from responsibility for the first $2 million of cleanup costs. Any costs exceeding that amount will be the responsibility of the Company; however, the Company believes that the cleanup costs will not exceed $2 million.

Under CERCLA, the EPA has identified, and a Phase II environmental assessment has revealed, low level, widespread contamination from hazardous substances at the Barter Metals Company (Barter) properties located in central Denver. For an estimated 30 years, the Company sold scrap metal and electrical equipment to Barter for reprocessing. The Company is involved in cleanup of this site which began in November 1992 and is expected to be completed in 1993. The total project cost is currently estimated to be approximately $4 million of which $0.3 million has been incurred at December 31, 1992. Negotiations among the parties as to allocation of such costs are continuing.

The Company believes that it is probable that costs incurred related to the cleanup of the Lowry Landfill and Barter sites will be recovered through claims made against the Company's historic insurance companies and filed in the District Court in and for the City and County of Denver in December 1992. In addition to these sites, the Company has identified several sites where cleanup of hazardous substances may be required. While potential liability and settlement costs are still under investigation and negotiation, the Company believes that the resolution of these matters will not have a material effect on its financial position or results of operations. The Company fully intends to pursue the recovery of all costs incurred for such projects through insurance claims and/or the rate regulatory process. To the extent any costs are not recovered through the options listed above, the Company would be required to recognize an expense for such unrecoverable amounts.

On November 15, 1990, President George Bush signed into law the Federal Clean Air Act Amendments of 1990 aimed at lowering the acidity of rainfall in the United States. The Amendments require coal burning power plants to reduce Sulfur Dioxide (SO_2) and Nitrogen Oxide (NOx) emissions to specified levels. The Company is currently meeting the emission standards placed on SO_2 through the use of low sulfur coal. The Company will be required to modify certain boilers by the year 2000 to reduce NOx emissions at an estimated total future cost of approximately $18.6 million.

On October 7, 1988, the results of the Metro Denver Brown Cloud Study, along with a ten point recommendation, were released by the Governor of the State of Colorado. The Company continues to voluntarily reduce SO_2 and NOx emissions in the metro area through the Brown Cloud ten point program and the Clean Coal Technology III program.

The Company believes that consistent with historical regulatory treatment, any costs to comply with pollution control regulations would be recovered from its customers. However, no assurance can be given that this practice will continue in the future.

Purchase requirements

Coal

At December 31, 1992, the Company had in place long-term contracts for the purchase of coal for existing power plants through 2017. The minimum remaining quantities to be purchased under these contracts total 107 million tons. The coal purchase prices are subject to periodic adjustment for inflation and market conditions. Total estimated obligations, based on current prices, were approximately $1.1 billion at December 31, 1992.

Coal transportation

The Company has entered into long-term contracts for the transportation of coal by railroad in Company-owned or leased railcars to existing power plants. These agreements, expiring in 1997, provide for a minimum remaining transport quantity of 26 million tons. Coal transport contract prices are negotiated based on market conditions and are adjusted periodically for inflation and operating factors. Total estimated obligations, based on current prices, were approximately $135 million at December 31, 1992.

Natural gas

The Company and its regulated subsidiaries have entered into long-term contracts expiring through 2002 for the purchase of natural gas in anticipation of future requirements. In general, purchase prices under these contracts are based on market price formulas. Total estimated obligations, based on current prices, were $273 million at December 31, 1992. The Company has two primary pipeline suppliers of gas which will continue to supply gas under contracts until no later than October 1, 1993. At this time, in compliance with rules established by FERC Order 636, the annual gas volumes purchased from these suppliers through sales agreements will be converted to transportation rights. The Company believes, however, that it will continue to purchase gas supplies from these interstate pipelines. This continued purchase of gas will minimize the gas supply realignment costs of the pipeline suppliers which may otherwise be applicable under FERC Order 636. Gas supply realignment costs, assuming gas purchases are not continued, are currently estimated by the pipeline suppliers to be approximately $83.5 million. Contract negotiations with the pipelines are in process and are expected to be completed in 1993.

Purchased power

The Company and Cheyenne have entered into agreements for purchased power to meet system load and energy requirements, to replace generation from Company-owned units under maintenance and outages, and to provide the Company's operating reserve obligation to the Inland Power Pool. These agreements expire on various dates through the year 2025. The price of the energy purchased is determined by contracts, which have been accepted by the FERC, providing generally for recovery by the sellers of their costs. The suppliers under these contracts have obtained financing for their facilities based on such contracts. Total payments associated with such contracts were $159 million, $170 million and $165 million for 1992, 1991 and 1990, respectively. The following table shows the fixed portion (which includes demand and energy costs) of commitments under these contracts (payable provided power is available) for each of the next five years and in the aggregate thereafter.

	(Thousands of Dollars)
Years ending December 31	
1993	$ 100,749
1994	151,399
1995	187,394
1996	188,312
1997	184,591
1998 and thereafter	1,968,514
Total	$ 2,780,959

In addition, the Company has other long-term purchased power contracts expiring through 2022 that include firm purchase commitments. These contracts similarly provide for recovery by sellers of their costs. Estimated firm commitments (payable provided power is available) under these contracts total $3.6 billion. The estimated total firm commitment amount includes contracts executed as part of the acquisition of Colorado-Ute assets discussed in Note 9.

