

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549-1004



Form 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1997

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)

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

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

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 27, 1998, the aggregate market value of the registrant's common stock held by non-affiliates (using the New York Stock Exchange closing price) was approximately \$5.5 billion.

- The number of shares outstanding of the registrant's common stock as of February 27, 1998 was 251,043,100.

Certain portions of the registrant's definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 20, 1998 (the "Proxy Statement") are incorporated in Part III by reference.

TABLE OF CONTENTS

	<u>Page</u>
PART I	
Item 1. Business	1
Item 2. Properties	10
Item 3. Legal Proceedings	13
Item 4. Submission of Matters to a Vote of Security Holders	14
PART II	
Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters	16
Item 6. Selected Financial Data	16
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations	17
Item 8. Financial Statements and Supplementary Data	32
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	63
PART III	
Item 10. Directors and Executive Officers of the Registrant	64
Item 11. Executive Compensation	64
Item 12. Security Ownership of Certain Beneficial Owners and Management	64
Item 13. Certain Relationships and Related Transactions	64
PART IV	
Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K	65
Signatures	70

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 wells and acres. Natural gas liquids are referred to herein as ("NGLs").

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 76% 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. The "Land Grant" consists of land granted by the Federal government to a predecessor and former affiliate of the Company in the mid-1800s which passes through the states of Colorado and Wyoming and into Utah. The Company has fee ownership of the mineral rights under approximately 7.9 million acres in the Land Grant. As of December 31, 1997, over 90% of the Company's revenues are generated, and assets and reserves, are located in the United States.

Business Strategy

The Company continues to be primarily in the business of developing and exploring for natural gas and crude oil in its core geographic areas. The Company's strategy is to focus on its core geographic areas in which the Company can apply economies of scale, its operating experience and its expertise in advanced drilling and completion technologies, as well as, to increase margins through reductions in drilling and operating costs, and to add value through effective sales and distribution networks. This focus generates increased production and enhanced well results. The Company also increases its drill site inventory through exploration, farm-in agreements and acquisitions of properties and companies. The Company recently purchased the capital stock of Norcen Energy Resources Limited ("Norcen") for approximately \$2.6 billion (not including Norcen debt). The Norcen acquisition will enhance the Company's onshore and offshore Gulf Coast core area and add new core areas in Canada, Guatemala and Venezuela. See page 27 for additional information including information regarding the impact of the Norcen acquisition on the Company's debt structure.

The Company strives to improve its service to its customers and other constituencies, including its partners, governmental agencies, interest owners, vendors, employees, investors, bankers, and producers. The Company believes that providing each customer with a high level of service will differentiate the Company from its competition and provide the Company with a competitive advantage.

Producing Properties Operations

The Company's oil and gas activities currently are concentrated in six core geographic areas: (1) the Austin Chalk trend in Texas and Louisiana, managed by the Austin Chalk business unit, (2) the western portion of the Land Grant Area in Wyoming and Utah, managed by the Rockies business unit, (3) the eastern portion of the Land Grant in Colorado and Wyoming, with additional operations primarily in Kansas, southern Texas and western Canada, managed by the South Texas/Plains/Canada business unit, (4) the onshore and offshore Gulf Coast area, managed by the Gulf Onshore/Offshore business unit, (5) eastern Texas, managed by the East Texas business unit, and (6) western Texas, managed by the West Texas business unit.

Natural gas and natural gas liquids constituted 81% of the Company's total proved reserves of 4.1 Tcfe as of December 31, 1997, and 83% of the Company's sales volumes of 1.9 Bcfe for the year then ended. For the same period, approximately 69% of the Company's production from producing properties was attributable to Company-operated properties.

The following table sets forth certain proved reserve and production information as of December 31, 1997 with respect to each of the Company's business units.

<u>Business Unit</u>	<u>Total Proved Reserves¹ (Bcfe)</u>	<u>Percent of Total</u>	<u>Producing Property Volume² (MMcfe)</u>	<u>Percent of Total</u>
Austin Chalk	724	18%	558	35%
Rockies	1,203	29	414	26
South Texas/Plains/Canada	602	15	213	13
Gulf Onshore/Offshore	327	8	122	8
East Texas	651	16	178	11
West Texas	593	14	114	7
Total	<u>4,100</u>	<u>100%</u>	<u>1,599</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 An additional 280 MMcfe volumes related to the Company's equity interest in gas plant ownership were produced for the year ended December 31, 1997.

