



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, 1996

Commission file number 1-13916

Union Pacific Resources Group Inc.

(Exact name of registrant as specified in its charter)

Utah
(State or other jurisdiction of
incorporation or organization)

13-2647483
(I.R.S. Employer
Identification No.)

801 Cherry Street
Fort Worth, Texas
(Address of principal executive offices)

76102
(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

Common Stock

Name of each exchange on
which registered

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 25, 1997, the aggregate market value of the registrant's common stock held by non-affiliates (using the New York Stock Exchange closing price) was approximately \$6,192,422,750.

The number of shares outstanding of the registrant's common stock as of February 25, 1997 was 253,776,970.

Certain portions of the registrant's definitive Proxy Statement for the annual meeting of shareholders to be held on May 7, 1997 (the "Proxy Statement") are incorporated in Part 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 (Mcf), millions of cubic feet of natural gas equivalent (MMcf), billions of cubic feet of natural gas equivalent (Bcf) or trillions of cubic feet of natural gas equivalent (Tcf). 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 working interests in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by the working interest owned therein. Unless otherwise specified, all references to wells and acres are gross.

PART I

ITEM 1. Business

General

Union Pacific Resources Group Inc., a Utah corporation (the "Company"), 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 72% of the Company's natural gas, 88% of its crude oil and 96% of its natural gas liquids, 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 nonoperated 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. Over 90% of the Company's revenues, assets and reserves are generated or located in the United States. See "Business Segment Information" on page 37.

In October 1995, the Company sold 42.5 million shares of its common stock in an initial public offering (the "Offering"). The Company's stock is 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"). Upon completion of the Offering and until October 15, 1996, UPC owned approximately 83% of the Company's outstanding common stock. Concurrent with the Offering, UPC announced its intention to distribute its remaining ownership interest in the Company to its shareholders as a dividend by means of a tax-free distribution (the "Distribution"). On October 15, 1996, the Distribution was consummated.

UPC acquired Champlin Petroleum Company ("Champlin") in 1970 to manage the exploitation of its oil and gas operations on the Land Grant. The Land Grant consists of land granted by the Federal government to a predecessor of UPC in the mid-1800s which passes through the states of Colorado and Wyoming and into Utah and intersects several highly productive oil and gas basins. In the Land Grant Area, the Company has fee ownership of the mineral rights under approximately 7.9 million acres constituting the initial Land Grant and controls the mineral rights under approximately 700,000 additional acres. In 1971, UPC combined its own oil and gas operations with those of Champlin. 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. In October 1995, UPRC and certain oil and gas operations of other affiliated companies which were wholly owned subsidiaries of UPC, representing, collectively, UPC's natural resources business segment, were combined to form the Company.

Business Strategy

In each of its 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. 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. The Company's 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 Oil & Gas, Inc. ("Amax") in March 1994.

Oil and Gas Operations

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 Colorado and Wyoming, with additional operations primarily in Kansas and western Canada, (4) the onshore and offshore Gulf Coast area, (5) eastern and southern Texas and (6) western Texas. Natural gas and natural gas liquids constituted 86% of the Company's total proved reserves of over 3.5 Tcfe as of December 31, 1996, and 82% of the Company's sales volumes of 1.7 Bcfe for the year then ended. For the same period, approximately 64% of the Company's production from producing properties was attributable to Company-operated properties.

The following table sets forth certain reserve and sales information as of December 31, 1996 with respect to each of the Company's business units.

Business Unit	Proved Reserves(1) As of December 31, 1996		Sales Volumes Year Ended December 31, 1996			
	Total Proved Reserves (Bcfe)	Percent of Total	Producing Property Volumes (MMcfe)	Sales from Gas Plant Ownership (MMcfe)	Total Sales Volumes(2) (MMcfe)	Percent of Total
Austin Chalk	558	16%	535	24	559	32%
Rockies	1,244	36	392	14	406	24
Plains/Canada	402	11	144	6	150	9
Gulf Onshore/Offshore	206	6	125	—	125	7
East/South Texas	538	15	163	20	183	11
West Texas	559	16	96	57	153	9
Natural Gas Processing	—	—	—	144	144	8
Total	<u>3,507</u>	<u>100%</u>	<u>1,455</u>	<u>265</u>	<u>1,720</u>	<u>100%</u>

- (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 — 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 700 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. The Louisiana Extension of the Austin Chalk currently is the focus of significant activity. Since 1988, the Company has participated in the drilling of approximately 1,300 horizontal wells and has made aggregate capital expenditures of \$1.9 billion in the Austin Chalk area. The Company currently controls approximately two million developed and undeveloped net acres in the Austin Chalk and has increased its sales volumes from 37 MMcfe in January 1990 to an average of 559 MMcfe during 1996. During 1996, 90% 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 area. The Company currently controls approximately 3.5 million developed and undeveloped net acres in the Rockies, principally attributable to its Land

Grant ownership. During 1996, 23% 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 primarily in three areas: the eastern portion of the Land Grant Area in Colorado and Wyoming, the Hugoton/Panoma field in Kansas and fields in western Canada. The Company currently controls more than 5.7 million developed and undeveloped net acres in Plains/Canada, principally attributable to its Land Grant ownership. As of December 31, 1996, the Company had an interest in approximately 1,300 gross producing wells in the Plains/Canada area. The Company also had royalty interests in 3,700 producing wells in Plains/Canada in which the Company did not also own a working interest. During 1996, 49% of the Company's production from Plains/Canada was attributable to Company-operated properties.

Gulf Onshore/Offshore Business Unit. The Gulf Onshore/Offshore 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 1996, 49% of the Company's production from the Gulf Onshore/Offshore area 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 northeastern Texas and the Stratton/Agua Dulce area in southern Texas. The Company also controls significant gathering, processing and transportation assets in East/South Texas that are integral to its natural gas production activities. For the year ended December 31, 1996, 87% 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 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 over 600 wells in the Ozona area and has substantially modernized and expanded its gathering, processing and transportation facilities. As of December 31, 1996, approximately 84% of the gross producing wells in the West Texas area were Company operated. During 1996, 93% of the Company's production from West Texas was attributable to Company-operated properties.

Plants and Pipelines. The Company owns interests in 21 natural gas processing plants, 16 of which it operates, with a current throughput capacity of 3.2 Bcfd (1.6 Bcfd net to the Company). Aggregate throughput of the Company's gas processing plants for the year ended December 31, 1996 averaged 84% of the plants' aggregate design capacity. For the year ended December 31, 1996, production of natural gas liquids attributable to the Company's ownership interest in gas processing facilities averaged approximately 39.8 MBbld. In addition to the gas value chain assets included in the Amax acquisition, the Company has invested approximately \$100 million per year in each of the last three years to increase processing and gathering capacity. The Company currently is developing a gas processing facility in the Austin Chalk and has plans to expand its Patrick Draw plant in the Rockies as well as its East Texas plant complex. See "Properties — Gas Processing Assets."

During 1996, the Company became a partner with Arco Pipeline Company on a 50/50 basis in the Black Lake liquids pipeline, a 270-mile pipeline in Louisiana which can transport up to 45 MBbld of natural gas liquids from the Austin Chalk area to markets on the Gulf Coast. Both the Black Lake and Panola pipelines deliver unfractionated natural gas liquids to the Enterprise and Mont Belvieu I fractionators in which the Company has equity ownership. The Company also has a 55% nonoperating interest in the Ferguson-Burleson County Gas Gathering System, a 585 MMcf capacity system serving the deep Giddings area of the Austin Chalk and controls both the 265-mile Overland Trail Transmission Company pipeline serving the Green River Basin in the Rockies and the 100 MMcf Wahsatch Gathering System, a sour gas pipeline serving the Yellow Creek and Cave Creek areas of the Overthrust. 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.

Marketing. In 1996, the Company, primarily through UP Fuels, sold approximately 1.8 Bcfd of natural gas (about 56% of which represented the Company's equity production), 151.6 MBbld of natural gas liquids (including 83.3 MBbld of third party liquids) and 63.5 MBbld of crude oil and condensate (including 12.9 MBbld of third party crude oil and condensate).

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 natural gas liquids customers that UP Fuels targets are wholesalers, industrial end users and traders. 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 owned fractionators in Mt. Belvieu, Texas. Where possible, UP Fuels sells crude oil directly to refiners. If these customers are not available locally, UP Fuels exchanges or sells the crude oil volumes to major trading locations where they are sold to both refiners and marketers.

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,		
	1994	1995	1996
Producing Properties:			
Average daily production (1):			
Natural gas (MMcfd)	754.8	915.6	980.3
Natural gas liquids (MBbld)	18.8	23.1	28.5
Crude oil (MBbld)	63.1	52.8	50.6
Total (MMcfd)	1,246.2	1,371.0	1,454.9
Average sales prices:			
Natural gas (per Mcf)	\$ 1.82	\$ 1.42	\$ 1.86
Natural gas liquids (per Bbl)	7.86	8.14	11.39
Crude oil (per Bbl)	14.34	16.08	18.84
Production costs (per Mcfe) (2)	0.55	0.42	0.49
Plants, Pipelines and Marketing:			
Average daily sales volumes attributable to gas plant ownership (3):			
Natural gas (MMcfd)	17.5	23.9	26.7
Natural gas liquids (MBbld)	31.2	34.2	39.8
Total (MMcfd)	204.7	229.1	265.4
Average sales prices:			
Natural gas (per Mcf)	\$ 1.81	\$ 1.51	\$ 2.01
Natural gas liquids (per Bbl)	9.97	9.38	13.16

- (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, 1994, 1995 and 1996 are 43.9 MMcfed, 66.5 MMcfed and 77.1 MMcfed, respectively. See "Supplementary Information — Average Daily Production and Sales Volume" on page 58.

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 nonoperated joint venture and royalty arrangements in coal and trona (natural soda ash) mines. In general, the Company reinvests the cash flow from its hard minerals operations in its oil and gas business units. The Minerals business unit generated \$120 million of operating income during 1996, as follows:

	1996 Operating Income	
	Amount	Percent
	(Millions of dollars)	
Royalties:		
Soda ash(1)	\$ 26.5	22%
Coal(2)	15.9	13
Total royalties	42.4	35
Nonoperated joint ventures:		
Soda ash(3)	13.7	11
Coal(4)	60.7	51
Total joint ventures	74.4	62
Overhead/other	3.2	3
Total operating income	<u>\$120.0</u>	<u>100%</u>

- (1) Includes properties leased to five soda ash producers, estimated to contain resources sufficient to support over 30 years of production at current production levels.
- (2) The Company leases coal resources to six operating mines. In 1996, 62% 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 OCI Wyoming LP, a nonoperated joint venture.
- (4) Represents the Company's 50% nonoperating interest in Black Butte Coal Company. Of this amount, \$54.8 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" and Note 12 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 cost levels, however, most of this resource is not economic 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 therefore 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, in the paper and water treatment industries and in the manufacture of certain chemicals and detergents. Natural soda ash from Wyoming has grown to 30% of the world soda ash supply with the remainder principally from synthetic processes, and will continue to expand while worldwide demand continues to increase. As a result of the continued increase in the worldwide demand for soda ash, the Company, along with its partner Oriental Chemical Industries, Inc., plans to expand the OCI Wyoming LP soda ash facility by 950,000 tons per year, from the plant's current nameplate capacity of 2.3 million tons per year, by 1999. The Company's share of expansion costs is expected to be funded primarily with partnership debt.

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.

Numerous Federal, state and local departments and agencies 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, 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 otherwise could 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 United States 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. Certain operations on such leases must be conducted pursuant to appropriate permits issued by the BLM and the MMS in addition to permits required from other agencies (such as the Coast Guard, Army Corps of Engineers and Environmental Protection Agency). The MMS also administers bonding requirements and 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. 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 apply directly 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 the 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. 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 was largely upheld by the United States Court of Appeals for the District of Columbia. Several parties have petitioned the Supreme Court to review the Court of Appeals' decision. It is uncertain whether the Supreme Court will agree to hear the case. Related orders under the Order No. 636 Series are the subject of numerous appeals to the United States Court of Appeals.

Through many interstate pipeline specific orders, the FERC has revised its policy regarding jurisdiction over gathering facilities and services. The FERC no longer asserts jurisdiction over these facilities and services and has stated that it is a matter to be left to the states for regulation. In 1996, the District of Columbia Court of Appeals largely upheld the FERC's policy. As a result of such court decision, the Texas Railroad Commission has begun initial inquiries regarding the scope of its regulation of gathering. The Company owns and operates extensive gathering systems in Texas. At this time, the Company cannot predict the extent to which any new Railroad Commission policy will affect its gathering activity. It is also possible that other states where the Company owns gathering facilities will become more active in the regulation of gathering.

As the owner of production area hubs and intrastate pipeline facilities in Wyoming and Texas, the Company also is 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 also can 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.

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. Several proposals that might affect the natural gas industry are pending before Congress and FERC. 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.

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 manner materially different than they would affect other oil and gas companies of similar size.

The Company's minerals operations are subject to a variety of Federal and state regulations with respect to safety, land use and reclamation. In addition, the Department of the Interior regulates the leasing of Federal lands for coal development as provided in the Mineral Lands Leasing Act of 1920.

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 but not limited to 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 currently is 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 certain specified levels. 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 \$15.6 million of Section 29 tax credits in 1996. Section 29 tax credits are not creditable against the alternative minimum tax but under certain circumstances may be carried forward and applied against regular tax liability in future years. Therefore, no assurance can be given that the Company's Section 29 tax credits will reduce its Federal income tax liability in any particular year.

In 1991 and 1992, the Company entered into transactions with a privately held company which provided funds for the Company to drill wells qualifying for Section 29 tax credits. 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 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 was entitled to receive a preferential distribution of a specified quantity of available production from this partnership, including gas that did not qualify for the tax credits as well as tax credit-qualified gas. Payout occurred in December 1996, after which point the limited partner is 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.

Texas Severance Tax Reduction

Natural gas produced from wells that have been certified as tight formations or deep wells by the Railroad Commission ("high cost wells") and that were spudded or completed during the period from May 24, 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 ending 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 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 based on actual drilling and completion costs reported by producers. More expensive wells will receive a greater amount of tax reduction. This tax rate reduction remains in effect for ten years or until the aggregate tax credits received equal 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 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 Title III 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 the Oil Pollution Act of 1990 ("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. 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 currently is subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides 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.

Employees

The Company had 1,584 employees as of December 31, 1996. The Company believes that its relationship 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 property, 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 undeveloped reserves of natural gas, natural gas liquids and crude oil of the Company as of December 31, 1996. Information set forth in the table is based on reserve estimates of the Company, prepared in accordance with the rules and regulations of the Securities and Exchange Commission.

Category	Reserves as of December 31, 1996			
	Natural Gas (Bcf)	Natural Gas Liquids (MMBbl)	Crude Oil (MMBbl)	Total (Bcf)
Proved developed	2,125.4	97.7	74.1	3,155.4
Proved undeveloped	253.0	9.8	6.5	351.4
Total proved	<u>2,378.4</u>	<u>107.5</u>	<u>80.6</u>	<u>3,507.4</u>

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 the fee mineral acreage by business unit owned by the Company as of December 31, 1996.

<u>Business Unit</u>	<u>Total Acres</u>	
	<u>Gross</u>	<u>Net</u>
	<u>(In thousands)</u>	
Austin Chalk	31	11
Rockies	3,253	3,252
Plains/Canada	5,316	4,922
Gulf Onshore/Offshore	215	73
East/South Texas	46	12
West Texas	690	238
Total fee acreage	<u>9,551</u>	<u>8,508</u>
Land Grant (included above in Rockies and Plains/Canada)	<u>7,912</u>	<u>7,722</u>

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. The Company's fee mineral acreage is primarily undeveloped.