Historically, all minimum coal, coal transportation, natural gas, and purchased power requirements have been met.

Miscellaneous purchases
Commitments made for the purchase of materials, plant and equipment and other various items aggregated approximately $240 million at December 31, 1992.

Fort St. Vrain
See Note 3 for certain contingencies relating to Fort St. Vrain.

Leasing program
The Company has in place a leasing program which includes a provision whereby the Company indemnifies the lessor for all liabilities which might arise from the acquisition, use, or disposition of the leased property. See Note 15 for additional discussion of leasing information.

9. Jointly-Owned Electric Utility Plants

On April 15, 1992, the Company, Tri-State Generation and Transmission Association, Inc. (Tri-State), PacifiCorp Electric Operations (PacifiCorp), and Intermountain Rural Electric Association completed the acquisition of assets of Colorado-Ute pursuant to the Joint Plan of Reorganization (Joint Plan) as filed and approved in the Chapter 11 reorganization of Colorado-Ute in the U.S. Bankruptcy Court.

The Company, Tri-State and PacifiCorp agreed to divide the electric load, assets and liabilities of Colorado-Ute. Under the agreement, Tri-State serves ten cooperatives that became members of Tri-State, representing about half the load of Colorado-Ute. The remaining four cooperatives (Holy Cross Electric Association, Inc., Yampa Valley Electric Association, Inc., Grand Valley Rural Power Lines, Inc. and Intermountain Rural Electric Association), which serve approximately 105,000 customers and represent the other half of the Colorado-Ute load (approximately 1.8 billion Kwh in 1991), became wholesale customers of the Company.

The generating assets of Colorado-Ute, primarily the Craig and Hayden coal-fired plants in northwestern Colorado, were divided among the Company, Tri-State and PacifiCorp. The Company acquired approximately 331 Mw of net dependable generating capability. Other property acquired included transmission and distribution lines and facilities.

The acquisition cost of the assets to the Company was approximately $265 million. The Company financed this asset acquisition primarily with debt instruments. On April 14, 1992, the Company issued $250 million in First Mortgage Bonds consisting of $100 million 8 1/8% series due 2004 and $150 million 8 3/4% series due 2022.

As part of the CPUC approval of the asset acquisition, recovery of a $10 million acquisition adjustment over a five year period, effective April 15, 1992, was authorized, subject to final review once the transaction was completed. On December 7, 1992, in connection with this final review, the Company filed an application with the CPUC requesting recovery of certain costs related to the Colorado-Ute acquisition and the adjusted fuel cost as approved by the CPUC previously. This filing requests that the CPUC approve recovery of an $11 million acquisition adjustment over a five year period. No CPUC action has been taken to date relating to this application.

In addition to the agreements discussed above, the Company entered into various purchase power agreements with Tri-State for the purchase of 200 Mw and PacifiCorp for the purchase of 176 Mw. These purchase agreements expire from 2011 to 2022 and will be in addition to existing purchase agreements. Short-term firm purchases will decrease as a result of these new purchased power agreements.

The FERC approved the acquisition of the Colorado-Ute assets and issued its final order under Section 203 of the Federal Power Act (FPA) on March 23, 1992. The FERC issued a final order pursuant to Section 205 of the FPA approving the rates specified in the purchased power agreements for the Company's four new wholesale customers on June 12, 1992. The Section 205 order allowed the Company to collect the approved rates as of April 15, 1992, the Joint Plan's effective date.

As a result of the acquisition of Colorado-Ute assets, the Company is responsible for its proportionate share of operating expenses (reflected in the 1992 consolidated statement of income) and construction expenditures. Following is the Company's investment in jointly-owned facilities and its ownership percentages as of December 31, 1992.

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
		(Thousands of Dollars)		
Hayden Unit 1	$ 35,008	$27,145	$ 224	75.50
Hayden Unit 2	36,564	16,485	122	37.40
Hayden Common Facilities	20,855	10,315	1,659	53.10
Craig Units 1 & 2	56,718	17,283	158	9.72
Craig Common Facilities Units 1 & 2	7,398	2,285	211	9.72
Craig Common Facilities Units 1, 2 & 3	8,125	2,410	154	6.47
Transmission Facilities, Including Substations	68,574	17,177	-	42.0-73.0
	$233,242	$93,100	$2,528	

10. Employee Benefits

Pensions

The Company and its subsidiaries (excluding Natural Fuels) maintain a noncontributory defined benefit pension plan covering substantially all employees. During 1991, the Board of Directors of the Company approved an amendment that removed the 35 years of credited service limitation in the retirement benefit formula and redefined eligible compensation used in the formula to be based on an employee's highest average compensation during any five years of credited service. In addition, during 1991, the Board of Directors of the Company approved an amendment and restatement of the Plan. The changes to the Plan were generally to comply with the Tax Reform Act of 1986 and did not result in a change in pension benefits.

