PLAINTIFF'S EXHIBIT
UPRC-4

Union Pacific Resources Group Inc.

1995 Form 10-K

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (FEE REQUIRED)

For the fiscal year ended December 31, 1995 **Commission file number 1-13916**

UNION PACIFIC RESOURCES GROUP INC.
(Exact name of registrant as specified in its charter)

Utah	13-2647483
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
P.O. Box 7, 801 Cherry Street Fort Worth, Texas (Address of principal executive offices)	76101 (Zip Code)

Registrant's telephone number, including area code: **(817) 877-6000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange, Inc.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [☑]

As of February 26, 1996, the aggregate market value of the registrant's Common Stock held by non-affiliates (using the New York Stock Exchange closing price) was approximately $1,112,561,346.

The number of shares outstanding of the registrant's Common Stock as of February 26, 1996 was 249,249,599.

Certain portions of the registrant's definitive Proxy Statement for the annual meeting of shareholders to be held on May 2, 1996 (the "Proxy Statement") are incorporated in Parts I and III by reference.

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Quantities of natural gas are expressed in this report in terms of thousand cubic feet (Mcf), million cubic feet (MMcf) or billion cubic feet (Bcf). Oil and natural gas liquids are quantified in terms of barrels (Bbl), thousands of barrels (MBbl) or millions of barrels (MMBbl). Oil and natural gas liquids are compared to natural gas in terms of thousands of cubic feet of natural gas equivalent (Mcfe), millions of cubic feet of natural gas equivalent (MMcfe), billions of cubic feet of natural gas equivalent (Bcfe) or trillions of cubic feet of natural gas equivalent (Tcfe). One barrel of oil or natural gas liquids is the energy equivalent of six Mcf of natural gas. Daily oil and gas production is signified by the addition of the letter "d" to the end of the terms defined above. Natural gas volumes also may be expressed in terms of one million British thermal units (MMBTU), which is approximately equal to one Mcf. With respect to information relating to the Company's (as hereinafter defined) working interest in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by the Company's working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I

Item 1. Business

In October 1995, Union Pacific Resources Group Inc., a Utah corporation (the "Company"), sold 42.5 million shares of the common stock of the Company (the "Common Stock") in an initial public offering (the "Offering"). The offering price to the public was $21 per share of Common Stock. The Common Stock is now traded on the New York Stock Exchange under the symbol "UPR." Prior to completion of the Offering, the Company was wholly owned by Union Pacific Corporation, a Utah corporation ("UPC"). UPC currently owns approximately 83% of the outstanding Common Stock. UPC has announced that it intends, subject to the receipt of a favorable ruling from the Internal Revenue Service and the satisfaction of certain other conditions, to distribute pro rata to its shareholders as a dividend its remaining ownership interest in the Company by means of a tax-free distribution (the "Distribution"). No assurance can be given that such favorable tax ruling will be obtained, nor can any assurance be given that, in any event, the Distribution will occur or that UPC will not sell its shares of Common Stock. See "Business—Relationship with UPC and Anschutz Shareholders."

UPC acquired Champlin Petroleum Company in 1970 to manage the exploitation of its oil and gas operations on the "Land Grant," which was granted by the Federal Government to a predecessor of Union Pacific Railroad Company, a subsidiary of UPC (the "Railroad"), at the time of the construction of the first North American transcontinental railroad in the mid-1800s. Consisting of alternating one square mile sections forming a checkerboard pattern extending 20 miles on each side of the railroad right of way, the Land Grant passes through the states of Colorado and Wyoming and into Utah and intersects several highly productive oil and gas basins and mineral deposits. In 1971, UPC combined its own oil and gas operations with those of Champlin Petroleum Company. In 1987, the Champlin name was changed to Union Pacific Resources Company ("UPRC"), and UPRC also became responsible for managing UPC's hard mineral assets. See "Business—Minerals." The Company currently has fee ownership of the mineral rights under approximately 7.5 million acres of the initial Land Grant (approximately one million acres of which are subject to exploration and production agreements with third parties) and controls through leases the mineral rights in approximately 700,000 additional gross acres in the same geographic region (together with the Land Grant, the "Land Grant Area").

Prior to completion of the Offering (1) UPC caused UPRC to become a wholly owned subsidiary of the Company, (2) UPC caused the Company and UPRC to own all the rights and assets historically employed by UPRC in connection with the operations presented in the Consolidated Financial Statements and notes thereto, including substantially all of the Land Grant properties and (3) the Company declared dividends to UPC totaling $1,621 million consisting of (i) a cash dividend of $912 million payable to UPC promptly after the completion of the Offering, (ii) a $650 million note payable to UPC and (iii) a $59 million receivable from UPC. In addition, the Company borrowed $68 million under two-bank credit agreements which was used, together with the $843.9 million net proceeds from the Offering, to pay the cash dividend of $912 million to UPC. Such transactions, collectively, are referred to herein as the "Asset Restructuring."

General

The Company is one of the largest independent energy companies in North America and is engaged primarily in the exploration for and the development and production of natural gas, natural gas liquids and crude oil in several major producing basins in the United States and Canada. The Company emphasizes natural gas in its exploration and production activities and also owns and operates significant assets, in proximity to its principal producing properties, dedicated to "gas value chain" activities, which consist of the gathering, processing, transportation and marketing of natural gas and natural gas liquids. The Company, through its wholly owned subsidiary, Union Pacific Fuels, Inc. ("UP Fuels"), markets approximately 70% of the Company's natural gas, 97% of its natural gas liquids and 87% of its crude oil, together with significant volumes of natural gas, natural gas liquids and crude oil produced by others. UP Fuels ranks among the largest natural gas and natural gas liquids marketers in the United States. In addition, the Company engages in the hard minerals business through non-operated joint venture and royalty interests in several coal and trona (natural soda ash) mines located on lands within and adjacent to its Land Grant holdings in Wyoming. See "Business Segments" on page F-8.

The Company's oil and gas activities are concentrated in six core geographic areas: (1) the Austin Chalk trend in Texas and Louisiana, (2) the Rockies, consisting of the western portion of the Land Grant Area in Wyoming and Utah, (3) Plains/Canada, consisting of the eastern portion of the Land Grant Area in Wyoming and Colorado, with additional operations in Kansas and western Canada, (4) the onshore and offshore Gulf Coast area, (5) eastern and southern Texas and (6) western Texas. In each of these core areas, the focus of the Company is on the exploration for and development of natural gas and crude oil resources, and on efforts to increase margins through reductions in drilling and operating costs and effective and efficient sales and distribution networks. Natural gas and natural gas liquids constituted 85% of the Company's total proved reserves of nearly 3.3 Tcfe as of December 31, 1995. For the year ended December 31, 1995, natural gas and natural gas liquids comprised 80% of the Company's sales volume of 1.6 Bcfed. For the same period, over 65% of the Company's production from producing properties was attributable to Company-operated properties. The Company owns interests in 26 natural gas processing plants, 18 of which it operates, with a current throughput capacity of over 3.6 Bcfd (1.5 Bcfd net to the Company). Aggregate throughput of the Company's 26 gas processing plants for the year ended December 31, 1995 averaged 83% of the plants' aggregate design capacity. Over 95% of the Company's revenues, assets and reserves are generated or located in the United States.

Business Strategy

The Company's strategy is to apply economies of scale, its operating experience in its core geographic areas and its expertise in advanced drilling and completion technologies to increase production by expanding the Company's North American drill site inventory and enhancing well performance results. In addition to developing its existing properties, the Company also increases drill site inventory through exploration, farm-in agreements and acquisitions of properties and companies. To support its development and production activities, the Company invests in natural gas and natural gas liquids gathering, processing and transportation assets and operations in its core geographic areas. UP Fuels markets natural gas, natural gas liquids and crude oil produced by the Company and others on a nationwide basis and focuses on value-added marketing services to maximize the prices realized for these hydrocarbons.

Oil and Gas Operations

Each of the Company's core geographic areas is organized as a separate business unit, responsible for its own exploration, development and production activities and for the operation of gathering, processing and transportation assets supporting such activities. In addition to the exploration activities within these business units, the Company has a new resources/exploration group that is responsible for discovering natural gas and crude oil fields that have the potential to develop into new core areas, evaluating new opportunities for the application of technology and creating opportunities for acquisitions and property purchases.

The following table sets forth certain reserve-and-sales information as of December 31, 1995 with respect to each of the Company's business units.

Business Unit	Proved Reserves (1) (As of December 31, 1995) Total Proved Reserves (Bcfe)	Percent of Total	Sales Volumes (For the Year Ended December 31, 1995) Producing Property Volumes (MMcfed)	Sales from Gas Plant Ownership (MMcfed)	Total Sales Volumes (2) (MMcfed)	Percent of Total
Austin Chalk	451	14%	438	90	528	33%
Rockies	1,279	39	389	33	422	26
Plains/Canada	387	12	140	4	144	9
Gulf Coast	165	5	157	1	158	10
East/South Texas	497	15	164	68	232	15
West Texas	498	15	83	33	116	7
Total	3,277	100%	1,371	229	1,600	100%

(1) Reflects future production attributable to (i) the Company's natural gas, natural gas liquids and crude oil production from producing properties and (ii) the Company's portion, by virtue of its ownership interest in gas processing facilities, of natural gas and natural gas liquids earned by such facilities through the processing of the Company's production from producing properties. At some of its gas processing facilities, the Company earns gas and natural gas liquids through the processing of third party volumes. Volumes attributable to third party processing are not reflected in the Company's proved reserves.

(2) Excludes natural gas, natural gas liquids and crude oil purchased from third parties for resale by UP Fuels. See "Business—Gathering, Processing and Marketing."

Austin Chalk Business Unit

The Austin Chalk business unit manages the Company's oil and gas activities in the Austin Chalk trend, which extends over 500 miles from southern Texas through central and eastern Texas into Louisiana. At present, the Company's Austin Chalk production is located primarily in the Giddings and Brookeland fields. Since 1988, the Company has participated in the drilling of over 1,100 horizontal wells (80% of which are Company-operated) and has made aggregate capital expenditures of nearly $1.3 billion in the Austin Chalk area. In 1996, the Company plans to maintain an active capital spending program in the Austin Chalk, including expenditures for gathering, processing and transportation activities.

The Austin Chalk business unit represented approximately 14% of the Company's total reserves as of December 31, 1995 (65% of which were natural gas and natural gas liquids) and 33% of the Company's sales volumes for the year ended December 31, 1995. The Company currently controls approximately 1,201,000 developed and undeveloped net acres in the Austin Chalk. The Company has increased its average daily sales in the Austin Chalk from 37 MMcfed in January 1990 to 528 MMcfed for 1995. For the year ended December 31, 1995, 91% of the Company's production from the Austin Chalk was attributable to Company-operated properties.

Rockies Business Unit

The Rockies business unit manages the Company's oil and gas activities in the western portion of the Land Grant Area in Wyoming and Utah. The Company's operations in the Rockies are concentrated in the Green River Basin and the Overthrust Belt. In 1996, the Company plans to maintain an active capital spending program in the Rockies, including expenditures for gathering, processing and transportation activities.

The Rockies business unit represented approximately 39% of the Company's total reserves as of December 31, 1995 (88% of which were natural gas and natural gas liquids) and 26% of the Company's sales volumes for the year ended December 31, 1995. As of December 31, 1995, the Company had working interests in over 1,300 producing wells in the Rockies, of which one-fourth were Company-operated. As of December 31, 1995, the Company also had royalty interests in over 200 producing wells in the Rockies in which the Company did not also own a working interest. For the year ended December 31, 1995, 39% of the Company's production from the Rockies was attributable to Company-operated properties.

Plains/Canada Business Unit

The Plains/Canada business unit manages the Company's oil and gas activities in three areas: the eastern portion of the Land Grant Area in Wyoming and Colorado, the Hugoton/Panoma field in Kansas and fields in western Canada. The Company plans to continue to conduct active drilling in all three areas.

The Plains/Canada business unit represented approximately 12% of the Company's total reserves as of December 31, 1995 (72% of which were natural gas and natural gas liquids) and 9% of the Company's sales volumes for the year ended December 31, 1995. As of December 31, 1995, the Company had an interest in 1,251 gross producing wells in the Plains/Canada area. As of December 31, 1995, the Company also had royalty interests in 3,590 producing wells in Plains/Canada in which the Company did not also own a working interest. For the year ended December 31, 1995, 47% of the Company's production from Plains/Canada was attributable to Company-operated properties.

Gulf Coast Business Unit

The Gulf Coast business unit manages the Company's oil and gas activities in the Gulf of Mexico and the onshore Gulf Coast. In addition to its producing operations, the unit conducts exploration activities in southern Louisiana, southern Texas and the Gulf of Mexico. During the twelve months ended December 31, 1995, the Company participated in the drilling of seven gross wells in southern Louisiana resulting in four commercial discoveries which will begin production in 1996. Also, a discovery well drilled in south Texas during 1995 has the potential for several offset wells. The Company's exploration activities in the Gulf of Mexico are concentrated in the shallow waters offshore Louisiana where the Company expects to have purchased 3,000 square miles of three-dimensional seismic by the end of 1997 to identify drilling prospects. In 1996, the Company plans to continue its active investment program in Gulf Coast exploration and production activities.

The Gulf Coast business unit represented approximately 5% of the Company's total reserves as of December 31, 1995 (77% of which were natural gas and natural gas liquids) and 10% of the Company's sales volumes for the year ended December 31, 1995. As of December 31, 1995, the Company had an interest in 289 gross producing wells in the Gulf Coast area. For the year ended December 31, 1995, 64% of the Company's production from the Gulf Coast was attributable to Company-operated properties.

East/South Texas Business Unit

The East/South Texas business unit manages the Company's oil and gas activities in two major producing areas: the Carthage and Oakhill fields in eastern Texas and the Stratton/Agua Dulce area in southern Texas. The Company also controls significant gathering, processing and transportation assets in each area that are integral to its natural gas production activities. In 1996, the Company plans to maintain an active capital spending program in East/South Texas, including expenditures for gathering, processing and transportation activities.

The East/South Texas business unit represented approximately 15% of the Company's total reserves as of December 31, 1995 (98% of which were natural gas and natural gas liquids) and 15% of the Company's sales volumes for the year ended December 31, 1995. As of December 31, 1995, the Company had interests in more than 1,400 producing wells in East/South Texas. For the year ended December 31, 1995, 94% of the Company's production from East/South Texas was attributable to Company-operated properties.

West Texas Business Unit

The West Texas business unit manages the Company's oil and gas activities in western Texas, principally in the Ozona field in the Permian Basin area. The Company obtained its producing properties in the Ozona field through the acquisition of Amax Oil & Gas, Inc. ("Amax") in March 1994. The Amax acquisition included approximately 850 operated natural gas wells in the Ozona field, which is characterized by long-lived natural gas wells that typically produce for 30 or more years. Since the Amax acquisition, the Company has drilled approximately 400 wells in the Ozona area and has substantially modernized and expanded its gathering, processing and transportation facilities. In 1996, the Company plans to maintain an active capital spending program in West Texas, including expenditures for gathering, processing and transportation activities.

The West Texas business unit represented approximately 15% of the Company's total reserves as of December 31, 1995 (94% of which were natural gas and natural gas liquids) and 7% of the Company's sales volumes for the year ended December 31, 1995. The Company currently controls approximately 363,000 developed and undeveloped net acres in western Texas. As of December 31, 1995, the Company operated over 1,300 gross producing wells in the West Texas area. For the year ended December 31, 1995, 84% of the Company's production from West Texas was attributable to Company-operated properties.

Gathering, Processing and Marketing

The Company seeks to enhance the profitability of its natural gas and natural gas liquids production through its gas value chain activities. The Company believes that ownership of natural gas and natural gas liquids gathering, processing and transportation assets and control of its marketing activities (1) ensure that the gathering, processing, transportation and marketing of its production are accomplished on a cost-effective basis with minimum production downtime, (2) assist the Company in maximizing the prices realized for its production and (3) increase its ability to obtain attractive drilling opportunities which, if successful, enhance the profitability of such gas value chain assets.

Gathering and Processing

The Company's ownership interests in 26 gas processing facilities and the extensive gathering systems supporting these facilities help ensure the efficient and reliable gathering and processing of the Company's production. The Company's interests in gas processing facilities also result in the Company being a significant producer of natural gas liquids. For the year ended December 31, 1995, production of natural gas liquids attributable to the Company's ownership interests in gas processing facilities averaged approximately 34.2 MBbld. Excluding the portion of the Amax acquisition price related to gas value chain assets, the Company invested approximately $100 million per year in both 1994 and 1995 to increase processing and gathering capacity.

The Company has four major gas plant projects that recently have been completed or are scheduled for completion by mid-1996. See "Properties—Gas Processing Assets." In August 1995, the Company completed the 360 MMcfd expansion of the non-operated Ferguson-Burleson County Gas Gathering System to handle natural gas from the deep Giddings area of the Austin Chalk. In addition, the 89%-owned Panola Pipeline extension became operational in June 1995. This 120-mile extension enables the Company to transport up to 40 MBbld of unfractionated natural gas liquids from the East Texas area to markets in Mt. Belvieu, Texas.

Marketing

UP Fuels markets approximately 70% of the Company's natural gas, 97% of the Company's natural gas liquids and 87% of the Company's crude oil, as well as significant volumes of natural gas, natural gas liquids and crude oil produced by others, and ranks among the largest natural gas and natural gas liquids marketers in the United States. UP Fuels focuses on value-added services, which include (1) aggregating volumes of natural gas from the Company and other producers, (2) arranging for the transportation and storage of these natural gas supplies through third party pipeline systems and storage facilities under firm and interruptible transportation agreements, (3) contracting for the sale of specific volumes of natural gas under a number of different pricing structures, (4) balancing the receipts and deliveries of natural gas based on customer requirements, (5) aggregating natural gas liquids recovered at the various gas processing plants where the Company owns an equity interest and (6) aggregating crude oil production and marketing crude oil at major trading locations. In addition, UP Fuels works with industry groups to develop natural gas and natural gas liquids marketing initiatives to increase demand.

In 1995, the Company, primarily through UP Fuels, sold approximately 1.6 Bcfd of natural gas (about 57% of which represented the Company's equity production). In addition, UP Fuels provides storage and transportation services in certain natural gas supply and market areas and manages the Company's market hubs in East Texas and the Land Grant Area. The Company has a diverse customer base for natural gas, which includes local distribution companies, power generation facilities, pipelines, industrial plants and other wholesale marketing companies.

The Company, primarily through UP Fuels, sold 103 MBbld of natural gas liquids in 1995, which included 46 MBbld of third party liquids. This total represents a 22% increase from 1994 levels. The customers that UP Fuels targets are wholesalers, industrial end users and traders. Where possible, UP Fuels prefers to sell its natural gas liquids in local markets, which generally offer more attractive pricing. Natural gas liquids not sold locally are shipped from the various plants by pipelines to the Company's partially controlled fractionators in Mt. Belvieu, Texas.

In 1995, the Company, primarily through UP Fuels, sold 74 MBbld of crude oil and condensate, which included 21 MBbld of third party crude oil and condensate. Where possible, UP Fuels sells crude oil directly to refiners. If these customers are not available locally, UP Fuels markets its crude oil volumes in a manner that will maximize volumes it can sell to refiners and marketers at major trading locations.

Volumes, Prices and Production Costs

The following table sets forth certain information regarding the Company's volumes of and average price realizations for natural gas, natural gas liquids and crude oil sales, and average production costs per Mcfe for each of the last three years.

	Years Ended December 31,		
	1993	1994	1995
Producing Properties:			
Average daily production(1):			
Natural gas (MMcfd)	608.2	754.8	915.6
Natural gas liquids (MBbld)	15.5	18.8	23.1
Crude oil (MBbld)	66.5	63.1	52.8
Total (MMcfed)	1,100.2	1,246.2	1,371.0
Average sales prices:			
Natural gas (per Mcf)	$ 1.80	$ 1.82	$ 1.44
Natural gas liquids (per Bbl)	8.77	7.86	8.14
Crude oil (per Bbl)	15.66	14.34	16.08
Production costs (per Mcfe)(2)	0.60	0.55	0.44
Plants, Pipelines and Marketing:			
Average daily sales volumes attributable to gas plant ownership(3):			
Natural gas (MMcfd)	11.0	17.5	23.9
Natural gas liquids (MBbld)	24.4	31.2	34.2
Total (MMcfed)	157.4	204.7	229.1
Average sales prices:			
Natural gas (per Mcf)	$ 2.63	$ 1.81	$ 1.51
Natural gas liquids (per Bbl)	10.52	9.97	9.38

(1) Does not include the Company's portion, by virtue of its ownership in gas processing facilities, of natural gas and natural gas liquids earned by such facilities in connection with the processing of natural gas.

(2) Includes lease operating costs, production overhead, other operating expenses and taxes other than income taxes.