Leasehold. The Company's leasehold acreage by business unit as of December 31, 1996 is set forth below.

<u>Business Unit</u>	<u>Acres</u>					
	<u>Developed</u>		<u>Undeveloped</u>		<u>Total</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
	<u>(In thousands)</u>					
Austin Chalk	783	561	1,995	1,459	2,778	2,020
Rockies	126	71	268	185	394	256
Plains/Canada	371	173	970	650	1,341	823
Gulf Onshore/Offshore	300	122	281	201	581	323
East/South Texas	224	125	604	321	828	446
West Texas	214	127	154	119	368	246
Total leasehold acreage	<u>2,018</u>	<u>1,179</u>	<u>4,272</u>	<u>2,935</u>	<u>6,290</u>	<u>4,114</u>

Total Leasehold and Fee Mineral. The total leasehold and fee mineral acreage by business unit as of December 31, 1996 is set forth below.

<u>Business Unit</u>	<u>Total Acres</u>	
	<u>Gross</u>	<u>Net</u>
	(In thousands)	
Austin Chalk	2,809	2,031
Rockies	3,647	3,508
Plains/Canada	6,657	5,745
Gulf Onshore/Offshore	796	396
East/South Texas	874	458
West Texas	1,058	484
Total acreage	<u>15,841</u>	<u>12,622</u>

Drilling Activity and Producing Well Summary

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

	<u>Years Ended December 31,</u>					
	<u>1994</u>		<u>1995</u>		<u>1996</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Development wells:						
Productive	615	364.5	679	505.7	575	413.4
Dry	14	8.7	18	7.7	35	25.7
Exploration wells:						
Productive	29	16.0	6	2.8	16	8.5
Dry	<u>19</u>	<u>8.1</u>	<u>22</u>	<u>10.7</u>	<u>29</u>	<u>18.2</u>
Total wells	<u>677</u>	<u>397.3</u>	<u>725</u>	<u>526.9</u>	<u>655</u>	<u>465.8</u>

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, 1996, the Company owned interests in 5,011 gross gas wells (2,703 net) and 2,786 gross oil wells (1,620 net). Gross wells include 577 wells with multiple completions. The Company operated 59% of the gross wells in which it owned an interest.

Gas Processing Assets

A listing of the Company's processing plants as of December 31, 1996 is provided below.

<u>Gas Plant by Business Unit</u>	<u>Working Interest %</u>	<u>Design Capacity (MMcfd) (1)</u>	<u>Average Gross Volumes Year Ended December 31, 1996</u>	
			<u>Natural Gas Throughput (MMcfd)</u>	<u>Natural Gas Liquids Produced (MBbbl)</u>
Austin Chalk				
Brookeland(2)	80	100	116	9.6
Rockies				
*Anschutz Ranch East(3,4)	12	650	390	17.5
Brady(5,6,7)	42	65	58	2.5
*Painter(8)	19	260	259	12.7
Pineview	49	15	2	0.2
*Whitney Canyon(6)	19	235	169	7.8

Gas Plant by Business Unit	Working Interest %	Design Capacity (MMcfd) (1)	Average Gross Volumes Year Ended December 31, 1996	
			Natural Gas Throughput (MMcfd)	Natural Gas Liquids Produced (MBbl/d)
Plains/Canada				
Bledsoe(4,5)	100	2	1	—
*Caroline(4,6)	7	300	329	29.5
Mt. Pearl(4,5)	52	11	9	0.4
Silo	100	5	3	0.4
East/South Texas				
Gulf Plains(7)	100	110	82	5.6
West Texas				
Ozona(7,9)	63	120	94	11.1
S.W. Ozona	100	90	59	7.2
Natural Gas Processing				
A&M(10)	55	50	48	4.9
Bryan(10)	55	60	56	10.3
Conroe	100	65	36	0.9
East Texas plant complex(7)	89	660	623	37.8
*Echo Springs	34	240	244	17.8
Emigrant Trail	100	60	41	1.8
Patrick Draw(7)	100	30	24	1.7
Yellow Creek(7,11)	100	80	34	0.3
Total		<u>3,208</u>	<u>2,677</u>	<u>180.0</u>

* Nonoperated

- (1) Represents the gross design capacity of the gas plant as of December 31, 1996.
- (2) Includes 50 MMcfd of design capacity which came on-line in 1996.
- (3) Design capacity includes 260 MMcfd utilized for field pressure maintenance. During 1995, pressure maintenance ceased, resulting in current processing capacity of 390 MMcfd. As a result, an additional 80 MMcfd from the Anschutz Ranch field normally processed at this plant currently is being processed at Painter complex.
- (4) 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).
- (5) Residue gas can be reinjected for pressure maintenance.
- (6) Sour gas facility (capable of processing gas containing hydrogen sulfide).
- (7) Includes fractionation facilities.
- (8) Nitrogen is reinjected for pressure maintenance.
- (9) Includes 30 MMcfd of design capacity which came on-line in May 1996.
- (10) Straddle plants which process gas gathered by the Ferguson-Burleson County Gas Gathering System.
- (11) Straddle plant (a plant located near a transmission facility which processes gas dedicated to or gathered by a third party).

Average throughput in these plants for 1996 was approximately 84% of 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 United States District Court for the District of Colorado. The Company plans to file a motion for summary judgment asking the state court to rule as a

matter of law that it owns the oil and gas and all minerals that are part of a severed mineral estate. No trial date currently is 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 Union Pacific Railroad Company 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 also should 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 also could 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.

The Company is a defendant in three contract suits now pending in Fayette County, Lee County and Harris County (transferred from Calhoun County), Texas, in which the plaintiffs allege that the Company underpaid their royalties for crude oil production in Texas. Plaintiffs seek certification as a class action in each suit. The Texas General Land Office is a plaintiff in the Fayette County suit (filed August 1995). The allegations are premised upon plaintiffs' theory that the defendants (including the Company) use "posted prices" to determine the amounts payable as royalties for crude oil production. Plaintiffs allege that the defendants "set" these posted prices, that posted prices are consistently below "market value," and that this practice has resulted in the underpayment of royalties to plaintiffs.

The Company also is one of the defendants in an antitrust suit filed in September 1996 in the Circuit Court of Escambia County, Alabama, against a number of crude oil producers alleging that the use of posted prices by defendants to pay royalties on crude oil produced in the United States arises from a combination, conspiracy or agreement designed to fix, depress and maintain such crude prices at artificially low levels. The plaintiffs have received a "conditional" certification as a class action on behalf of all working and royalty interest owners of crude oil produced in the United States since 1986 who have been paid by defendants based on posted prices. The suit was removed to Federal court, United States District Court, Southern District, Mobile, Alabama Division, on October 17, 1996. Plaintiffs' motion to remand the suit back to the Circuit Court is pending. Defendants' motion to transfer the suit to Houston also is pending.

None of these suits described above articulate a theory of recovery or a specific amount of damages. This litigation activity against the Company and others in the oil and gas industry 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 and Alabama. The Company intends to defend vigorously against the foregoing, as well as any similar suits. If such suits ultimately are resolved against the Company on a widespread basis, however, damage awards and a loss of future revenue could result which, in the aggregate, could be materially adverse to the Company.

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 its results of operations or financial condition.

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, 1996.

Executive Officers of the Registrant

<u>Name</u>	<u>Position</u>	<u>Age</u>
Jack L. Messman(1)	Chairman and Chief Executive Officer	57
George Lindahl III(2)	President and Chief Operating Officer	50
V. Richard Eales(3)	Executive Vice President	61
Anne M. Franklin(4)	Vice President — People	40
Mark S. Knouse(5)	Vice President — External Affairs and Secretary	46
Joseph A. LaSala, Jr.(6)	Vice President and General Counsel	42
Donald W. Niemiec(7)	Vice President — Marketing	50
Morris B. Smith(8)	Vice President and Chief Financial Officer	52
John B. Vering(9)	Vice President — Exploration and Production Services	47

- (1) Mr. Messman has been Chairman and Chief Executive Officer of the Company since October 1996. He was President and Chief Executive Officer of the Company from August 1995 to October 1996, and has been a Director of the Company since September 1991. He has been President, Chief Executive Officer and a Director of UPRC since May 1991.
- (2) Mr. Lindahl has held his current position with the Company since October 1996. He was Executive Vice President — Operations of the Company from August 1995 to October 1996. From 1992 to August 1995, he was Vice President — Operations for UPRC. Prior thereto, he was Vice President — Exploration for UPRC.
- (3) Mr. Eales has held his current position with the Company since June 1996. From August 1995 to June 1996, he was Executive Vice President and Chief Financial Officer of the Company. Prior thereto, he was Vice President — Corporate Development of 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. Prior thereto, she held various positions in marketing and operations at Indiana Bell Telephone Company (currently Ameritech).
- (5) Mr. Knouse has held his current position with the Company since August 1995. Prior thereto, he was Vice President — Government Relations and Public Affairs of UPRC.
- (6) 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, Inc., a former subsidiary of UPC, from May 1993 until December 1994 and, prior thereto, Vice President — External Relations of USPCI.
- (7) Mr. Niemiec has held his current position with the Company since August 1995. He has been Vice President — Marketing of UPRC since 1993 and President of UP Fuels since 1990.
- (8) Mr. Smith has held his current position with the Company since June 1996. From September 1995 until June 1996, he was Vice President and Controller of UPC. From January through August 1995, he served as Vice President — Finance of Union Pacific Railroad Company; from June 1993 through December 1994, he served as Vice President — Finance of USPCI, Inc. Prior thereto, he was Assistant Controller — Planning and Analysis of UPC.
- (9) Mr. Vering has held his current position with the Company since October 1996. Prior thereto, he was General Manager — Austin Chalk of the Company and UPRC.

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 of the Company is traded on the New York Stock Exchange under the symbol "UPR." Information with respect to the quarterly high and low sales prices per share for the Company's common stock, as reported on the New York Stock Exchange Composite Tape, as well as the dividends declared on such stock, is set forth under Selected Quarterly Data on page 62.

At February 25, 1997, there were 253,776,970 shares of outstanding common stock and approximately 58,000 shareholders of record. At that date, the closing price of the common stock on the New York Stock Exchange was \$24.63.

The Company has paid quarterly cash dividends of \$0.05 per share since its initial public offering. 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 exploratory 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.

In October 1996, the Board of Directors adopted a shareholder rights plan with a "flip-in" threshold of 15% to ensure that all shareholders of the Company receive fair value for their common stock in the event of any proposed takeover of the Company and to guard against the use of coercive tactics to gain control of the Company without offering fair value to the Company's shareholders. In February 1997, the Board of Directors adopted a stock repurchase program which authorizes the Company to purchase up to \$50 million of its common stock outstanding in any given fiscal year.

ITEM 6. Selected Financial Data

Five-Year Financial Summary

	<u>1992</u>	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>
	(Millions, except per share amounts)				
Income Statement Data:					
Operating revenues	\$1,222.5	\$1,277.1	\$1,332.9	\$1,476.7(a)	\$1,831.0
Operating income	318.7	382.9	351.3	470.1(a)	526.6
Net income	272.3	243.8(b)	390.0(c)	350.7(a)	320.8
Per share:					
Net income(d)	n/a	n/a	n/a	n/a	1.28
Dividends	n/a	n/a	n/a	0.05(e)	0.20
Financial Position Data:					
Properties — net	\$1,660.5	\$1,780.2	\$2,600.1(f)	\$2,764.3	\$2,972.4
Total assets	2,586.4	2,714.1	3,247.0	3,308.9	3,648.9
Long-term debt	48.2	45.6	37.7	101.5	670.9(g)
Shareholders' equity	1,475.2	1,596.1	1,834.9	1,312.4	1,514.3
Cash Flow Data:					
Capital and exploratory expenditures ...	\$ 594.4	\$ 560.4	\$1,389.3(f)	\$ 686.4	\$ 880.3
Cash provided by operations	776.2	567.5	821.0	829.4	990.4

(a) In November 1995, the Company recorded a \$122.5 million pre-tax (\$78.5 million after-tax) gain resulting from the Columbia Gas Transmission Company bankruptcy settlement (see Note 4 to the Consolidated Financial Statements).

(b) 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.

- (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 4 to the Consolidated Financial Statements).
- (d) Earnings per share prior to 1996 have been omitted as the Company was a wholly owned subsidiary of UPC until the 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 62.
- (e) 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 the fourth quarter of 1995.
- (f) In March 1994, the Company acquired Amax Oil & Gas, Inc., for a net purchase price of \$725 million.
- (g) During 1996, the Company repaid its \$650 million note payable to UPC (incurred at the time of the Offering) using cash from operations and proceeds from the issuance of long-term debt and commercial paper (see Note 8 to the Consolidated Financial Statements).

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. The consolidated statements of income for previous periods include certain reclassifications that were made to conform to the current presentation. Such reclassifications effect previously reported operating revenues and expenses but have no effect on previously reported operating income or net income.

RESULTS OF OPERATIONS

Year Ended December 31, 1996 Compared to Year Ended December 31, 1995

Selected Financial Data

	Years Ended December 31,	
	1995	1996
	(Millions of dollars)	
Total operating revenues	\$1,476.7	\$1,831.0
Total operating expenses	1,006.6	1,304.4
Operating income	470.1	526.6
Net income	350.7	320.8

The Company reported net income of \$320.8 million for the year ended December 31, 1996, down by \$29.9 million (9%) from \$350.7 million in 1995. Improved operating results were more than offset by the absence of a \$78.5 million after-tax gain in 1995 from the Columbia bankruptcy settlement; the absence of favorable 1995 tax adjustments; reduced Section 29 tax credits; and increased interest expense and, to a lesser extent, increased general and administrative costs incurred as a result of being a stand-alone public company following the Offering and related debt restructuring in October 1995. On a pro forma basis, after giving effect to transactions occurring at the time of the Offering as if such transactions had occurred at the beginning of 1995, 1996 net income would have been \$4.6 million (1%) above 1995 pro forma net income (see Note 2 to the Consolidated Financial Statements).

Operating income increased by \$56.5 million (12%) over 1995 levels as a result of higher product price realizations (27%) and volume growth (8%), partially offset by the absence of a \$122.5 million pre-tax gain in 1995 from the Columbia bankruptcy settlement. Demand for hydrocarbons to replenish inventory, the unresolved Iraqi situation, capacity problems in Mexico and weather-related demand provided product price support throughout 1996. Volume growth has been achieved through drilling, property purchases, plant expansion and ethane recovery. These gains were offset partially by property writedowns, cost increases associated with expanded exploration activity and increased administrative expenses associated with being a stand-alone public company.

Oil and Gas Operations

Operating Revenues

Operating Revenues — Oil and Gas Operations

	Years Ended December 31,	
	1995	1996
	(Millions of dollars)	
Producing properties	\$853.6	\$1,133.3
Plants, pipelines and marketing	339.9	503.8
Other oil and gas revenues	166.9	65.0

Producing property revenues increased by \$279.7 million (33%) to \$1,133.3 million. Production volume increases of 83.9 MMcfed (6%) added \$39.6 million in revenues while higher product prices of \$0.42/Mcfe (25%) added \$240.1 million in revenues.