The Company and its subsidiaries' funding policy is to contribute annually, at a minimum, the amount necessary to satisfy the Internal Revenue Service (IRS) funding standards. The net pension expense in 1992, 1991 and 1990 was comprised of:

		(Thousands of Dollars)	
	1992	1991	1990
Service cost	**$ 14,788**	$ 12,196	$ 11,441
Interest cost on projected benefit obligation	**35,695**	33,322	31,436
Loss (return) on plan assets	**(34,317)**	(79,467)	1,773
Amortization of net transition asset at adoption of Statement of Financial Accounting Standards No. 87	**(3,674)**	(3,673)	(3,674)
Other items	**(6,317)**	39,807	(38,726)
Net pension expense	**$ 6,175**	$ 2,185	$ 2,250

Significant assumptions used in determining net periodic pension cost were:

	1992	1991	1990
Discount rate	**8.2%**	8.9%	8.7%
Expected long-term increase in compensation level	**5.5%**	5.5%	5.5%
Expected weighted average long-term rate of return on assets	**11%**	11%	11%

Variances between actual experience and assumptions for costs and returns on assets are amortized over the average remaining service lives of employees in the plan.

A comparison of the actuarially computed benefit obligations and plan assets at December 31, 1992 and 1991, is presented in the following table. Plan assets are stated at fair value and are comprised primarily of corporate debt and equity securities, a real estate fund and government securities held either directly or in commingled funds.

	(Thousands of Dollars)	
	1992	1991
Actuarial present value of benefit obligations:		
Vested	**$ 336,632**	$ 314,924
Nonvested	**29,800**	28,543
	366,432	343,467
Effect of projected future salary increases	**110,776**	103,586
Projected benefit obligation for service rendered to date	**477,208**	447,053
Plan assets at fair value	**(483,941)**	(459,847)
Plan assets in excess of projected benefit obligation	**6,733**	12,794
Unrecognized net loss	**34,763**	27,628
Prior service cost not yet recognized in net periodic pension cost	**10,870**	11,672
Unrecognized net transition asset at January 1, 1986, being recognized over 17 years	**(36,737)**	(40,411)
Prepaid pension asset	**$ 15,629**	$ 11,683

Significant assumptions used in determining the benefit obligations were:

	1992	1991
Discount rate	**8.2%**	8.2%
Expected long-term increase in compensation level	**5.5%**	5.5%

Postretirement benefits other than pensions

In addition to providing pension benefits, the Company and its subsidiaries provide certain health care and life insurance benefits for retired employees. A significant portion of the employees become eligible for these benefits if they reach either early or normal retirement age while working for the Company or its subsidiaries. The cost of providing health care and life insurance benefits to active, retired and disabled employees amounted to $36.6 million, $33.4 million and $30.4 million in 1992, 1991 and 1990, respectively. The cost of providing these benefits for retired employees (2,480 in 1992, 2,375 in 1991 and 2,338 in 1990) was $9.1 million, $8.0 million and $7.5 million, respectively. Active and disabled employees' (6,434 in 1992, 6,407 in 1991 and 6,709 in 1990) benefit costs were $27.5 million, $25.4 million and $22.9 million, respectively.

In December 1990, the Financial Accounting Standards Board (FASB) issued SFAS 106 which establishes the accounting and reporting standards for postretirement benefits other than pensions (OPEB). The statement requires the accrual, during the years that an employee renders service to the Company, of the expected cost of providing postretirement benefits to the employee and the employee's beneficiaries and covered dependents. The statement is effective January 1, 1993.

During 1991, the CPUC approved a rate Settlement Agreement (see Note 8) and the Fort St. Vrain Supplemental Settlement Agreement (see Note 3), both of which address the accounting and regulatory treatment of the costs of postretirement benefits other than pensions. The rate Settlement Agreement stipulates that the Company continue to recover such costs as paid until the date new rates are effective. The Fort St. Vrain Supplemental Settlement Agreement stipulates that, on the effective date of new rates, the Company will be allowed to recover the costs of postretirement benefits other than pensions as accrued in accordance with the provisions of SFAS 106, modified as follows:

- the actuarial calculation of such liability will include a return on assets that reflects monthly contributions net of benefit payments throughout the year;
- the attribution period will reflect each employee's expected retirement date rather than the full eligibility date;
- a forty-year levelized principal and interest amortization will be used for the transition obligation; and
- the accounting and regulatory treatment for life insurance benefits will remain on an as paid basis.

Based on an evaluation prepared by the Company's actuary, the postretirement benefit obligation at January 1, 1993, determined as prescribed by the CPUC for the Company, is estimated to be $183.7 million. The 1993 expense for these benefits, based on this approach, is estimated to be $17.4 million. The postretirement benefit obligation at January 1, 1993, determined in accordance with SFAS 106, is estimated to be $254.2 million. The 1993 expense, determined in accordance with SFAS 106, is approximately $38.3 million.

Pursuant to the Fort St. Vrain Supplemental Settlement Agreement, the Company had anticipated that any difference in expense resulting from the CPUC prescribed approach and the approach required by SFAS 106 would be reflected as a regulatory asset in the consolidated balance sheet and would be recovered from customers over future periods.

In January 1993, however, the Emerging Issues Task Force (EITF) provided guidance as to what additional criteria or evidence is needed for a rate regulated enterprise to recognize a regulatory asset equal to the amount of OPEB costs for which rate recovery has been deferred. Generally, a utility must determine that it is probable future rates will allow for the recovery of this OPEB regulatory asset. In addition, no later than approximately five years from the date of adoption, rates must include full SFAS 106 costs and the recovery of the regulatory asset established during the deferral period must be accomplished within approximately twenty years. The EITF's conclusions do not include the CPUC approach prescribed in the Fort St. Vrain Supplemental Settlement Agreement.