(3) Represents the Company's portion, by virtue of its ownership interest in gas processing facilities, of natural gas and natural gas liquids earned by such facilities in connection with the processing of natural gas. The portion of the total average daily sales volumes representing the Company's portion earned by such facilities with respect to processing the Company's production for each of the three years ended December 31, 1993, 1994 and 1995 are 44.0 MMcfed, 43.9 MMcfed and 66.5 MMcfed, respectively. See "Supplementary Information—Average Daily Production and Sales Volume" on page F-28.

Minerals

The Minerals business unit contributes significantly to the Company's operating income by exploiting the hard minerals portion of the Company's extensive fee mineral interests in the Land Grant through non-operated joint venture and royalty arrangements in coal and trona (natural soda ash) mines. The Minerals business unit generated $107.1 million of operating income during 1995, as follows:

	1995 Operating Income	
	Amount (Millions of dollars)	Percent
Royalties:		
Soda ash(1)	$ 26.0	24%
Coal(2)	13.9	13
Total royalties	39.9	37
Non-operated joint ventures:		
Soda ash(3)	7.0	7
Coal(4)	61.1	57
Total joint ventures	68.1	64
Overhead/other	(0.9)	(1)
Total operating income	$107.1	100%

(1) Includes properties currently leased to five trona producers, estimated to contain resources sufficient to support over 30 years of production at current production levels.

(2) The Company leases coal resources to eight operating mines. In 1995, 72% of the Company's coal royalties were attributable to a single mine which supplies an adjacent power station that is owned and operated by affiliates of the mine owners.

(3) Represents a 49% interest in a non-operated joint venture.

(4) Represents the Company's 50% non-operated interest in Black Butte Coal Company. Of this amount, $55 million is attributable to a single coal supply contract, the financially beneficial terms of which terminate at the end of 2001. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview" and Note 13 to the Consolidated Financial Statements.

The Company's low sulfur coal deposits compete with other western coals for industrial and utility boiler markets. At current coal pricing and extraction levels, however, most of this resource is not ecomonic to extract, except for sale to local markets. As a result, there are limited opportunities for new coal mine development in the Land Grant.

The world's largest deposit of trona ore, constituting 90% of the world's known trona resources, is located in the Green River Basin in southwestern Wyoming. Approximately 40% of this trona deposit lies within the Land Grant and is owned by the Company. Natural soda ash, which is produced by refining trona ore, is used primarily in the production of glass for containers and flat glass, as well as in the paper and water treatment industries and in the manufacture of certain chemicals and detergents. Although domestic soda ash sales have been relatively flat over the last several years, exports of natural soda ash from the United States have nearly tripled since 1982, currently representing over one-third of total United States soda ash sales. The continued success of the Company's natural soda ash in international markets will depend largely on shipping costs and the relaxation of import barriers. In February 1996, OCI Enterprises Inc., a United States subsidiary of Oriental Chemical Industries, a Korean manufacturer of soda ash and other chemicals, announced the purchase of the 51% operated interest in the Company's soda ash joint venture previously owned by Rhone-Poulenc, Inc.

In general, the Company reinvests the cash flow from its hard minerals operations in its oil and gas business units. The Company does not anticipate making any significant capital expenditures with respect to its Minerals business unit in 1996.

Competition

The oil and gas industry is highly competitive. The Company actively competes for reserve acquisitions and for exploration leases, licenses and concessions and skilled industry personnel, frequently against companies with substantially larger financial and other resources. The Company's competitors include major integrated oil and gas companies and numerous other independent oil and gas companies and individual producers and operators. To the extent the Company's capital budget is lower than that of certain of its competitors, the Company may be disadvantaged in effectively competing for certain reserves, leases, licenses and concessions. Competitive factors include price, contract terms and types and quality of service, including pipeline distribution logistics and efficiencies.

Government Regulation

The Company's natural gas, natural gas liquids and crude oil exploration, development and production operations are subject to extensive rules and regulations promulgated by Federal, provincial, state and local authorities.

Domestic legislation affecting the oil and gas industry is under constant review for amendment. In addition, numerous departments and agencies, Federal, state and local, are authorized by statute to issue and have issued rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for noncompliance. State statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. Most states in which the Company operates also have statutes and regulations governing conservation and safety matters, including the unitization or pooling of oil and gas properties and the establishment of maximum rates of production from oil and gas wells and the spacing of such wells. Such statutes and regulations may limit the rate at which oil and gas could otherwise be produced from the Company's properties. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability.

A substantial portion of the Company's oil and gas leases in the Gulf of Mexico and a portion of its onshore leases were granted by the U.S. Government and are administered by two agencies within the Department of the Interior, the Bureau of Land Management ("BLM") and the Minerals Management Service ("MMS"). Such leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed BLM and MMS regulations and orders (which are subject to change by the BLM and the MMS). For offshore operations, lessees must obtain MMS approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the Coast Guard, Army Corps of Engineers and Environmental Protection Agency), lessees must obtain a permit from the BLM or the MMS prior to the commencement of drilling.

Effective November 26, 1993, the MMS requires lessees in the Gulf of Mexico to increase the area-wide bonding level from $300,000 to $3 million. The Company has satisfied this increased bonding requirement. The MMS also has the right to require lessees to post supplemental bonds if it deems that additional security is necessary to cover royalties due or the costs of regulatory compliance.

Under certain extraordinary circumstances, the Federal agencies have the power to suspend or terminate Company operations on Federal leases. Any such suspension or termination could materially and adversely affect the Company's financial condition and operations. The MMS also intends to adopt financial responsibility regulations under the Oil Pollution Act of 1990 ("OPA"). See "Environmental Regulation—Oil Spills."

Currently there are no laws that regulate the price for sales of natural gas, natural gas liquids and crude oil by the Company. However, the Company's rates charged and terms and conditions for the movement of gas in interstate commerce through certain of its intrastate pipelines and production area hubs are subject to regulation under the Natural Gas Policy Act of 1978 ("NGPA"). The pipelines' and hubs' construction activities are, to a limited extent, also subject to regulation under the Natural Gas Act of 1938 ("NGA"). The NGA also establishes comprehensive controls over interstate pipelines, including the transportation and resale of gas in interstate commerce. While these NGA controls do not directly apply to the Company, their effect on natural gas markets can be significant in terms of competition and cost of transportation services. The Federal Energy Regulatory Commission ("FERC") administers the NGA and NGPA.

Through a series of orders, most recently the Order No. 636 Series, FERC has taken significant steps to increase competition in the sale, purchase, storage and transportation of natural gas. Under these orders, FERC has caused pipelines to open up access to transportation, essentially eliminated the pipelines from the role of natural gas merchant and "unbundled" transportation services so that a buyer can purchase only those services it needs. FERC's regulatory programs generally allow more accurate and timely price signals from the consumer to the producer and, on the whole, have helped natural gas to be more responsive to changing market conditions. Nonetheless, the ability to respond to market forces can and does add to price volatility, inter-fuel competition and pressure on the value of transportation and other services. The Order No. 636 Series, and related orders thereunder, are the subject of numerous appeals to the United States Court of Appeals.

Several proposals that might affect the natural gas industry are pending before Congress and FERC. Congress is considering modifications to the Public Utility Regulatory Policies Act of 1978, which could affect the Company's natural gas sales to gas-fired independent power projects. In addition, as a result of the Energy Policy Act of 1992, FERC has recently announced a proposed rule that, if adopted, would fundamentally alter the electric power industry. In particular, the proposed rule would require those transmission-owning utilities which are subject to FERC jurisdiction to offer non-discriminatory transmission services to future wholesale buyers and sellers of power. Natural gas is an important source of supply to power generators and competes with other fuels for new generating capacity. FERC's restructuring of the power generation and distribution industry could affect natural gas markets in various ways, including demand for natural gas, prices and market structure. It is, however, too early to assess the extent and direction of these potential impacts.

As the owner of production area hubs and pipeline facilities in Wyoming and Texas, the Company is also subject to regulation by those states as to safety, rates and the provision of transportation services. As a seller of natural gas to end users, the Company can also be affected by state regulation of local distribution activities. While the extent of such state regulation varies, a number of states where the Company markets its natural gas are taking steps similar to steps taken by FERC to increase gas competition. As these programs take hold, direct access to local markets should increase, together with competitive pressures on prices and the value of distribution services. Some states are also considering increasing competition in the electric utility industry. The potential impacts of such measures are uncertain.

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts. The Company cannot predict when or if any such proposals might become effective and their effect, if any, on the Company's operations. Historically, the natural gas industry has been heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC, Congress and the states will continue indefinitely into the future.

Pursuant to the Mineral Lands Leasing Act of 1920 and related regulations, a corporation may not be entitled to hold Federal onshore oil and natural gas leases if stock of such corporation is owned by citizens of foreign countries which are not deemed to be reciprocal under such Act. The Company holds substantial Federal onshore oil and natural gas leases, and a portion of the Common Stock is owned by citizens of foreign countries, some of which may not be deemed reciprocal under such Act. To the Company's knowledge, no action has ever been taken against a publicly-held corporation for violation of the non-reciprocal alien provisions of such Act.

The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Oil and gas exported from Canada is subject to regulation by the National Energy Board ("NEB") and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts meet certain criteria prescribed by the NEB and the government of Canada. Exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude oil and not exceeding two years in the case of heavy crude oil and natural gas, provided that an order approving any such export has been obtained from the NEB. Any export to be made pursuant to a contract of longer duration requires an NEB license and Governor in Council approval. The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations. In addition, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. It is not expected that any of these controls or

regulations will affect the operations of the Company in a manner materially different than they would affect other oil and gas companies of similar size.

Section 29 Tax Credits

Federal tax law provides an income tax credit against regular Federal income tax liability with respect to sales of the Company's production of certain fuels produced from nonconventional sources (including both coal seam natural gas and natural gas produced from tight sand formations), subject to a number of limitations ("Section 29 tax credits"). Fuels qualifying for the tax credit must be produced from a well drilled or a facility placed in service after December 31, 1979 and before January 1, 1993, and be sold before January 1, 2003.

The basic credit, which is currently approximately $0.52 per MMBTU of natural gas produced from tight sand reservoirs, is computed by reference to the price of crude oil and is phased out as the price of oil exceeds $23.50/Bbl in 1979 dollars (as adjusted for inflation) with complete phaseout if such price exceeds $29.50/Bbl in 1979 dollars (as adjusted for inflation). Under this formula, the commencement of phaseout would be triggered if the average price for crude oil rose above approximately $45/Bbl in current dollars. The natural gas production from wells drilled on certain of the Company's properties in the Moxa Arch and Wamsutter areas in the Rockies, the Carthage field in East Texas, the Ozona field in West Texas and certain areas in the Austin Chalk trend qualifies for this tax credit. The Company recorded approximately $37.9 million of Section 29 tax credits in 1995, $19.1 million of which related to prior years' production. Section 29 tax credits are not creditable against the alternative minimum tax, but under certain circumstances may be carried over and applied against regular tax liability in future years. Therefore, no assurances can be given that the Company's Section 29 tax credits will reduce its Federal income tax liability in any particular year.

In 1991, the Company entered into a transaction with a privately held company which provided funds for the Company to drill wells qualifying for Section 29 tax credits. A second transaction, with the same investor and under similar terms and conditions, was completed in 1992. Pursuant to these transactions, the Company conveyed much of its producing and tax credit eligible acreage in the Carthage field and Moxa Arch and Wamsutter areas to a limited partnership which, utilizing drilling funds contributed by the investor as limited partner, drilled 208 wells which qualify for Section 29 tax credits. The Company is the managing general partner of this producing partnership, and has broad latitude in conducting operations on the assets therein. Prior to a defined payout, the limited partner is entitled to receive a preferential distribution of a specified quantity of available production from this partnership, including gas that does not qualify for the tax credits as well as tax credit-qualified gas. The Company expects payout to occur in December 1996, at which point the limited partner will be entitled to receive only 1% of ongoing production. Both the historic and future forecasted production allocable to the limited partner have been deducted from the Company's reserve and production statistics. For accounting purposes, the proceeds received from the sale of these reserves are recorded as deferred revenues which will be recognized as income as the volumes are distributed to the investor.

Texas Severance Tax Reduction

Natural gas produced from wells that have been certified as tight formations or deep wells by the Texas Railroad Commission ("high cost wells") and that are spudded or completed during the period from June 16, 1989 to September 1, 1996 qualifies for an exemption from the 7.5% severance tax in Texas on natural gas and natural gas liquids produced by such wells prior to August 31, 2001. The natural gas production from wells drilled on certain of the Company's properties in the Austin Chalk, West Texas and East/South Texas business units qualifies for this tax reduction. In addition, high cost wells that are spudded or completed during the period from September 1, 1996 to August 31, 2002 are entitled to receive a severance tax reduction. Operators have 180 days after first production to obtain a high cost gas certification. The tax reduction is based on a formula composed of the statewide "median" (as determined by the State of Texas from producer reports) and the producer's actual drilling and completion costs. More expensive wells will receive a greater amount of tax credit. This tax rate reduction remains in effect for ten years or until the aggregate tax credits received equal 50% of the total drilling and completion costs.

Environmental Regulation

The Company's operations are subject to extensive Federal, state, provincial and local environmental laws and regulations governing the protection of the environment. The Company is in compliance, in all material respects, with applicable environmental requirements. Although future environmental obligations are not expected to have a material impact on the results of operations or financial condition of the Company, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause the Company to incur material environmental liabilities or costs.

Air Emissions

The operations of the Company are subject to regulations controlling emissions of air pollution. The primary legislation affecting the Company's air emissions is the Federal Clean Air Act and its 1990 Amendments (the "CAA"). Among other things, the CAA requires all major sources of air emissions to obtain operating permits; the amendments also revised the definition of a "major source" such that additional equipment involved in oil and gas production may now be covered by the permitting requirements. Although the precise requirements of the 1990 Amendments are not yet known, the Company may incur substantial expenditures for the additional capital, operating and maintenance costs required to comply with these new regulations.

Hazardous Substances and Waste Disposal

The Company currently owns or leases numerous properties that have been used for many years for hard-minerals production or natural gas and crude oil production. Although the Company has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company. In addition, some of these properties have been operated by third parties over whom the Company had no control. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. The Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid wastes" and "hazardous wastes." Although CERCLA currently excludes petroleum from its definition of hazardous substance, many state laws affecting the Company's operations impose clean-up liability regarding petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as "nonhazardous," such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. If such a change in legislation were to be enacted, it could have a significant impact on the Company's operating costs, as well as the oil and gas industry in general. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Environmental Costs."

Oil Spills

Under OPA, owners and operators of onshore facilities and pipelines and lessees or permittees of an area in which an offshore facility is located ("Responsible Parties") are strictly liable on a joint and several basis for removal costs and damages that result from a discharge of oil into United States waters. These damages include, for example, natural resource damages, real and personal property damages and economic losses. OPA limits the strict liability of Responsible Parties for removal costs and damages that result from a discharge of oil to $350 million in the case of onshore facilities and $75 million plus removal costs in the case of offshore facilities, except that these limits do not apply if the discharge was caused by gross negligence or willful misconduct, or by the violation of an applicable Federal safety, construction or operating regulation by the Responsible Party, its agent or subcontractor.

In addition, OPA requires certain vessels and offshore facilities to provide evidence of financial responsibility in the amount of $150 million. The MMS, which has jurisdiction over certain offshore facilities and pipelines, has not yet issued a proposed rule to implement the financial responsibility requirements and, therefore, the financial responsibility requirements applicable under laws existing prior to OPA still apply to such facilities. OPA also requires offshore facilities and certain onshore facilities to prepare facility response plans, which the Company has done, for responding to a "worst case discharge" of oil. Failure to comply with these

requirements or failure to cooperate during a spill event may subject a Responsible Party to civil or criminal enforcement actions and penalties.

Offshore Production

Offshore oil and gas operations are subject to regulations of the United States Department of the Interior which currently impose strict liability upon the lessee under a Federal lease for the cost of clean-up of pollution resulting from the lessee's operations, and such lessee could be subject to possible liability for pollution damages. In the event of a serious incident of pollution, the Department of the Interior may require a lessee under Federal leases to suspend or cease operations in the affected areas.

Canadian Environmental Regulation

The oil and gas industry in Canada is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties. In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. In addition to replacing a variety of older statutes which related to environmental matters, AEPEA also imposes certain new environmental responsibilities on oil and natural gas operators in Alberta and, in certain instances, imposes greater penalties for violations. In British Columbia, regulations affecting the oil and gas industry are administered by the Ministry of Energy, Mines and Petroleum Resources.

Relationship with UPC and Anschutz Shareholders

UPC owns approximately 83% of the outstanding Common Stock. Subject to certain conditions, following completion of the Distribution, Philip F. Anschutz, the Chairman of the Board of Directors of Southern Pacific Rail Corporation, and certain of his affiliates (collectively, the "Anschutz Shareholders") may beneficially own approximately 5.6% of the Common Stock. Information concerning control of the Company, related party transactions and conflicts of interest with respect to UPC and the Anschutz Shareholders is included under the headings "Principal Shareholder; Control of the Company" and "Relationship with Anschutz Shareholders" in the Proxy Statement and is incorporated herein by reference.

Employees

The Company had 1,523 employees as of December 31, 1995. The Company believes that its relations with its employees are good.

Other Business Matters

The Company's operations are subject to the usual hazards incident to the drilling and operation of oil and gas wells and the processing and transportation of natural gas and natural gas liquids, such as cratering, explosions, uncontrollable flows of oil, gas or well fluids, fire, pollution and other environmental risks. In general, many of these risks increase when drilling at greater depths under higher pressure conditions. In addition, certain of the Company's operations are currently offshore and subject to the additional hazards of marine operations, such as capsizing, collision and damage or loss from severe weather. Other operations involve the production, handling, processing and transportation of gas containing hydrogen sulfide and other hazardous substances. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, environmental damage and suspension of operations. Litigation arising from a catastrophic occurrence in the future at one of the Company's locations may result in the Company being named as a defendant in lawsuits asserting potentially large claims. In accordance with customary industry practices, insurance is maintained for the Company against some, but not all, of the consequences of these risks. Losses and liabilities arising from such events could reduce revenues and increase costs to the Company to the extent not covered by insurance or already provided for.

Item 2. Properties

Proved Reserves

The following table sets forth the proved developed and proved undeveloped reserves of natural gas, natural gas liquids and crude oil of the Company as of December 31, 1995. Information set forth in the following table is based on reserve estimates of the Company, prepared in accordance with the rules and regulations of the Securities and Exchange Commission.

	Reserves as of December 31, 1995			
Category	Natural Gas (Bcf)	Natural Gas Liquids (MMBbl)	Crude Oil (MMBbl)	Total (Bcfe)
Proved developed	1,957.1	89.8	78.2	2,965.1
Proved undeveloped	216.4	10.3	5.6	311.8
Total proved	2,173.5	100.1	83.8	3,276.9

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. The reserve data set forth herein represent estimates only. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Acreage

Land Grant and Other Fee Minerals

The following table summarizes by business unit the fee mineral acreage owned by the Company as of December 31, 1995.

	Acres	
Business Unit	Gross	Net
	(In thousands)	
Austin Chalk	13	4
Rockies	4,716	4,151
Plains/Canada	3,943	3,083
Gulf Coast	426	111
East/South Texas	28	8
West Texas	615	203
Total acreage	9,741	7,560
Land Grant (included above in Rockies and Plains/Canada)		
Developed	462	192
Undeveloped	7,099	6,361
Total Land Grant	7,561	6,553

The Company holds royalty interests of varying percentages in the approximately one million gross acres of the Land Grant that are subject to exploration and production agreements with third parties.

Leasehold

The Company's leasehold acreage by business unit as of December 31, 1995 is set forth below.

Business Unit	Acres					
	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
Austin Chalk	608	417	1,120	780	1,728	1,197
Rockies	112	61	265	189	377	250
Plains/Canada	384	184	993	572	1,377	756
Gulf Coast	307	142	872	594	1,179	736
East/South Texas	177	88	28	24	205	112
West Texas	234	125	53	35	287	160
Total acreage	1,822	1,017	3,331	2,194	5,153	3,211

Total Leasehold and Fee Minerals

The total leasehold and fee mineral acreage by business unit as of December 31, 1995 is set forth below.

Business Unit	Acres	
	Gross	Net
	(In thousands)	
Austin Chalk	1,741	1,201
Rockies	5,093	4,401
Plains/Canada	5,320	3,839
Gulf Coast	1,605	847
East/South Texas	233	120
West Texas	902	363
Total acreage	14,894	10,771

Drilling Activity and Producing Well Summary

The table below summarizes the Company's drilling activity over the last three years.

	Years Ended December 31,					
	1993		1994		1995	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	478	295.4	615	364.5	679	505.7
Dry	13	7.7	14	8.7	18	7.7
Exploration wells:						
Productive	13	9.5	29	16.0	6	2.8
Dry	25	10.2	19	8.1	22	10.7
Total wells	529	322.8	677	397.3	725	526.9

The number of wells drilled is not a valid measure or indicator of the relative success or value of a drilling program because the significance of the reserves and their economic potential may vary widely for each project. As of December 31, 1995, the Company owned interests in 4,046 gross gas wells (2,181 net) and 3,199 gross oil wells (1,656 net). Gross wells include 600 wells with multiple completions. The Company operated 59% of the gross wells in which it owned an interest.