	Years Ended December 31,			
	1995 (without hedging)	1996	1995 (with hedging)	1996
Average product price realizations — producing properties:				
Natural gas (per Mcf)	\$ 1.30	\$ 1.94	\$ 1.42	\$ 1.86
Natural gas liquids (per Bbl)	8.14	11.39	8.14	11.39
Crude oil (per Bbl)	16.35	20.09	16.08	18.84
Average (per Mcfe)	1.64	2.23	1.71	2.13

	Years Ended December 31,	
	1995	1996
Production volumes — producing properties:		
Natural gas (MMcfd)	915.6	980.3
Natural gas liquids (MBbld)	23.1	28.5
Crude oil (MBbld)	52.8	50.6
Total (MMcfed)	1,371.0	1,454.9

Natural gas volumes increased by 64.7 MMcfd (7%) to 980.3 MMcfd with increases from development drilling programs in the Austin Chalk (98.1 MMcfd) and West Texas (17.6 MMcfd) and a lower distribution of preferential volumes related to the Company's Section 29 Limited Partnership (22.4 MMcfd). Offsetting these increases were declines in the Gulf Onshore/Offshore (30.4 MMcfd) resulting largely from the depletion of several offshore wells, and declines in the Rockies (13.3 MMcfd) resulting from production problems. Natural gas liquids ("NGL") volumes from producing properties increased by 5.4 MBbld (23%) to 28.5 MBbld primarily due to ethane recovery in the Rockies and Plains/Canada and additional lease gas being processed in the Austin Chalk by the expanded Brookeland plant. Crude oil volumes were 2.2 MBbld (4%) lower at 50.6 MBbld as a result of production declines in Plains/Canada and the Rockies and the sale of certain non-core properties, partially offset by property acquisitions and drilling in the Austin Chalk.

Plants, pipelines and marketing revenues of \$503.8 million increased by \$163.9 million (48%) from \$339.9 million in 1995. Increased plant volumes of 36.3 MMcfd (16%) added \$21.2 million in plant revenues while higher prices of \$0.62/Mcfe (40%) added \$59.8 million in plant revenues. Pipeline revenue increases of \$63.9 million were primarily attributable to increased throughput and higher prices at the Ferguson/Burleson pipeline in the Austin Chalk (\$25.3 million) and Ozona pipeline in West Texas (\$33.5 million). Revenues from the Wahsatch pipeline in the Rockies were down with lower throughput and tariff rates. Marketing revenues increased by \$24.6 million primarily as a result of improved natural gas and NGL margins, additional marketed volumes and increased natural gas storage activity.

	Years Ended December 31,	
	1995	1996
Average product price realizations — plants:		
Natural gas (per Mcf)	\$ 1.51	\$ 2.01
Natural gas liquids (per Bbl)	9.38	13.16
Average (per Mcfe)	1.56	2.18
Sales volumes — plants:		
Natural gas (MMcfd)	23.9	26.7
Natural gas liquids (MBbld)	34.2	39.8
Total (MMcfd)	229.1	265.4

NGL volumes increased by 5.6 MBbld (16%) to 39.8 MBbld primarily due to the expansion of the Ozona (West Texas), Brookeland (Austin Chalk) and Echo Springs (Rockies) plants, greater retention percentages at the East Texas plant reflecting third parties' elections to reject liquids, as well as ethane recovery in other Rockies plants. Volume decreases occurred with a contract revision at Gulf Plains in East/South Texas, leaner gas streams and lower inlets at Giddings plants in the Austin Chalk and the disposition of certain plants in West Texas and the Rockies. Natural gas volumes were up 2.8 MMcfd (12%) to 26.7 MMcfd resulting from the Brookeland expansion and increased throughput at Gulf Plains.

In November 1995, the Company received a cash payment from Columbia Gas Transmission Company ("Columbia") as a part of Columbia's emergence from Chapter 11 bankruptcy. As a result of the payment from Columbia, after taking into account possible tax and royalty claims, the Company recorded a \$122.5 million pre-tax (\$78.5 million after-tax) gain in the fourth quarter of 1995 which is included in other oil and gas revenues in the Company's 1995 Consolidated Statement of Income. During 1996, as a result of favorable litigation activity and the determination and payment of its severance tax liability, the Company recognized \$31.3 million in other oil and gas revenues related to a reduction in its litigation and contingencies accrual pertaining to the Columbia payment.

Other oil and gas revenues declined by \$101.9 million (61%) in 1996 reflecting the absence of the 1995 Columbia settlement, lower preferential volumes distributed to an investor in the Company's Section 29 Limited Partnership (\$10.1 million) and lower net gains on property sales (\$10.3 million), partially offset by the 1996 release of a portion of the Company's litigation and contingency accrual related to the Columbia settlement and the absence of a 1995 hedging loss (\$8.1 million).

Operating Expenses — Oil and Gas Operations

	Years Ended December 31,	
	1995	1996
	(Millions of dollars)	
Production	\$210.5	\$259.5
Exploration	89.4	144.6
Plants, pipelines and marketing	189.0	290.0
Depreciation, depletion and amortization	458.6	533.9

Production expenses increased by \$49.0 million (23%) to \$259.5 million, largely attributable to higher production taxes and higher lease operating costs. The increase in production taxes of \$29.2 million (57%) reflects increased producing property revenues, the absence of a favorable 1995 Wyoming production tax settlement (\$12.0 million) and an unfavorable 1996 ad valorem tax adjustment (\$4.5 million). Lease operating costs were up \$16.1 million primarily in the Austin Chalk, East/South Texas and West Texas as a result of increased production volumes and greater workover costs. Production overhead was unfavorable by \$4.0 million. Production expenses on a per unit basis of \$0.49/Mcfe were \$0.07/Mcfe higher than 1995, principally reflecting the increase in production taxes.

Exploration expenses increased by \$55.2 million (62%) primarily due to higher dry hole and surrendered lease provisions. The dry hole provision was up \$23.3 million due to an increase in exploratory drilling in South Louisiana, offshore, and North and South Dakota. The surrendered lease provision was \$29.1 million higher than 1995 reflecting a writeoff of North and South Dakota leasehold (\$9.1 million) as well as increases in Austin Chalk and Gulf Onshore/Offshore leasing activity. Exploration overhead was unfavorable by \$5.4 million.

Plants, pipelines and marketing expenses increased by \$101.0 million (53%) with higher plant and pipeline gas purchase costs and a SFAS 121 asset impairment adjustment related to the Wahsatch pipeline (\$17.0 million). Gas purchase costs were up \$71.7 million as a result of increased throughput and higher prices at the Ozona, Peachridge and Ferguson/Burleson pipelines (\$53.0 million) and Giddings plants (\$8.8 million) and increased retention percentages at East Texas (\$4.0 million). Marketing expenses were up \$9.6 million with system development, legal and other operating costs.

Depreciation, depletion and amortization increased by \$75.3 million (16%) to \$533.9 million as a result of SFAS 121 asset impairment adjustments related to certain properties in the Rockies and Gulf Onshore/Offshore (\$17.4 million), several offshore property writeoffs (\$9.0 million), higher producing property volumes (\$25.8 million), a higher asset base in plants and pipelines (\$11.0 million) and an unfavorable unit of production rate (\$11.0 million). On a per unit basis for producing properties, depreciation, depletion and amortization, excluding the writedowns, increased by \$0.02/Mcfe to \$0.83/Mcfe.

Total Oil and Gas Operating Income

Total oil and gas operating income increased by \$63.3 million (15%) with higher producing property operating income of \$11.2 million and increased plants, pipelines and marketing operating income of \$52.1 million.

Minerals — Minerals operating income increased by \$12.9 million to \$120.0 million (12%), primarily due to higher soda ash joint venture income of \$6.7 million reflecting higher prices, an increase in ballast income, higher coal royalty income associated with more tons mined from the Company's leases and favorable operating expense.

General and Administrative Expenses — General and administrative expenses increased by \$18.1 million (36%) to \$68.4 million principally reflecting increased costs associated with being a stand-alone public

company and costs of completing information and accounting system conversions. On a pro forma per unit basis, general and administrative expenses increased by \$0.01/Mcfe (10%) to \$0.11/Mcfe. See Note 2 to the Consolidated Financial Statements for pro forma income information.

Interest and Other Income — Interest expense increased by \$31.5 million to \$50.6 million, while other income/expense was unfavorable by \$10.4 million. These changes principally reflect the annual effects of debt restructuring which occurred at the time of the Offering in 1995.

Income Taxes — Income taxes of \$151.8 million increased by \$44.5 million from 1995 levels due to higher income before taxes, a \$22.3 million decrease in Section 29 tax credits, a \$3.0 million unfavorable state tax adjustment relating to prior years' Federal income tax audits and the absence of favorable 1995 tax adjustments totaling \$22.2 million. Excluding such adjustments, the effective tax rate for 1996 would have been 31.5% (including Section 29 tax credits of \$15.6 million) compared with 28.3% in 1995 (including Section 29 tax credits of \$37.9 million).

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

Selected Financial Data

	Years Ended December 31,	
	1994	1995
	(Millions of dollars)	
Total operating revenues	\$1,332.9	\$1,476.7
Total operating expenses	981.6	1,006.6
Operating income	351.3	470.1
Net income	390.0	350.7

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 the absence of a \$100 million after-tax gain on the sale of oil and gas properties in Wilmington, California, 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 would have been \$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 becoming a stand-alone public company.

Total operating revenues increased by \$143.8 million (11%) to \$1,476.7 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 \$90.8 million were offset partially by decreases in revenues from producing properties (\$32.4 million), other oil and gas revenues (\$32.1 million) and minerals revenues (\$5 million). Operating expenses increased by \$25.0 million to \$1,006.6 million reflecting higher plants, pipelines and marketing costs (\$38.2 million), depreciation, depletion and amortization expenses (\$32.2 million) and general and administrative costs (\$10.3 million), partially offset by lower production costs (\$41.8 million) and exploration expenses (\$18.2 million). Operating income increased by \$118.8 million (34%) to \$470.1 million. Excluding the Columbia settlement, 1995 operating income would have been \$3.7 million lower than 1994.

Oil and Gas Operations
Operating Revenues

Operating Revenues — Oil and Gas Operations

	Years Ended December 31,	
	1994	1995
	(Millions of dollars)	
Producing properties	\$886.0	\$853.6
Plants, pipelines and marketing	249.1	339.9
Other oil and gas revenues	76.5	166.9

Producing property revenues decreased by \$32.4 million (4%) to \$853.6 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.

	Years Ended December 31,			
	1994 (without hedging)	1995	1994 (with hedging)	1995
Average product price realizations — producing properties:				
Natural gas (per Mcf)	\$ 1.69	\$ 1.30	\$ 1.82	\$ 1.42
Natural gas liquids (per Bbl)	7.86	8.14	7.86	8.14
Crude oil (per Bbl)	14.34	16.35	14.34	16.08
Average (per Mcfe)	1.87	1.64	1.95	1.71

	Years Ended December 31,	
	1994	1995
Production volumes — producing properties:		
Natural gas (MMcfd)	754.8	915.6
Natural gas liquids (MBbld)	18.8	23.1
Crude oil (MBbld)	63.1	52.8
Total (MMcfd)	1,246.2	1,371.0

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. NGL 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).

Plants, pipelines and marketing revenues increased by \$90.8 million (36%) to \$339.9 million. Increased plant volumes of 24.4 MMcfd (12%) added \$15.3 million in plant revenues, but lower prices reduced revenues by \$10 million. Plant revenues also benefitted from a \$23.7 million improvement in other revenues, stemming principally from higher processing and compression fees. 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 14 to the Consolidated Financial Statements). Pipeline revenues increased by \$44.5 million primarily as a result of the start-up and expansion of pipelines in the Austin Chalk, West Texas and the Rockies.

	Years Ended December 31,	
	1994	1995
Average product price realizations — plants:		
Natural gas (per Mcf)	\$ 1.81	\$ 1.51
Natural gas liquids (per Bbl)	9.97	9.38
Average (per Mcfe)	1.67	1.56
Sales volumes — plants:		
Natural gas (MMcfd)	17.5	23.9
Natural gas liquids (MBbld)	31.2	34.2
Total (MMcfd)	204.7	229.1

NGL 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.

Other oil and gas revenues increased by \$90.4 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, 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 the absence of a favorable 1994 market sharing settlement (\$4.9 million).

Operating Expenses

Operating Expenses — Oil and Gas Operations

	Years Ended December 31,	
	1994	1995
	(Millions of dollars)	
Production	\$252.3	\$210.5
Exploration	107.6	89.4
Plants, pipelines and marketing	150.8	189.0
Depreciation, depletion and amortization	426.4	458.6

Production expenses decreased by \$41.8 million (17%) to \$210.5 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 \$38.2 million (25%) to \$189.0 million principally 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 nonrecurring costs associated with the Offering, increased costs associated with being a stand-alone public 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 and favorable 1995 tax adjustments totaling \$22.2 million. The effective tax rate for 1995, excluding such favorable tax adjustments, would have been 28.3% (including \$37.9 million of Section 29 tax credits) compared with 25.1% for 1994 (including \$52.2 million of Section 29 tax credits).

LIQUIDITY AND CAPITAL RESOURCES

Cash provided by operations for 1996 was \$990.4 million, up by \$161 million from 1995. The increase principally relates to increases in producing property revenues net of production costs, improvements in cash margins from plants, pipelines and marketing, higher distributed equity income primarily from Black Butte Coal Company ("Black Butte") and favorable changes in working capital. These increases were partially offset by the absence of the 1995 Columbia bankruptcy settlement, increased payments for interest and income taxes and, to a lesser extent, increased general and administrative costs associated with being a stand-alone public company.

The Company expects to increase its oil and gas sales volumes in 1997 while growing its reserves. Sales volume growth is anticipated primarily in the Gulf Onshore/Offshore, Austin Chalk and West Texas. The Company expects to remain one of the most active drillers in the United States in 1997 based on the number of active drilling rigs, and will continue to search for properties and reserves which will supplement its drill site inventory. In addition, third party pipeline expansions which will increase gas transportation capacity from Wyoming by approximately 395 MMcfd should be in service in 1997. This new capacity should enable Rockies gas to be shipped to higher-price markets in the future.

The Company owns a nonoperating 50% interest in Black Butte, a partnership which operates a surface coal mine complex in southwestern Wyoming. During 1996, Black Butte's sales to its largest customer under an amended coal supply contract accounted for \$54.8 million, or 10%, of the Company's consolidated 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 receives currently under the amended contract with incremental coal sales.

Capital spending for 1996 of \$880.3 million was up by \$193.9 million (28%) compared to \$686.4 million for 1995. The Company's ability to maintain and improve its operating income and cash flow is dependent, among other things, upon continued capital spending. A summary of capital expenditures for 1996 compared to 1995 is as follows:

	Years Ended December 31,	
	1995	1996
	(Millions of dollars)	
Producing properties:		
Production	\$382.2	\$429.5
Exploration	95.2	237.5
Property acquisitions	100.5	85.7
Total producing properties	577.9	752.7
Plants, pipelines and marketing	106.5	118.1
Minerals and other	2.0	9.5
Total	<u>\$686.4</u>	<u>\$880.3</u>

Producing property capital spending was up by \$174.8 million (30%) as a result of higher lease acquisition costs of \$114.8 million primarily in the Austin Chalk (\$63.1 million), East/South Texas (\$33.3 million) and North and South Dakota (\$13.7 million), and increased exploratory and development drilling (\$77.2 million). Drilling accounted for \$468.2 million (53%) of capital expenditures, with \$207.8 million (44%) in the Austin Chalk. Property acquisitions totaling \$85.7 million were completed in 1996 compared to \$100.5 million in 1995.

The Company expects to increase its level of capital spending in 1997 to over \$1.0 billion. Spending is expected to focus on exploration and development activities in the Austin Chalk business unit, drilling in the Gulf Onshore/Offshore and exploration and development in East/South Texas as well as gas value chain assets. The Company plans to complete construction of the Masters Creek gas plant to facilitate development of the Louisiana Extension of the Austin Chalk, expand the Patrick Draw plant in the Rockies from 30 MMcfd of capacity to 120 MMcfd and add a fifth gas processing plant at its East Texas plant complex. The Company's capital spending programs may be adjusted as business and operating conditions change.