As a result, and under the provisions of the Fort St. Vrain Supplemental Settlement Agreement, the parties to this Agreement have initiated discussions and negotiations focused on resolving this issue to the mutual acceptance of all parties without disrupting the overall Agreement. While these discussions are in the preliminary stages, the Company believes the matter will ultimately be resolved in a manner that will comply with the conclusions reached by the EITF relative to the recognition of OPEB regulatory assets for which rate recovery has been deferred. Should the currently approved methodology not be modified to conform with the EITF consensus, the Company would be required to record as an expense the difference between the amounts allowed in rates and that required by SFAS 106.

Postemployment benefits

In November 1992, the FASB issued Statement of Financial Accounting Standards No. 112-"Employers' Accounting for Postemployment Benefits" (SFAS 112) which establishes the accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement (postemployment benefits). This statement is effective January 1, 1994. The Company is currently analyzing the provisions of SFAS 112 and believes application of the new standard will not have a material financial impact on the Company's financial position or results of operations.

Incentive compensation

The Company's shareholders approved the Omnibus Incentive Plan at the 1992 Annual Shareholders Meeting. The Omnibus Incentive Plan provides for annual and long-term incentive awards for officers and management employees. One million shares of common stock have been authorized for awards under the Omnibus Incentive Plan. The Omnibus Incentive Plan allows for the issuance of stock options and/or restricted shares. The stock options would be issued at the then fair market value of the Company's common stock and vest over a three year period. No awards were made under the Omnibus Incentive Plan in 1992.

During 1992, the Company established the Employee Incentive Plan which recognizes the contribution of all employees toward corporate financial goals. This plan is effective beginning in 1993 and provides for a cash award to employees if corporate performance goals are met during 1993.

11. Financial Instruments

Fair value of financial instruments

The estimated fair values of the Company's financial instruments are as follows:

	(Thousands of Dollars) 1992 Carrying Amount	Fair Value
Assets		
Cash and temporary cash investments	$ 51,155	$ 51,180
Investments, at cost, for which it is:		
Practicable to estimate fair value	15,221	16,535
Not applicable*	4,004	
Liabilities		
Notes payable and commercial paper	250,626	249,760
Preferred stock subject to mandatory redemption, including amounts redeemable within one year	45,654	45,895
Dividends payable	32,248	32,248
Customers' deposits	16,807	16,807
Accrued interest**	31,032	31,032
Other deferred credits that are:		
Practicable to estimate fair value	5,644	5,644
Not applicable*	13,842	
Long-term debt:		
Including amount due within one year	1,198,007	1,218,998
Capital leases excluded*	1,772	

* Some assets or liabilities do not meet the definition of a financial instrument, or disclosure is not required.
** Accrued interest includes notes payable, customers' deposits and long-term debt.

The following methods and assumptions were used to estimate the fair value of each class of financial instrument.

Cash and temporary cash investments
The carrying amount is a reasonable approximation of fair value due to the nature of the instruments and the length of maturity. The fair value of the majority of these instruments is equal to the amount payable upon demand at the reporting date. The fair value of the remainder of these instruments was based on dealer market prices.

Investments, at cost
The fair value of the majority of these investments are based on a reasonable estimate of fair value arrived at by using quoted market prices for similar investments. For the remaining investments, the carrying amount is a reasonable approximation of fair value due to the nature of the instruments. Investments categorized as not applicable consist primarily of the investment in the natural gas transmission project owned by WGT.

Notes payable and commercial paper
The carrying amount of these financial instruments is a reasonable approximation of their fair value due to their nature and short maturity. The majority of these instruments are comprised of commercial paper, the fair value of which is estimated by discounting the accrued interest.

Preferred stock subject to mandatory redemption
The fair value was based on quoted market prices for similar instruments.

Dividends payable
Due to the nature and length of maturity of dividends payable, the carrying amount approximates fair value.

Customers' deposits
The fair value of customers' deposits is the obligation payable upon meeting the conditions for the return of the deposit. Due to the nature of these deposits, the carrying amount is a reasonable approximation of fair value.

Other deferred credits
Due to the nature of these deferred credits, the carrying amount approximates fair value. The deferred credits classified as not applicable include primarily deferred compensation amounts as well as certain other miscellaneous items.

Long-term debt
The estimated fair value of the Company's debt was based on quoted market prices or securities with similar terms and maturities. Anticipated regulatory treatment of the difference between carrying and fair value of the Company's long-term debt, if in fact it were settled at amounts approximating those above, would dictate that these amounts be

used to reduce or increase the Company's rates over a prescribed amortization period. Accordingly, the settlement would not result in a material impact on the Company's financial position or results of operations.

Other items
In accordance with NRC decommissioning funding requirements for nuclear power reactors, the Company has obtained a $125 million irrevocable letter of credit which bears a market interest rate. The NRC is the beneficiary of this letter of credit. At December 31, 1992, no amounts were outstanding under this letter of credit. In general, such letter of credit may be exercised by the NRC in the event the Company is in default of its performance obligations under the decommissioning plan. In addition, as discussed in Note 7, the Company and its subsidiaries have unused available commitments of $49.4 million under a credit facility. This facility is short-term and bears a market interest rate.