Gas Processing Assets

The Company owns an interest in 26 gas plants (18 of which are Company-operated) with design capacity of over 3.6 Bcfd (1.5 Bcfd net to the Company's ownership). In general, the Company owns extensive gathering systems behind each of its natural gas processing plants which it uses to transport unprocessed gas from producing wells to the inlet of the plant. A listing of the Company's processing plants is provided below.

Gas Plant by Business Unit	Working Interest	Design Capacity (MMcfd)(1)	Average Gross Volumes Year Ended December 31, 1995: Natural Gas Throughput (MMcfd)	Average Gross Volumes Year Ended December 31, 1995: Natural Gas Liquids Produced (MBbld)
Austin Chalk				
A&M(2)	55%	65	57	6.2
Brookeland(4)	80	50	50	4.9
Bryan(2)	55	60	57	10.3
*Bryan Hicks(2)	55	15	15	1.5
Rockies				
*Anschutz Ranch East(6,7)	12	650	570	25.0
Brady(5,8,9)	42	65	62	0.8
*Echo Springs(10)	34	240	125	5.5
Emigrant Trail	100	60	50	1.3
*Painter(11)	19	260	255	9.0
Patrick Draw(9)	100	30	26	1.6
Pineview	49	15	2	0.3
*Whitney Canyon(8)	19	235	180	5.3
Yellow Creek(3,9)	100	80	23	0.3
Plains/Canada				
Arapahoe(5,7)	56	10	5	—
Bledsoe(5,7)	100	2	1	—
*Caroline(7,8)	7	300	285	25.2
Frontera(5,7)	59	4	2	—
Mt. Pearl(5,7)	52	18	8	0.4
Silo	100	5	5	0.4
*Wattenberg	6	225	163	8.2
East/South Texas				
Conroe	100	65	32	0.7
East Texas plant complex(9)	89	640	586	34.6
Gulf Plains(9)	100	110	86	5.9
West Texas				
*Block 31(9,11)	5	225	225	9.5
Ozona(9,12)	63	90	56	4.2
S.W. Ozona(13)	100	90	50	5.1
Total		3,609	2,976	166.2

* Non-operated

(1) Represents the gross design capacity of the gas plant as of December 31, 1995, unless otherwise indicated.

(2) Straddle plants (plants located near a transmission facility which process gas dedicated to or gathered by a third party) which process gas gathered by the Ferguson-Burleson County Gas Gathering System. The Company anticipates shutting down the Bryan Hicks plant in 1996.

(3) Straddle plant.

(4) An incremental 50 MMcfd of design capacity is expected to come on line by the second quarter of 1996.

(5) Residue gas can be reinjected for pressure maintenance.

(Footnotes continued on next page)

(Footnotes continued from previous page)

(6) Design capacity includes 260 MMcfd utilized for field pressure maintenance. During 1995, pressure maintenance ceased, resulting in current processing capacity of 390 MMcfd as of August 1995. As a result, an additional 80 MMcfd from the Anschutz Ranch field normally processed at this plant is currently being processed at Painter complex.

(7) Financial and operating statistics are included in the producing property, rather than the plants, pipelines and marketing disclosures (the plant is accounted for as a lease facility).

(8) Sour gas facility (capable of processing gas containing hydrogen sulfide).

(9) Includes fractionation facilities.

(10) An incremental 120 MMcfd of design capacity came on line in November 1995.

(11) Nitrogen is reinjected for pressure maintenance.

(12) A 58 MMcfd plant was acquired through the Amax acquisition in March 1994, and its expansion to 90 MMcfd design capacity was completed in October 1995.

(13) A 28 MMcfd plant was acquired through the Amax acquisition in March 1994. In April 1995, a plant expansion to a design capacity of 90 MMcfd was completed.

Average throughput in these plants for 1995 was approximately 83% of aggregate design capacity.

Item 3. Legal Proceedings

In August 1994, the surface owners of portions of five sections of Colorado land that are subject to mineral reservations made by the Company's predecessor in title brought suit against the Company in the District Court of Weld County, Colorado to quiet title to minerals, including crude oil (in some of the lands) and natural gas. In September 1994, the case was removed to the U.S. District Court for the District of Colorado, but the plaintiffs are asking the District Court to remand the case back to the state court. The Company has filed a motion for summary judgment asking the District Court to rule as a matter of law that the Company owns the oil and gas and all minerals that are part of a severed mineral estate. No trial date is currently set. Similar claims were made under identical mineral reservations by Utah and Wyoming surface owners in cases litigated in the Federal courts of Utah and Wyoming between 1979 and 1987. In those cases, the Federal courts held as a matter of law that, under the laws of Utah and Wyoming, these mineral reservations unambiguously reserved oil and gas to the Railroad and its successors. These holdings were affirmed by the United States Court of Appeals for the Tenth Circuit. While the Company believes that the rule of law applied by the Federal courts in Utah and Wyoming should also be applied under Colorado law, there are Colorado court decisions that could provide a basis for an alternative interpretation. The value of the disputed reserves in the properties subject to the lawsuit is estimated to be approximately $5 million. Approximately 400,000 acres of other lands in Weld County, Colorado are subject to mineral reservations that are in the same form as the reservations at issue in the present suit. An adverse interpretation of the reservations at issue is likely to implicate the mineral title in these other lands as well. In addition, over two million acres of lands elsewhere in Colorado are subject to the same forms of mineral reservations. Depending on the grounds of an adverse decision in the case, title to minerals held by the Company in some or all of these lands could also be affected, which might have the effect of significantly reducing the Company's interest in the Las Animas area of southeastern Colorado and the Denver-Julesburg Basin in eastern Colorado.

On August 31, 1995, the Texas General Land Office and two other royalty owners filed a suit against the Company in the Texas District Court of Fayette County, Texas. The suit alleges that the Company underpaid the plaintiffs for their royalty interest share of the Company's crude oil production in Texas, and seeks certification as a class action. Since late August 1995, the Company has been made a party to a number of other lawsuits making allegations similar to those made in the Fayette County suit. On August 25, 1995, an individual interest owner filed suit in County Court in Calhoun County, Texas and on August 31, 1995, the Lee County Attorney filed suit in the Texas District Court in Lee County on behalf of the State of Texas, Lee County and two individual royalty owners. These additional suits all name the Company and a number of other non-affiliated defendants, and all seek certification as class actions. The premise of these suits is that the Company and the other named defendants used "posted prices" to determine the amounts payable for crude oil production

attributable to the plaintiffs' interests. Plaintiffs allege that these posted prices have been set consistently below "market value," and that this practice has resulted in plaintiffs and other interest owners being underpaid for their interests. The Calhoun County case makes additional claims not made in the other suits, including claims with respect to prices paid for natural gas and natural gas liquids as well as for crude oil. The Calhoun County case alleges that the defendants discriminated against plaintiffs in (1) sales of natural gas and natural gas liquids, (2) charges for transportation and other services and (3) the prices used for accounting to the plaintiffs for such sales and services. The Calhoun County suit also alleges that the Company and the other named defendants have breached fiduciary duties to certain purported class members and intentionally misrepresented the circumstances of their purchases and sales of oil. In addition, the Lee County and Calhoun County cases name the Company's marketing subsidiary, UP Fuels, and certain other affiliates of the Company as defendants. The Lee County case also alleges discriminatory practices in sales of crude oil, claims that the defendants have conspired and acted in concert to accomplish a shared unlawful purpose in making sales of crude oil, and alleges violations of numerous state statutes. These suits are similar to suits recently brought in Texas by the Texas General Land Office against eight other major crude oil producers and in New Mexico and Oklahoma by private royalty owners against major crude oil producers, not including the Company. Also, an additional suit has been filed in Lee County against a number of major crude oil producers. This suit, which does not name the Company, makes allegations similar to the Lee County suit described above. More recently, the Company has been brought into interest owner litigation on natural gas. In November 1995, a suit was filed against the Company in the District Court for Panola County, Texas by an individual royalty owner contending that the Company has not paid royalties on the highest price obtainable and, further, that the Company has improperly deducted costs from its interest owners. Plaintiff seeks certification as a class action. In January 1996, the Railroad was named a party in a suit brought in the District Court for the City and County of Denver, Colorado, alleging that the Railroad and other named defendants are improperly deducting post-production costs from interest owners in gas production. The plaintiffs are individual interest owners and seek certification as a class action. One of the plaintiffs has a surface owner agreement with the Railroad. The Company has not been named as a defendant, but the Company does administer the surface owner agreements and make the payments thereunder, and has agreed to indemnify the Railroad with respect to this litigation. This litigation activity against the Company and other crude oil and natural gas producers suggests that more suits of this type may be filed against the Company including, perhaps, suits by other types of interest owners and in jurisdictions other than Texas. While the Company intends to defend vigorously against these lawsuits and any similar lawsuits, if suits of this type are ultimately resolved against the Company on a widespread basis, damage awards and a loss of future revenue could result which, in the aggregate, may be material.

In July 1991, Columbia Gas Transmission Company ("Columbia") filed for protection from its creditors under Chapter 11 of the bankruptcy laws. Columbia and the Company were parties to a long-term contract for the sale by the Company to Columbia of substantial volumes of natural gas at above 1991 market prices. Shortly after the filing, Columbia rejected the Company's contract and most of its other gas purchase contracts, leaving the Company and nearly 2,000 other gas producers as unsecured creditors. Following the Chapter 11 filing, there was extensive litigation and proceedings involving the value of Columbia's estate and the amount of each gas producer's claim. In April 1995, Columbia filed a Plan of Reorganization which was approved by the Bankruptcy Court and became effective in November 1995, at which time the Company received a cash payment. An issue remains as to whether the payment received is royalty bearing, other than that portion of the payment applicable to gas actually produced and sold to Columbia, and the Company has instituted a legal proceeding to obtain a declaration of its rights and obligations. As a result of the settlement with Columbia, after taking into account possible tax and royalty claims, the Company recorded pre-tax income of $122.5 million in the fourth quarter of 1995 ($78.5 million after tax).

The Company is a defendant in a number of lawsuits and is involved in governmental proceedings arising in the ordinary course of business in addition to those described above, including personal injury claims and environmental claims. While the Company cannot predict the outcome of such litigation and other proceedings, it does not expect those matters to have a materially adverse effect on the results of operations or financial condition of the Company.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders during the quarter ended December 31, 1995.

Executive Officers of the Registrant

Name	Position	Age	Business Experience During Past Five Years
Jack L. Messman	President and Chief Executive Officer; Director	56	(1)
V. Richard Eales	Executive Vice President and Chief Financial Officer	60	(2)
George Lindahl, III	Executive Vice President—Operations	49	(3)
Anne M. Franklin	Vice President—People	39	(4)
Patrick D. Hanley	Vice President—Finance	51	(5)
Mark S. Knouse	Vice President—External Affairs and Secretary	45	(6)
Joseph A. LaSala, Jr	Vice President and General Counsel	41	(7)
Donald W. Niemiec	Vice President—Marketing	49	(8)

(1) Mr. Messman has been President and Chief Executive Officer of the Company since August 1995, and a Director of the Company since September 1991. He has been President, Chief Executive Officer and a Director of UPRC since May 1991. Prior thereto, Mr. Messman was Chairman of the Board of Directors and Chief Executive Officer of USPCI, Inc. ("USPCI"), a former subsidiary of UPC. Mr. Messman continued as Chairman of USPCI through December 1994.

(2) Mr. Eales has held his current position with the Company since August 1995. From 1991 to August 1995, he was Vice President—Corporate Development of UPRC. Prior thereto, Mr. Eales was Vice President—Corporate Development of USPCI.

(3) Mr. Lindahl has held his current position with the Company since August 1995. From 1992 to August 1995, he was Vice President—Operations for UPRC. Prior thereto, he was Vice President—Exploration for UPRC.

(4) Ms. Franklin has held her current position with the Company since August 1995. She joined UPRC as Vice President—People in June 1995. From 1993 to June 1995, she was Director of Executive Leadership and Development for Ameritech, Inc. ("Ameritech"). Prior thereto, she held various positions in marketing and operations at Ameritech and Indiana Bell Telephone Company (currently Ameritech).

(5) Mr. Hanley has held his current position with the Company since August 1995. He was Vice President and Chief Financial Officer of UPRC from 1993 to August 1995 and, prior thereto, Vice President—Finance of UPRC.

(6) Mr. Knouse has held his current position with the Company since August 1995. From 1991 to August 1995, he was Vice President—Government and Public Affairs of UPRC and, prior thereto, Director of Washington Affairs of UPC.

(7) Mr. LaSala has held his current position with the Company since January 1996. Mr. LaSala joined UPRC in January 1995 as Assistant General Counsel. He was Vice President—Government and Regulatory Affairs of USPCI from May 1993 until 1995 and, prior thereto, Vice President—External Relations of USPCI.

(8) Mr. Niemiec has held his current position with the Company since August 1995. He has been Vice President—Marketing of UPRC since 1993 and prior thereto was Manager—Marketing and Trading of UPRC. Mr. Niemiec has been President of UP Fuels since 1990.

PART II

Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters

The Company completed an initial public offering of its Common Stock in October 1995. The Common Stock is traded on the New York Stock Exchange under the symbol "UPR." The high and low sales prices per share for the Common Stock, as reported on the New York Stock Exchange Composite Tape for the period from October 10, 1995 until December 31, 1995, were $26.25 and $21.125, respectively.

At February 26, 1996, there were 249,249,599 shares of outstanding Common Stock and approximately 362 shareholders of record. At that date, the closing price of the Common Stock on the New York Stock Exchange was $26.00.

The Company paid a cash dividend of $0.05 per share in January 1996 with respect to the fourth quarter of 1995. The Company currently intends to continue to pay quarterly cash dividends on its outstanding shares of Common Stock. The determination of the amount of future cash dividends, if any, to be declared and paid by the Company will depend upon, among other things, the Company's financial condition, funds from operations, the level of its capital and exploration expenditures, future business prospects and other factors deemed relevant by the Board of Directors. Accordingly, there can be no assurance that dividends will be paid.

Under the terms of the Company's Intercompany Credit Agreement with UPC, after the Distribution and for so long as any intercompany indebtedness remains outstanding, the Company and UPRC are precluded from declaring any dividend or distribution on their capital stock, other than quarterly dividends paid in cash which do not exceed the last quarterly dividend paid by the Company or UPRC prior to the Distribution.

Item 6. Selected Financial Data

Five-Year Financial Summary

	1991	1992	1993	1994	1995(a)
	(Millions of dollars, except per share amounts)				
Income Statement Data:					
Operating revenues	$1,070.7	$1,222.5	$1,277.1	$1,332.9	$ 1,455.8 (b)
Operating income	264.8	318.7	382.9	351.3	470.1 (b)
Income before income taxes	306.4	384.2	440.1	520.7(c)	458.0 (b)
Net income	206.8	272.3	243.8(d)	390.0(c)	350.7 (b)
Per share:					
Net income	n/a	n/a	n/a	n/a	n/a (e)
Dividends	n/a	n/a	n/a	n/a	0.05 (f)
Financial Position Data:					
Working capital	$ 160.4	$ 278.0	$ 355.7	$ 28.0	$ (646.5)(g)
Properties—net	1,564.8	1,660.5	1,780.2	2,600.1(h)	2,764.3
Total assets	2,276.8	2,586.4	2,714.1	3,247.0	3,308.9
Long-term debt	54.6	48.2	45.6	37.7	101.5
Shareholders' equity	1,318.5	1,475.2	1,596.1	1,834.9	1,312.4
Cash Flow Data:					
Capital and exploratory expenditures	$ 465.3	$ 594.4	$ 560.4	$1,389.3(h)	$ 686.4
Cash provided by operations	554.0	776.2	567.5	821.0	829.4

(a) Represents historical financial information. See Note 2 to the Consolidated Financial Statements for adjustments necessary to give effect to the Asset Restructuring and the Offering as if such transactions had occurred at the beginning of 1995.

(Footnotes continued on next page)

(Footnotes continued from previous page)

(b) In November 1995, the Company recorded a $122.5 million pre-tax ($78.5 million after-tax) gain resulting from the Columbia bankruptcy settlement (see Note 16 to the Consolidated Financial Statements).

(c) In March 1994, the Company sold its interest in the Wilmington field and Harbor Cogeneration Plant to the Port of Long Beach, California. The Wilmington sale resulted in a $159.2 million pre-tax ($100 million after-tax) gain (see Note 5 to the Consolidated Financial Statements).

(d) In January 1993, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," and SFAS No. 109 "Accounting for Income Taxes," with a cumulative after-tax charge to 1993 earnings of $59 million.

(e) Earnings per share have been omitted as the Company was a wholly owned subsidiary of UPC until its initial public offering in October 1995. Therefore, net income per share is not applicable for periods prior to the fourth quarter of 1995. See "Selected Quarterly Data" on page F-32.

(f) Represents the dividend declared with respect to the fourth quarter of 1995. Prior to October 1995 the Company was wholly owned by UPC. Therefore, dividends per share is not applicable for periods prior to 1995. See "Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters."

(g) Includes the $650 million note payable to UPC incurred in connection with the Asset Restructuring. The Company currently intends to refinance these borrowings (see Note 9 to the Consolidated Financial Statements).

(h) In March 1994, the Company acquired Amax for a net purchase price of $725 million.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following information should be read in conjunction with the information contained in the Consolidated Financial Statements and the notes thereto included in Item 8 of this Report.

Overview

As an independent energy company, the Company is engaged in the exploration for and development and production of natural gas, natural gas liquids and crude oil in North America. The Company's results of operations are determined in large part by the differences between the prices received for the natural gas, natural gas liquids and crude oil produced and the cost to find, develop, produce and market such resources. The Company's production volume growth in recent years has occurred through exploration and development in core geographic areas, as well as producing property purchases, the most significant of which was the $725 million acquisition of Amax in March 1994.

The Company is principally a natural gas company, as natural gas and natural gas liquids made up 78% of the Company's equity production in 1995. Changes in sales prices received for production directly affect the Company's determination to proceed with the exploration for and development of natural gas and crude oil and the quantity of proved reserves. Its revenues, profitability and cash flow are substantially dependent upon prevailing prices for its hydrocarbon product. Based upon the results of operations for the year ended December 31, 1995, and excluding the effect of the Company's hedging program, a change of $0.10/Mcf in the average price of natural gas, a change of $1.00/Bbl in the average price of natural gas liquids and a change of $1.00/Bbl in the average price of crude oil throughout such period would have resulted in approximate changes in net income of $21.2 million, $12.9 million and $11.9 million, respectively. Historically, the Company has been able to manage a portion of the operating risk relating to hydrocarbon price volatility through hedging activities. See "Other Matters—Hedging Activities and Derivative Financial Instruments."

Natural gas and, to a lesser degree, crude oil and natural gas liquids prices are influenced by seasonal factors, natural gas transportation and storage infrastructure, imports, political and regulatory developments and competition from other sources of energy, and have been volatile over the last three years. Final prices for prompt

month natural gas contracts traded on the New York Mercantile Exchange ("NYMEX") for delivery of gas at Henry Hub, Louisiana during the period from January 1, 1993 to December 31, 1995, have ranged from $1.39/Mcf to $2.76/Mcf. Cash prices received by the Company in its specific producing areas have exhibited similar volatility during this same period.

The Company owns a non-operated 50% interest in Black Butte Coal Company ("Black Butte"), a partnership which operates a surface coal mine complex in southwestern Wyoming. During 1995, Black Butte's sales to its largest customer under an amended coal supply contract accounted for $55 million, or 51%, of Minerals operating income. Operating income from this amended contract is expected to be relatively constant through the end of 2001, when the financially beneficial terms of this agreement will terminate. Although Black Butte continues to seek new buyers for its low-sulfur coal, its mining costs are considerably higher than the mining costs for competing supplies. The Company does not expect to be able to replace the operating income it currently receives under the amended contract with incremental coal sales.

Year Ended December 31, 1995 Compared to Year Ended December 31, 1994

Selected Financial Data

	Year Ended December 31,	
	1994	1995
	(Millions of dollars)	
Total operating revenues	$1,332.9	$1,455.8
Total operating expenses	981.6	985.7
Operating income	351.3	470.1
Net income	390.0	350.7
Total operating revenues excluding 1995 Columbia Gas Transmission Company bankruptcy settlement	1,332.9	1,333.3
Operating income excluding 1995 Columbia settlement	351.3	347.6
Net income excluding 1994 sale of Wilmington field and 1995 Columbia settlement	290.0	272.2

Total operating revenues increased by $122.9 million (9%) to $1,455.8 million in 1995 as the pre-tax gain of $122.5 million from the Columbia bankruptcy settlement and increased plants, pipelines and marketing revenues of $62.7 million were partially offset by decreases in revenues from producing properties ($25.3 million), other oil and gas revenues ($32 million) and Minerals revenues ($5 million). Excluding the Columbia settlement, 1995 revenues were essentially unchanged from 1994. Operating expenses increased by $4.1 million to $985.7 million reflecting higher depreciation, depletion and amortization expenses ($32.2 million) and general and administrative costs ($10.3 million), partially offset by lower production costs ($34.5 million) and exploration expenses ($18.2 million). Operating income increased by $118.8 million (34%) to $470.1 million, slightly less than the increase in operating revenues, due to the small net increase in operating expenses. Excluding the Columbia settlement, 1995 operating income was $3.7 million lower than 1994.