In addition, as a result of continued increase in the worldwide demand for soda ash, the Company, along with its partner Oriental Chemical Industries, Inc., plans to expand the OCI Wyoming LP soda ash facility by 950,000 tons per year, from the plant's current nameplate capacity of 2.3 million tons per year, by 1999. The Company's share of expansion costs is expected to be funded primarily with partnership debt.

The Company restructured its debt portfolio in 1996, refinancing its indebtedness to UPC with a combination of long-term fixed-rate notes and debentures and short-term commercial paper. As of December 31, 1995 and 1996, the total capitalization of the Company was as follows:

	As of December 31,	
	1995	1996
	(Millions of dollars)	
Short-term debt		
Note payable to Union Pacific Corporation	\$ 650.0	\$ —
Advances (to) Union Pacific Corporation	(82.2)	—
Total short-term debt	<u>567.8</u>	<u>—</u>
Long-term debt		
Bank credit agreement	68.0	—
Commercial paper, net	—	99.6
7% Notes due 2006	—	200.0
7.5% Debentures due 2026	—	200.0
7.5% Debentures due 2096	—	150.0
Tax exempt revenue bonds	33.5	24.0
Discount on notes and debentures	—	(2.7)
Total long-term debt	<u>101.5</u>	<u>670.9</u>
Shareholders' equity	<u>1,312.4</u>	<u>1,514.3</u>
Total capitalization	<u>\$1,981.7</u>	<u>\$2,185.2</u>
Debt to total capitalization	<u>33.8%</u>	<u>30.7%</u>

In October 1996, the Company issued \$200 million of 7% Notes due 2006 and \$200 million of 7.5% Debentures due 2026. In November 1996, the Company issued \$150 million of 7.5% Debentures due 2096. Proceeds were used, together with proceeds from the issuance of commercial paper, to repay the Company's note payable to UPC and for general corporate purposes. None of the Company's Notes and Debentures are redeemable prior to maturity and none are subject to any sinking fund requirements. In addition, the Company has filed a Form S-3 Registration Statement with the Securities and Exchange Commission which would permit the Company to offer up to \$900 million in debt and equity securities upon the effectiveness of such Registration Statement.

The Company has a \$600 million revolving credit agreement that expires in August 2001. Borrowings under the agreement, at the Company's election, 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 Company's senior debt rating. The Company is required to pay facility fees on the aggregate amount of the commitment ranging from .06% to .15% also depending on the Company's senior debt rating. The agreement contains covenants which limit the ratio of debt to the sum of debt and shareholders' equity of the Company to 65% and which require the combined EBITDAX (the sum of operating income; depreciation, depletion and amortization; and exploration expenses) of the Company's Principal Operating Subsidiaries (as defined in the agreement) to be at least 80% of the Company's consolidated EBITDAX. The agreement also imposes certain restrictions on the Company regarding the creation of liens, incurrence of indebtedness, transactions with affiliates, sales of the stock of UPRC and certain mergers, consolidations and asset sales. As of December 31, 1996, there were no borrowings outstanding under this credit facility although borrowing capacity is reduced by outstanding commercial paper. The Company had the capacity to borrow \$500 million under such credit facility as of December 31, 1996.

Excluding commercial paper, the Company has no debt maturing in the next five years. Outstanding commercial paper has been classified as long-term debt reflecting the Company's intent to maintain these short-term borrowings on a long-term basis either through the continued issuance of commercial paper and/or

through new long-term financings, or by using its currently available long-term credit facility if alternative financing is not available.

The Company paid cash dividends of \$49.8 million in 1996, which represents a \$0.05 per share quarterly cash dividend 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 exploratory 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 1996 refinancing of its debt, cash from operations and additional available financing will enable it to fund its capital expenditures, dividends and working capital requirements for the foreseeable future.

OTHER MATTERS

Price Risk Management

The Company is principally a natural gas company, as natural gas and natural gas liquids made up 82% of the Company's production in 1996. 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, 1994 to December 31, 1996, have ranged from \$1.39/Mcf to \$3.90/Mcf. Cash prices received by the Company in its specific producing areas have exhibited similar volatility during this same period.

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, 1996, 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 \$23 million, \$15 million and \$11 million, respectively.

The Company uses hydrocarbon-based derivative financial instruments from time to time to reduce risks associated with hydrocarbon price volatility. While the use of these hedging arrangements may limit the downside risk of adverse price movements, it may also limit future gains from favorable movements. Hedging generally is accomplished pursuant to exchange-traded futures contracts or master swap agreements based on standard forms. Hedging gains and losses are deferred and recognized at delivery of the commodity. The Company does not hold or issue derivative financial instruments for trading purposes and does not hedge any significant amount of production beyond a 24-month time frame. The Company also enters into long-term fixed price sales agreements for physical deliveries of natural gas. Such long-term commitments are not reflected in the Company's Consolidated Statements of Financial Position.

The Company had certain financial and fixed price sales contracts in place at December 31, 1996 (see Note 5 to the Consolidated Financial Statements). The total unrecognized mark-to-market present value gain related to such contracts at December 31, 1996 was \$30.5 million, consisting of a \$26.4 million net gain on contracts for physical delivery and a \$4.1 million net gain on financial contracts. 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.

In connection with its futures contract hedging activity, the Company is required to deposit monies with NYMEX, representing cash requirements for contract margins and deposits for 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, 1996, the Company had margin requirements totaling \$44.7 million, which had been met with cash deposits of \$30.9 million and unrealized gains on open contracts of \$13.8 million.

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 1994 and 1995, revenues were \$36 million and \$27 million higher, respectively, while during 1996, revenues were \$52 million lower as a result of hedging activities.

Environmental Costs

The Company generates and disposes of hazardous and nonhazardous 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, 1996, long and short-term liabilities totaling \$94.3 million had been accrued for future costs of all sites where the Company's obligation is probable and where such costs reasonably can be 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 \$44.2 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 accrued adequately 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 \$6.2 million in 1995 and \$11.4 million in 1996. In 1997, the Company anticipates spending a total of \$20 million for remediation, control and prevention, including \$10 million relating to the Wilmington properties. The majority of the December 31, 1996 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.

FORWARD LOOKING INFORMATION

Certain information included in this report contains, and other materials filed or to be filed by the Company with the Securities and Exchange Commission (as well as information included in oral statements or other written statements made or to be made by the Company) contain, or will contain or include, forward looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. Such forward looking statements may be or may concern, among other things, capital expenditures, drilling activity, acquisitions and dispositions, development activities, cost savings efforts, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, hedging activities and the results thereof, liquidity, regulatory matters, competition and the Company's ability to realize significant improvements with the change to a more adaptive corporate culture. Such forward looking statements generally are accompanied by words such as "estimate," "expect," "predict," "anticipate," "goal," "should," "assume," "believe" or other words that convey the uncertainty of future events or outcomes.

Such forward looking information is based upon management's current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward looking statements made by or on behalf of the Company. The risks and uncertainties include generally the volatility of oil, gas and hydrocarbon-based financial derivative prices; basis risk and counterparty credit risk in executing hydrocarbon price risk management activities; economic, political, judicial and regulatory developments; competition in the oil and gas industry as well as competition from other sources of energy; the economics of producing certain reserves; demand and supply of oil and gas; the ability to find or acquire and develop reserves of natural gas and crude oil; and the actions of customers and competitors. Additionally, unpredictable or unknown factors not discussed herein could have material adverse effects on actual results related to matters which are the subject of forward looking information. The Company does not intend to update these cautionary statements.

With respect to expected capital expenditures and drilling activity, additional factors such as the extent of the Company's success in acquiring oil and gas properties and in identifying prospects for drilling, the availability of acquisition opportunities which meet the Company's objectives as well as competition for such opportunities, exploration and operating risks, the success of management's cost reduction efforts and the availability of technology may affect the amount and timing of such capital expenditures and drilling activity. With respect to expected growth in production and sales volumes and estimated reserve quantities, factors such as the extent of the Company's success in finding, developing and producing reserves, the timing of capital spending and acquisition programs, uncertainties inherent in estimating reserve quantities and the availability of technology may affect such production volumes and reserve estimates. With respect to liquidity, factors such as the state of domestic capital markets, credit availability from banks or other lenders and the Company's results of operations may affect management's plans or ability to incur additional indebtedness. With respect to cash flow, factors such as changes in oil and gas prices, the Company's success in acquiring producing properties, environmental matters and other contingencies, hedging activities, the Company's credit rating and debt levels, and the state of domestic capital markets may affect the Company's ability to generate expected cash flows. With respect to contingencies, factors such as changes in environmental and other governmental regulation, and uncertainties with respect to legal matters may affect the Company's expectations regarding the potential impact of contingencies on the operating results or financial condition of the Company. Certain factors, such as changes in oil and gas prices and underlying demand and the extent of the Company's success in exploiting its current reserves and acquiring or finding additional reserves may have pervasive effects on many aspects of the Company's business in addition to those outlined above.

ITEM 8. *Financial Statements and Supplementary Data*

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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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 six 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

Chairman and Chief Executive Officer

MORRIS B. SMITH

Vice President and Chief Financial Officer

JOHN E. JACKSON

Controller and Chief Accounting Officer

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, 1995 and 1996, 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, 1996. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 1995 and 1996, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1996 in conformity with generally accepted accounting principles.

DELOITTE & TOUCHE LLP

Fort Worth, Texas
January 29, 1997

UNION PACIFIC RESOURCES GROUP INC.
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 1994, 1995 and 1996

	<u>1994</u>	<u>1995</u>	<u>1996</u>
	(Millions, except per share amounts)		
Operating revenues: (Note 5)			
Oil and gas operations:			
Producing properties	\$ 886.0	\$ 853.6	\$1,133.3
Plants, pipelines and marketing	249.1	339.9	503.8
Other oil and gas revenues (Note 4)	76.5	166.9	65.0
Total oil and gas operations	1,211.6	1,360.4	1,702.1
Minerals (Note 12)	121.3	116.3	128.9
Total operating revenues	<u>1,332.9</u>	<u>1,476.7</u>	<u>1,831.0</u>
Operating expenses:			
Production	252.3	210.5	259.5
Exploration	107.6	89.4	144.6
Plants, pipelines and marketing	150.8	189.0	290.0
Minerals (Note 12)	4.5	8.8	8.0
Depreciation, depletion and amortization	426.4	458.6	533.9
General and administrative	40.0	50.3	68.4
Total operating expenses	<u>981.6</u>	<u>1,006.6</u>	<u>1,304.4</u>
Operating income	351.3	470.1	526.6
Other income — net (Notes 3 and 4)	174.0	7.0	(3.4)
Interest expense — net (Notes 3 and 8)	(4.6)	(19.1)	(50.6)
Income before income taxes	520.7	458.0	472.6
Income taxes (Note 7)	(130.7)	(107.3)	(151.8)
Net income (Note 2)	<u>\$ 390.0</u>	<u>\$ 350.7</u>	<u>\$ 320.8</u>
Earnings per share (see Significant Accounting Policies — Earnings Per Share)			\$ 1.28
Weighted average shares outstanding			250.1
Cash dividends per share			\$ 0.20

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, 1995 and 1996

ASSETS

	1995	1996
	(Millions of dollars)	
Current assets:		
Cash and temporary investments	\$ 27.6	\$ 118.9
Accounts receivable (net of allowance for doubtful accounts of \$4.9 million in 1995 and \$4.5 million in 1996)	240.1	351.6
Inventories	67.5	29.4
Other current assets	84.8	86.4
Total current assets	<u>420.0</u>	<u>586.3</u>
Properties: (Note 6)		
Cost	5,450.4	6,190.0
Accumulated depreciation, depletion and amortization	<u>(2,686.1)</u>	<u>(3,217.6)</u>
Total properties	2,764.3	2,972.4
Intangible and other assets (Note 12)	124.6	90.2
Total assets	<u>\$ 3,308.9</u>	<u>\$ 3,648.9</u>

LIABILITIES AND SHAREHOLDERS' EQUITY

Current liabilities:		
Accounts payable	\$ 347.0	\$ 407.4
Accrued taxes payable	87.4	134.1
Note payable to and advances from Union Pacific Corporation — net (Notes 3 and 8)	567.8	—
Other current liabilities	<u>64.3</u>	<u>71.3</u>
Total current liabilities	1,066.5	612.8
Long-term debt (Note 8)	101.5	670.9
Deferred income taxes (Note 7)	438.5	434.7
Retiree benefits obligations (Note 10)	73.1	151.4
Deferred revenues	26.4	4.9
Other long-term liabilities (Notes 12, 13, 14 and 15)	290.5	259.9
Shareholders' equity (see page 36)	<u>1,312.4</u>	<u>1,514.3</u>
Total liabilities and shareholders' equity	<u>\$ 3,308.9</u>	<u>\$ 3,648.9</u>

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, 1994, 1995 and 1996

	1994	1995	1996
	(Millions of dollars)		
Cash provided by operations:			
Net income	\$ 390.0	\$ 350.7	\$ 320.8
Non-cash charges to income:			
Depreciation, depletion and amortization	426.4	458.6	533.9
Deferred income taxes (Note 7)	174.4	(18.3)	37.0
Other non-cash charges (credits) — net	(139.2)	(65.8)	8.0
Exploratory expenditures	45.8	36.0	51.6
Changes in current assets and liabilities	(76.4)	68.2	39.1
Cash provided by operations	<u>821.0</u>	<u>829.4</u>	<u>990.4</u>
Investing activities:			
Capital and exploratory expenditures (Notes 4 and 16)	(1,389.3)	(686.4)	(880.3)
Proceeds from sales of assets (Note 4)	331.0	111.1	30.2
Other investing activities — net	0.5	(7.5)	(2.8)
Cash (used) by investing activities	<u>(1,057.8)</u>	<u>(582.8)</u>	<u>(852.9)</u>
Financing activities:			
Dividends paid (Note 2)	(148.0)	(1,713.9)	(49.8)
Debt financings (Note 8)	21.2	68.0	547.3
Debt repaid	(18.3)	(47.4)	(77.5)
Proceeds from initial public offering (Note 2)	—	843.9	—
Advances from (to) Union Pacific Corporation (Notes 2 and 3) ..	399.6	627.1	(567.8)
Other financings — net (Note 8)	(22.3)	(3.4)	101.6
Cash provided (used) by financing activities	<u>232.2</u>	<u>(225.7)</u>	<u>(46.2)</u>
Net change in cash and temporary investments	(4.6)	20.9	91.3
Balance at beginning of year	11.3	6.7	27.6
Balance at end of year	<u>\$ 6.7</u>	<u>\$ 27.6</u>	<u>\$ 118.9</u>
Changes in current assets and liabilities:			
Accounts receivable	\$ 33.8	\$ 4.0	\$(111.5)
Inventories	(34.2)	(9.2)	38.1
Note receivable	(62.7)	62.7	(0.6)
Federal income tax receivable	(44.1)	44.1	—
Other current assets	(25.2)	(27.1)	(1.0)
Accounts payable	18.0	10.0	60.4
Accrued taxes payable	(5.6)	22.4	46.7
Short-term debt	10.9	(43.2)	—
Other current liabilities	32.7	4.5	7.0
Total	<u>\$ (76.4)</u>	<u>\$ 68.2</u>	<u>\$ 39.1</u>
Supplemental cash flow disclosure:			
Interest paid	\$ 4.6	\$ 20.0	\$ 43.4
Income taxes paid	14.9	29.7	79.0