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. The Austin Chalk business unit's production is located primarily in three fields: Giddings, Brookeland and Masters Creek. The Masters Creek field in Louisiana and the Shallow Giddings field in Texas are currently the most active. Since 1988, the Company has participated in the drilling of approximately 1,500 wells and has made aggregate capital expenditures over \$2 billion in the Austin Chalk trend. The Company controls approximately 2.1 million developed and undeveloped net acres in the Austin Chalk and has increased its volumes from an average of 37 MMcfe in January 1990 to an average of 558 MMcfe during 1997. During 1997, 90% of the Austin Chalk business unit's production 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 in Wyoming and Utah. The Rockies business unit operations are concentrated in the Green River Basin and the Overthrust area. The Rockies business unit currently controls approximately 3.5 million developed and undeveloped net acres, principally attributable to the Land Grant. During 1997, 25% of the production from the Rockies business unit was attributable to Company-operated properties.

South Texas/Plains/Canada Business Unit. The South Texas/Plains/Canada business unit manages the Company's oil and gas activities primarily in four areas: the eastern portion of the Land Grant in Colorado and Wyoming, the Hugoton/Panoma field in Kansas, the Stratton/Agua Dulce area in southern Texas and fields in western Canada. The South Texas/Plains/Canada business unit currently controls more than 5.8 million developed and undeveloped net acres, principally attributable to the Land Grant. During 1997, 67% of the production from the South Texas/Plains/Canada business unit 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 in the onshore Gulf Coast area. The Gulf Onshore/Offshore business unit primarily conducts exploration activities in southern Louisiana and the Gulf of Mexico. During 1997, the Company drilled a successful deepwater well in Mississippi Canyon Block 755 in the Gulf of Mexico which resulted in the discovery of significant reserves. The Company has also formed an alliance with another major oil and gas company to evaluate a large geographic acreage position in southwestern Louisiana. During 1997, 42% of the production from the Gulf Onshore/Offshore business unit was attributable to Company-operated properties.

East Texas Business Unit. The East Texas business unit manages the Company's oil and gas activities in eastern Texas. The East Texas business unit's activities are concentrated in two major areas: the Carthage and Oakhill fields. In addition, the Company conducted exploration activities in the Cotton Valley Pinnacle Reef

Trend. For the year ended December 31, 1997, 81% of the production from the East Texas business unit 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 has drilled over 850 wells in the Ozona area which is characterized by long-lived natural gas wells that typically produce for 30 or more years. In addition, the Company has recently applied its horizontal expertise in the western Texas area and has drilled over 50 horizontal wells. As of December 31, 1997, approximately 95% of the producing wells in the West Texas business unit were Company-operated and 92% of the production in West Texas business unit was attributable to Company-operated properties.

Gathering, Processing and Marketing Operations

Processing. As of December 31, 1997, the Company owned interests in 24 natural gas processing plants, 19 of which it operates, with a current throughput capacity of 3.4 Bcfd (1.8 Bcfd net to the Company). In 1997, the Company expanded its gathering, processing and marketing business unit with the purchase of Highlands Gas Corporation ("Highlands") which included three gas processing plants. The Company was able to add approximately 300 MMcfd throughput capacity with the purchase of Highlands, start-up of the new Masters Creek plant in Louisiana and the expansion of the Patrick Draw plant in Wyoming. Aggregate throughput of the Company's gas processing plants for the year ended December 31, 1997 averaged 83% of the plants' aggregate design capacity. For the year ended December 31, 1997, production of natural gas liquids attributable to the Company's ownership interest in gas processing facilities averaged approximately 41.7 MBbld. See "Properties—Gas Processing Assets".

Gathering. The Company invests in gathering systems and natural gas, natural gas liquids and crude oil pipelines. Some of the Company's more significant investments in pipelines and gathering systems, include: (1) the Company's 50% interest in the Black Lake Pipeline, a 317 mile pipeline in Louisiana which transports natural gas liquids from the Austin Chalk area to markets on the Gulf Coast; (2) the Company's 90% interest in the Panola Pipeline in the eastern Texas area; (3) the Company's 100% interest in the Sonora/Fin Tex NGL Pipeline which serves the western Texas area; (4) the Company's 55% interest in the Ferguson-Burleson County Gas Gathering System ("Ferguson-Burleson"), which serves the Giddings area of the Austin Chalk area; (5) the Company's 99% interest in the Overland Trail Transmission Company pipeline, a 305 mile pipeline, serving the Green River Basin in Wyoming; and (6) the Company's 100% interest in the Wahsatch Gathering System, a sour gas pipeline serving the Overthrust area in Wyoming. In addition to the systems listed in the "Properties-Pipeline Assets" table, the Company generally 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 plants.