The carrying amount of accounts payable approximates fair value due to the length of maturity and nature of the instruments.

Accounts receivable
The carrying amount of accounts receivable is a reasonable approximation of fair value due to the recognition of uncollectible amounts, the nature of the instruments and the length of maturity.

The Company is required to provide service and grant credit to a diverse customer base within its service territory. The Company may require security deposits prior to providing service to customers depending upon an assessment of credit worthiness. The Company reviews customer accounts receivable on a regular basis and has in effect an uncollectible accounts policy.

The Company has reviewed its customer base for concentrations of credit risk and has determined that no individual customer or group of customers engaged in similar activities represent a material concentration of credit risk to the Company.

12. Income Tax Expense

Income tax expense consists of the following:

		(Thousands of Dollars)	
	1992	1991	1990
Current income taxes:			
Federal	**$ 34,265**	$40,156	$40,742
State	**1,513**	8,240	3,931
	35,778	48,396	44,673
Deferred income taxes (benefits) related to:			
Contributions in aid of construction	**(8,006)**	(4,789)	(3,300)
Accelerated depreciation	**17,789**	20,721	23,893
Net unbilled revenues	**(914)**	(7,552)	(2,780)
Fort St. Vrain defueling and decommissioning	**15,831**	12,531	21,596
Termination of Synhytech project	**(10,063)**	–	–
Loss on sale of real estate investments	**7,986**	–	–
Alternative minimum tax	**145**	2,231	(5,114)
Other book-tax timing differences	**(259)**	2,980	(8)
	22,509	26,122	34,287
Amortization of investment tax credits	**(5,138)**	(5,230)	(4,982)
Total income taxes	**$ 53,149**	$69,288	$73,978

Deferred tax provisions are not recorded on certain book-tax timing differences. As of December 31, 1992, the cumulative net amount of such timing differences was $356.9 million. The tax effect of this amount is not recorded currently as regulatory commission procedures will result in such costs being charged to customers when the timing differences reverse and the related taxes are paid.

As a result of the Tax Reform Act of 1986, the Company determines its income tax liability to be the greater of regular income tax or AMT. For the year 1992, the Company has an excess AMT liability over regular tax liability which becomes a credit that will be applied against future regular tax liabilities. The cumulative AMT credit as of December 31, 1992 is approximately $3.7 million.

A reconciliation of the statutory U.S. income tax rates and the effective tax rates is as follows:

						(Thousands of Dollars)
	1992		1991		1990	
Tax computed at U.S. statutory rate on pre-tax accounting income	**$64,522**	**34.0%**	$74,454	34.0%	$74,842	34.0%
Increase (decrease) in tax from:						
Allowance for funds used during construction	**(3,827)**	**(2.0)**	(2,767)	(1.3)	(2,122)	(1.0)
Amortization of investment tax credits	**(5,128)**	**(2.7)**	(5,095)	(2.3)	(5,195)	(2.4)
State income taxes, net of federal income tax benefit	**997**	**0.5**	5,431	2.5	2,588	1.2
Capitalized software, net of amortization	**(7,115)**	**(3.7)**	(5,533)	(2.5)	(3,678)	(1.7)
Fort St. Vrain defueling and decommissioning	**2,992**	**1.6**	2,661	1.2	4,637	2.1
Uniform capitalization rules	**7,112**	**3.7**	4,732	2.1	1,723	0.8
Lease amortization	**3,407**	**1.8**	2,992	1.4	1,891	0.9
Cash surrender value of life insurance policies	**(4,620)**	**(2.4)**	(2,572)	(1.2)	(3,252)	(1.5)
Other–net	**(5,191)**	**(2.8)**	(5,015)	(2.3)	2,544	1.2
Total income taxes	**$53,149**	**28.0%**	$69,288	31.6%	$73,978	33.6%

On February 11, 1992, the FASB issued Statement of Financial Accounting Standards No. 109-"Accounting for Income Taxes" (SFAS 109). This statement is effective January 1, 1993. SFAS 109 requires an asset and liability approach to determining income tax liabilities. The new pronouncement requires recognition of the deferred tax liabilities for (a) income tax benefits associated with timing differences previously passed on to the Company's ratepayers (flow-through) and (b) the equity component of allowance for funds used during construction, and also requires the adjustment of deferred tax liabilities or assets for an enacted change in tax laws or rates, among other things.

Although the Company does not expect this new statement to have a material impact on its cash flow, results of operations or financial position because of the effect of rate regulation, the changes discussed above will require the Company to recognize additional accumulated deferred income taxes and a corresponding regulatory asset or liability to ratepayers (in amounts equal to the required deferred income tax adjustment) to reflect the future revenues or reduction in revenues that will be required when the above temporary differences turn around and are recovered or settled in rates.

13. Supplementary Income Statement Information

			(Thousands of Dollars)
	1992	1991	1990
Taxes (other than income taxes)			
Real estate and personal property taxes	**$51,378**	$43,746	$41,307
Social security taxes	**20,752**	20,398	19,951
City and state use taxes	**8,072**	8,397	8,625
Miscellaneous taxes	**7,839**	7,045	5,823
	$88,041	$79,586	$75,706
Charged:			
Directly to income:			
Operating expenses	**$82,040**	$74,335	$70,033
Other	**155**	138	124
To property, plant and equipment and various other accounts	**5,846**	5,113	5,549
	$88,041	$79,586	$75,706

The amounts of maintenance and repairs charged to clearing and other accounts and not shown separately in the consolidated financial statements were not material. There were no charges for royalties. The amounts of advertising costs were less than 1% of gross revenues.