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, 1994, 1995 and 1996

	1994	1995	1996
	(Millions of dollars)		
Common stock, \$1.00 par value; authorized 5,000,000 shares; 4,485,000 shares issued and outstanding at December 31, 1994			
Balance at beginning of year.....	\$ 4.5	\$ 4.5	\$ —
Asset restructuring (Note 2)	—	(4.5)	—
Balance at end of year.....	<u>4.5</u>	<u>—</u>	<u>—</u>
Common stock, no par value; authorized 400,000,000 shares; 249,248,603 shares issued and outstanding at December 31, 1995 and 250,058,019 shares issued at December 31, 1996 (Note 2)			
Balance at beginning and end of year	—	—	—
Paid-in surplus:			
Balance at beginning of year.....	421.2	421.2	860.2
Asset restructuring (Note 2)	—	(421.2)	—
Initial public offering (Note 2)	—	843.9	—
Conversion, award and appreciation of retention shares (Note 11) ..	—	9.9	15.9
Other	—	6.4	(3.2)
Balance at end of year.....	<u>421.2</u>	<u>860.2</u>	<u>872.9</u>
Retained earnings:			
Balance at beginning of year.....	1,180.6	1,422.6	472.9
Net income	390.0	350.7	320.8
Total	1,570.6	1,773.3	793.7
Dividends declared on common stock (Note 2)	(148.0)	(1,726.3)	(49.8)
Pension asset adjustment (Note 10)	—	—	(69.2)
Asset restructuring (Note 2)	—	425.9	—
Balance at end of year.....	<u>1,422.6</u>	<u>472.9</u>	<u>674.7</u>
Unearned compensation:			
Balance at beginning of year.....	—	—	(9.2)
Conversion, award, appreciation and amortization of retention shares — net (Note 11)	—	(9.2)	(8.2)
Balance at end of year.....	<u>—</u>	<u>(9.2)</u>	<u>(17.4)</u>
Deferred foreign exchange adjustment:			
Balance at beginning of year.....	(10.2)	(13.4)	(11.2)
Foreign currency translation adjustment	(3.2)	1.9	(0.2)
Balance at end of year.....	<u>(13.4)</u>	<u>(11.5)</u>	<u>(11.4)</u>
Treasury stock, at cost; 154,417 shares at December 31, 1996			
Balance at end of year.....	—	—	(0.2)
Total shareholders' equity	<u>\$1,834.9</u>	<u>\$1,312.4</u>	<u>\$1,511.7</u>

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

UNION PACIFIC RESOURCES GROUP INC.
BUSINESS SEGMENT INFORMATION
For the Years Ended December 31, 1994, 1995 and 1996

	1994	1995	1996
	(Millions of dollars)		
Operating revenues:			
Oil and gas	\$1,211.6	\$1,360.4	\$1,702.1
Minerals	121.3	116.3	128.9
Total	<u>\$1,332.9</u>	<u>\$1,476.7</u>	<u>\$1,831.0</u>
Depreciation, depletion and amortization:			
Oil and gas	\$ 423.3	\$ 456.0	\$ 529.2
Minerals	0.5	0.4	0.9
Corporate	2.6	2.2	3.8
Total	<u>\$ 426.4</u>	<u>\$ 458.6</u>	<u>\$ 533.9</u>
Other operating expenses:			
Oil and gas	\$ 510.7	\$ 488.9	\$ 694.1
Minerals	4.5	8.8	8.0
Corporate	40.0	50.3	68.4
Total	<u>\$ 555.2</u>	<u>\$ 548.0</u>	<u>\$ 770.5</u>
Operating income:			
Oil and gas	\$ 277.6	\$ 415.5	\$ 478.8
Minerals	116.3	107.1	120.0
Corporate	(42.6)	(52.5)	(72.2)
Total	<u>\$ 351.3</u>	<u>\$ 470.1</u>	<u>\$ 526.6</u>
Capital and exploratory expenditures:			
Oil and gas	\$1,387.3	\$ 684.2	\$ 870.8
Minerals	0.2	0.2	0.8
Corporate	1.8	2.0	8.7
Total	<u>\$1,389.3</u>	<u>\$ 686.4</u>	<u>\$ 880.3</u>
Assets:			
Oil and gas	\$2,815.3	\$2,985.7	\$3,331.0
Minerals	26.8	29.2	23.5
Corporate(a)	404.9	294.0	294.4
Total	<u>\$3,247.0</u>	<u>\$3,308.9</u>	<u>\$3,648.9</u>

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

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

UNION PACIFIC RESOURCES GROUP INC.
NOTES TO 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"). These operations are hereinafter referred to collectively as the "Company". 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. The consolidated statements of income for previous periods include certain reclassifications that were made to conform to the current presentation. Such reclassifications have no effect on previously reported operating income or net income.

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

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

Oil and Gas Properties. Oil and gas properties are accounted for using the successful efforts method. Under this method, drilling costs of unsuccessful exploration 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 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 are accrued (based on internal engineering estimates) 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. Costs of future site restoration, dismantlement and abandonment for offshore wells and production platforms also are accrued based on internal engineering estimates using the unit of production method with a charge to depreciation, depletion and amortization expense. The balance of the offshore abandonment accrual at December 31, 1995 and 1996 was \$13.1 million and \$6.2 million, respectively, and is classified in other long-term liabilities.

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; all other unproved properties are assessed annually on an aggregate basis. In addition, a quarterly impairment analysis of aggregate properties is performed by the Company using undiscounted future net cash flows determined based upon current prices and costs.

Costs of retired, sold or abandoned properties that constitute part of an amortization base are charged to, credited, net of proceeds, to accumulated depreciation, depletion and amortization unless such nonrecognition would significantly affect the unit of production rate. Gains or losses from the disposition of other properties are recognized currently. Gains and losses from the sale of operating assets that constitute an entire production center and significant nonoperating assets are recorded in other income. Gains and losses from all other dispositions of operating assets are recognized in other oil and gas revenues.

Goodwill. Intangible and other assets include goodwill of \$68.6 million arising from business combinations prior to 1971. Such goodwill is not being amortized because it is considered to have continuing value over an indefinite period. Goodwill is reviewed periodically to determine whether any potential impairment exists.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Revenue Recognition. 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.

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

Hedging Transactions. The Company uses hydrocarbon-based derivative financial instruments from time to time to reduce risks associated with hydrocarbon price volatility. Gains and losses from hedging 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%, affected derivative positions are marked to market, with the resulting gain or loss recognized immediately in income (see Note 5).

Income Taxes. 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.

Until its spinoff from Union Pacific Corporation ("UPC") in October 1996 (see Note 2), the Company was included in UPC's consolidated income tax return. The consolidated income tax liability of UPC through such date has been allocated among its 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.

Stock-Based Compensation. Compensation expense is recorded with respect to stock option grants and retention stock awards to employees using the intrinsic value method. 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 shares, if any. The expense is recognized over the vesting period of the grant or award.

Earnings Per Share. Earnings per share for 1996 is based upon 250,077,716 weighted average common shares outstanding during the period, including shares issuable upon exercise of outstanding stock options determined using the treasury stock method.

Earnings per share for the years ended December 31, 1994 and 1995 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 1995 earnings per share (see Note 2) and fourth quarter 1995 earnings per share (see page 62) are based upon 249.7 million average common shares outstanding during the period from completion of the Offering (hereinafter defined) until December 31, 1995.

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 and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties which may cause actual results to differ materially from the Company's estimates. Significant estimates underlying these financial statements include the estimated quantities of proved oil and gas reserves and the related present value of estimated future net cash flows therefrom (see Supplementary Information beginning on page 57).

Recently Issued Accounting Standards. The Accounting Standards Executive Committee of the American Institute of Certified Public Accountants has adopted Statement of Position 96-1, "Environmental Remediation Liabilities," which provides guidance on the recognition, measurement, display and disclosure of environmental remediation liabilities. The statement is effective for the Company's 1997 fiscal year.

UNION PACIFIC RESOURCES GROUP INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Management has evaluated such statement and believes that it will not have a material effect on the financial condition or results of operations of the Company.

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 principally in the United States. The Company 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. The Company has a diverse customer base for its hydrocarbon products. In addition, the Company engages in the hard mineral business through nonoperated joint venture and royalty interests in several coal and trona (natural soda ash) mines.

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. Hydrocarbon prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of factors beyond the control of the Company. These factors include worldwide political instability, the foreign supply of oil and natural gas, the price of foreign imports, the level of consumer demand and the price and availability of alternative fuels. Historically, the Company has been able to manage a portion of the operating risk relating to hydrocarbon price volatility through hedging activities (see Note 5).

2. Spinoff from Union Pacific Corporation

In October 1995, the Company sold 42.5 million shares of its common stock in an initial public offering (the "Offering") at an offering price of \$21 per share. Prior to consummation of the Offering, the Company was wholly owned by UPC. Following the Offering and until October 15, 1996, UPC owned approximately 83% of the Company's outstanding common stock. Concurrent with the Offering, UPC announced its intention to distribute its remaining ownership interest in the Company to its shareholders as a dividend by means of a tax-free distribution (the "Distribution"). On October 15, 1996, the Distribution was consummated.

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) \$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. 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 and thereafter.

As a result of the Offering and related transactions, historical results of operations are not directly comparable to results for the year ended December 31, 1996. The following pro forma information reflects

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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.

	Year Ended December 31, 1995		
	Historical	Pro Forma Adjustments	Pro Forma
	(Millions, except per share amounts)		
Operating income	\$ 470.1	\$ (6.9) (a)	\$ 463.2
Other income — net	7.0	(3.8) (b)	3.2
Interest expense	(19.1)	(44.6) (c)	(63.7)
Income before income taxes	458.0	(55.3)	402.7
Income taxes	(107.3)	20.8 (d)	(86.5)
Net income	<u>\$ 350.7</u>	<u>\$ (34.5)</u>	<u>\$ 316.2</u>
Earnings per share			<u>\$ 1.27</u>
Weighted average shares outstanding(e)			<u>249.7</u>

- (a) Adjustment to reflect management's estimate of additional administrative and third party costs that the Company is incurring as a result of becoming a stand-alone public company. 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 annual stock compensation costs related to employee retention shares (see Note 11) and (4) fees 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 \$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.
- (d) Adjustment to reflect decreased Federal and state income tax expense resulting from increased expenses in entries (a) through (c) above, calculated at an assumed income tax rate of 37.5%.
- (e) See "Significant Accounting Policies — Earnings Per Share."

In addition, reported 1996 results include approximately \$2.0 million of pension expense representing one quarter of approximately \$8.0 million additional annual pension expense associated with the October 1996 allocation of pension assets between the Company and UPC (see Note 10).

3. Related Party Transactions

At December 31, 1995, the Company had a \$567.8 million net payable to UPC at 8.5%, reflecting the \$650 million note payable incurred in connection with the Asset Restructuring (see Note 2), partially offset by \$82.2 million in cash advances to UPC. Such intercompany debt was repaid in part during 1996 using cash from operations with the remainder repaid immediately following the Distribution using proceeds from the issuance of long-term debt and commercial paper (see Note 8). Intercompany interest income related to amounts receivable from UPC was \$15.8 million and \$9.6 million in 1994 and 1995, respectively, which is included in other income in the Company's Consolidated Statements of Income. Intercompany interest expense related to amounts payable to UPC after the Offering was \$14.5 million in 1995 and \$32.6 million in 1996 which is included in interest expense in the Company's Consolidated Statements of Income.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Services historically performed by UPC on behalf of the Company included 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 entered into a number of agreements for the purpose of defining the ongoing relationship between them. Costs incurred by the Company in 1995 and 1996 related to such agreements were \$0.9 million and \$2.7 million, respectively, principally reflecting the cost of administrative services and certain financial guarantees. In connection with the Distribution, most of these agreements with UPC have been terminated and the terms of any ongoing agreements between the Company and UPC have been amended as a result of arm's length negotiations. The financial impact of any ongoing agreements is not expected to be significant.

4. Significant Items

Columbia Gas Transmission Company. In November 1995, the Company received a cash payment from Columbia Gas Transmission Company ("Columbia") as a part of Columbia's emergence from Chapter 11 bankruptcy. 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 payment from 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 in the Company's 1995 Consolidated Statement of Income. During 1996, the Company reached settlements or took default judgment with respect to a number of royalty owners named in the suit. The Company also made a determination and payment of its severance tax liability. As a result, in the fourth quarter of 1996, the Company recognized \$31.3 million in other oil and gas revenues related to a reduction in its litigation and contingencies accrual pertaining to the Columbia payment (see Note 15).

Amax Oil & Gas, Inc. In March 1994, the Company acquired Amax Oil & Gas, Inc. ("Amax") for \$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 million in cash and two interest-bearing notes of \$62.5 million each which subsequently have been collected. The Wilmington sale resulted in a \$159.2 million pre-tax (\$100 million after-tax) gain. Such pre-tax gain is included in other income in the Company's 1994 Consolidated Statement of Income. 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 agreed to participate with the Port of Long Beach in funding environmental remediation and site preparation, as specified by the Port of Long Beach, to a maximum of \$105.5 million. 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 (\$97.9 million in total remaining at December 31, 1996) categorized as other current and long-term liabilities (see Notes 13 and 15). The majority of cash outlays for these liabilities is expected to occur over the next five years.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

5. Financial Instruments

Hedging. The Company uses hydrocarbon-based derivative financial instruments from time to time to reduce risks associated with hydrocarbon price volatility. While the use of these hedging arrangements may limit the downside risk of adverse price movements, it may also limit future gains from favorable movements. Hedging generally is accomplished pursuant to exchange-traded futures contracts or master swap agreements based on standard forms. Hedging gains and losses are deferred and recognized at delivery of the commodity. The Company does not hold or issue derivative financial instruments for trading purposes and does not hedge any significant amount of production beyond a 24-month time frame. In connection with its futures contract hedging activity, the Company is required to deposit monies with the New York Mercantile Exchange ("NYMEX"), representing cash requirements for contract margins and deposits for 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, 1996, the Company had margin requirements totaling \$44.7 million, which were met with cash deposits of \$30.9 million and unrealized gains on open contracts of \$13.8 million. Deferred losses on other derivative positions, primarily representing January hedges deferred as of December 31, were \$17.1 million at December 31, 1996, and are included in other current assets in the Company's Consolidated Statement of Financial Position.

The Company addresses market risk by selecting hydrocarbon-based derivative financial instruments whose historical value fluctuations correlate with those of the item being hedged, so that gains or losses on the financial instruments will be substantially offset by gains or losses on the hedged item. Basis risk, which arises from differences between wellhead prices in the Company's specific producing locations and the underlying NYMEX prices contained in the financial instruments, is managed by using basis swaps in combination with futures contracts and price swaps. In December 1995, the Company recorded an \$8.1 million pre-tax (\$5.3 million after-tax) charge relating to loss of correlation between NYMEX prices and the actual wellhead prices ultimately received by the Company for a portion of its first quarter 1996 hedged natural gas production. Such loss was included as a reduction in other oil and gas revenues in the Company's 1995 Consolidated Statement of Income.

The Company is exposed to credit losses in the event of nonperformance by its counterparties. Credit risk related to hedging activities is managed by requiring that counterparties meet certain minimum credit standards and by conducting mark-to-market analysis to review potential exposure and determine if collateral is required. At December 31, 1996, the largest credit risk associated with any of the Company's counterparties, representing the fair value of contracts with a positive net fair value at the reporting date, was approximately \$4.0 million. The Company anticipates that its counterparties, which consist principally of organized exchanges, major financial institutions and large dealers, will be able to satisfy their obligations related to the Company's contracts.