The Company reported net income of $350.7 million for the year ended December 31, 1995, down by $39.3 million from $390 million in 1994. The decrease resulted from a $100 million after-tax gain on the sale of the Wilmington field in 1994, partially offset by the $78.5 million after-tax gain from the Columbia settlement in 1995. Excluding the 1994 Wilmington sale and the 1995 Columbia settlement, 1995 net income of $272.2 million was $17.8 million lower than 1994 net income, primarily reflecting additional general and administrative and interest expense incurred in the fourth quarter of 1995 attributable to the Asset Restructuring and the Offering.

Oil and Gas Operations

Operating Revenues

Operating Revenues—Oil and Gas Operations

	Year Ended December 31,	
	1994	1995
	(Millions of dollars)	
Producing properties	$886.0	$860.7
Plants, pipelines and marketing	249.1	311.8
Other oil and gas revenues	76.5	167.0

Producing property revenues decreased by $25.3 million (3%) to $860.7 million. Production volumes increased by 124.8 MMcfed (10%) to add $65.5 million in revenues; however, this improvement was more than offset by lower prices which reduced revenues by $90.8 million. Natural gas volumes increased by 160.8 MMcfd (21%) to 915.6 MMcfd. The Austin Chalk accounted for 84.7 MMcfd of the increase. Crude oil volumes declined by 10.3 MBbld (16%) to 52.8 MBbld. The Austin Chalk declined by 5.6 MBbld to 25.8 MBbld as a result of more emphasis on the gas prone deep portions of the trend and the natural decline of older properties. The October 1994 sale of Point Arguello, an offshore California heavy oil field, reduced crude production by another 5.2 MBbld. Natural gas liquids production from producing properties increased by 4.3 MBbld (23%) to 23.1 MBbld. All business units showed improvement with the majority of the increase coming from the Rockies (2.3 MBbld).

Average product price realizations for 1995 decreased by 11% from 1994. Natural gas realizations decreased by $0.38/Mcf (21%) to $1.44/Mcf. Natural gas liquids realizations increased by $0.28/Bbl (4%) to $8.14/Bbl. Crude oil price realizations increased by $1.74/Bbl (12%) to $16.08/Bbl.

The Company's crude oil and natural gas hedging activities affected price realizations in both 1994 and 1995. Excluding the impact of hedging, average natural gas price realizations would have been $1.32/Mcf in 1995 (compared with $1.44/Mcf including hedging) and $1.69/Mcf in 1994 (compared with $1.82/Mcf including hedging). Average crude oil price realizations would have been $16.35/Bbl in 1995 (compared with $16.08/Bbl including hedging) and were unchanged at $14.34/Bbl in 1994. Average natural gas liquids realizations were not affected by hedging in 1994 and 1995.

Plants, pipelines and marketing revenues increased by $62.7 million (25%) to $311.8 million. Increased plant volumes of 24.4 MMcfed (12%) added $15.3 million in plant revenues, but lower prices reduced revenues by $10 million. Natural gas liquids volumes increased by 3 MBbld (10%) to 34.2 MBbld primarily due to the expansion of the Company's two Ozona plants in West Texas. Natural gas volumes were up by 6.4 MMcfd (37%) to 23.9 MMcfd primarily because of higher throughput volumes associated with a full year of production at the Brookeland plant in the Austin Chalk. Marketing revenues increased by $17.3 million to $56.3 million in 1995, primarily as a result of lower firm transportation costs and a rate refund related to the Company's transportation agreement with Kern River Gas Transmission Company (see Note 15 to the Consolidated Financial Statements). Pipeline revenues increased by $40.1 million to $125.2 million primarily as a result of the start-up and expansion of pipelines in the Austin Chalk, West Texas and the Rockies.

Average natural gas and natural gas liquids price realizations relating to plants, pipelines and marketing revenues decreased by $0.30/Mcf (17%) to $1.51/Mcf and $0.59/Bbl (6%) to $9.38/Bbl, respectively.

Other oil and gas revenues increased by $90.5 million in 1995 as a result of the Columbia settlement ($122.5 million), partially offset by an $8.1 million loss brought about by weakened correlation for natural gas hedges (see "Other Matters—Hedging Activities and Derivative Financial Instruments"), lower gains on property sales ($12.3 million), a decrease in recognition of deferred revenue ($8 million) reflecting lower preferential volumes distributed to an investor in the Company's Section 29 limited partnership (see "Business—Section 29 Tax Credits") and a favorable market sharing settlement in 1994 ($4.9 million).

Operating Expenses

Operating Expenses—Oil and Gas Operations

	Year Ended December 31,	
	1994	1995
	(Millions of dollars)	
Production	$252.3	$217.8
Exploration	107.6	89.4
Plants, pipelines and marketing	150.8	160.8
Depreciation, depletion and amortization	426.4	458.6

Production expenses decreased by $34.5 million (14%) to $217.8 million, largely because of lower production taxes ($23.7 million) reflecting the successful resolution of a production tax audit, lower product prices and tax exemptions related to high cost gas wells. Production expenses excluding production taxes decreased on a per unit basis from $0.39/Mcfe to $0.33/Mcfe in 1995 as the sale of several properties with relatively high operating costs reduced lease costs by $8.7 million.

Exploration expenses decreased by $18.2 million to $89.4 million, primarily due to a decrease in dry hole costs ($18.9 million) associated with a reduction in exploratory drilling. Expenditures for seismic data were $4 million higher than in 1994.

Operating expenses for plants, pipelines and marketing were up by $10 million (7%) to $160.8 million due to expenses from the start-up and expansion of additional gas value chain assets, partially offset by lower gas plant expenses.

Depreciation, depletion and amortization increased by $32.2 million (8%) to $458.6 million as a result of higher production and a higher asset base in plants. On a per unit basis for producing properties, depreciation, depletion and amortization expense decreased by $0.01/Mcfe from $0.82/Mcfe to $0.81/Mcfe.

Total Oil and Gas Operating Income

Total oil and gas operating income increased by $137.9 million to $415.5 million in 1995, primarily reflecting the $122.5 million pre-tax gain from the Columbia bankruptcy settlement.

Minerals

Minerals revenues declined by $5 million to $116.3 million, largely due to lower coal royalties associated with fewer tons mined from the Company's leases. Minerals expenses were up by $4.3 million. As a result, Minerals operating income declined by $9.2 million.

General and Administrative Expenses

General and administrative expenses increased by $10.3 million in 1995 to $50.3 million principally reflecting non-recurring costs associated with the Offering, increased costs associated with being a stand-alone company and costs of converting to new information and accounting systems. See Note 2 to the Consolidated Financial Statements for pro forma income information.

Interest and Other Income

Interest and other income declined by $181.5 million to a $12.1 million expense, primarily reflecting the absence of the $159.2 million pre-tax gain recorded on the sale of the Wilmington field in 1994 and a $14.5 million increase in interest expense in 1995 associated with debt incurred at the time of the Offering.

Income Taxes

Income taxes decreased by $23.4 million in 1995 because of lower income before taxes, primarily reflecting the difference between the gain on the sale of the Wilmington field ($159.2 million) in 1994 and the gain on the Columbia settlement ($122.5 million) in 1995. The effective tax rate for 1995 was 23.4% (including $37.9 million of Section 29 tax credits) compared with 25.1% for 1994 (including $52.2 million of Section 29 tax credits).

Year Ended December 31, 1994 Compared to Year Ended December 31, 1993

Selected Financial Data

	Year Ended December 31,	
	1993	1994
	(Millions of dollars)	
Total operating revenues	$1,277.1	$1,332.9
Total operating expenses	894.2	981.6
Operating income	382.9	351.3
Net income	243.8	390.0
Net income excluding 1994 Wilmington sale and 1993 accounting changes	302.8	290.0

Total operating revenues increased by $55.8 million (4%) to $1,332.9 million in 1994, as total oil and gas operating revenues increased by $39.8 million and Minerals operating revenues increased by $16 million. The increase in revenues was offset by an $87.4 million increase in operating expenses, $83.8 million of which related to oil and gas operating expenses, causing a $31.6 million decline in operating income.

Net income of $390 million for the year ended December 31, 1994 was up by $146.2 million (60%) over the year ended December 31, 1993. The increase was largely the result of the $100 million after-tax gain from the sale of the Wilmington field, and a $13.7 million after-tax gain on the sale of various producing properties in non-core areas, offset by an $11 million after-tax loss on the sale of Point Arguello. In addition, 1993 results included a $59 million charge to reflect the cumulative effect of accounting changes for the adoption of SFAS No. 106 and SFAS No. 109 and a $6.4 million deferred tax charge for prior years as a result of the Omnibus Budget Reconciliation Act of 1993 (the "1993 Tax Act").

Oil and Gas Operations

Operating Revenues

Operating Revenues—Oil and Gas Operations

	Year Ended December 31,	
	1993	1994
	(Millions of dollars)	
Producing properties	$829.7	$886.0
Plants, pipelines and marketing	217.2	249.1
Other oil and gas revenues	124.9	76.5

Producing property revenues increased by $56.3 million (7%) to $886 million for 1994, as increased volumes of 146 MMcfed added $87.5 million, partially offset by lower prices, which reduced revenue by $31.2 million. Gas volumes increased by 146.6 MMcfd (24%) as a result of the inclusion of nine months of production from the properties acquired in the Amax acquisition (70 MMcfd), higher volumes from the Austin Chalk (40 MMcfd) and additional tight sands volumes from the Green River Basin. Crude oil volumes declined by 3.4 MBbld (5%) to 63.1 MBbld, as a result of the sale of the Wilmington field (4 MBbld) and normal field production declines in the Austin Chalk (3 MBbld), partially offset by an increase from the Amax acquisition (2 MBbld). Natural gas liquids volumes increased by 3.3 MBbld (21%) to 18.8 MBbld as a result of a 2 MBbld increase from the Amax acquisition and a 1 MBbld increase from the Austin Chalk.

Average product price realizations for 1994 decreased by 6% from 1993. Average natural gas realizations increased by $0.02/Mcf (1%) to $1.82/Mcf for 1994, and average natural gas liquids realizations declined by $0.91/Bbl (10%) to $7.86/Bbl for 1994. Average crude oil price realizations declined by $1.32/Bbl (8%) to $14.34/Bbl for 1994.

The Company's hedging activities affected price realizations in both 1993 and 1994. Excluding the impact of hedging, natural gas price realizations in 1994 would have been $1.69/Mcf (compared with $1.82/Mcf including hedging) and 1993 natural gas price realizations would have been $1.99/Mcf (compared with

$1.80/Mcf including hedging). Crude oil price realizations in 1994 would have been unchanged at $14.34/Bbl and 1993 crude oil price realizations would have been $15.18/Bbl (compared with $15.66/Bbl including hedging). The Company did not engage in any natural gas liquids hedging activities during 1993 or 1994.

Plants, pipelines and marketing revenues increased by $31.9 million for 1994 (15%), as increased plant volumes, which added $32.2 million, and increased marketing revenues of $15.8 million from higher sales margins, were partially offset by the effect of lower plant prices ($11.5 million) and lower pipeline revenues ($3.2 million). Total plant natural gas liquids volumes increased by 6.8 MBbld (28%) as higher Austin Chalk gas volumes and the new Brookeland plant added 2 MBbld, volumes at the East Texas plant complex increased 2 MBbld primarily as a result of the plant expansion, the Amax acquisition contributed 2 MBbld, and throughput increases at the Gulf Plains plant in South Texas added 1 MBbld.

Average natural gas liquids price realizations relating to plants, pipelines and marketing revenues declined by $0.55/Bbl to $9.97/Bbl and natural gas price realizations declined by $0.82/Mcf to $1.81/Mcf because of the expiration of an above-market supply contract.

Other oil and gas revenues declined by $48.4 million in 1994 as a result of a $21 million decrease in recognition of deferred revenue reflecting lower preferential volumes distributed to an investor in the Company's Section 29 limited partnership (see "Business—Section 29 Tax Credits"). Additional factors contributing to the decline in other oil and gas revenues include the absence of operating income from the Harbor Cogeneration facility included in the 1994 sale of the Wilmington field which had operating income of $8.7 million in 1993, and the inclusion in other oil and gas revenues for 1993 of two insurance settlements related to business interruptions at an offshore platform and a natural gas processing facility in Wyoming and two settlements with interstate pipelines received in 1993, which settlements totaled $30.4 million. The decreases associated with the decline in deferred revenue recognition and the absence of these non-recurring items in 1994 were partially offset by $21.1 million from gains in 1994 on the sale of certain non-core assets.

Operating Expenses

Operating Expenses—Oil and Gas Operations

	Year Ended December 31,	
	1993	1994
	(Millions of dollars)	
Production	$240.2	$252.3
Exploration	111.2	107.6
Plants, pipelines and marketing	144.6	150.8
Depreciation, depletion and amortization	357.8	426.4

Production expenses increased by $12.1 million in 1994 (5%) due to increased volumes of 146 MMcfed which resulted in $15 million of additional lease operating costs and production taxes; however, costs calculated on a per unit basis declined from $0.60 to $0.55 per Mcfe in 1994, reflecting the elimination of the Wilmington production, the acquisition of lower cost Amax production and the reengineering of field operations.

Exploration expenses of $107.6 million were lower by $3.6 million (3%), due in part to an $8.7 million reduction in expense for seismic data acquisition, which was partially offset by a $6.9 million increase in dry hole expense.

Plants, pipelines and marketing expenses increased by $6.2 million (4%), primarily as a result of an increase in pipeline operating costs of $4.8 million reflecting the 1994 start-up of the Wahsatch Gathering System.

Depreciation, depletion and amortization expenses increased by $68.6 million (19%), primarily as a result of increased production volumes ($42 million), new plants and pipelines put into service during 1994 ($14 million), and higher depreciation, depletion and amortization rates ($9 million). On a per unit basis for producing properties, depreciation, depletion and amortization expenses increased by $0.02/Mcfe from $0.80/Mcfe to $0.82/Mcfe.

Total Oil and Gas Operating Income

Total oil and gas operating income declined by $44 million (14%) to $277.6 million in 1994.

Minerals

Minerals revenues increased by $16 million (15%) to $121.3 million largely because of higher income at the Black Butte mine ($7 million) relating primarily to higher sales tonnage (1.5 million tons) principally in the spot markets. As a result of this and other favorable items, operating income increased by $14.3 million to $116.3 million.

General and Administrative Expenses

General and administrative expenses increased by $2.3 million in 1994 (6%) to $40 million as a result of incremental employee benefit costs.

Interest and Other Income

Other income increased by $113.6 million in 1994 to $174 million, reflecting the $159.2 million pre-tax gain on the sale of the Wilmington field, partially offset by a $16.9 million loss associated with the sale of the Point Arguello field. Intercompany interest income in 1994 declined by $34.2 million (68%), as intercompany interest paid by UPC to the Company declined due to a $399.5 million net reduction in the Company's intercompany receivable from UPC, reflecting the $725 million Amax acquisition, offset in part by proceeds relating to the Wilmington sale.

Income Taxes

Income taxes decreased by $6.6 million in 1994. The effective tax rate for 1994 was 25.1% (including $52.2 million of Section 29 tax credits) compared with 31.1% for 1993 (including $14.4 million of Section 29 tax credits). The 1993 effective rate also included an $8 million write-off related to the exit from certain international activities and a $6.4 million deferred tax charge related to the increase in the effective corporate tax rate as a result of the 1993 Tax Act.

Cumulative Effect of Changes in Accounting Principles

Effective January 1, 1993, the Company adopted SFAS No. 106 which requires that the cost of non-pension benefits for retirees be accrued during the period of their employment. Also effective January 1, 1993, the Company adopted SFAS No. 109 which requires the balance sheet approach of accounting for income taxes, whereby assets and liabilities are recorded at the tax rates currently enacted. The cumulative effect of adopting SFAS No. 106 and SFAS No. 109 was a one-time charge of $59 million in 1993.

Liquidity and Capital Resources

Cash provided by operations for 1995 was $829.4 million. 1995 capital expenditures were $686.4 million. The Company's ability to maintain and improve its operating income and cash flow is dependent upon continued capital spending. The Company expects to maintain its current level of capital spending of approximately $670 million in 1996. Spending is expected to focus on drilling in the Austin Chalk, Gulf Coast, West Texas and the Rockies. The Company's capital spending programs may be adjusted as business and operating conditions change.

The Company significantly altered its capital structure in 1995 as a result of the initial public offering of its Common Stock and related Asset Restructuring. As of December 31, 1995, the total capitalization of the Company is as follows:

	As of December 31, 1995 (Millions of dollars)
Short-term debt	
Note payable to Union Pacific Corporation	$ 650.0
Advances from (to) Union Pacific Corporation	(82.2)
Total short-term debt	567.8
Long-term debt	
Bank Credit Agreement	68.0
Other	33.5
Total long-term debt	101.5
Shareholders' equity	1,312.4
Total capitalization	$1,981.7

The Company's $650 million note payable to UPC, incurred in connection with the Asset Restructuring, bears interest at 8.5% per annum and is payable within 90 days following the Distribution. In addition, the Company is a participant in UPC's intercompany cash management system. Excess funds generated by the Company or cash borrowings required by the Company for working capital and other purposes are transferred to and from UPC subject to an aggregate limit on net advances by UPC of $200 million. Interest on advances to and from UPC accrues at a rate of 8.5% per annum. The Company's ability to obtain advances from UPC will terminate upon completion of the Distribution, unless the arrangement is terminated earlier by either party following a breach by the other party or the prepayment of the $650 million note payable to UPC. At December 31, 1995, UPC owed the Company $82.2 million under this arrangement.

The available credit of $200 million under the cash management agreement with UPC combined with cash from operations should provide sufficient liquidity to fund the Company's capital expenditures, dividends and working capital requirements but, based on capital spending plans, will not enable the Company to significantly reduce its overall level of indebtedness. Therefore, prior to 90 days following the Distribution, the Company will refinance its short-term borrowings. Management intends to refinance this intercompany debt with a combination of long-term fixed rate debentures and short-term commercial paper. The Company's debt to capitalization ratio of 33.8% at December 31, 1995 and investment grade rating from credit agencies should allow it to successfully refinance its intercompany debt at favorable interest rates.

The Company's Bank Credit Agreement consists of two $50 million revolving credit facilities, each with a term of five years (see Note 9 to the Consolidated Financial Statements). In connection with the refinancing of its intercompany debt, the Company will enter into a new bank credit agreement to provide security for a commercial paper program and a potential source of additional debt financing.

Cash provided by operations for 1995 of $829.4 million was up by $8.4 million from 1994. The increase principally relates to cash received from the Columbia bankruptcy settlement ($179.5 million) partially offset by payment of taxes related to the sale of the Wilmington field ($42.7 million), increased futures margin deposits related to the Company's hedging activities ($36.8 million), payment of interest on the $650 million note payable to UPC ($14.5 million) and changes in other assets, liabilities and working capital.

Cash used by investing activities decreased by $475 million to $582.8 million for 1995. In 1994, the Company used $725 million for the Amax acquisition, which was partially offset by $280 million in proceeds received from the sale of the Wilmington field. Excluding these items, other capital expenditures increased by $22.1 million for the year ended December 31, 1995, while other proceeds from asset sales, including the collection of notes receivable from the Wilmington sale, increased by $60.1 million.

The Company paid cash dividends to UPC of $120 million and $148 million in 1993 and 1994, respectively, $93 million during the first nine months of 1995 prior to the Offering and $1,621 million in October 1995 related to the Asset Restructuring (see Note 2 to the Consolidated Financial Statements). The Company also paid a $0.05

per share ($12.4 million) quarterly cash dividend on its outstanding shares of Common Stock in January 1996, representing the dividend declared in the fourth quarter of 1995, the first quarterly dividend following the Offering. Such dividend level, if continued, would equal approximately $50 million annually. The Company's lower future annual dividends are anticipated to offset the increased interest expense resulting from changes in the Company's debt structure due to the Asset Restructuring. The determination of the amount of future cash dividends, if any, to be declared and paid by the Company will depend upon, among other things, the Company's financial condition, funds from operations, the level of its capital and exploration expenditures, future business prospects and other facts deemed relevant by the Board of Directors. Accordingly, there can be no assurance that dividends will be paid. The Company has no current plans to increase its dividend rate.

The Company believes that, following the anticipated refinancing of its intercompany and bank debt, cash from operations and additional available financing will enable it to fund its capital expenditures, dividends and working capital requirements.