14. Segments of Business

Segment information for the year ended December 31, 1992 is as follows:

(Thousands of Dollars)

	Electric	Gas (1)	Other (2)	Total
Operating revenues	$1,260,769	$568,886	$ 32,618	$1,862,273
Operating expenses, excluding depreciation and income taxes	886,215	529,225	16,740	1,432,180
Depreciation and amortization	97,274	27,621	2,422	127,317
Total operating expenses*	983,489	556,846	19,162	1,559,497
Operating income*	$ 277,280	$ 12,040	$ 13,456	$ 302,776
Plant construction expenditures**	$ 185,170	$ 73,685	$ 2,811	$ 261,666
Identifiable assets, December 31, 1992:				
Property, plant and equipment**	$2,331,116	$653,898	$ 92,495	$3,077,509
Materials and supplies	$ 67,618	$ 13,302	$ 82	81,002
Fuel inventory	$ 33,384	$ –	$ 189	33,573
Gas in underground storage	$ –	$ 14,393	$ –	14,393
Other corporate assets				553,106
				$3,759,583

(1) Includes additional expense of approximately $26.9 million associated with the termination of the Synhytech project.
(2) Includes additional expense of approximately $11.4 million associated with the loss on sale of BCC real estate properties.

* Before income taxes.
** Includes allocation of common utility property.

Segment information for the year ended December 31, 1991 is as follows:

(Thousands of Dollars)

	Electric	Gas	Other	Total
Operating revenues	$1,180,501	$587,609	$ 26,794	$1,794,904
Operating expenses, excluding depreciation and income taxes	847,798	518,157	4,355	1,370,310
Depreciation and amortization	83,416	25,831	2,481	111,728
Total operating expenses*	931,214	543,988	6,836	1,482,038
Operating income*	$ 249,287	$ 43,621	$ 19,958	$ 312,866
Plant construction expenditures**	$ 155,457	$ 99,771	$ 5,476	$ 260,704
Identifiable assets, December 31, 1991:				
Property, plant and equipment**	$2,006,776	$637,083	$101,941	$2,745,800
Materials and supplies	$ 65,242	$ 13,059	$ 66	78,367
Fuel inventory	$ 34,238	$ –	$ 209	34,447
Gas in underground storage	$ –	$ 14,803	$ –	14,803
Other corporate assets				589,251
				$3,462,668

* Before income taxes.
** Includes allocation of common utility property.

Segment information for the year ended December 31, 1990 is as follows:

(Thousands of Dollars)

	Electric	Gas	Other	Total
Operating revenues	$1,145,915	$561,712	$ 26,312	$1,733,939
Operating expenses, excluding depreciation and income taxes	806,287	503,415	5,326	1,315,028
Depreciation and amortization	79,950	23,669	2,908	106,527
Total operating expenses*	886,237	527,084	8,234	1,421,555
Operating income*	$ 259,678	$ 34,628	$ 18,078	$ 312,384
Plant construction expenditures**	$ 150,780	$105,233	$ 5,208	$ 261,221
Identifiable assets, December 31, 1990:				
Property, plant and equipment**	$1,939,301	$569,108	$100,852	$2,609,261
Materials and supplies	$ 60,404	$ 11,486	$ 29	71,919
Fuel inventory	$ 33,219	$ –	$ 208	33,427
Gas in underground storage	$ –	$ 13,701	$ –	13,701
Other corporate assets				505,532
				$3,233,840

* Before income taxes
** Includes allocation of common utility property.

15. Operating Leases

The Company and its subsidiaries maintain operating leases for equipment and facilities used in the normal course of business. The majority of these operating leases are under a leasing program that has initial noncancelable terms of one year, while the remaining operating leases have various terms. These leases may be renewed or replaced. No material restrictions exist in these leasing agreements concerning dividends, additional debt, or further leasing. Rental expense for 1992, 1991 and 1990 was $25.1 million, $21.7 million and $18.4 million, respectively. At December 31, 1992, estimated future minimum rental payments applicable to noncancelable operating leases were as follows:

	(Thousands of Dollars)
Years ending December 31	
1993	$ 21,835
1994	19,641
1995	14,227
1996	11,417
1997	9,871
1998 and thereafter	42,395
Total minimum rental payments	$119,386

16. Quarterly Financial Data (Unaudited)

The following summarized quarterly information for 1992 and 1991 is unaudited but includes all adjustments (consisting only of normal recurring accruals) which the Company considers necessary for a fair presentation of the results for the periods. Information for any one quarterly period is not necessarily indicative of the results which may be expected for a twelve month period due to seasonal and other factors.