At December 31, 1996, the Company had near-term futures contracts and price swaps for February through December 1997 with respect to natural gas volumes of 696 MMcfd at \$2.06/Mcf. The unrecognized mark-to-market gain associated with such contracts, representing the price the Company would receive to close such contracts at the reporting date, was \$23.7 million. With respect to crude oil, at December 31, 1996, the Company had near-term NYMEX-related contracts for January through December 1997 with respect to crude oil volumes of 20 MBbl at \$20.23/Bbl, with an unrecognized mark-to-market loss of \$19.8 million. Additionally, the Company has simultaneously purchased commodity put options (floor) and sold commodity call options (ceiling), the combination of which has the effect of establishing a minimum and maximum price the Company would receive for its crude oil. At December 31, 1996, the Company had established a floor of \$19.17/Bbl (including net premium paid) and a ceiling of \$24.67/Bbl (including net premium paid) with respect to 25.0 MBbl of crude oil for January through December 1997. The Company will continue to receive current market prices for its crude oil as long as market prices remain within the range established by the floor and the ceiling. The fair value of such options at December 31, 1996 was a negative

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

\$1.8 million, representing the net cost to repurchase the options given current market prices using an option pricing model. Net option premiums, which are included in other current assets in the Company's Consolidated Statements of Financial Position, are deferred and recognized in income as the related volumes are produced.

Also at December 31, 1996, the Company had near-term futures contracts and price swaps for January through December 1998 with respect to natural gas volumes of 37 MMcfd at \$2.21/Mcf. The unrecognized mark-to-market gain associated with such contracts was \$0.7 million.

The Company also enters into long-term fixed price sales agreements for physical deliveries of natural gas, and at December 31, 1996, had outstanding contracts relating to 81.5 Bcf of natural gas for periods through December 31, 2008. Average annual commitments during this period would have comprised no more than 2% of the Company's 1996 natural gas sales volumes. Such long-term commitments are not reflected in the Company's Consolidated Statements of Financial Position. The Company's marketing subsidiary, Union Pacific Fuels, Inc. ("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. At December 31, 1996, long-term fixed price sales commitments for which corresponding financial positions had not been entered into totaled 69.8 Bcf at an average price of \$2.95/Mcf, with a positive fair value of \$26.6 million. The remaining commitments for 11.7 Bcf had been offset with financial contracts for similar volumes. The unrecognized mark-to-market present value related to such hedged commitments at December 31, 1996 comprises a \$0.2 million loss on the long-term fixed price sales commitments and a \$1.3 million gain on the corresponding financial contracts.

At December 31, 1996, the Company had a total unrecognized mark-to-market present value gain of \$30.5 million related to the financial and fixed price sales contracts described above. Such gain comprises a \$26.4 million net gain on contracts for physical delivery and a \$4.1 million net gain on financial contracts. 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 1994 and 1995, revenues were \$36 million and \$27 million higher, respectively, while during 1996, revenues were \$52 million lower as a result of hedging activities.

Fair Value of Financial Instruments. At December 31, 1996, the carrying value of the Company's long-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.

Concentrations of Credit Risk. Financial instruments which subject the Company to concentrations of credit risk consist principally of trade receivables and short-term cash investments. The Company places its temporary excess cash investments in high quality short-term instruments through several high credit quality financial institutions. A significant portion of the Company's trade receivables relate to customers in the oil and gas industry, and, as such, the Company is directly affected by the economy of that industry. However, the credit risk associated with trade receivables is minimized by the Company's large customer base and ongoing procedures to monitor the creditworthiness of customers. The Company generally requires no collateral from its customers. Historically, the Company has not experienced significant losses on trade receivables.

UNION PACIFIC RESOURCES GROUP INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

6. Properties

Major property classifications as of December 31 are as follows:

	<u>1995</u>	<u>1996</u>
	(Millions of dollars)	
Producing properties	\$3,873.7	\$4,311.3
Non-producing properties	276.4	371.3
Plants, pipelines and equipment	898.8	1,010.7
Construction in progress	254.4	348.8
Other	<u>147.1</u>	<u>147.9</u>
Total	<u>\$5,450.4</u>	<u>\$6,190.0</u>

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

	<u>1995</u>	<u>1996</u>
	(Millions of dollars)	
Producing properties	\$2,196.5	\$2,604.1
Non-producing properties	86.3	142.7
Plants, pipelines and equipment	334.7	396.0
Other	<u>68.6</u>	<u>74.8</u>
Total	<u>\$2,686.1</u>	<u>\$3,217.6</u>

Based upon the Company's analysis of expected future net cash flows from its oil and gas properties, certain properties were deemed to be impaired following recent downward revisions in reserve estimates. Accordingly, in the fourth quarter of 1996, the Company adjusted the net book value of such properties to their fair value, determined using a discounted cash flow approach, with a charge to operations of \$34.4 million.

Fixed asset additions included capitalized interest of \$0.9 million in 1994, \$1.0 million in 1995 and \$0.2 million in 1996.

7. Income Taxes

Components of income tax expense are as follows:

	<u>1994</u>	<u>1995</u>	<u>1996</u>
	(Millions of dollars)		
Current:			
Federal	\$(41.4)	\$130.2	\$105.8
State	<u>(2.3)</u>	<u>(4.6)</u>	<u>9.0</u>
Total current	<u>(43.7)</u>	<u>125.6</u>	<u>114.8</u>
Deferred:			
Federal	168.6	(20.8)	33.0
State	<u>5.8</u>	<u>2.5</u>	<u>4.0</u>
Total deferred	<u>174.4</u>	<u>(18.3)</u>	<u>37.0</u>
Total	<u>\$130.7</u>	<u>\$107.3</u>	<u>\$151.8</u>

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	1995	1996
	(Millions of dollars)	(Millions of dollars)
Excess tax over book items, including depreciation and exploration costs ..	\$479.5	\$561.0
State taxes — net	12.3	11.4
Long-term liabilities	(51.3)	(40.7)
Alternative minimum tax	(37.7)	(56.6)
Pension and other retirement benefits	(18.5)	(60.0)
Other	54.2	19.6
Net deferred tax liability	<u>\$438.5</u>	<u>\$434.7</u>

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

	1994	1995	1996
Statutory tax rate	35.0%	35.0%	35.0%
State taxes — net	0.5	(0.3)	1.8
Section 29 tax credits	(10.0)	(8.3)	(3.3)
Tax settlements	—	(2.2)	—
Other	(0.4)	(0.8)	(1.4)
Effective tax rate	<u>25.1%</u>	<u>23.4%</u>	<u>32.1%</u>

The Company generates Section 29 tax credits from the sale of certain fuels produced from nonconventional sources. 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 generated \$52.2 million, \$39.9 million and \$15.6 million of Section 29 tax credits in 1994, 1995 and 1996, respectively. The Federal tax law provides for the use of these credits against regular Federal income tax liability. Accordingly, the Company utilized on its tax returns \$27.5 million of Section 29 tax credits in 1994 and anticipates the utilization of \$15.6 million in 1996. Section 29 tax credits of \$18.8 million in 1995 increased the alternative minimum tax credit and may be carried over and applied against regular tax liability in future years.

All tax years prior to 1979 have been closed with the Internal Revenue Service ("IRS"). UPC has reached a partial settlement with the Appeals Office of the IRS for 1980 through 1985; the remaining issues will be resolved as part of refund claims filed for those years. Additionally, UPC is negotiating with the Appeals Office concerning 1986 through 1989. The IRS is examining UPC's returns for 1990 through 1994. The Company believes it has adequately provided for Federal and state income taxes.

UNION PACIFIC RESOURCES GROUP INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

8. Debt

Total debt as of December 31 is summarized below:

	1995	1996
	(Millions of dollars)	
Note payable to and advances from UPC — net, 8.5%, due 1996 . . .	\$ 567.8	\$ —
Commercial paper, net of discount, average of 5.7% at		
December 31, 1996	—	99.6
Bank credit agreement, 6.1% LIBOR floating at December 31, 1995	68.0	—
Notes, 7%, due 2006	—	200.0
Debentures, 7.5%, due 2026	—	200.0
Debentures, 7.5%, due 2096	—	150.0
Tax exempt revenue bonds, 4.15% to 4.25%, due 2003 through 2012	33.5	24.0
Discount on notes and debentures	—	(2.7)
Total debt	669.3	670.9
Less current portion	(567.8)	—
Total long-term debt	<u>\$ 101.5</u>	<u>\$ 670.9</u>

Excluding commercial paper, the Company has no debt maturing in the next five years. Outstanding commercial paper has been classified as long-term debt reflecting the Company's intent to maintain these short-term borrowings on a long-term basis either through the continued issuance of commercial paper and/or through new long-term financings, or by using its currently available long-term credit facility if alternative financing is not available.

The Company has a \$600 million revolving credit agreement that expires in August 2001. Borrowings under the agreement, at the Company's election, 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 Company's senior debt rating. The Company is required to pay facility fees on the aggregate amount of the commitment ranging from .06% to .15% also depending on the Company's senior debt rating. The agreement contains covenants which limit the ratio of debt to the sum of debt and shareholders' equity of the Company to 65% and which require the combined EBITDAX (the sum of operating income; depreciation, depletion and amortization; and exploration expenses) of the Company's Principal Operating Subsidiaries (as defined in the agreement) to be at least 80% of the Company's consolidated EBITDAX. The agreement also imposes certain restrictions on the Company regarding the creation of liens, incurrence of indebtedness, transactions with affiliates, sales of the stock of UPRC and certain mergers, consolidations and asset sales. As of December 31, 1996, there were no borrowings outstanding under this credit facility although borrowing capacity is reduced by outstanding commercial paper. The Company had the capacity to borrow \$500 million under such credit facility as of December 31, 1996.

In October 1996, the Company issued \$200 million of 7% Notes due 2006 and \$200 million of 7.5% Debentures due 2026. In November 1996, the Company issued \$150 million of 7.5% Debentures due 2096. Proceeds were used, together with proceeds from the issuance of commercial paper, to repay the Company's note payable to UPC and for general corporate purposes. None of the Company's Notes and Debentures are redeemable prior to maturity and none are subject to any sinking fund requirements. In addition, the Company has filed a Form S-3 Registration Statement with the Securities and Exchange Commission which would permit the Company to offer up to \$900 million in debt and equity securities upon the effectiveness of such Registration Statement.

UNION PACIFIC RESOURCES GROUP INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

9. 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, 1996, are as follows:

	<u>(Millions of dollars)</u>
1997	\$ 56.8
1998	57.1
1999	48.5
2000	40.2
2001	30.2
Later years	<u>59.3</u>
Total minimum payments	<u>\$292.1</u>

Rent expense, net of sublease income, for operating leases with terms exceeding one month was \$33.8 million in 1994, \$31.0 million in 1995 and \$27.2 million in 1996. Sublease rentals for the next five years are \$28.7 million in 1997, \$28.4 million in 1998, \$28.3 million in 1999, \$28.1 million in 2000, \$28.1 million in 2001 and \$56.7 million thereafter.

10. Retirement Plans

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

Pension Benefits. 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 valuations.

Pension cost includes the following components:

	<u>1994</u>	<u>1995</u>	<u>1996</u>
	<u>(Millions of dollars)</u>		
Service cost — benefits earned during the period	\$ 4.7	\$ 5.3	\$ 4.4
Interest on projected benefit obligation	13.1	14.4	13.3
Return on assets:			
Actual (gain) loss	4.0	(49.5)	(41.7)
Deferred gain (loss)	(22.9)	30.0	22.1
Net amortization costs	<u>(2.2)</u>	<u>(2.4)</u>	<u>(3.7)</u>
Net pension credit	<u>\$ (3.3)</u>	<u>\$ (2.2)</u>	<u>\$ (5.6)</u>

The projected benefit obligation was determined using a discount rate of 7.25% in 1995 and 7.5% in 1996. The estimated rate of salary increase approximated 5.25% in 1995 and 5.5% in 1996. The expected long-term rate of return on plan assets was 8.0% in both years. The portion of the funded plan's assets held in fixed-income and short-term securities was approximately 32% and 29% as of December 31, 1995 and 1996, respectively, with the remainder primarily in equity securities.

UNION PACIFIC RESOURCES GROUP INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	Funded Pension Plan		Unfunded Supplemental Plan	
	1995	1996	1995	1996
	(Millions of dollars)			
Plan assets at fair value	\$282.3	\$221.3	\$ —	\$ —
Actuarial present value of benefit obligations:				
Vested benefits	156.4	152.9	2.8	4.5
Non-vested benefits	7.0	6.4	0.2	0.2
Accumulated benefit obligation	163.4	159.3	3.0	4.7
Additional benefits based on estimated future salaries	29.2	17.4	5.5	2.5
Projected benefit obligation	192.6	176.7	8.5	7.2
Plan assets (over) under projected benefit obligation	(89.7)	(44.6)	8.5	7.2
Unamortized net transition asset (obligation)	23.6	21.0	(1.8)	(1.1)
Unrecognized prior service cost	(6.0)	(5.2)	(6.1)	(3.8)
Unrecognized net gain (loss)	59.5	105.0	(3.4)	(2.2)
Minimum liability	—	—	5.8	4.6
Pension liability (asset)	<u>\$(12.6)</u>	<u>\$ 76.2</u>	<u>\$ 3.0</u>	<u>\$ 4.7</u>

In connection with the Distribution, pension assets related to UPC's funded pension plan, in which the Company had participated, were allocated between UPC and the Company, resulting in the elimination of the balance of net pension assets and the creation of a December 31, 1996 funded pension liability of \$76.2 million, as well as a net-of-tax charge to retained earnings of \$69.5 million. The Company has adopted a new pension plan with substantially the same terms as those of the UPC pension plan. The additional cost to the Company associated with the allocation of pension assets between UPC and the Company is expected to be approximately \$8 million annually.

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

	1994	1995	1996
	(Millions of dollars)		
Service cost — benefits earned during the period	\$ 1.2	\$ 1.2	\$ 1.0
Interest costs on accumulated benefit obligation	3.7	4.3	3.4
Net amortization costs	(0.9)	(1.5)	(2.3)
Charge to operations	<u>\$ 4.0</u>	<u>\$ 4.0</u>	<u>\$ 2.1</u>

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	1995	1996
	(Millions of dollars)	
Accumulated postretirement benefit obligation ("APBO"):		
Retirees	\$45.2	\$35.5
Fully eligible active employees	2.0	1.9
Other active employees	12.2	7.7
Total APBO	59.4	45.1
Unrecognized prior service gain	5.2	4.4
Unrecognized net gain	11.5	25.1
Postretirement benefits liability	<u>\$76.1</u>	<u>\$74.6</u>

The APBO was determined using a discount rate of 7.25% in 1995 and 7.5% in 1996. The health care cost trend rate is assumed to gradually decrease from 9.5% for 1997 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 \$0.6 million and the APBO would rise by \$4.4 million. The Company does not currently pre-fund health care and life insurance benefit costs. Cash payments for these benefits were \$1.6 million in 1995 and \$3.6 million in 1996.

11. Shareholders' Equity

Stock Option and Retention Stock Plans. Pursuant to the Company's stock option and retention stock plans, 11,660,601 and 9,215,933 shares of common stock or options for such shares were available at December 31, 1995 and 1996, respectively, for grant to employees and directors. 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 up to ten years from grant date. Multi-year option grants have been made to officers and key employees and vest over a three-year period from grant date.

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 one to five years from grant. Multi-year retention stock awards also have been made, with vesting three to five years from grant.

To become exercisable, 1994 multi-year grants of stock options and retention stock also required that designated Company stock prices be met. These performance conditions were achieved during 1995 for stock options and during 1996 for retention stock.