Accounting Policies

The Financial Accounting Standards Board ("FASB") has issued Statement No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," which establishes methods for determining and measuring asset impairment and the required timing of asset impairment evaluations. This statement is effective for fiscal years beginning after December 15, 1995. Management has evaluated Statement No. 121 and believes that it will not have a significant effect on the financial results of the Company. The FASB has also issued Statement No. 123, "Accounting for Stock-Based Compensation," which encourages, but does not require, employers to adopt a fair value method of accounting for stock-based employee compensation and which requires certain disclosures about costs associated with stock-based employee compensation plans. The Company has adopted the disclosure requirements of Statement No. 123 in preparing its 1995 financial disclosure. The Company does not intend to elect expense recognition for stock options; therefore, implementation of this statement has no effect on the financial results of the Company.

Other Matters

Hedging Activities and Derivative Financial Instruments

The Company uses hydrocarbon-based derivative financial instruments to limit the effects of unfavorable hydrocarbon price movements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. All hedging is accomplished pursuant to exchange-traded futures contracts or master swap agreements generally based on standard forms. The Company does not hold or issue such financial instruments for trading purposes and does not hedge any significant amount of production beyond a 24 month time frame. The Company addresses market risk by selecting hydrocarbon-based financial instruments whose historical value fluctuations correlate strongly with those of the item being hedged. Credit risk related to hedging activities is managed by requiring that counterparties meet minimum credit standards and by monthly mark-to-market analysis to determine if collateral is required. At December 31, 1995, the largest credit risk associated with any of the Company's counterparties was approximately $20.9 million, which is partially protected by a $10 million letter of credit. In connection with its futures contract hedging activity, the Company is required to deposit monies with NYMEX, representing contract margin requirements and deposits required relating to unrealized losses on open contracts. Such deposits are included in other current assets in the Company's Consolidated Statements of Financial Position. At December 31, 1995, the Company had made such deposits totaling $38.4 million, representing $26.8 million for contract margin deposits and $11.6 million relating to unrealized losses on open contracts.

Basis risk arises from differences in the cash price of the hedged item and the underlying price of the hedging instrument. The Company uses futures contracts and price swaps denominated in NYMEX prices in its hedging activities. In order to lessen the resulting basis risk and to provide better correlation, the Company uses basis swaps in combination with these futures contracts and price swaps when relative movements in the NYMEX price do not fully correspond to movements in the cash price for a given location. Because of differences in the markets for NYMEX contracts and basis swaps, the Company may temporarily have outstanding NYMEX contracts without corresponding basis swaps, or basis swaps without corresponding NYMEX positions. During such periods, unusual market price swings may weaken correlation between the financial instrument and the underlying item being hedged, thereby exposing the Company to potential losses.

In late December 1995, prices of first quarter 1996 NYMEX natural gas futures contracts (which reflect prices for delivery at Henry Hub in south Louisiana) rose significantly, reaching an all-time high of $3.44 per MMBTU for January contracts. However, January cash prices for areas where the Company produces the majority of its gas did not rise proportionately. In addition, the relationships between NYMEX prices and cash prices for February and March indicated that this price aberration could continue. As a result, in late 1995 and early 1996 the Company closed out NYMEX and basis contracts that had suffered weakened correlation significant enough to disallow continued hedge accounting treatment. The Company recognized an $8.1 million pre-tax ($5.3 million after-tax) loss in December relating to these contracts, which was included in other oil and gas revenues in the Company's 1995 Consolidated Statement of Income.

After the closure of the affected contracts, the Company had the following 1996 natural gas positions, either in combination with basis swaps or relating to production subject to pricing at Henry Hub:

Month	NYMEX Volume (MMcfd)	NYMEX Price	Basis Volume (MMcfd)	Basis Price
January	—	$ —	—	$ —
February	277	1.94	175	(0.47)
March	277	1.83	175	(0.47)
April	250	1.95	175	(0.81)
May	250	1.84	175	(0.81)
June	227	1.79	175	(0.81)

At December 31, 1995, the Company had also entered into near-term futures contracts and price swaps for the first three months of 1996 with respect to crude oil sales volumes of 25 MBbld at $17.96/Bbl.

The Company also enters into long-term fixed price sales agreements for physical deliveries of natural gas and at December 31, 1995, had outstanding contracts relating to 162.8 Bcf of natural gas for periods through December 31, 2008. Average annual commitments during this period would have comprised no more than 4% of 1995 natural gas sales volumes. The Company's marketing subsidiary, UP Fuels, enters into long-term financial contracts that, in combination with these long-term fixed price sales agreements, secure a margin on the corresponding volume positions. Where necessary, UP Fuels also enters into basis swaps, which are currently available for 1996 and 1997, to strengthen the hedge securing the margin on the corresponding positions. At December 31, 1995, long-term fixed price sales commitments for which corresponding financial positions had not been entered into totaled 63.7 Bcf at an average price of $3.08/Mcf, with a mark-to-market present value of $28.7 million. The remaining commitments for 99.1 Bcf had been offset with financial contracts for similar volumes, resulting in a $0.39/Mcf average profit on those volumes. The unrecognized mark-to-market present value on these corresponding positions comprises a $58.8 million gain on the long-term fixed price sales commitments and a $27.8 million loss on the corresponding financial contracts, resulting in a $31 million unrecognized mark-to-market present value margin for the Company.

At December 31, 1995, the Company had a total unrecognized mark-to-market present value gain of $55.5 million related to all open hedging and associated risk management transactions. Unrecognized mark-to-market gains or losses were determined based upon current market value, as quoted by recognized dealers, assuming a round lot transaction and using a mid-market convention without regard to market liquidity.

As a result of its hedging program, the Company's oil and gas revenues can be higher or lower than revenues that would be reported if hedging did not occur. During 1993, revenues were $29 million lower, while during 1994 and 1995, revenues were $36 million and $27 million higher, respectively, as a result of hedging activities.

Environmental Costs

The Company generates and disposes of hazardous and non-hazardous waste in its current and former operations and is subject to increasingly stringent Federal, state and local environmental regulations. The Company has identified 10 sites currently subject to environmental response actions or on the Superfund National Priorities List or state superfund lists, at which it is or may be liable for remediation costs associated with alleged contamination or for violations of environmental requirements. Certain Federal legislation imposes joint and several liability for the remediation of various sites; consequently, the Company's ultimate environmental liability may include costs relating to other parties in addition to costs relating to its own activities at each site. In

addition, the Company is or may be liable for certain environmental remediation matters involving existing or former facilities.

As of December 31, 1995, long and short-term liabilities totaling $103.3 million had been accrued for future costs of all sites where the Company's obligation is probable and where such costs can be reasonably estimated; however, the ultimate cost could be lower or as much as 10% higher. This accrual includes future costs for remediation and restoration of sites, as well as for ongoing monitoring costs, but excludes any anticipated recoveries from third parties. The accrual also includes $50.3 million for the obligation to participate in the remediation of the Wilmington field properties. Cost estimates were based on information available for each site, financial viability of other Potentially Responsible Parties ("PRPs") and existing technology, laws and regulations. The Company believes that it has adequately accrued for its share of costs at sites subject to joint and several liability. The ultimate liability for remediation is difficult to determine with certainty because of the number of PRPs involved, site-specific cost sharing arrangements with other PRPs, the degree of contamination by various wastes, the scarcity and quality of volumetric data related to many of the sites and the speculative nature of remediation costs.

The Company also is involved in reducing emissions, spills and migration of hazardous materials. Remediation of identified sites and control and prevention of environmental exposures required spending of $7.9 million in 1994 and $6.2 million in 1995. In 1996, the Company anticipates spending a total of $25 million for remediation, control and prevention, including $20 million relating to the Wilmington properties. The majority of the December 31, 1995 accrued environmental liability is expected to be paid out over the next five years, funded by cash generated from operations. Based on current rules and regulations, management does not expect future environmental obligations to have a material impact on the results of operations or financial condition of the Company.

Pension Costs

The Company's employees participate in UPC's funded Pension Plan for Salaried Employees of Union Pacific Corporation and Affiliates (the "UPC Plan"). As of the date of the Distribution, UPC will allocate to the Company a portion of the UPC Plan liabilities representing the pension obligation of the Company to its current and (with certain exceptions) former employees, together with a portion of the UPC Plan assets. The assets will be allocated to the Company based on the Company's share of the total pension liability under the UPC Plan. These assets will be formally withdrawn from the UPC Plan and contributed to a new pension fund to be established by the Company.

Historically, pension assets allocated to the Company for the purposes of calculating annual pension expense have been based on assets contributed to the UPC Plan by the Company and its predecessor companies. Because the allocation to be made pursuant to an agreement between the Company and UPC will be based on the Company's share of the total pension liability, the Company's annual pension expense will increase by approximately $7 million over 1995 pension expense. The Company's plan is expected to be fully funded under current guidelines set forth in the Employee Retirement Income Security Act of 1974, as amended, based on the method of allocating pension assets at the time of the Distribution.

Outlook

The Company improved its hydrocarbon reserve position in 1995 despite rising production volumes. The Company expects to remain one of the most active drillers in the United States in 1996 based on the number of active drilling rigs. The Company also expects to increase its oil and gas production volume in 1996 while maintaining its reserve position. This volume growth is anticipated primarily in the Austin Chalk and West Texas. In addition, plant and pipeline income is expected to grow with a full year of operations from 1995 additions, exploration spending will rise with increased drilling and general and administrative expenses and interest costs should increase reflecting a full year as a stand-alone company.

Item 8. Financial Statements and Supplementary Data

The information required hereunder is included in this report as set forth in the "Index to Consolidated Financial Statements" on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

(a) Directors of Registrant.

Information as to the names, ages, positions and offices with the Company, terms of office, periods of service, business experience during the past five years and certain other directorships held by each director or person nominated to become a director is set forth under "Election of Directors" in the Proxy Statement and is incorporated herein by reference.

(b) Executive Officers of Registrant.

Information concerning executive officers is presented in Part I of this report under "Executive Officers of the Registrant."

(c) Section 16(a) Compliance.

Information concerning compliance with Section 16(a) of the Securities Exchange Act of 1934 is set forth under "Reports of Ownership" in the Proxy Statement and is incorporated herein by reference.

Item 11. Executive Compensation

Information concerning remuneration received by executive officers and directors is presented under "Compensation of Directors," "Stock Option Plan for Outside Directors," "Compensation Committee Interlocks and Insider Participation" and "Executive Compensation" in the Proxy Statement and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information as to the number of shares of equity securities beneficially owned as of March 1, 1996 by each director and nominee for director, the five most highly compensated executive officers and directors and executive officers as a group is set forth under "Security Ownership of Certain Executives and Beneficial Owners" in the Proxy Statement and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

Information on related transactions is set forth under "Principal Shareholder; Control of the Company" and "Compensation Committee Interlocks and Insider Participation" in the Proxy Statement and is incorporated herein by reference.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) (1) and (2) Financial Statements and Schedules.

See "Index to Consolidated Financial Statements" set forth on page F-1.

No schedules are required to be filed because of the absence of conditions under which they would be required or because the required information is set forth in the financial statements referred to above.

(3) Exhibits—Exhibits not incorporated herein by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated herein by reference to the Company's Form S-1 Registration Statement, Registration No. 33-95398, filed on October 10, 1995 ("Form S-1").

3.1	— Amended and Restated Articles of Incorporation of Union Pacific Resources Group Inc. (Exhibit 3.1 to Form S-1)
3.2	— Amended and Restated By-Laws of Union Pacific Resources Group Inc. (Exhibit 3.2 to Form S-1)
4	— Specimen of Certificate evidencing the Common Stock. (Exhibit 4 to Form S-1)
10.1	— Services Agreement, dated as of October 1, 1995, by and between Union Pacific Corporation and Union Pacific Resources Group Inc. (Exhibit 10.1 to Form S-1)
10.2	— Stock Restriction, Registration and Option Agreement, dated as of October 1, 1995, by and between Union Pacific Corporation and Union Pacific Resources Group Inc. (Exhibit 10.2 to Form S-1)
10.3	— Tax Allocation Agreement, dated as of October 6, 1995, by and between Union Pacific Corporation and Union Pacific Resources Group Inc. (Exhibit 10.3 to Form S-1)
10.4	— Indemnification Agreement, dated as of October 1, 1995, by and between Union Pacific Corporation and Union Pacific Resources Group Inc. (Exhibit 10.4 to Form S-1)
10.5	— Cash Management Agreement, dated as of October 1, 1995, by and among Union Pacific Corporation, Union Pacific Resources Group Inc. and Union Pacific Resources Company. (Exhibit 10.5 to Form S-1)
10.6	— Intercompany Credit Agreement, dated as of October 1, 1995, by and among Union Pacific Corporation, Union Pacific Resources Group Inc. and Union Pacific Resources Company. (Exhibit 10.6 to Form S-1)
10.7	— Pension Plan Agreement, dated as of October 1, 1995, by and between Union Pacific Corporation and Union Pacific Resources Group Inc. (Exhibit 10.7 to Form S-1)
10.8	— Purchase and Sale Agreement, dated as of February 23, 1994, by and between Union Pacific Resources Company, Union Pacific Energy Company, Union Pacific Land Resources Corporation and City of Long Beach. (Exhibit 10.18 to Form S-1)
10.9	— Executive Incentive Plan of Union Pacific Resources Group Inc. (Exhibit 10.9 to Form S-1)
10.10	— 1995 Stock Option and Retention Stock Plan of Union Pacific Resources Group Inc. (Exhibit 10.10 to Form S-1)
*10.11	— The Supplemental Pension Plan for Officers and Managers of Union Pacific Corporation and Affiliates, with amendments.
*10.12	— The Supplemental Pension Plan for Exempt Salaried Employees of Union Pacific Resources Group Inc. and Affiliates, with amendments.
10.13(a)	— Form of Conversion Agreement. (Exhibit 10.13(a) to Form S-1)
10.13(b)	— Form of Conversion Agreement for Drew Lewis. (Exhibit 10.13(b) to Form S-1)
10.13(c)	— Form of Conversion Agreement for Jack L. Messman. (Exhibit 10.13(c) to Form S-1)
10.14	— 1995 Directors Stock Option Plan. (Exhibit 10.14 to Form S-1)
10.15	— Stock Unit Grant and Deferred Compensation Plan for the Board of Directors, effective September 28, 1995. (Exhibit 10.15 to Form S-1)
10.16	— Amended and Restated 1976 Coal Purchase Contract, dated as of January 1, 1993, between Commonwealth Edison Company and Black Butte Coal Company. (Exhibit 10.19 to Form S-1)
10.17	— Transportation Agreement, dated December 15, 1989, by and between Kern River Gas Transmission Company and Union Pacific Fuels, Inc. (Exhibit 10.21 to Form S-1)

10.18 — Nineteenth Amendment to Transportation Agreement dated December 15, 1989, dated as of May 23, 1994, by and between Kern River Gas Transmission Company and Union Pacific Fuels, Inc. (Exhibit 10.22 to Form S-1)

*10.19 — Registration Rights Agreement, dated as of August 3, 1995, among Union Pacific Resources Group Inc., The Anschutz Corporation and Anschutz Foundation.

*10.20 — Agreement, dated as of August 3, 1995, by and among Union Pacific Resources Group Inc., The Anschutz Corporation, Anschutz Foundation and Mr. Philip F. Anschutz.

*10.21 — US$150,000,000 Revolving Credit Agreement, dated as of October 5, 1995, among Union Pacific Resources Group Inc., certain Banks named therein and Nationsbank of Texas, N.A., as administrative agent, with amendment.

*10.22 — US$150,000,000 Revolving Credit Agreement, dated as of October 5, 1995, among Union Pacific Resources Group Inc., certain Banks named therein and Texas Commerce Bank National Association, as adminstrative agent, with amendment.

10.23 — Agreement Regarding 1971 Plan of Reorganization, dated October 3, 1995, among Union Pacific Railroad Company and Union Pacific Resources Group Inc., Union Pacific Land Resources Corporation, Upland Industries Corporation, Upland Industrial Development Company, Union Pacific Resources Company and Rock Springs Royalty Company. (Exhibit 10.27 to Form S-1)

10.24 — Asset Purchase and Sale Agreement, dated October 3, 1995, by and among Union Pacific Railroad Company and Union Pacific Realty Company, Upland Industries Corporation, Union Pacific Land Resources Corporation, Upland Industrial Development Company, Union Pacific Resources Group Inc., Union Pacific Resources Company and Rock Springs Royalty Company. (Exhibit 10.28 to Form S-1)

10.25 — Asset Purchase and Sale Agreement, dated October 3, 1995, by and among Missouri Pacific Railroad Company and Union Pacific Land Resources Corporation and Union Pacific Resources Company. (Exhibit 10.29 to Form S-1)

10.26 — Asset Exchange Agreement, dated October 3, 1995, by and among Missouri Improvement Company and Missouri Pacific Railroad Company and Union Pacific Land Resources Corporation and Union Pacific Resources Company. (Exhibit 10.30 to Form S-1)

10.27 — Asset Exchange Agreement, dated October 3, 1995, by and among MRT Exploration Company and Missouri Pacific Railroad Company and Union Pacific Land Resources Corporation and Union Pacific Resources Company. (Exhibit 10.31 to Form S-1)

10.28 — Asset Exchange Agreement, dated October 3, 1995, by and among Missouri Pacific Railroad Company and Upland Industrial Development Company and Union Pacific Resources Company. (Exhibit 10.32 to Form S-1)

10.29 — Asset Exchange Agreement, dated October 3, 1995, by and among Missouri Pacific Railroad Company and Upland Industries Corporation and Union Pacific Resources Company. (Exhibit 10.33 to Form S-1)

10.30 — Asset Exchange Agreement, dated October 3, 1995, by and among Missouri Pacific Railroad Company and Union Pacific Land Resources Corporation and Union Pacific Resources Company. (Exhibit 10.34 to Form S-1)

10.31 — Asset Exchange Agreement, dated October 3, 1995, by and among Union Pacific Railroad Company and Union Pacific Land Resources Corporation and Union Pacific Resources Company. (Exhibit 10.35 to Form S-1)

10.32 — Form of Assignment of Right to Apply for Lease, between Union Pacific Railroad Company and Union Pacific Resources Company. (Exhibit 10.36 to Form S-1)

*11 — Computation of pro forma earnings per share.

*12 — Computation of ratio of earnings to fixed charges.

*21 — List of subsidiaries.

*24 — Powers of attorney.

(b) Reports on Form 8-K.

No reports on Form 8-K were filed during the quarter ended December 31, 1995.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on this 21st day of March, 1996.

UNION PACIFIC RESOURCES GROUP INC.

By: /s/ V. RICHARD EALES
(V. Richard Eales, Executive Vice President and Chief Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below, on this 21st day of March, 1996, by the following persons on behalf of the registrant and in the capacities indicated.

President, Chief Executive Officer and Director (Principal Executive Officer)	/s/ JACK L. MESSMAN (Jack L. Messman)
Executive Vice President and Chief Financial Officer (Principal Financial Officer)	/s/ V. RICHARD EALES (V. Richard Eales)
Vice President—Finance (Principal Accounting Officer)	/s/ PATRICK D. HANLEY (Patrick D. Hanley)

H. Jesse Arnelle*	Director
Lynne V. Cheney*	Director
Lawrence M. Jones*	Director
Drew Lewis*	Director
Claudine B. Malone*	Director
L. White Matthews, III*	Director
John W. Poduska, Sr., Ph.D.*	Director
Gary M. Stuart*	Director
Judy L. Swantak*	Director
James R. Thompson*	Director
Carl W. von Bernuth*	Director

*By: /s/ V. RICHARD EALES
(V. Richard Eales, as attorney-in-fact)

UNION PACIFIC RESOURCES GROUP INC.

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RESPONSIBILITIES FOR FINANCIAL STATEMENTS

The accompanying financial statements, which consolidate the accounts of Union Pacific Resources Group Inc. and its subsidiaries, have been prepared in conformity with generally accepted accounting principles.

The integrity and objectivity of data in these financial statements and accompanying notes, including estimates and judgments related to matters not concluded by year-end, are the responsibility of management, as is all other information in this report. Management devotes ongoing attention to review and appraisal of its system of internal controls. This system is designed to provide reasonable assurance, at an appropriate cost, that the Company's assets are protected, that transactions and events are recorded properly and that financial reports are reliable. The system is augmented by a staff of internal auditors; careful attention to selection and development of qualified financial personnel; programs to further timely communication and monitoring of policies, standards and delegated authorities; and evaluation by independent auditors during their examinations of the annual financial statements.

The Audit Committee of the Board of Directors, composed of four non-employee directors, meets regularly with financial management, the internal auditors and the independent auditors to review financial reporting and accounting and financial controls of the Company. Both the independent auditors and the internal auditors have unrestricted access to the Audit Committee and meet regularly with the Audit Committee, without financial management representatives present, to discuss the results of their examinations and their opinions on the adequacy of internal controls and quality of financial reporting.

JACK L. MESSMAN
President and Chief Executive Officer

V. RICHARD EALES
Executive Vice President and Chief Financial Officer

PATRICK D. HANLEY
Vice President—Finance

INDEPENDENT AUDITORS' REPORT

To the Board of Directors
Union Pacific Resources Group Inc.
Fort Worth, Texas

We have audited the accompanying consolidated statements of financial position of Union Pacific Resources Group Inc. (the "Company") as of December 31, 1994 and 1995, and the related consolidated statements of income, changes in shareholders' equity and cash flows for each of the three years in the period ended December 31, 1995. 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 misstatements. 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, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 1994 and 1995, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1995 in conformity with generally accepted accounting principles.