(Thousands–except per share data)

1992 Three Months Ended	March 31	June 30	September 30	December 31
Operating revenues	$526,874	$422,489	$407,326	$505,584
Operating income	$ 71,504	$ 58,282	$ 61,323	$ 58,518
Net income	$ 46,204	$ 28,948	$ 29,840	$ 31,631
Earnings available for common stock	$ 43,180	$ 25,924	$ 26,820	$ 28,622
Weighted average common shares outstanding	56,701	57,382	57,840	58,308
Earnings per weighted average common share	$0.76	$0.45	$0.46	$0.49

(Thousands–except per share data)

1991 Three Months Ended	March 31	June 30	September 30	December 31
Operating revenues	$550,843	$390,723	$379,693	$473,645
Operating income	$ 69,447	$ 35,763	$ 58,114	$ 80,254
Net income	$ 45,093	$ 12,212	$ 34,340	$ 58,048
Earnings available for common stock	$ 42,017	$ 9,136	$ 31,282	$ 55,024
Weighted average common shares outstanding	54,746	55,267	55,721	56,152
Earnings per weighted average common share	$0.77	$0.16	$0.56	$0.99

Dividends

Dividends on common stock, as declared by the Board of Directors, are generally payable on the first day of February, May, August and November of each year. The company pays regular quarterly dividends on its preferred stock on the first of March, June, September, and December of each year.

Dividends paid on stock held in "street name" are paid to the holder of record, generally a brokerage firm or bank nominee. The dividends are then redistributed to beneficial owners by the brokerage firm or bank in accordance with the beneficial owners' instructions.

Shareholders of record receive dividends directly from the company unless such shareholder has elected to reinvest dividends through the company's Dividend Reinvestment Plan (DRP) or has authorized direct deposit of dividends to a financial institution.

Dividend Reinvestment Plan

The company's DRP provides an opportunity for holders of the company's common stock to acquire additional shares of such stock in a convenient and economical manner. Participants in the Plan may reinvest cash dividends on all or a portion of their shares of common stock and/or make optional cash payments. The company currently offers a 3% discount on shares purchased with reinvested dividends.

Stock Trading

The company's common stock ($5 par value) is listed for trading on the New York, Midwest and Pacific Stock Exchanges under the ticker symbol "PSR". Quotes may be obtained in daily newspapers where the common stock is listed as "PSvCol" in the New York Stock Exchange listing table.

Three series of cumulative preferred stock are actively traded: 4 1/4 % ($100 par value) on the American Stock Exchange; 7.15% ($100 par value) on the New York Stock Exchange; and 8.40% ($25 par value) on the New York Stock Exchange and Boston Stock Exchange. All other series are not actively traded and market prices are not published.

Transfer Agent

The company is the sole transfer agent and registrar for its common and preferred stock.

Annual Meeting

The annual meeting of shareholders will be held at 10:00 a.m. on May 12, 1993, at the Auditorium Theatre, 14th and Curtis Streets, Denver, Colorado.

Fees for Services

In an effort to achieve greater efficiencies related to shareholder information services, the company is initiating a program to assess fees for the duplication of services previously provided. Beginning July 1, 1993, fees will be assessed ranging from $5 to $25 for repeated shareholder requests. These fees will apply to such items as account histories, research to verify a prior transaction and copies of dividend reinvestment statements. For further details or fee schedule information, shareholders can contact the Shareholder Services Department.

Shareholders' Inquiries and Assistance

Shareholders desiring assistance with lost or stolen stock certificates or dividend checks, name changes, address changes, stock transfers, information on the DRP, or other matters should call the Shareholder Services Department. If you would like to eliminate duplicate company mailings, please send the annual report mailing label to Shareholder Services. The following telephone numbers are available during business hours, **8:00 a.m. to 5:00 p.m. (MST)**

Denver Metro Area	(303) 294-2566
Toll-Free Number	(800) 635-0566

Written communication should be addressed to:

Public Service Company of Colorado
Shareholder Services
P.O. Box 840, Suite 300
Denver, Colorado 80201-0840

BOARD OF DIRECTORS AND EXECUTIVE OFFICERS

BOARD OF DIRECTORS

D. D. Hock
Denver, CO (1985)
Chairman of the Board,
President and
Chief Executive Officer
Age 57

Collis P. Chandler, Jr.
Denver, CO (1985)
President
Chandler & Associates, Inc.
Age 66

Doris M. Drury, PhD
Denver, CO (1975)
Regis College
Executive Director,
MBA program
President, Center for Business
and Economic Forecasting, Inc.
Age 66

Thomas T. Farley
Pueblo, CO (1983)
Attorney at Law
Petersen & Fonda
Professional Corp.
Age 58

Gayle L. Greer
Denver, CO (1986)
Vice President,
American Television
and Communications
Corporation
Age 51

A. Barry Hirschfeld
Denver, CO (1988)
President, A. B. Hirschfeld
Press, Inc.
Age 50

George B. McKinley
Evanston, WY (1976)
President
First McKinley Corp.
Age 65

Will F. Nicholson, Jr.
Denver, CO (1981)
Chairman of the Board
and President
Colorado National
Bankshares, Inc.
Age 63

J. Michael Powers
Cheyenne, WY (1978)
President, Powers Brick and Tile
and Powers Products Co.
Age 50

Thomas E. Rodriguez
Denver, CO (1986)
President, Thomas E. Rodriguez
& Associates, P.C.
Age 48