Upon completion of the Offering and Distribution, UPC non-qualified stock options and certain UPC Incentive Stock Options ("ISOs"), as well as UPC retention shares held by officers and employees of the Company, were converted into non-qualified Company stock options, ISOs and retention shares, respectively. The converted options and retention shares retain the same exercise dates and vesting requirements as the UPC options and retention shares for which they were exchanged.

UNION PACIFIC RESOURCES GROUP INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	<u>Company Shares</u>	<u>Weighted Average Exercise Price</u>
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
Balance at December 31, 1995	3,789,638	16.11
Conversion of UPC stock options	681,206	19.49
Granted	1,471,400	27.81
Exercised	(437,472)	14.76
Expired/surrendered	(288,698)	16.02
Balance at December 31, 1996	<u>5,216,074</u>	19.97
Exercisable December 31:		
1995	2,235,470	\$16.26
1996	3,035,905	16.81
	<u>Regular</u>	<u>Performance</u>
Retention shares:		
1995		
Awarded	33,585	14,143
Conversion of UPC retention shares	389,880	310,653
Unvested at December 31, 1995	423,465	324,796
1996		
Awarded	604,530	—
Conversion of UPC retention shares	2,610	18,698 (a)
Achievement of performance conditions	301,066	(301,066)
Vested	(124,733)	—
Forfeited, surrendered and other	(2,376)	(42,428) (a)
Unvested at December 31, 1996	<u>1,204,562</u>	<u>—</u>
Weighted-average grant-date fair value of options and retention shares granted:		
	<u>Options(b)</u>	<u>Retention Shares(c)</u>
1995	\$8.31	\$25.88
1996	9.15	27.81

(a) Activity occurred prior to achievement of performance conditions.

(b) Calculated in accordance with the Black-Scholes option pricing model, using the following assumptions:

	<u>1995</u>	<u>1996</u>
Expected volatility	28%	26%
Expected dividend yield	.86%	.7%
Expected option term	5 years	5 years
Risk-free rate of return	5.5%	6.3%

(c) Represents market value on grant date.

UNION PACIFIC RESOURCES GROUP INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Stock options outstanding as of December 31, 1996 are as follows:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number	Weighted Average Years to Expiration	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
\$8.09-15.07.....	380,861	2.75	\$11.65	380,861	\$11.65
15.18-20.94.....	3,141,176	6.90	16.94	2,531,544	17.20
23.78-28.94.....	1,694,037	9.50	27.47	123,500	24.66
8.09-28.94.....	<u>5,216,074</u>	7.52	19.97	<u>3,035,905</u>	16.81

The Company applies the intrinsic value method in accounting for its stock option and retention stock plans. Accordingly, no compensation cost has been recognized for its stock option plans. Compensation cost recognized for its retention stock plan was \$0.7 million and \$7.4 million in 1995 and 1996, respectively. Had compensation cost for the Company's stock option plan been determined based on the fair value at the grant dates for awards under the plan and for options that were converted at the Offering and Distribution, as described above, the Company's net income would have been reduced by \$3.4 million in 1995 (essentially all of which relates to option conversion at the Offering) and \$3.0 million in 1996 (of which \$0.7 million relates to option conversion at the Distribution). Earnings per share would have been reduced by \$0.01 per share in both 1995 and 1996.

Employee Stock Ownership Plan. Effective January 2, 1997, the Company instituted an employee stock ownership plan ("ESOP"). The ESOP purchased 3.7 million shares or \$107.3 million of newly issued common stock (the "ESOP Shares") from the Company, which will be used to fund the Company's matching obligation under its 401(k) Thrift Plan. All regular employees of the Company are eligible to participate in the ESOP.

The ESOP Shares, which are held in trust, were purchased with the proceeds from a 30-year loan from the Company. Such shares initially have been pledged as collateral for the loan. As loan payments are made, shares will be released from collateral, based on the proportion of debt service paid. Principal and interest requirements are \$8.7 million annually, and will be funded with dividends paid on the unallocated ESOP Shares and with cash contributions from the Company. Principal or interest prepayments may be made to ensure that the Company's minimum matching obligation is met.

Shares held by the ESOP will be included in the computation of earnings per share as such ESOP Shares are released from collateral. Such releases of ESOP Shares will be allocated to participants' accounts and will be charged to compensation expense at the fair market value of the shares on the date of the employer match. Dividends on allocated ESOP Shares will be recorded as a reduction of retained earnings; dividends on unallocated ESOP Shares will be recorded as a reduction of the principal or accrued interest on the loan.

Preferred Stock and Shareholder Rights. The Company has 100 million shares of no-par-value preferred stock authorized, none of which are outstanding. On October 28, 1996, the Company's Board of Directors designated 3,000,000 of the authorized preferred shares as non-redeemable Series A Junior Participating Preferred Shares (the "Series A Preferred Stock"). Upon issuance, each one-hundredth of a share of the Series A Preferred Stock will have dividend and voting rights approximately equal to those of one share of the Company's common stock. In addition, on October 28, 1996, the Board of Directors adopted a shareholder rights plan with a "flip-in" threshold of 15% to ensure that all shareholders of the Company receive fair value for their common stock in the event of any proposed takeover of the Company and to guard against the use of coercive tactics to gain control of the Company without offering fair value to the Company's shareholders. Under the related Rights Agreement, the Company declared a dividend of one right ("Right") for each outstanding share of common stock to shareholders of record on November 7, 1996. Under certain limited

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

conditions as defined in the Rights Agreement, each Right entitles the registered holder to purchase from the Company one one-hundredth of a share of Series A Preferred Stock at \$135 subject to adjustment. The Rights are not exercisable until the Distribution Date (as defined in the Rights Agreement) which will occur upon the earlier of (i) ten days following a public announcement that an Acquiring Person (as defined in the Rights Agreement) has acquired beneficial ownership of 15% or more of the Company's outstanding common stock (the "Stock Acquisition Date") or (ii) ten business days following the commencement of a tender offer or exchange offer that would result in a person or group owning 15% or more of the Company's outstanding common stock.

The Rights have certain anti-takeover effects. The Rights will cause substantial dilution to a person or group that attempts to acquire the Company without conditioning the offer on a substantial number of Rights being redeemed. In the event that at any time following the Stock Acquisition Date certain events occur as defined in the Rights Agreement, each holder of a Right, except the Acquiring Person, will thereafter have the right to receive, upon exercise, Company common stock or common stock of the acquiring company, as the case may be, having a value equal to two times the exercise price of the Right.

The Rights should not interfere with any merger or other business combination approved by the Company since the Board of Directors may, at its option, at any time prior to the close of business on the earlier of the tenth day following the Stock Acquisition Date or October 28, 2006, redeem all but not less than all of the then outstanding Rights at \$0.01 per Right. The Rights expire on October 28, 2006, and do not have voting power or dividend privileges.

12. Investment in Unconsolidated Affiliate

The Company has a 50% ownership interest in Black Butte Coal Company and R-K Leasing Company ("Black Butte"), a partnership which operates a surface coal mine complex in southwestern Wyoming. Summarized financial information for Black Butte as of and for the year ended December 31 is as follows:

	1995	1996
	(Millions of dollars)	
Current assets	\$ 35.7	\$ 39.8
Non-current assets	60.5	46.4
Current liabilities	16.1	20.2
Non-current liabilities and equity (see Note 13)	80.1	66.0
Sales	176.0	192.4
Operating income	109.2	137.0
Partners' income	108.9	137.0

During 1996, Black Butte's sales to its largest customer under an amended coal supply contract accounted for \$54.8 million, or 10%, of the Company's consolidated 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.

A supplier of coal to Black Butte has been assessed by the Minerals Management Service of the United States 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 for reimbursement from Black Butte. Although the management of Black Butte will vigorously contest these claims, the liability

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

associated with the underpaid royalty and production taxes, if any, could range from zero to \$36 million, of which the Company would recognize its proportionate share, which could range from zero to \$18 million.

13. Environmental Exposure

The Company generates and disposes of hazardous and nonhazardous 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, 1996, long and short-term liabilities totaling \$94.3 million had been accrued for future costs of all sites where the Company's obligation is probable and where such costs reasonably can be 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 \$44.2 million for the obligation to participate in the remediation of the Wilmington field properties (see Note 4). 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 accrued adequately 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 \$6.2 million in 1995 and \$11.4 million in 1996. In 1997, the Company anticipates spending a total of \$20 million for remediation, control and prevention, including \$10 million relating to the Wilmington properties. The majority of the December 31, 1996 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.

In addition, Black Butte provides an accrual for reclamation of mined properties, based on the estimated cost of restoration of such properties in compliance with laws governing strip mining. Accrued reclamation costs for Black Butte as of December 31, 1996 are \$54.3 million, of which the Company's share is \$27.2 million. The majority of cash expenditures for reclamation are expected to be incurred from five to ten years in the future.

14. Commitments and Contingencies

UP Fuels is a party to a long-term 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. Eleven 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

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

cost of service factors and prevailing rate policy at the Federal Energy Regulatory Commission. The undiscounted amount of the commitment is \$197 million. UP Fuels is party to an additional agreement under which it may acquire in 2001, at its option, an additional 25 MMcf of transportation rights on the Kern River system for periods beginning in 2002.

In the last ten 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. 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 its results of 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. The Company intends to defend vigorously against these lawsuits as well as any similar lawsuits. If such suits ultimately are resolved against the Company on a widespread basis, however, damage awards and a loss of future revenue could result which, in the aggregate, could be materially adverse to the Company.

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 also has 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 its results of operations or financial condition.

15. Other Long-Term Liabilities

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

	1995	1996
	(Millions of dollars)	(Millions of dollars)
Environmental (Notes 4 and 13)	\$ 78.0	\$ 74.5
Wilmington field site preparation (Note 4)	53.7	53.7
Litigation and contingencies (Notes 4 and 14)	93.5	73.8
Offshore platform lease accrual	14.5	14.3
Other	50.8	43.6
Total	<u>\$290.5</u>	<u>\$259.9</u>

UNION PACIFIC RESOURCES GROUP INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

16. Capital and Exploratory Expenditures

Capital and exploratory expenditures include the following:

	<u>1994</u>	<u>1995</u>	<u>1996</u>
	(Millions of dollars)		
Capital expenditures:			
Producing properties	\$ 790.8	\$482.7	\$515.2
Non-producing properties	192.4	35.0	149.8
Exploratory drilling	28.5	24.2	36.1
Plants, pipelines and marketing	329.8	106.5	118.1
Other	2.0	2.0	9.5
Total capital expenditures	<u>1,343.5</u>	<u>650.4</u>	<u>828.7</u>
Exploratory expenditures:			
Expensed geological and geophysical costs	18.4	22.4	19.0
Expensed dry hole costs	27.4	13.6	32.6
Total exploratory expenditures	<u>45.8</u>	<u>36.0</u>	<u>51.6</u>
Total capital and exploratory expenditures	<u>\$1,389.3</u>	<u>\$686.4</u>	<u>\$880.3</u>

UNION PACIFIC RESOURCES GROUP INC.
SUPPLEMENTARY INFORMATION (UNAUDITED)

A. Proved Reserves

The following table reflects estimated quantities of proved oil and gas reserves which have been prepared by the Company's petroleum engineers. The Company considers such estimates to be reasonable; however, there are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. Reserve engineering is a subjective process which is dependent on the quality of available data and on engineering and geological interpretation and judgment. Such reserve estimates are subject to change over time as additional information becomes available.

	<u>1994</u>	<u>1995</u>	<u>1996</u>
Natural gas (Bcf) (a):			
Beginning of year	1,731.2	2,126.0	2,173.5
Revisions of previous estimates	(33.1)	(122.3)	45.7
Extensions, discoveries and other additions	360.3	518.0	481.3
Purchases of reserves-in-place	385.4	26.7	52.0
Sales of reserves-in-place	(36.0)	(32.0)	(5.5)
Production	(281.8)	(342.9)	(368.6)
Total proved, end of year	<u>2,126.0</u>	<u>2,173.5</u>	<u>2,378.4</u>
Proved developed reserves	<u>2,054.4</u>	<u>1,957.1</u>	<u>2,125.4</u>
Natural gas liquids (MMBbl) (a):			
Beginning of year	74.3	83.8	100.1
Revisions of previous estimates	(5.8)	9.9	12.0
Extensions, discoveries and other additions	4.6	18.2	9.1
Purchases of reserves-in-place	21.4	0.2	0.2
Sales of reserves-in-place	(2.2)	(1.0)	(0.4)
Production	(8.5)	(11.0)	(13.5)
Total proved, end of year	<u>83.8</u>	<u>100.1</u>	<u>107.5</u>
Proved developed reserves	<u>81.2</u>	<u>89.8</u>	<u>97.7</u>
Crude oil, including condensate (MMBbl):			
Beginning of year	82.6	70.9	83.8
Revisions of previous estimates	4.9	14.1	(0.6)
Extensions, discoveries and other additions	24.5	19.1	14.3
Purchases of reserves-in-place	6.5	1.9	3.6
Sales of reserves-in-place	(24.6)	(2.9)	(2.0)
Production	(23.0)	(19.3)	(18.5)
Total proved, end of year	<u>70.9</u>	<u>83.8</u>	<u>80.6</u>
Proved developed reserves	<u>69.9</u>	<u>78.2</u>	<u>74.1</u>
Proved reserves equivalent, end of year (Bcfe) (b):			
Natural gas	2,126.0	2,173.5	2,378.4
Natural gas liquids	502.9	600.6	645.0
Crude oil, including condensate	425.2	502.8	483.6
Total proved	<u>3,054.1</u>	<u>3,276.9</u>	<u>3,507.0</u>
Proved developed reserves	<u>2,961.0</u>	<u>2,965.1</u>	<u>3,155.8</u>

(a) 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).

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

UNION PACIFIC RESOURCES GROUP INC.
SUPPLEMENTARY INFORMATION (UNAUDITED) — (Continued)

B. Drilling Activity(a)

	<u>1994</u>	<u>1995</u>	<u>1996</u>
Gross wells	677	725	655
Gross productive wells	644	685	591
Net wells:			
Exploration	24	14	27
Development	<u>373</u>	<u>513</u>	<u>439</u>
Total net wells	<u>397</u>	<u>527</u>	<u>466</u>
Net productive wells:			
Exploration	16	3	9
Development	<u>365</u>	<u>506</u>	<u>413</u>
Total net productive wells	<u>381</u>	<u>509</u>	<u>422</u>

(a) In addition, at December 31, 1996, 140 gross wells (95 net wells) were in the process of being drilled.