As discussed in Note 3 to the consolidated financial statements, in January 1993, the Company changed its method of accounting for postretirement benefits other than pensions and income taxes.

DELOITTE & TOUCHE LLP

Fort Worth, Texas
January 18, 1996

UNION PACIFIC RESOURCES GROUP INC.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 1993, 1994 and 1995

	1993	1994	1995
	(Millions of dollars)		
Operating revenues: (Note 6)			
Oil and gas operations:			
Producing properties	$ 829.7	$ 886.0	$ 860.7
Plants, pipelines and marketing	217.2	249.1	311.8
Other oil and gas revenues (Note 16)	124.9	76.5	167.0
Total oil and gas operations	1,171.8	1,211.6	1,339.5
Minerals (Note 13)	105.3	121.3	116.3
Total operating revenues	1,277.1	1,332.9	1,455.8
Operating expenses:			
Production	240.2	252.3	217.8
Exploration	111.2	107.6	89.4
Plants, pipelines and marketing	144.6	150.8	160.8
Minerals (Note 13)	2.7	4.5	8.8
Depreciation, depletion and amortization	357.8	426.4	458.6
General and administrative	37.7	40.0	50.3
Total operating expenses	894.2	981.6	985.7
Operating income	382.9	351.3	470.1
Other income—net (Note 17)	60.4	174.0	7.0
Interest expense (Notes 4 and 9)	(3.2)	(4.6)	(19.1)
Income before income taxes	440.1	520.7	458.0
Income taxes (Note 8)	(137.3)	(130.7)	(107.3)
Income before cumulative effect of changes in accounting principles	302.8	390.0	350.7
Cumulative effect of changes in accounting principles (Note 3)	(59.0)	—	—
Net income (Note 2)	$ 243.8	$ 390.0	$ 350.7

The accompanying accounting policies and notes to the consolidated financial statements are an integral part of these statements.

UNION PACIFIC RESOURCES GROUP INC.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As of December 31, 1994 and 1995

	1994	1995
	(Millions of dollars)	
ASSETS		
Current assets:		
Cash and temporary investments	$ 6.7	$ 27.6
Accounts receivable—(net of allowance for doubtful accounts of $5.1 million in 1994 and $4.9 million in 1995)	244.1	240.1
Inventories	58.3	67.5
Note receivable (Note 5)	62.7	—
Receivable from Union Pacific Corporation (Note 4)	59.4	—
Federal income tax receivable	44.1	—
Other current assets	57.7	84.8
Total current assets	533.0	420.0
Properties: (Note 7)		
Cost	4,965.2	5,450.4
Accumulated depreciation, depletion and amortization	(2,365.1)	(2,686.1)
Total properties	2,600.1	2,764.3
Intangible and other assets (Note 13)	113.9	124.6
Total assets	$3,247.0	$3,308.9
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 337.0	$ 347.0
Accrued taxes payable	65.0	87.4
Short-term debt	43.2	—
Note payable to and advances from Union Pacific Corporation—net (Notes 4 and 9)	—	567.8
Other current liabilities	59.8	64.3
Total current liabilities	505.0	1,066.5
Long-term debt (Note 9)	37.7	101.5
Deferred income taxes (Note 8)	458.0	438.5
Retiree benefits obligation (Note 11)	73.8	73.1
Deferred revenues	57.4	26.4
Other long-term liabilities (Notes 13, 14, 15, 16 and 18)	280.2	290.5
Shareholders' equity (see page F-7)	1,834.9	1,312.4
Total liabilities and shareholders' equity	$3,247.0	$3,308.9

The accompanying accounting policies and notes to the consolidated financial statements are an integral part of these statements.

UNION PACIFIC RESOURCES GROUP INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 1993, 1994 and 1995

	1993	1994	1995
	(Millions of dollars)		
Cash provided by operations:			
Net income	$ 243.8	$ 390.0	$ 350.7
Non-cash charges to income:			
Depreciation, depletion and amortization	357.8	426.4	458.6
Deferred income taxes (Note 8)	32.9	174.4	(18.3)
Cumulative effect of accounting changes (Note 3)	59.0	—	—
Other non-cash charges (credits)—net	(41.0)	(139.2)	(65.8)
Exploratory expenditures	53.0	45.8	36.0
Changes in current assets and liabilities	(138.0)	(76.4)	68.2
Cash provided by operations	567.5	821.0	829.4
Investing activities:			
Capital and exploratory expenditures (Notes 5 and 19)	(560.4)	(1,389.3)	(686.4)
Proceeds from sales of assets (Note 5)	8.1	331.0	111.1
Other investing activities—net	29.7	0.5	(7.5)
Cash (used) by investing activities	(522.6)	(1,057.8)	(582.8)
Financing activities:			
Dividends paid to Union Pacific Corporation (Note 2)	(120.0)	(148.0)	(1,713.9)
Debt repaid	(25.9)	(18.3)	(47.4)
Proceeds from initial public offering (Note 2)	—	—	843.9
Advances from Union Pacific Corporation (Notes 2 and 4)	63.1	399.6	627.1
Other financings—net (Note 2)	40.7	(1.1)	64.6
Cash provided (used) by financing activities	(42.1)	232.2	(225.7)
Net change in cash and temporary investments	2.8	(4.6)	20.9
Cash at beginning of year	8.5	11.3	6.7
Cash at end of year	$ 11.3	$ 6.7	$ 27.6
Changes in current assets and liabilities:			
Accounts receivable	$ (53.1)	$ 33.8	$ 4.0
Inventories	(5.2)	(34.2)	(9.2)
Note receivable	—	(62.7)	62.7
Federal income tax receivable	—	(44.1)	44.1
Other current assets	(3.9)	(25.2)	(27.1)
Accounts payable	(82.9)	18.0	10.0
Accrued taxes payable	4.6	(5.6)	22.4
Short-term debt	17.5	10.9	(43.2)
Other current liabilities	(15.0)	32.7	4.5
Total	$ (138.0)	$ (76.4)	$ 68.2
Supplemental cash flow disclosure:			
Interest paid	$ 3.2	$ 4.6	$ 20.0
Income taxes paid	103.8	14.9	29.7

The accompanying accounting policies and notes to the consolidated financial statements are an integral part of these statements.

UNION PACIFIC RESOURCES GROUP INC.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the Years Ended December 31, 1993, 1994 and 1995

	1993	1994	1995
	(Millions of dollars)		
Common stock:			
Common stock, $1.00 par value; authorized 5,000,000 shares, 4,485,000 shares issued and outstanding at December 31, 1993 and 1994			
Balance at beginning of year	$ 4.5	$ 4.5	$ 4.5
Asset restructuring (Note 2)	—	—	(4.5)
Balance at end of year	4.5	4.5	—
Common stock, no par value; authorized 400,000,000 shares, 249,298,603 shares issued and outstanding at December 31, 1995 (Note 2)			
Balance at beginning and end of year	—	—	—
Paid-in surplus:			
Balance at beginning of year	421.2	421.2	421.2
Asset restructuring (Note 2)	—	—	(421.2)
Initial public offering (Note 2)	—	—	843.9
Contributions of assets and other	—	—	6.4
Conversion and appreciation of retention shares (Note 12)	—	—	9.9
Balance at end of year	421.2	421.2	860.2
Retained earnings:			
Balance at beginning of year	1,056.8	1,180.6	1,422.6
Net income	243.8	390.0	350.7
Total	1,300.6	1,570.6	1,773.3
Dividends declared on common stock (Note 2)	(120.0)	(148.0)	(1,726.3)
Asset restructuring (Note 2)	—	—	425.9
Balance at end of year	1,180.6	1,422.6	472.9
Unearned compensation:			
Balance at beginning of year	—	—	—
Conversion, appreciation and amortization of retention shares (Note 12)	—	—	(9.2)
Balance at end of year	—	—	(9.2)
Deferred foreign exchange adjustment:			
Balance at beginning of year	(7.3)	(10.2)	(13.4)
Foreign currency translation adjustment	(2.9)	(3.2)	1.9
Balance at end of year	(10.2)	(13.4)	(11.5)
Total shareholders' equity	$1,596.1	$1,834.9	$1,312.4

The accompanying accounting policies and notes to the consolidated financial statements are an integral part of these statements.

UNION PACIFIC RESOURCES GROUP INC.

BUSINESS SEGMENTS

For the Years Ended December 31, 1993, 1994 and 1995

	1993	1994	1995
	(Millions of dollars)		
Operating revenues:			
Oil and gas	$1,171.8	$1,211.6	$1,339.5
Minerals	105.3	121.3	116.3
Total	$1,277.1	$1,332.9	$1,455.8
Depreciation, depletion and amortization:			
Oil and gas	$ 354.2	$ 423.3	$ 456.0
Minerals	0.6	0.5	0.4
Corporate	3.0	2.6	2.2
Total	$ 357.8	$ 426.4	$ 458.6
Other operating expenses:			
Oil and gas	$ 496.0	$ 510.7	$ 468.0
Minerals	2.7	4.5	8.8
Corporate	37.7	40.0	50.3
Total	$ 536.4	$ 555.2	$ 527.1
Operating income:			
Oil and gas	$ 321.6	$ 277.6	$ 415.5
Minerals	102.0	116.3	107.1
Corporate	(40.7)	(42.6)	(52.5)
Total	$ 382.9	$ 351.3	$ 470.1
Capital and exploratory expenditures:			
Oil and gas	$ 557.3	$1,387.3	$ 684.2
Minerals	—	0.2	0.2
Corporate	3.1	1.8	2.0
Total	$ 560.4	$1,389.3	$ 686.4
Assets:			
Oil and gas	$1,957.6	$2,815.3	$2,985.7
Minerals	27.1	26.8	29.2
Corporate(a)	729.4	404.9	294.0
Total	$2,714.1	$3,247.0	$3,308.9

(a) Includes items such as unallocated working capital, intercompany accounts and intangible and other assets.

This information should be read in conjunction with the accompanying accounting policies and notes to the consolidated financial statements.

Significant Accounting Policies

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Union Pacific Resources Group Inc. and subsidiaries, including its principal operating subsidiary Union Pacific Resources Company ("UPRC"), and certain other affiliated companies. These operations are hereinafter referred to collectively as the "Company." The Company is approximately 83% owned by Union Pacific Corporation ("UPC") (see Notes 2 and 4). The Company accounts for investments in affiliated companies (20% to 50% owned) on the equity method of accounting and consolidates its proportionate share of oil and gas ventures. All material intercompany transactions are eliminated.

Cash and Temporary Investments

Temporary investments are stated at cost which approximates fair market value and consist of investments with original maturities of six months or less.

Inventories

Inventories consist primarily of hydrocarbon volumes and materials and supplies carried on a first-in first-out basis at the lower of cost or market.

Exploration and Production

Oil and gas exploration costs are accounted for using the successful efforts method. Under this method, drilling costs of unsuccessful exploratory wells, geological and geophysical costs, non-producing leasehold amortization and delay rentals are charged to expense when incurred. Costs to develop producing properties, including drilling costs and applicable leasehold acquisition costs, are capitalized.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization of producing properties, including depreciation of well and support equipment and amortization of related lease costs, are determined by using a unit-of-production method based upon estimated proved reserves. Acquisition costs of unproved properties are amortized from the date of acquisition on a composite basis, which considers past success experience and average lease life.

Provisions for depreciation of property and equipment other than producing properties are computed principally on the straight-line method based on estimated service lives, which range from three to 30 years.

Costs of future site restoration, dismantlement and abandonment for onshore producing properties, which costs are based on internal engineering estimates, are accrued as part of depreciation, depletion and amortization expense for tangible equipment by assuming no salvage value in the calculation of the unit of production rate. The resultant accrual is included in the balance of accumulated depreciation, depletion and amortization. Such estimated costs for offshore wells and production platforms are also accrued using the unit of production method with a charge to depreciation, depletion and amortization expense; however, the accrual for offshore abandonment costs is classified in other long-term liabilities. The balance of the offshore abandonment accrual at December 31, 1994 and 1995 was $8.9 million and $13.1 million, respectively.

Significant Accounting Policies—(Continued)

Asset Impairment

Potential impairment of producing properties and significant unproved properties is assessed annually (unless economic events warrant more frequent reviews) on a field-by-field basis with all other unproved properties assessed on an aggregate basis. In addition, a quarterly impairment analysis of aggregated properties is performed by the Company using undiscounted future net cash flows determined based upon current prices.

Sale of Assets

Gains and losses from the sale of operating assets that constitute an entire profit center and significant non-operating assets are recorded in other income. Gains and losses from all other dispositions of operating assets are recognized in other oil and gas revenues.

Production Imbalances

Sales from producing gas wells are recognized on the entitlement method of accounting which defers recognition of sales and related costs when, and to the extent that, deliveries to customers exceed the Company's net revenue interest in production. Similarly, when deliveries are below the Company's net revenue interest in production, sales and related costs are recorded to reflect the full net revenue interest.

Hedging Transactions

The Company uses hydrocarbon-based derivative financial instruments to protect against unfavorable hydrocarbon price movements. Gains and losses from these transactions generally are recognized at delivery of the commodity. However, when correlation between the derivative contract price and the price of the underlying commodity falls below 80% and is therefore not adequate to allow for hedge accounting, affected derivative positions are marked-to-market, with the resulting gain or loss recognized immediately in income (see Note 6).

Marketing

Marketing revenue included in plants, pipelines and marketing revenues is recorded net of the cost of hydrocarbons purchased.

Income Taxes

The Company is included in the consolidated income tax return of UPC. The consolidated income tax liability of UPC is allocated among the affiliated companies on the basis of their separate contributions to the consolidated income tax liability, with full benefit of tax losses and credits utilized in consolidation being allocated to the individual companies generating such losses and credits.

Deferred income taxes are provided for items of income and expense that are included in income for financial reporting purposes in different reporting periods than for Federal income tax purposes (see Note 8).

Stock-Based Compensation

Compensation expense is recorded with respect to stock option grants and retention stock awards to employees using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25. This method calculates compensation expense on the measurement date (usually the date of grant) as the excess of the current market price of the underlying Company stock over the amount the employee is required to pay for the

Significant Accounting Policies—(Continued)

shares, if any. The expense is recognized over the vesting period of the grant or award. The Company does not intend to elect the fair value method of accounting for stock-based compensation encouraged, but not required, by Statement of Financial Accounting Standards ("SFAS") No. 123, "Accounting for Stock-Based Compensation." The Company has adopted the disclosure requirements of SFAS No. 123 in preparing its 1995 financial disclosure (see Note 12).

Earnings Per Share

Earnings per share have been omitted from the Consolidated Statements of Income as the Company was a wholly owned subsidiary of UPC until its initial public offering in October 1995. Pro forma earnings per share for 1995 (see Note 2) and fourth quarter 1995 earnings per share (see page F-32) are based upon 249.7 million average common shares outstanding during the period from completion of the Offering (hereinafter defined) until December 31, 1995, including shares issuable upon exercise of outstanding stock options determined using the treasury stock method.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses as of and for each reporting period. Estimates and assumptions are also required in the disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results may differ from such estimates.

1. Nature of Operations

The Company is an independent energy company engaged primarily in the exploration for and development and production of natural gas, natural gas liquids and crude oil. The Company's oil and gas operations are concentrated in six core geographic areas: (1) the Austin Chalk trend in Texas and Louisiana, (2) the Rocky Mountain area in Wyoming and Utah, (3) the Plains/Canada area in Colorado, Wyoming, Kansas and western Canada, (4) both the onshore and offshore Gulf Coast areas, (5) eastern and southern Texas and (6) western Texas. The Company also owns and operates significant assets, in proximity to its principal producing properties, dedicated to the gathering, processing and transportation of natural gas and natural gas liquids. The Company markets a substantial portion of its own natural gas, natural gas liquids and crude oil production together with significant volumes of natural gas, natural gas liquids and crude oil produced by others. In addition, the Company engages in the hard minerals business through non-operated joint venture and royalty interests in several coal and trona (natural soda ash) mines located on lands within and adjacent to its Land Grant (hereinafter defined) holdings in Wyoming.

The Company's results of operations are largely dependent on the difference between the prices received for its hydrocarbon products and the cost to find, develop, produce and market such resources. Historically, the Company has been able to manage a portion of the operating risk relating to hydrocarbon price volatility through hedging activities (see Note 6).

2. Asset Restructuring and Pro Forma Information

In October 1995, the Company sold 42.5 million shares of the common stock of the Company (the "Common Stock") in an initial public offering (the "Offering"). The offering price to the public was $21 per share of Common Stock. Prior to consummation of the Offering, the Company was wholly owned by UPC. UPC currently owns approximately 83% of the outstanding Common Stock. UPC has announced that it intends,

2. Asset Restructuring and Pro Forma Information—(Continued)

subject to the receipt of a favorable ruling from the Internal Revenue Service ("IRS") and the satisfaction of certain other conditions, to distribute pro rata to its shareholders as a dividend its remaining ownership interest in the Company by means of a tax-free distribution (the "Distribution").

Prior to the Offering (1) UPC caused the Company to own all the rights and assets historically employed by the natural resources business segment of UPC in connection with the operations presented in the Consolidated Financial Statements and (2) the Company declared dividends to UPC totaling $1,621 million consisting of (i) a cash dividend of $912 million payable promptly after the completion of the Offering, (ii) a $650 million note payable to UPC bearing interest at 8.5% per annum payable within 90 days of the Distribution and (iii) a $59 million receivable from UPC. In addition, the Company borrowed $68 million which was used, together with the $843.9 million net proceeds from the Offering, to pay the cash dividend of $912 million. Such transactions, referred to collectively as the "Asset Restructuring," are reflected in the Consolidated Financial Statements as of December 31, 1995.

The following pro forma information reflects adjustments to the historical 1995 Consolidated Statement of Income necessary to give effect to the Asset Restructuring and the Offering as if such transactions had occurred at the beginning of 1995. Pro forma adjustments to income include the annual impacts described in footnotes (a) through (c) below, reduced by actual amounts recorded by the Company in 1995 subsequent to the Offering.

	Year Ended December 31, 1995		
	Historical	Pro Forma Adjustments	Pro Forma As Adjusted
	(Millions, except per share amounts)		
Operating income	$ 470.1	$ (14.1)(a)	$ 456.0
Other income—net	7.0	(3.8)(b)	3.2
Interest expense	(19.1)	(44.7)(c)	(63.8)
Income before income taxes	458.0	(62.6)	395.4
Income taxes	(107.3)	23.5 (d)	(83.8)
Net income	$ 350.7	$ (39.1)	$ 311.6
Earnings per share of Common Stock			$ 1.25
Average shares of Common Stock outstanding(e)			249.7

(a) Adjustment to reflect management's estimate of additional administrative and third-party costs that the Company will incur as a result of becoming a stand-alone entity. These costs include (1) additional administrative personnel, (2) additional third-party fees such as audit fees, actuarial fees, legal fees and stock transfer fees, (3) additional pension costs of approximately $6.7 million annually associated with the allocation of pension plan assets between the Company and UPC (see Note 11), (4) additional annual stock compensation costs of $4.6 million related to employee retention shares (see Note 12) and (5) fees of $2.2 million annually payable to UPC for certain financial guarantees provided to the Company.

(b) Adjustment to eliminate intercompany interest income recorded by the Company during the period, as a result of the dividend to UPC of the $59 million intercompany receivable.

(c) Adjustment to reflect increased interest expense from the $650 million note payable to UPC at 8.5% per annum and the $68 million in bank debt at 6.1% per annum, which debt was incurred to pay a portion of the $912 million cash dividend to UPC.

(Footnotes continued on next page)

2. Asset Restructuring and Pro Forma Information—(Continued)

(Footnotes continued from previous page)

(d) Adjustment to reflect decreased Federal and state income tax expense resulting from increased expenses in entries (a) through (c) above, calculated at an income tax rate of 37.5%.

(e) See "Significant Accounting Policies—Earnings Per Share."

Pro forma net income and earnings per share of Common Stock are not necessarily indicative of future results.

3. Accounting Changes

The Company adopted the following accounting changes in January 1993:

Other Postretirement Benefits

The Financial Accounting Standards Board ("FASB") issued SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," which requires that the cost of non-pension benefits for retirees be accrued during their period of employment. The Company adopted the Statement with a cumulative charge to 1993 earnings of $44.0 million. The adoption of this Statement does not affect future cash funding requirements for these benefits (see Note 11).

Income Taxes

The FASB issued SFAS No. 109, "Accounting for Income Taxes," which requires the balance sheet approach of accounting for income taxes, whereby assets and liabilities are recorded at the tax rates currently enacted. The Company adopted the Statement with a cumulative charge to 1993 earnings of $15.0 million. The Company's future results may be affected by changes in the corporate income tax rate (see Note 8).