Rodney E. Slifer
Vail, CO (1988)
Partner
Slifer, Smith & Frampton
Age 58

W. Thomas Stephens
Denver, CO (1989)
Chairman, President, and
Chief Executive Officer
Manville Corporation
Age 50

Robert G. Tointon
Greeley, CO (1988)
President
Phelps-Tointon, Inc.
Age 59

( ) Year elected to the
Board of Directors

Ages as of December 31, 1992

EXECUTIVE COMMITTEE

D. D. Hock
Doris M. Drury
George B. McKinley
Will F. Nicholson, Jr.
Robert G. Tointon

AUDIT COMMITTEE

J. Michael Powers
Thomas T. Farley
Gayle L. Greer
Thomas E. Rodriguez

PENSION INVESTMENT COMMITTEE

W. T. Stephens
A. Barry Hirschfeld
Rodney E. Slifer

COMPENSATION COMMITTEE

Doris M. Drury
George B. McKinley
Will F. Nicholson, Jr.
W. T. Stephens
Robert G. Tointon

EXECUTIVE OFFICERS

D. D. Hock
Chairman of the Board,
President and
Chief Executive Officer
Age 57 (30)

Clark B. Ewald
Senior Vice President
Customers
Age 58 (33)

Richard C. Kelly
Senior Vice President
Finance and Administration
Chief Financial Officer
Age 46 (24)

Patrick W. McCarter
Senior Vice President
Electric Operations
Age 55 (33)

James R. McCotter
Senior Vice President,
General Counsel and
Corporate Secretary
Age 49 (17)

A. E. Middents
Senior Vice President
Gas Operations
Age 54 (32)

A. C. Crawford
Vice President
Electric Production
Age 60 (3)

Dale V. Fetchenhier
Vice President
Information Technology
and Services
Age 59 (35)

Ross C. King, Jr.
Vice President
Metropolitan Customer Operations
Age 51 (26)

William J. Martin
Vice President
Electric Engineering
and Planning
Age 61 (35)

Earl E. McLaughlin, Jr.
Vice President
Marketing, Customer Services
and Support Services
Age 52 (32)

James H. Ranniger
Vice President
Rates and Regulations
Age 56 (34)

Philip D. Shaffer
Vice President
Division Customer Operations
Age 47 (19)

Marilyn E. Taylor
Vice President
Administrative Services
Age 50 (5)

Ralph Sargent III
Treasurer
Age 43 (14)

OTHER OFFICERS

W. Wayne Brown
Assistant Secretary
and Controller
Age 42 (20)

Thomas W. Hess
Assistant Secretary
Age 43 (20)

Michael J. McFadden
Assistant Secretary
Age 42 (18)

Carol J. Peterson
Assistant Secretary
Age 50 (6)

J. Anthony Terrell
Assistant Secretary and
Assistant Treasurer
Age 49 (2)

Stephen H. Whitcomb
Assistant Secretary
Age 42 (17)

Richard L. Hunt
Assistant Treasurer
Age 50 (26)

William E. Lewis
Assistant Treasurer
Age 43 (21)

Michael D. Pritchard
Assistant Treasurer
Age 46 (21)

MANAGERS, GEOGRAPHIC DIVISIONS

S. G. Arnold
Boulder Division
& Foothills Region
Age 39 (17)

Bill L. Croley
Denver Metropolitan
Age 52 (20)

David P. Davia
Northern Metropolitan Region
Age 47 (24)

Anthony J. DeNovellis
Southern Region
& Pueblo Division
Age 44 (22)

Michael J. Geile
Home Light
Age 50 (28)

W. Bruce Hansford
Northern Division
Age 51 (24)

Douglas C. Lockhart
Western
Age 50 (28)

Joseph O. Marquez
San Luis Valley
Age 55 (32)

Mary M. McMillan
Front Range
Age 39 (13)

Phillip L. Noll
Mountain
Age 53 (34)

V. Clark Stephens
Southeast Metropolitan
Age 55 (32)

George A. Senkus
Southwest Metropolitan
Age 56 (25)

PRESIDENTS SUBSIDIARY COMPANIES*

D. D. Hock
Bannock Center Corporation
1480 Welton, Inc.
Green and Clear Lakes Company
P.S. Colorado Credit Corporation
P.S.R. Investments, Inc.
Age 57 (30)

A. E. Middents
Fuel Resources Development Co.
Age 54 (32)

Philip D. Shaffer
Cheyenne Light, Fuel
and Power Company
Age 47 (19)

Thomas E. Moore
Natural Fuels Corporation
Age 31 (2)

*Effective January 1, 1993, WestGas, a former subsidiary, was merged into Public Service Company.

LEGAL COUNSEL

Kelly, Stansfield & O'Donnell
Denver, Colorado

AUDITORS

Arthur Andersen & Co.
717 - 17th Street, Suite 1900
Denver, Colorado 80202

Transfer Agent and Registrar for all Issues of Capital Stock Principal Transfer Agent, Dividend Paying Agent, Dividend Reinvestment Plan Agent, Registrar

Public Service Company
of Colorado
Denver, Colorado

( ) Denotes years of service or association with the Company through December, 1992.

Ages as of December 31, 1992

BULK RATE
U.S. POSTAGE
PAID
PUBLIC
SERVICE CO.

Public Service Company of Colorado

P.O. Box 840
Denver, Colorado 80201-0840
(303) 571-7511

Shareholder Information
(800) 635-0566