C. Average Sales Price and Cost

	<u>1994</u>	<u>1995</u>	<u>1996</u>
Producing properties:			
Natural gas sales price (per Mcf)	\$ 1.82	\$ 1.42	\$ 1.86
Natural gas liquids sales price (per Bbl)	7.86	8.14	11.39
Crude oil sales price (per Bbl)	14.34	16.08	18.84
Production cost (per Mcfe)	0.55	0.42	0.49
Gas plants:			
Natural gas sales price (per Mcf)	\$ 1.81	\$ 1.51	\$ 2.01
Natural gas liquids sales price (per Bbl)	9.97	9.38	13.16

D. Average Daily Production and Sales Volume

	<u>1994</u>	<u>1995</u>	<u>1996</u>
Producing properties:			
Natural gas (MMcfd)	754.8	915.6	980.3
Natural gas liquids (MBbld)	18.8	23.1	28.5
Crude oil (MBbld)	63.1	52.8	50.6
Total producing properties (MMcfd)	1,246.2	1,371.0	1,454.9
Plant share of equity gas processed:			
Natural gas (MMcfd)	17.5	23.9	26.7
Natural gas liquids (MBbld)	4.4	7.1	8.4
Total plant share of equity gas (MMcfd)	43.9	66.5	77.1
Total production reflected in estimates of proved reserves (MMcfd)	1,290.1	1,437.5	1,532.0
Plant share of third party gas processed (MBbld)	26.8	27.1	31.4
Total sales (MMcfd)	1,450.9	1,600.1	1,720.2
Plant share of natural gas liquids sales (MBbld):			
Equity gas processed	4.4	7.1	8.4
Third party gas processed	<u>26.8</u>	<u>27.1</u>	<u>31.4</u>
Total	<u>31.2</u>	<u>34.2</u>	<u>39.8</u>

UNION PACIFIC RESOURCES GROUP INC.
SUPPLEMENTARY INFORMATION (UNAUDITED) — (Continued)

E. Acreage and Wells

Oil and gas leasehold acreage as of December 31 is as follows(a):

	<u>1995</u>	<u>1996</u>
	<u>(Thousands of</u>	<u>acres)</u>
Gross developed	1,822	2,018
Net developed	1,017	1,179
Gross undeveloped	3,331	4,272
Net undeveloped	2,194	2,935

Productive oil and gas wells at December 31, 1996 are as follows:

	<u>Oil</u>	<u>Gas</u>
	<u>(Wells)</u>	
Gross(b)	2,786	5,011
Net	1,620	2,703

- (a) In addition, the Company has fee mineral ownership of approximately 9.6 million gross acres (8.5 million net acres), including 7.9 million gross acres (7.7 million net acres) acquired through 19th century Congressional Land Grant Acts. Substantial portions of this acreage are undeveloped and are considered prospective for oil and gas.
- (b) Approximately 577 are multiple completions, 405 of which are gas wells.

F. Capitalized Exploration and Production Costs

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

	<u>1995</u>	<u>1996</u>
	<u>(Millions of dollars)</u>	
Proved properties	\$ 865.7	\$ 889.5
Unproved properties	148.3	280.9
Wells and related equipment	3,136.1	3,512.2
Uncompleted wells and equipment	182.6	291.6
Gross capitalized costs	4,332.7	4,974.2
Accumulated depreciation, depletion and amortization	(2,282.8)	(2,746.8)
Net capitalized costs	<u>\$ 2,049.9</u>	<u>\$ 2,227.4</u>

- (a) Excludes plants, pipelines and marketing assets.

UNION PACIFIC RESOURCES GROUP INC.
SUPPLEMENTARY INFORMATION (UNAUDITED) — (Continued)

G. Costs Incurred in Exploration and Development

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

	1994	1995	1996
	(Millions of dollars)		
Costs incurred:			
Proved acreage	\$ 440.6	\$100.5	\$ 85.7
Unproved acreage	35.4	35.0	149.8
Exploration costs(a)	100.5	80.9	114.6
Development costs	507.2	382.2	429.5
Total costs incurred(b)	<u>\$1,083.7</u>	<u>\$598.6</u>	<u>\$779.6</u>

- (a) Includes allocated exploration overhead costs of \$21.6 million in 1994, \$17.1 million in 1995 and \$22.5 million in 1996, and delay rentals of \$4.6 million in 1994, \$3.6 million in 1995 and \$4.4 million in 1996.
- (b) Excludes capital expenditures relating to plants, pipelines and marketing of \$329.8 million in 1994, \$106.5 million in 1995 and \$118.1 million in 1996.

H. Results of Operations for Producing Activities(a)

	1994	1995	1996
	(Millions of dollars)		
Revenues	\$ 962.5	\$1,027.7	\$1,198.3
Production costs	(252.3)	(217.8)	(259.5)
Exploration expenses	(107.6)	(89.4)	(144.6)
Depreciation, depletion and amortization	(373.2)	(403.1)	(465.5)
Total costs	(733.1)	(710.3)	(869.6)
Pre-tax results	229.4	317.4	328.7
Income taxes	(28.8)	(70.4)	(94.9)
Results of operations	<u>\$ 200.6</u>	<u>\$ 247.0</u>	<u>\$ 233.8</u>

- (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 \$26.5 million in 1994, \$14.2 million in 1995 and \$3.9 million in 1996, and the \$122.5 million Columbia bankruptcy settlement in 1995.

UNION PACIFIC RESOURCES GROUP INC.
SUPPLEMENTARY INFORMATION (UNAUDITED) — (Continued)

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

	1994	1995	1996
	(Millions of dollars)		
Future cash inflows from sales of oil and gas	\$ 5,023.1	\$ 5,809.2	\$11,945.7
Future production and development costs	(1,790.9)	(1,747.8)	(2,013.1)
Future income taxes	(722.3)	(1,114.6)	(3,031.7)
Future net cash flows	2,509.9	2,946.8	6,900.9
10% annual discount	(851.2)	(1,075.5)	(2,661.9)
Standardized measure of discounted future net cash flows ..	<u>\$ 1,658.7</u>	<u>\$ 1,871.3</u>	<u>\$ 4,239.0</u>

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

	1994	1995	1996
	(Millions of dollars)		
Beginning of year	\$ 1,288.6	\$ 1,658.7	\$ 1,871.3
Changes due to current year operations:			
Additions and discoveries less related production and other costs	570.7	549.7	1,135.5
Sales of oil and gas — net of production costs	(744.0)	(716.1)	(961.0)
Development costs	745.6	382.2	429.5
Purchases of reserves-in-place	270.9	48.8	181.1
Sales of reserves-in-place	(36.1)	(49.5)	(48.0)
Changes due to revisions in:			
Price	(9.6)	334.0	2,763.1
Development costs	(811.9)	(293.6)	(268.6)
Quantity estimates	(80.4)	68.1	27.9
Income taxes	184.2	(271.5)	(1,062.9)
Other	107.0	(31.8)	(69.6)
Discount accretion	173.7	192.3	240.7
End of year	<u>\$ 1,658.7</u>	<u>\$ 1,871.3</u>	<u>\$ 4,239.0</u>

Future oil and gas sales and production and development costs have been estimated using prices and costs in effect as of each year end. Prices used to estimate future oil and gas sales represent the closing price for trading in December contracts on the New York Mercantile Exchange adjusted for appropriate regional price differentials. Future production hedged as of year end is included in future net revenues at the hedged price. Such prices may vary significantly from actual prices realized by the Company for its future production. Future net revenues were discounted to present value at 10%, a uniform rate set by the Financial Accounting Standards Board. 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, hydrocarbon price volatility, 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.

UNION PACIFIC RESOURCES GROUP INC.
SUPPLEMENTARY INFORMATION (UNAUDITED) — (Continued)

J. Selected Quarterly Data

Selected unaudited quarterly data are as follows:

	For the Quarter Ended			
	March 31	June 30	September 30	December 31
	(Millions, except per share amounts)			
1996				
Operating revenues	\$389.7	\$427.9	\$447.1	\$566.3(a)
Operating income	97.3	120.1	127.3	181.9(a)
Net income	59.2	70.4	76.9	114.3(a)
Per share:				
Net income	\$ 0.24	\$ 0.28	\$ 0.31	\$ 0.46
Dividends	0.05	0.05	0.05	0.05
Common stock price:				
High	\$ 26 $\frac{3}{8}$	\$ 28	\$ 29	\$ 31 $\frac{1}{2}$
Low	24 $\frac{1}{8}$	24 $\frac{1}{4}$	25 $\frac{3}{8}$	25 $\frac{3}{4}$
1995				
Operating revenues	\$324.7	\$341.3	\$335.3	\$475.4(b)
Operating income	86.5	88.1	98.4	197.1(b)
Net income	61.2	73.6	76.7	139.2(b)
Per share:				
Net income(c)	n/a	n/a	n/a	\$ 0.56
Dividends(c)	n/a	n/a	n/a	0.05
Common stock price:				
High(c)	n/a	n/a	n/a	\$ 26 $\frac{1}{4}$
Low(c)	n/a	n/a	n/a	21 $\frac{1}{8}$

- (a) Fourth quarter 1996 results reflect the impact of increases in hydrocarbon prices (see "Management's Discussion and Analysis of Financial Condition and Results of Operations"). In addition, during the fourth quarter of 1996, operating revenues reflect the release of a \$31.3 million contingency accrual related to potential claims in connection with the 1995 Columbia bankruptcy settlement (see Note 4) and operating expenses were impacted by \$43.5 million related to the writeoff and impairment of certain oil and gas assets (see Note 6).
- (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 4).
- (c) 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).

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 in the Election of Directors segment of 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 in the Reports of Ownership segment of the Proxy Statement and is incorporated herein by reference.

ITEM 11. *Executive Compensation*

Information concerning remuneration received by executive officers and directors is presented in the Compensation of Directors, Compensation Committee Interlocks and Insider Participation and Executive Compensation segments of 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 3, 1997, 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 in the Security Ownership of Certain Executive and Beneficial Owners segment of the Proxy Statement and is incorporated herein by reference.

ITEM 13. *Certain Relationships and Related Transactions*

Information on related transactions is set forth in the Compensation Committee Interlocks and Insider Participation segment of 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 30.

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.

(a) (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") or as otherwise indicated.

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
3.1	— Amended and Restated Articles of Incorporation of Union Pacific Resources Group Inc. (Exhibit 3.1 to Form S-1)
*3.2	— Articles of Amendment of the Amended and Restated Articles of Incorporation of Union Pacific Resources Group Inc., dated November 5, 1996
3.3	— Amended and Restated By-Laws of Union Pacific Resources Group Inc. (Exhibit 3.2 to Form S-1)
4.1	— Specimen of Certificate evidencing the Common Stock (Exhibit 4 to Form S-1)
4.2	— Rights Agreement, dated as of October 28, 1996, between Union Pacific Resources Group Inc. and Harris Trust and Savings Bank, as rights agent (incorporated herein by reference to the Company's Current Report on Form 8-K filed on November 1, 1996)
4.3	— Indenture, dated as of March 27, 1996, between Union Pacific Resources Group Inc. and Texas Commerce Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the Company's Form S-3 Registration Statement, Registration No. 333-2984, dated May 23, 1996)
4.4	— Form of Debt Security (incorporated herein by reference to Exhibit 4.3 to the Company's Form S-3 Registration Statement, Registration No. 333-2984, dated May 23, 1996)
4.5	— Form of Fixed Rate Note (incorporated herein by reference to Exhibit 4.4 to the Company's Form S-3 Registration Statement, Registration No. 333-2984, dated May 23, 1996)
10.1	— Services Agreement (Exhibit 10.1 to Form S-1)
10.2	— Stock Restriction, Registration and Option Agreement (Exhibit 10.2 to Form S-1)
10.3	— Tax Allocation Agreement (Exhibit 10.3 to Form S-1)
10.4	— Indemnification Agreement (Exhibit 10.4 to Form S-1)
10.5	— Cash Management Agreement (Exhibit 10.5 to Form S-1)
10.6	— Intercompany Credit Agreement (Exhibit 10.6 to Form S-1)
10.7	— Pension Plan Agreement (Exhibit 10.7 to Form S-1)
10.8	— Asset Exchange Agreement (Exhibit 10.8 to Form S-1)
10.9	— Asset Purchase and Sale Agreement (Exhibit 10.26 to Form S-1)
10.10	— Amended Agreement Regarding 1971 Plan of Reorganization (Exhibit 10.27 to Form S-1)
10.11	— Executive Incentive Plan of Union Pacific Resources Group Inc. (Exhibit 10.9 to Form S-1)
10.12	— 1995 Stock Option and Retention Stock Plan of Union Pacific Resources Group Inc. (Exhibit 10.10 to Form S-1)

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
10.13	— The Supplemental Pension Plan for Officers and Managers of Union Pacific Corporation and Affiliates, with amendments (incorporated herein by reference to Exhibit 10.11 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.14	— The Supplemental Pension Plan for Exempt Salaried Employees of Union Pacific Resources Company and Affiliates, with amendments (incorporated herein by reference to Exhibit 10.12 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.15(a)	— Conversion Agreement (Exhibit 10.13(a) to Form S-1)
10.15(b)	— Conversion Agreement for Drew Lewis (Exhibit 10.13(b) to Form S-1)
10.15(c)	— Conversion Agreement for Jack L. Messman (Exhibit 10.13(c) to Form S-1)
*10.16	— The Union Pacific Resources Group Inc. Executive Life Insurance Plan, adopted February 26, 1997
*10.17(a)	— Form of Agreement relating to Change in Control by and between Union Pacific Resources Group Inc. and Jack L. Messman, dated February 4, 1997
*10.17(b)	— Form of Agreement relating to Change in Control by and between Union Pacific Resources Group Inc. and each of George Lindahl III and V. Richard Eales, dated February 4, 1997
*10.17(c)	— Form of Agreement relating to Change in Control by and between Union Pacific Resources Group Inc. and each of Anne M. Franklin, Mark S. Knouse, Joseph A. LaSala, Jr., Donald W. Niemiec, Morris B. Smith and John B. Vering, dated February 4, 1997
10.18	— 1995 Directors Stock Option Plan (Exhibit 10.14 to Form S-1)
10.19	— Stock Unit Grant and Deferred Compensation Plan for the Board of Directors, effective September 28, 1995 (Exhibit 10.15 to Form S-1)
10.20	— 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)
10.21	— 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)
10.22	— 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)
10.23	— Registration Rights Agreement, dated as of August 3, 1995, among Union Pacific Resources Group Inc., The Anschutz Corporation and Anschutz Foundation (incorporated herein by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
10.24	— 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 ("the Anschutz Agreement") (incorporated herein by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K for the year ended December 31, 1995)
*10.25	— Letter agreement, dated as of January 20, 1997, amending the Anschutz Agreement

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
10.26	— U.S. \$900,000,000 Competitive Advance/Revolving Credit Agreement, dated April 16, 1996, among Union Pacific Resources Group Inc., the lenders therein and Texas Commerce Bank National Association, as administrative as amended through September 13, 1996 (incorporated herein by reference Exhibit 10 to the Company's Quarterly Report on Form 10-Q for the period September 30, 1996)
*10.27	— Letter, dated as of November 15, 1996, amending the Competitive Advance/Revolving Credit Agreement
*11	— Computation of pro forma earnings per share
*12	— Computation of ratio of earnings to fixed charges
*21	— List of subsidiaries
*23	— Consent of Deloitte & Touche LLP dated as of March 21, 1997
*24	— Powers of attorney
*27	— Financial data schedule
99	— Financial statements for the fiscal year ended December 31, 1996, required by Form 11-K for the Union Pacific Resources Group Inc. Thrift Plan — to be amended

(b) Reports on Form 8-K.

None.

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, 1997.

UNION PACIFIC RESOURCES GROUP INC.

By /s/ MORRIS B. SMITH
(Morris B. Smith, 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, 1997, by the following persons on behalf of the registrant and in the capacities indicated.

/s/ JACK L. MESSMAN
(Jack L. Messman)

Chairman and Chief Executive Officer
(Principal Executive Officer)

/s/ MORRIS B. SMITH
(Morris B. Smith)

Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ JOHN E. JACKSON
(John E. Jackson)

Controller
(Principal Accounting Officer)

*
H. Jesse Arnelle

Director

*
Lynne V. Cheney

Director

*
Preston M. Geren III

Director

*
Lawrence M. Jones

Director

*
Drew Lewis

Director

*
Claudine B. Malone

Director

*
John W. Poduska, Sr., Ph.D.

Director

*
Samuel K. Skinner

Director

*
James R. Thompson

Director

*By /s/ MARK L. JONES
(Mark L. Jones, as attorney-in-fact)