4. Related Party Transactions

Advances to and from affiliated companies have historically accrued interest at a rate which represents UPC's aggregate cost of borrowing. The Company had a net $59.4 million receivable from UPC at December 31, 1994, principally as a result of advances of the proceeds from asset sales in recent years offset by the cost of the Amax Oil & Gas, Inc. ("Amax") acquisition (see Note 5). The Company had a $567.8 million net payable to UPC at December 31, 1995, reflecting the $650 million note payable incurred in connection with the Asset Restructuring (see Note 2), offset by an $82.2 million receivable from UPC under the Company's cash management agreement with UPC (see Note 9). Intercompany interest income related to amounts receivable from UPC was $50.0 million, $15.8 million and $9.6 million in 1993, 1994 and 1995, respectively. Intercompany interest expense related to amounts payable to UPC after the Offering was $14.5 million in 1995.

Services performed by UPC on behalf of the Company include services in the areas of cash management, internal audit and tax and employee benefits administration. Prior to the Offering, the cost of such services, which is not significant, was not charged to the Company. As a result of the Asset Restructuring and the Offering, UPC and the Company have entered into a number of agreements for the purpose of defining the ongoing relationship between them. Costs incurred by the Company in 1995 related to such agreements were $0.9 million, principally reflecting the cost of administrative services and certain financial guarantees. As a result of UPC's ownership interest in the Company, the terms of such agreements were not, and the terms of any future amendments to those agreements may not be, the result of arm's length negotiations.

4. Related Party Transactions—(Continued)

To the extent UPC maintains a substantial investment in the Company, UPC may continue to be in a position to control the policies and affairs of the Company and to determine the outcome of corporate actions requiring shareholder approval.

5. Acquisitions and Property Dispositions

Amax Oil & Gas, Inc.

In March 1994, the Company acquired Amax for a net purchase price of $725 million. Amax's operations consisted principally of natural gas producing properties and related processing and transportation facilities, located primarily in western and southern Texas and Louisiana. At the date of acquisition, these properties included interests in 14 major fields, encompassing over 500,000 acres and approximately 2,000 producing wells. The Company initially recorded 550 Bcfe of proved reserves related to the Amax acquisition.

Wilmington Field Sale

In March 1994, the Company sold its interest in the Wilmington, California field and the Harbor Cogeneration Plant to the Port of Long Beach, California. Proceeds from the sale consisted of $280.0 million in cash and two interest-bearing notes of $62.5 million each payable in December 1994 and 1995, respectively, which subsequently have been collected. The Wilmington sale resulted in a $159.2 million pre-tax ($100.0 million after-tax) gain. The sale of the Wilmington hydrocarbon reserves (approximately 3% of the Company's year end 1993 proved reserves) has not significantly affected the Company's ongoing operating results.

As part of the Wilmington sales agreement, the Company has agreed to participate with the Port of Long Beach in funding environmental remediation and site preparation, as specified by the Port of Long Beach, up to a maximum of $105.5 million in total. As a result, the determination of the gain on the sale of the Wilmington properties included provisions of $50.5 million for future environmental costs and $55.0 million for future site preparation costs ($104.0 million in total remaining at December 31, 1995) categorized as other long-term liabilities (see Notes 14 and 18). The majority of cash outlays for these liabilities is expected to occur over the next five years.

6. Financial Instruments

Hedging

The Company uses hydrocarbon-based derivative financial instruments to limit the effects of unfavorable hydrocarbon price movements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. All hedging is accomplished pursuant to exchange-traded futures contracts or master swap agreements generally based on standard forms. The Company does not hold or issue such financial instruments for trading purposes and does not hedge any significant amount of production beyond a 24 month time frame. The Company addresses market risk by selecting hydrocarbon-based financial instruments whose historical value fluctuations correlate strongly with those of the item being hedged. Credit risk related to hedging activities is managed by requiring that counterparties meet minimum credit standards and by monthly mark-to-market analysis to determine if collateral is required. At December 31, 1995, the largest credit risk associated with any of the Company's counterparties was approximately $20.9 million, which is partially protected by a $10 million letter of credit. In connection with its futures contract hedging activity, the Company is required to deposit monies with the New York Mercantile

6. Financial Instruments—(Continued)

Exchange ("NYMEX"), representing contract margin requirements and deposits required relating to unrealized losses on open contracts. Such deposits are included in other current assets in the Company's Consolidated Statements of Financial Position. At December 31, 1995, the Company had made such deposits totaling $38.4 million, representing $26.8 million for contract margin deposits and $11.6 million relating to unrealized losses on open contracts.

Basis risk arises from differences in the cash price of the hedged item and the underlying price of the hedging instrument. The Company uses futures contracts and price swaps denominated in NYMEX prices in its hedging activities. In order to lessen the resulting basis risk and to provide better correlation, the Company uses basis swaps in combination with these futures contracts and price swaps when relative movements in the NYMEX price do not fully correspond to movements in the cash price for a given location. Because of differences in the markets for NYMEX contracts and basis swaps, the Company may temporarily have outstanding NYMEX contracts without corresponding basis swaps, or basis swaps without corresponding NYMEX positions. During such periods, unusual market price swings may weaken correlation between the financial instrument and the underlying item being hedged, thereby exposing the Company to potential losses.

In late December 1995, prices of first quarter 1996 NYMEX natural gas futures contracts (which reflect prices for delivery at Henry Hub in south Louisiana) rose significantly, reaching an all-time high of $3.44 per MMBTU for January contracts. However, January cash prices for areas where the Company produces the majority of its gas did not rise proportionately. In addition, the relationships between NYMEX prices and cash prices for February and March indicated that this price aberration could continue. As a result, in late 1995 and early 1996 the Company closed out NYMEX and basis contracts that had suffered weakened correlation significant enough to disallow continued hedge accounting treatment. The Company recognized an $8.1 million pre-tax ($5.3 million after-tax) loss in December relating to these contracts, which was included in other oil and gas revenues in the Company's 1995 Consolidated Statement of Income.

After the closure of the affected contracts, the Company had the following 1996 natural gas positions, either in combination with basis swaps or relating to production subject to pricing at Henry Hub:

Month	NYMEX Volume (MMcfd)	NYMEX Price	Basis Volume (MMcfd)	Basis Price
January	—	$ —	—	$ —
February	277	1.94	175	(0.47)
March	277	1.83	175	(0.47)
April	250	1.95	175	(0.81)
May	250	1.84	175	(0.81)
June	227	1.79	175	(0.81)

At December 31, 1995, the Company had also entered into near-term futures contracts and price swaps for the first three months of 1996 with respect to crude oil sales volumes of 25 MBbld at $17.96/Bbl.

The Company also enters into long-term fixed price sales agreements for physical deliveries of natural gas and at December 31, 1995, had outstanding contracts relating to 162.8 Bcf of natural gas for periods through December 31, 2008. Average annual commitments during this period would have comprised no more than 4% of 1995 natural gas sales volumes. The Company's marketing subsidiary, UP Fuels, enters into long-term financial contracts that, in combination with these long-term fixed price sales agreements, secure a margin on the corresponding volume positions. Where necessary, UP Fuels also enters into basis swaps, which are currently available for 1996 and 1997, to strengthen the hedge securing the margin on the corresponding positions. At December 31, 1995, long-term fixed price sales commitments for which corresponding financial positions had not been entered into totaled 63.7 Bcf at an average price of $3.08/Mcf, with a mark-to-market present value of

6. Financial Instruments—(Continued)

$28.7 million. The remaining commitments for 99.1 Bcf had been offset with financial contracts for similar volumes, resulting in a $0.39/Mcf average profit on those volumes. The unrecognized mark-to-market present value on these corresponding positions comprises a $58.8 million gain on the long-term fixed price sales commitments and a $27.8 million loss on the corresponding financial contracts, resulting in a $31.0 million unrecognized mark-to-market present value margin for the Company.

At December 31, 1995, the Company had a total unrecognized mark-to-market present value gain of $55.5 million related to all open hedging and associated risk management transactions. Unrecognized mark-to-market gains or losses were determined based upon current market value, as quoted by recognized dealers, assuming a round lot transaction and using a mid-market convention without regard to market liquidity.

As a result of its hedging program, the Company's oil and gas revenues can be higher or lower than revenues that would be reported if hedging did not occur. During 1993, revenues were $29 million lower, while during 1994 and 1995, revenues were $36 million and $27 million higher, respectively, as a result of hedging activities.

Fair Value of Financial Instruments

At December 31, 1995, the carrying value of the Company's long and short-term debt approximates its fair market value, estimated using current borrowing rates. The carrying value of all other financial instruments also approximates fair market value.

7. Properties

Major property classifications as of December 31 are as follows:

	1994	1995
	(Millions of dollars)	
Producing properties	$3,532.1	$3,873.7
Non-producing properties	305.7	276.4
Plants, pipelines and equipment	762.2	898.8
Construction in progress	234.7	254.4
Other	130.5	147.1
Total	$4,965.2	$5,450.4

Accumulated depreciation, depletion and amortization by major property classifications is as follows:

	1994	1995
	(Millions of dollars)	
Producing properties	$1,949.6	$2,196.5
Non-producing properties	78.6	86.3
Plants, pipelines and equipment	270.8	334.7
Other	66.1	68.6
Total	$2,365.1	$2,686.1

Fixed asset additions included capitalized interest of $1.5 million in 1993, $0.9 million in 1994 and $1.0 million in 1995.

8. Income Taxes

Components of income tax expense are as follows:

	1993	1994	1995
	(Millions of dollars)		
Current:			
Federal	$101.0	$(41.4)	$130.2
State	3.4	(2.3)	(4.6)
Total current	104.4	(43.7)	125.6
Deferred:			
Federal	29.9	168.6	(20.8)
State	3.0	5.8	2.5
Total deferred	32.9	174.4	(18.3)
Total	$137.3	$130.7	$107.3

In August 1993, President Clinton signed the Omnibus Budget Reconciliation Act into law raising the Federal corporate income tax rate to 35% from 34%, retroactive to January 1, 1993. As a result, 1993 income tax expense increased by $11.0 million: $6.4 million for the one-time, non-cash recognition of deferred income taxes related to prior periods and $4.6 million of incremental 1993 Federal income tax expense.

Deferred tax liabilities (assets) as of December 31 include the following:

	1994	1995
	(Millions of dollars)	
Excess tax over book items, including depreciation and exploration costs	$472.7	$479.5
State taxes—net	11.9	12.3
Long-term liabilities	(38.6)	(69.8)
Alternative minimum tax	(34.5)	(37.7)
Other	46.5	54.2
Net deferred tax liability	$458.0	$438.5

A reconciliation between statutory and effective tax rates is as follows:

	1993	1994	1995
Statutory tax rate	35.0%	35.0%	35.0%
Cumulative effect of Federal tax rate increase	1.5	—	—
State taxes—net	0.9	0.5	(0.3)
Section 29 credits	(3.3)	(10.0)	(8.3)
Foreign stock loss	(1.8)	—	—
Tax settlements	—	—	(2.2)
Other	(1.2)	(0.4)	(0.8)
Effective tax rate	31.1%	25.1%	23.4%

The Company generates Section 29 credits from the sale of certain fuels produced from nonconventional sources. The Company generated $14.4 million, $52.2 million and $37.9 million of Section 29 credits in 1993, 1994 and 1995, respectively. The Federal tax law provides for the use of these credits against regular Federal income tax liability. Fuels qualifying for the credit must be produced from a well drilled or a facility placed in service after December 31, 1979, and before January 1, 1993, and sold before January 1, 2003. The Company utilized on its tax returns $30.5 million of Section 29 credits in 1993, $27.5 million in 1994 and $17.5 million in 1995.

8. Income Taxes—(Continued)

All material IRS deficiencies prior to 1984 have been settled. UPC and the IRS have settled all issues and are in the process of concluding Tax Court cases for years through 1979. UPC has reached a partial settlement with the Appeals Office of the IRS for 1980 through 1983; the remaining issues will be resolved as part of the refund claims filed for those years. UPC is negotiating with the Appeals Office concerning 1984 through 1986. The IRS is examining UPC's returns for 1987 through 1994. The Company believes it has adequately provided for its allocable share of any Federal and state income taxes.

9. Debt

Total debt as of December 31 is summarized below:

	1994	1995
	(Millions of dollars)	
Tax exempt revenue bonds, 4.2% to 9.6%, due 2001 through 2012	$ 37.7	$ 33.5
Note payable to and advances from UPC—net, 8.5%, due 1996	—	567.8
Bank Credit Agreement, 6.1% LIBOR floating at December 31, due 2000	—	68.0
Other	43.2	—
Total debt	80.9	669.3
Less current portion	(43.2)	(567.8)
Total long-term debt	$ 37.7	$101.5

The Company's Bank Credit Agreement consists of two $50 million revolving credit facilities, each with a term of five years. Borrowings under the Bank Credit Agreement bear interest either at a spread over London Interbank Offered Rate ("LIBOR") or at a spread over domestic certificate of deposit rates, in each case depending on the rating of the Company's senior unsecured indebtedness. The Company is required to pay facility fees on the aggregate amount of the unused facilities, also dependent on the rating of the Company's senior unsecured indebtedness. The Bank Credit Agreement contains covenants with respect to the ratio of debt to the sum of debt and shareholders' equity of the Company on a consolidated basis, and imposes certain restrictions on the Company regarding the creation of liens on certain properties, incurrence of indebtedness, transactions with UPC, sales by the Company of the stock of certain of its subsidiaries including UPRC and certain mergers, consolidations and asset sales.

In October 1995, the Company entered into a cash management agreement with UPC. Under the terms of the agreement, the Company is required to remit to UPC all cash generated by its operations and may borrow up to a maximum of $200 million from UPC. At December 31, 1995, UPC owed the Company $82.2 million under this agreement. In addition, the Company has a $650 million note payable to UPC incurred in connection with the Asset Restructuring (see Note 2). The resulting $567.8 million net payable to UPC at December 31, 1995 bears interest at 8.5% per annum and must be repaid within 90 days following the Distribution (see Note 4). The Company currently intends to refinance this intercompany debt with a combination of long-term fixed rate debentures and short-term commercial paper.

Under the terms of the Company's $650 million note payable to UPC, after the Distribution and for so long as any intercompany indebtedness remains outstanding, the Company and UPRC are precluded from declaring any dividend or distribution on their capital stock, other than quarterly dividends paid in cash which do not exceed the last quarterly dividend paid by the Company or UPRC prior to the Distribution.

10. Leases

The Company leases its headquarters office building, certain production platforms and other property. Future minimum lease payments for operating leases with initial non-cancelable lease terms in excess of one year as of December 31, 1995, are as follows:

	(Millions of dollars)
1996	$ 63.4
1997	62.9
1998	62.5
1999	45.9
2000	36.0
Later years	78.5
Total minimum payments	$349.2

Rent expense, net of sublease income, for operating leases with terms exceeding one month was $28.0 million in 1993, $33.8 million in 1994 and $31.0 million in 1995. Sublease rentals for the next five years are $28.8 million in 1996, $28.7 million in 1997, $28.4 million in 1998, $28.3 million in 1999, $28.0 million in 2000 and $71.0 million thereafter.

11. Retirement Plans

The Company provides pension, health care and life insurance benefits to all eligible retirees.

Pension Benefits

The Company's employees participate in UPC's pension plan. Pension plan benefits are based on years of service and compensation during the last years of employment. Contributions to the plans are calculated based on the Projected Unit Credit actuarial funding method and are not less than the minimum funding standards set forth in the Employee Retirement Income Security Act of 1974, as amended. The following pension credits and funded status are based on historical actuarial allocations. Future valuations will be based upon a revised allocation of pension plan assets made pursuant to an agreement between the Company and UPC, which may result in additional pension expense and liability to the Company as described below.

Pension cost includes the following components:

	1993	1994	1995
	(Millions of dollars)		
Service cost—benefits earned during the period	$ 4.5	$ 4.7	$ 5.3
Interest on projected benefit obligation	13.5	13.1	14.4
Return on assets:			
Actual (gain) loss	(30.9)	4.0	(49.5)
Deferred gain (loss)	13.3	(22.9)	30.0
Net amortization costs	(2.4)	(2.2)	(2.4)
Net pension credit	$(2.0)	$(3.3)	$(2.2)

The projected benefit obligation was determined using a discount rate of 8.0% in 1994 and 7.25% in 1995. The estimated rate of salary increase approximated 6.0% in 1994 and 5.25% in 1995. The expected long-term rate of return on plan assets was 8.0% in both years. These changes in rate assumptions will not significantly affect 1996 pension cost. The portion of the funded plan's assets held in fixed-income and short-term securities was approximately 32% as of both December 31, 1994 and 1995, with the remainder primarily in equity securities.

11. Retirement Plans—(Continued)

The funded status of the plan as of December 31 is as follows:

	1994	1995
	(Millions of dollars)	
Plan assets at fair value	$244.7	$282.3
Actuarial present value of benefit obligations:		
Vested benefits	140.6	156.4
Non-vested benefits	6.7	7.0
Accumulated benefit obligation	147.3	163.4
Additional benefits based on estimated future salaries	33.1	29.2
Projected benefit obligation	180.4	192.6
Plan assets over projected benefit obligation	64.3	89.7
Unamortized net transition asset	(26.3)	(23.6)
Unrecognized prior service cost	7.2	6.0
Unrecognized net gain	(37.1)	(59.5)
Prepaid pension costs	$ 8.1	$ 12.6

Following the Distribution, pension assets will be allocated between UPC and the Company. Based on the plan status as of December 31, 1995, such allocation would result in the elimination of the $12.6 million prepaid pension cost and the creation of a $70.8 million pension liability as well as a $31.3 million deferred tax asset which would reduce the Company's deferred tax liability, resulting in a charge to equity of $52.1 million. The additional pension cost to the Company associated with this allocation of pension plan assets would be approximately $6.7 million annually. The final allocation of pension plan assets will be based on the plan status at the time of the Distribution; therefore, actual amounts may differ from these estimates.

Other Postretirement Benefits

Postretirement health and life insurance benefits cost includes the following components:

	1993	1994	1995
	(Millions of dollars)		
Service cost—benefits earned during the period	$ 1.3	$ 1.2	$ 1.2
Interest costs on accumulated benefit obligation	4.3	3.7	4.3
Net amortization costs	—	(0.9)	(1.5)
Charge to operations	$ 5.6	$ 4.0	$ 4.0

The liability for other postretirement benefit plans as of December 31 is as follows:

	1994	1995
	(Millions of dollars)	
Accumulated postretirement benefit obligation ("APBO"):		
Retirees	$ 42.6	$ 45.2
Fully eligible active employees	1.5	2.0
Other active employees	10.4	12.2
Total APBO	54.5	59.4
Unrecognized prior service gain	6.1	5.2
Unrecognized net gain	13.2	11.5
Postretirement benefits liability	$ 73.8	$ 76.1

11. Retirement Plans—(Continued)

The APBO was determined using a discount rate of 8.0% in 1994 and 7.25% in 1995. The health care cost trend rate is assumed to gradually decrease from 11.9% for 1996 to 5.0% for 2009 and all future years. If the assumed health care cost trend rate increases by one percentage point in each subsequent year, the aggregate of the service and interest cost components of annual postretirement benefit expense would increase by $0.7 million and the APBO would rise by $6.7 million. The Company does not currently pre-fund health care and life insurance benefit costs. Cash payments for these benefits were $2.4 million in 1994 and $1.6 million in 1995.

12. Stock Option and Retention Stock Plans

Pursuant to the Company's stock option and retention stock plans, 11,660,601 shares of Common Stock or options for such shares were available at December 31, 1995 for grant to employees and directors, prior to conversion of the remaining UPC Incentive Stock Options ("ISOs") described below. Options under the plans are granted at 100% of fair market value at the date of grant, become exercisable no earlier than one year after grant and are exercisable for a period of ten years from grant date. Multi-year option grants have been made to officers and key employees, covering normal annual grants for three years and becoming exercisable over a three-year period, provided designated Company and/or UPC common stock prices are met, or becoming fully exercisable in any event after nine years.

Retention shares of common stock are awarded under the plans to eligible employees, subject to forfeiture if employment terminates during the prescribed retention period, generally not less than three years from grant. Multi-year retention stock awards also have been made, with vesting three years from grant provided certain Company and/or UPC stock prices are met.

Upon completion of the Offering and pursuant to the plans, UPC non-qualified stock options and certain UPC ISOs, as well as UPC retention shares held by officers and employees of the Company, were converted into non-qualified Company options and retention shares, respectively. Remaining UPC ISOs held by Company employees (247,600 UPC ISOs at December 31, 1995) will be converted into Company ISOs at the time of the Distribution. The terms of the UPC plans under which such UPC options and retention shares originally were granted are the same as the terms of the Company's plans described above. The converted options and retention shares generally retain the same exercise dates and vesting requirements as the UPC options and retention shares for which they were exchanged.

12. Stock Option and Retention Stock Plans—(Continued)

The status of the Company's stock-based compensation programs is as follows:

	Company Shares	Weighted Average Exercise Price
Stock options:		
Balance at December 31, 1994	—	$ —
Conversion of UPC stock options	3,702,443	15.87
Granted	88,695	25.88
Exercised	(1,500)	15.18
Expired/surrendered	—	—
Balance at December 31, 1995	3,789,638	16.11
Exercisable December 31, 1995	2,235,470	$16.26
Retention shares unvested at December 31, 1995:		
Regular	423,465	
Performance	324,796	
During the year:		
Retention shares awarded—regular	33,585	$25.88(a)
Retention shares awarded—performance	14,143	$25.88(a)
Retention shares converted from UPC shares—regular	389,880	
Retention shares converted from UPC shares—performance	310,653	
Average per option fair value of options granted (b)	$ 8.31	
Compensation cost recognized for employee stock-based awards (millions)	$ 0.7	

(a) Represents market value on grant date.

(b) Calculated in accordance with the Black-Scholes option pricing model, using the following assumptions: expected volatility—28%; expected dividend yield—0.86%; expected option term—5 years; and risk-free rate of return—5.5%.

Stock options outstanding at December 31, 1995 are as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Years to Expiration	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$ 8.09- 9.49	72,533	2.33	$ 8.95	72,533	$ 8.95
11.08-13.14	365,280	3.84	12.06	365,280	12.06
15.18-17.61	2,754,708	8.27	15.66	1,289,235	16.09
20.74-25.88	597,117	8.19	21.50	508,422	20.74
8.09-25.88	3,789,638	7.72	16.11	2,235,470	16.26

13. Investment in Unconsolidated Affiliate

The Company has a 50% ownership interest in Black Butte Coal Company and R-K Leasing Company ("Black Butte"). Summarized financial information for Black Butte as of December 31 is as follows:

	1994	1995
	(Millions of dollars)	
Current assets	$ 35.0	$ 35.7
Non-current assets	73.9	60.5
Current liabilities	17.1	16.1
Non-current liabilities and equity	91.8	80.1
Sales	205.4	176.0
Operating income	113.0	109.2
Partners' income	112.8	108.9

A supplier of coal to Black Butte has been assessed by the Minerals Management Service of the U.S. Department of the Interior and the State of Montana Department of Revenue for underpayment of royalties and production taxes related to coal previously sold to Black Butte. The supplier is contesting these claims; however, should the claims be successful the supplier may make a claim to Black Butte to be reimbursed for such claims. Although the management of Black Butte will vigorously contest these claims, the liability associated with the underpaid royalty and production taxes, if any, could range from zero to $32 million, of which the Company would recognize its proportionate share, which could range from zero to $16 million.

14. Environmental Exposure

The Company generates and disposes of hazardous and non-hazardous waste in its current and former operations and is subject to increasingly stringent Federal, state and local environmental regulations. The Company has identified 10 sites currently subject to environmental response actions or on the Superfund National Priorities List or state superfund lists, at which it is or may be liable for remediation costs associated with alleged contamination or for violations of environmental requirements. Certain Federal legislation imposes joint and several liability for the remediation of various sites; consequently, the Company's ultimate environmental liability may include costs relating to other parties in addition to costs relating to its own activities at each site. In addition, the Company is or may be liable for certain environmental remediation matters involving existing or former facilities.

As of December 31, 1995, long and short-term liabilities totaling $103.3 million had been accrued for future costs of all sites where the Company's obligation is probable and where such costs can be reasonably estimated; however, the ultimate cost could be lower or as much as 10% higher. This accrual includes future costs for remediation and restoration of sites, as well as for ongoing monitoring costs, but excludes any anticipated recoveries from third parties. The accrual also includes $50.3 million for the obligation to participate in the remediation of the Wilmington field properties. Cost estimates were based on information available for each site, financial viability of other Potentially Responsible Parties ("PRPs") and existing technology, laws and regulations. The Company believes that it has adequately accrued for its share of costs at sites subject to joint and several liability. The ultimate liability for remediation is difficult to determine with certainty because of the number of PRPs involved, site-specific cost sharing arrangements with other PRPs, the degree of contamination by various wastes, the scarcity and quality of volumetric data related to many of the sites and the speculative nature of remediation costs.

The Company also is involved in reducing emissions, spills and migration of hazardous materials. Remediation of identified sites and control and prevention of environmental exposures required spending of $7.9 million in 1994 and $6.2 million in 1995. In 1996, the Company anticipates spending a total of $25 million for remediation, control and prevention, including $20 million relating to the Wilmington properties. The

14. Environmental Exposure—(Continued)

majority of the December 31, 1995 accrued environmental liability is expected to be paid out over the next five years, funded by cash generated from operations. Based on current rules and regulations, management does not expect future environmental obligations to have a material impact on the results of operations or financial condition of the Company.

15. Commitments and Contingencies

UP Fuels is a party to a 15-year firm transportation agreement with Kern River Gas Transmission Company that expires in 2007. Under the transportation agreement, UP Fuels has the right to transport 75 MMcfd of gas on the Kern River pipeline system which extends from Opal, Wyoming to an interconnection with the Southern California Gas Company pipeline system in southern California. Twelve years remain on the primary term of the agreement, and the current transportation rate is $0.69 per Mcf. UP Fuels is obligated to pay the fixed portion of that rate, presently $0.6878 per Mcf, whether or not it actually transports any gas. This rate will be in effect through at least mid-1997, and thereafter can change based on cost of service factors and prevailing rate policy at the Federal Energy Regulatory Commission. The undiscounted amount of the commitment is $217 million. UP Fuels is party to two additional agreements under which it may acquire, at its option, in 1996 and 2001, an additional 25 MMcfd of transportation rights on the Kern River system for periods beginning in 1997 and 2002, respectively.

In the last nine years, the Company has disposed of significant pipeline, refining and producing property assets, including the sale of its 37.5% interest in a Corpus Christi petrochemical complex (July 1987), the Calnev pipeline (October 1988), the Wilmington refinery (December 1988), the Corpus Christi refinery (half sold in March 1987 and the balance in January 1989), and Wilmington field (March 1994). In connection therewith, the Company has given certain representations and warranties relating to the assets sold (covering, among other matters, the condition and capabilities of assets and compliance with environmental and other laws) and certain indemnities with respect to liabilities associated with such assets. With respect to the Calnev pipeline and the Corpus Christi and Wilmington refinery sales, the Company has been advised of possible claims which may be asserted by the relevant purchasers for alleged breaches of representations and warranties. Claims concerning the physical conditions and capabilities of assets associated with the Corpus Christi refinery and related terminals were resolved in April 1995. Such resolution did not have a material adverse effect on the results of operations or financial condition of the Company. Certain claims related to compliance with environmental laws remain pending. In addition, as some of the representations, warranties and indemnities related to some of the disposed assets have not expired, further claims may be made against the Company. While no assurance can be given as to the actual outcome of these claims, the Company does not expect these matters to have a materially adverse effect on the results of its operations or financial condition.

There are lawsuits pending against the Company and certain of its subsidiaries which are described in Part I, Item 3—Legal Proceedings in this report. While the Company intends to defend vigorously against these lawsuits and any similar lawsuits, if the suits with respect to the underpayment of royalties based on "posted prices" are ultimately resolved against the Company on a widespread basis, damage awards and a loss of future revenue could result which, in the aggregate, could be material.

The Company is a defendant in a number of other lawsuits and is involved in governmental proceedings arising in the ordinary course of business in addition to those described above. The Company has also entered into commitments and provided guarantees for specific financial and contractual obligations of its subsidiaries and affiliates. The Company does not expect that these lawsuits, commitments or guarantees will have a materially adverse effect on the results of its operations or financial condition.

16. Columbia Gas Transmission Company

In July 1991, Columbia Gas Transmission Company ("Columbia") filed for protection from its creditors under Chapter 11 of the bankruptcy laws. Columbia and the Company were parties to a long-term contract for the sale by the Company to Columbia of substantial volumes of natural gas at above 1991 market prices. Shortly after the filing, Columbia rejected the Company's contract and most of its other gas purchase contracts, leaving the Company and nearly 2,000 other gas producers as unsecured creditors. Following the Chapter 11 filing, there was extensive litigation and proceedings involving the value of Columbia's estate and the amount of each gas producer's claim. In April 1995, Columbia filed a Plan of Reorganization which was approved by the Bankruptcy Court and became effective in November 1995, at which time the Company received a cash payment. An issue remains as to whether the payment received is royalty bearing, other than that portion of the payment applicable to gas actually produced and sold to Columbia, and the Company has instituted a legal proceeding to obtain a declaration of its rights and obligations. As a result of the settlement with Columbia, after taking into account possible tax and royalty claims, the Company recorded pre-tax income of $122.5 million in the fourth quarter of 1995 ($78.5 million after tax) which is included in other oil and gas revenues.

17. Other Income—Net

Other income—net includes the following:

	1993	1994	1995
	(Millions of dollars)		
Gain on Wilmington sale (Note 5)	$ —	$159.2	$ —
Intercompany interest income (Note 4)	50.0	15.8	9.6
Other—net	10.4	(1.0)	(2.6)
Total	$ 60.4	$174.0	$ 7.0

18. Other Long-Term Liabilities

Other long-term liabilities as of December 31 include the following:

	1994	1995
	(Millions of dollars)	
Environmental (Notes 5 and 14)	$100.5	$ 78.0
Wilmington field site preparation (Note 5)	53.7	53.7
Litigation and contingencies (Notes 15 and 16)	44.7	93.5
Offshore platform lease accrual	26.7	14.5
Other	54.6	50.8
Total	$280.2	$290.5

19. Capital and Exploratory Expenditures

Capital and exploratory expenditures include the following:

	1993	1994	1995
	(Millions of dollars)		
Capital expenditures:			
Producing properties	$368.5	$ 790.8	$482.7
Non-producing properties	56.8	192.4	35.0
Exploratory drilling	11.1	28.5	24.2
Plants, pipelines and marketing	67.9	329.8	106.5
Other	3.1	2.0	2.0
Total capital expenditures	507.4	1,343.5	650.4
Exploratory expenditures:			
Expensed geological and geophysical costs	27.1	18.4	22.4
Expensed dry hole costs	25.9	27.4	13.6
Total exploratory expenditures	53.0	45.8	36.0
Total capital and exploratory expenditures	$560.4	$1,389.3	$686.4

UNION PACIFIC RESOURCES GROUP INC.

SUPPLEMENTARY INFORMATION (UNAUDITED)

A. Proved Reserves(a)

	1993	1994	1995
Natural gas (Bcf)(b):			
Beginning of year	1,709.2	1,731.2	2,126.0
Revisions of previous estimates	(35.6)	(33.1)	(122.3)
Extensions, discoveries and other additions	237.0	360.3	518.0
Purchases of reserves-in-place	53.1	385.4	26.7
Sales of reserves-in-place	(6.5)	(36.0)	(32.0)
Production	(226.0)	(281.8)	(342.9)
Total proved, end of year	1,731.2	2,126.0	2,173.5
Proved developed reserves	1,643.5	2,054.4	1,957.1
Natural gas liquids (MMBbl)(b):			
Beginning of year	67.8	74.3	83.8
Revisions of previous estimates	7.0	(5.8)	9.9
Extensions, discoveries and other additions	2.9	4.6	18.2
Purchases of reserves-in-place	4.4	21.4	0.2
Sales of reserves-in-place	(0.1)	(2.2)	(1.0)
Production	(7.7)	(8.5)	(11.0)
Total proved, end of year	74.3	83.8	100.1
Proved developed reserves	72.9	81.2	89.8
Crude oil, including condensate (MMBbl):			
Beginning of year	88.8	82.6	70.9
Revisions of previous estimates	(1.5)	4.9	14.1
Improved recovery	1.3	—	—
Extensions, discoveries and other additions	17.9	24.5	19.1
Purchases of reserves-in-place	0.3	6.5	1.9
Sales of reserves-in-place	—	(24.6)	(2.9)
Production	(24.2)	(23.0)	(19.3)
Total proved, end of year	82.6	70.9	83.8
Proved developed reserves	80.9	69.9	78.2
Proved reserves equivalent, end of year (Bcfe)(c):			
Natural gas	1,731.2	2,126.0	2,173.5
Natural gas liquids	445.8	502.9	600.6
Crude oil, including condensate	495.6	425.2	502.8
Total proved	2,672.6	3,054.1	3,276.9
Proved developed reserves	2,566.3	2,961.0	2,965.1

(a) Reserve estimates as of December 31, 1994 and thereafter include the effects of the Amax acquisition and the sale of the Wilmington field (see Note 5).

(b) Includes the plant share of equity gas processed (natural gas and natural gas liquids, as appropriate, earned by gas processing facilities through the processing of the Company's equity production).

(c) Calculated using the ratio of one Bbl to six Mcf.

B. Drilling Activity(a)

	1993	1994	1995
Gross wells	529	677	725
Gross productive wells	491	644	685
Net wells:			
Exploration	20	24	14
Development	303	373	513
Total net wells	323	397	527
Net productive wells:			
Exploration	10	16	3
Development	295	365	506
Total net productive wells	305	381	509

(a) In addition, at December 31, 1995, 89 gross wells (57 net wells) were in the process of being drilled.

C. Average Sales Price and Cost

	1993	1994	1995
Producing properties:			
Natural gas sales price (per Mcf)	$ 1.80	$ 1.82	$ 1.44
Natural gas liquids sales price (per Bbl)	8.77	7.86	8.14
Crude oil sales price (per Bbl)	15.66	14.34	16.08
Production cost (per Mcfe)	0.60	0.55	0.44
Gas plants:			
Natural gas sales price (per Mcf)	$ 2.63	$ 1.81	$ 1.51
Natural gas liquids sales price (per Bbl)	10.52	9.97	9.38

D. Average Daily Production and Sales Volume

	1993	1994	1995
Producing properties:			
Natural gas (MMcfd)	608.2	754.8	915.6
Natural gas liquids (MBbld)	15.5	18.8	23.1
Crude oil (MBbld)	66.5	63.1	52.8
Total producing properties (MMcfed)	1,100.2	1,246.2	1,371.0
Plant share of equity gas processed:			
Natural gas (MMcfd)	11.0	17.5	23.9
Natural gas liquids (MBbld)	5.5	4.4	7.1
Total plant share of equity gas (MMcfed)	44.0	43.9	66.5
Total production reflected in estimates of proved reserves (MMcfed)	1,144.2	1,290.1	1,437.5
Plant share of third party gas processed (MBbld)	18.9	26.8	27.1
Total sales (MMcfed)	1,257.6	1,450.9	1,600.1
Plant share of natural gas liquids sales (MBbld):			
Equity gas processed	5.5	4.4	7.1
Third party gas processed	18.9	26.8	27.1
Total	24.4	31.2	34.2

E. Acreage and Wells

Oil and gas acreage as of December 31 is as follows:

	1994	1995
	(Thousands of acres)	
Gross developed	1,811	2,284
Net developed	847	1,209
Gross undeveloped(a)	11,351	12,610
Net undeveloped(a)	9,444	9,562

Productive oil and gas wells at December 31, 1995 are as follows:

	Oil	Gas
	(Wells)	
Gross(b)	3,199	4,046
Net	1,656	2,181

(a) Includes approximately 7.1 million gross undeveloped acres (6.4 million net undeveloped acres) as of December 31, 1994 and 1995 which were acquired through 19th century Congressional Land Grant Acts (the "Land Grant"). Substantial portions of this acreage are considered prospective for oil and gas.

(b) Approximately 600 are multiple completions, 419 of which are gas wells.

F. Capitalized Exploration and Production Costs

Capitalized exploration and production costs as of December 31 are as follows(a):

	1994	1995
	(Millions of dollars)	
Proved properties	$ 785.7	$ 865.7
Unproved properties	146.3	148.3
Wells and related equipment	2,908.7	3,136.1
Uncompleted wells and equipment	178.3	182.6
Gross capitalized costs	4,019.0	4,332.7
Accumulated depreciation, depletion and amortization	(2,028.2)	(2,282.8)
Net capitalized costs	$ 1,990.8	$ 2,049.9

(a) Excludes plants, pipelines and marketing assets.

G. Costs Incurred in Exploration and Development

Costs incurred (whether capitalized or expensed) in oil and gas property acquisitions, and exploration and development activities are as follows:

	1993	1994	1995
	(Millions of dollars)		
Costs incurred:			
Proved acreage	$ 27.1	$ 440.6	$ 100.5
Unproved acreage	56.8	35.4	35.0
Exploration costs(a)	91.3	100.5	80.9
Development costs	341.4	507.2	382.2
Total costs incurred(b)	$ 516.6	$1,083.7	$ 598.6

(a) Includes allocated exploration overhead costs of $22.6 million in 1993, $21.6 million in 1994 and $17.1 million in 1995, and delay rentals of $4.6 million in 1993, $4.6 million in 1994 and $3.6 million in 1995.

(b) Excludes capital expenditures relating to plants, pipelines and marketing of $67.9 million in 1993, $329.8 million in 1994 and $106.5 million in 1995.

H. Results of Operations for Producing Activities(a)

	1993	1994	1995
	(Millions of dollars)		
Revenues	$ 954.6	$ 962.5	$1,027.7
Production costs	(240.2)	(252.3)	(217.8)
Exploration expenses	(111.2)	(107.6)	(89.4)
Depreciation, depletion and amortization	(321.5)	(373.2)	(403.1)
Total costs	(672.9)	(733.1)	(710.3)
Pre-tax results	281.7	229.4	317.4
Income taxes	(81.9)	(28.8)	(70.4)
Results of operations	$ 199.8	$ 200.6	$ 247.0

(a) Plants, pipelines and marketing results, general and administrative expenses and interest costs have been excluded in computing these results of operations. Revenues include net gains from sales of assets of $6.1 million in 1993, $26.5 million in 1994 and $14.2 million in 1995, and the $122.5 million Columbia bankruptcy settlement in 1995. Amounts for 1993 and 1994 have been restated to conform to current year presentation.

I. Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	1993	1994	1995
	(Millions of dollars)		
Future cash inflows from sale of oil and gas	$ 4,540.1	$ 5,023.1	$ 5,809.2
Future production and development costs	(1,631.1)	(1,790.9)	(1,747.8)
Future income taxes	(858.5)	(722.3)	(1,114.6)
Future net cash flows	2,050.5	2,509.9	2,946.8
10% annual discount	(761.9)	(851.2)	(1,075.5)
Standardized measure of discounted future net cash flows	$ 1,288.6	$ 1,658.7	$ 1,871.3

An analysis of changes in the standardized measure of discounted future net cash flows follows:

	1993	1994	1995
	(Millions of dollars)		
Beginning of year	$ 1,551.7	$ 1,288.6	$ 1,658.7
Changes due to current year operations:			
Additions and discoveries less related production and other costs	441.3	570.7	549.7
Sales of oil and gas—net of production costs	(732.7)	(744.0)	(716.1)
Development costs	400.3	745.6	382.2
Purchases of reserves-in-place	27.8	270.9	48.8
Sales of reserves-in-place	—	(36.1)	(49.5)
Changes due to revisions in:			
Price	(516.6)	(9.6)	334.0
Development costs	(358.3)	(811.9)	(293.6)
Quantity estimates	(5.1)	(80.4)	68.1
Income taxes	142.7	184.2	(271.5)
Other	123.2	107.0	(31.8)
Discount accretion	214.3	173.7	192.3
End of year	$ 1,288.6	$ 1,658.7	$ 1,871.3

Future oil and gas sales and production and development costs have been estimated using prices and costs in effect as of each year end. Future net revenues were discounted to present value at 10%, a uniform rate set by the FASB. Income taxes represent the tax effect (at statutory rates) of the difference between the standardized measure values and tax bases of the underlying properties at the end of the year.

Changes in the supply and demand for oil, natural gas and natural gas liquids, inflation, timing of production, reserve revisions and other factors make these estimates inherently imprecise and subject to substantial revision. As a result, these measures are not the Company's estimate of future cash flows nor do these measures serve as an estimate of current market value.

J. Selected Quarterly Data

Selected unaudited quarterly data are as follows:

	For the Quarter Ended			
	Mar. 31	Jun. 30	Sep. 30	Dec. 31
	(Dollars in millions, except per share amounts)			
1995				
Operating revenues	$321.3	$336.7	$331.3	$466.5(a)
Operating income	86.5	88.1	98.4	197.1(a)
Net income	61.2	73.6	76.7	139.2(a)
Per share:				
Net income(b)	n/a	n/a	n/a	$ 0.56
Dividends(b)	n/a	n/a	n/a	0.05
1994				
Operating revenues	$305.2	$332.6	$353.4	$341.7
Operating income	76.9	85.8	100.9	87.7
Net income	155.5(c)	72.4	75.6	86.5

(a) In November 1995, the Company recorded a $122.5 million pre-tax ($78.5 million after-tax) gain resulting from the Columbia bankruptcy settlement (see Note 16).

(b) Net income and dividends per share have been omitted for all periods prior to the fourth quarter of 1995 as the Company was a wholly owned subsidiary of UPC until October 1995 (see Note 2).

(c) In March 1994, the Company sold its interest in the Wilmington field and Harbor Cogeneration Plant to the Port of Long Beach, California, resulting in a $159.2 million pre-tax ($100.0 million after-tax) gain (see Note 5).