Marketing. In 1997, the Company, primarily through UP Fuels, sold approximately 2 Bcfd of natural gas (about 57% of which represented the Company's equity production), 145 MBbld of natural gas liquids (including 73 MBbld of third party liquids) and 68 MBbld of crude oil and condensate (including 15 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 eastern 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. To maximize profits, UP Fuels sells crude oil directly to refiners whenever possible. UP Fuels also exchanges or sells the crude oil volumes to major trading locations, where the crude oil is 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,		
	1997	1996	1995
Producing Properties:			
Average daily production: ¹			
Natural gas (MMcfd)	1,102.3	980.3	915.6
Natural gas liquids (MBbld)	29.9	28.5	23.1
Crude oil (MBbld)	52.9	50.6	52.8
Total (MMcfd)	1,598.8	1,454.9	1,371.0
Average sales prices:			
Natural gas (per Mcf)	\$ 2.00	\$ 1.86	\$ 1.42
Natural gas liquids (per Bbl)	11.20	11.39	8.14
Crude oil (per Bbl)	18.36	18.84	16.08
Production costs (per Mcfe): ²	0.50	0.49	0.42
Gas Processing Plants:			
Average daily sales volumes attributable to gas plant ownership: ³			
Natural gas (MMcfd)	30.5	26.7	23.9
Natural gas liquids (MBbld)	41.7	39.8	34.2
Total (MMcfd)	280.5	265.4	229.1
Average sales prices:			
Natural gas (per Mcf)	\$ 2.40	\$ 2.01	\$ 1.51
Natural gas liquids (per Bbl)	11.91	13.16	9.38

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

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

³ Represents the Company's portion, by virtue of its ownership interest in gas processing facilities, of natural gas and natural gas liquids earned by such facilities in connection with the processing of natural gas. The portion of the total average daily sales volumes representing the Company's portion earned by such facilities with respect to processing the Company's production for each of the three years ended December 31, 1997, 1996 and 1995 are 63.9 MMcfd, 77.1 MMcfd and 66.5 MMcfd, respectively. See "Supplementary Information—Average Daily Production and Sales Volume".

Minerals Operations

Minerals operations contribute 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 into its oil and gas operations. For the year ended December 31, 1997, the Minerals operations generated \$135.5 million of operating income of the Company as follows:

	1997 Operating Income	
	Amount	Percent
(Millions of dollars)		
Royalties:		
Soda ash ¹	\$ 41.9	31%
Coal ²	16.4	12
Total royalties	58.3	43
Nonoperated joint ventures:		
Soda ash ³	7.6	6
Coal ⁴	66.9	49
Total joint ventures	74.5	55
Overhead/other	2.7	2
Total operating income	\$135.5	100%

(Footnotes continued on next page)

- 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 1997, 58% 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, \$59.3 million is attributable to a single coal supply contract, the financially beneficial terms of which terminate at the end of year 2000. 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 United States coals for industrial and utility boiler markets. At current coal pricing and extraction cost levels, however, most of the coal deposits are not economic to extract, except for sale to local markets. As a result, there are currently 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 production from Wyoming has increased to 30% of the world's soda ash supply with the remainder principally from synthetic processes. As a result of the increase in the worldwide demand for soda ash, the Company, along with its partner Oriental Chemical Industries, Inc. ("OCI"), 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. For the year ended December 31, 1997, the Company invested an additional \$19.7 million in OCI Wyoming LP and guaranteed 49% of a \$100 million credit facility to finance the soda ash facility expansion.

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. 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. Although a few issues were remanded to the FERC by the Court of Appeals, the outcome of the remanded proceedings is not expected to have a significant impact on the Company. The remanded proceedings are pending before the FERC. Several parties petitioned the Supreme Court to review the Court of Appeals' decision. The Court, in 1996, denied the parties' petitions and therefore the Order No. 636 Series is no longer subject to court review but for the remanded proceeding referenced above. 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 conducted inquiries regarding the scope of its regulation of gathering facilities and services. The Company owns and operates extensive gathering systems in Texas. In 1996, the Texas Railroad Commission initiated a rulemaking and ultimately issued new regulations regarding gathering. Although the new regulations increased the regulatory burden to a limited extent, the regulations are not expected to have a significant impact on the Company's 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 a 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 both coal seam natural gas and natural gas produced from tight sand formations), subject to a number of limitations ("Section 29 tax credits"). Fuels qualifying for the tax credit must be produced from a well drilled or a facility placed in service after December 31, 1979 and before January 1, 1993, and be sold before January 1, 2003.

The basic credit, which 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 phase-out would be triggered if the average price for crude oil rose above approximately \$45 per barrel 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 Wyoming, the Carthage field in eastern Texas, the Ozona field in western Texas and certain areas in the Austin Chalk trend qualifies for this tax credit. The Company recorded approximately \$18.8 million of Section 29 tax credits in 1997. Section 29 tax credits are not creditable against the alternative minimum tax but under certain circumstances may be carried over and applied against regular tax liability in future years. Therefore, no 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 ("Section 29 Limited Partnership"). This Section 29 Limited Partnership utilized drilling funds contributed by the investor-as limited partner and drilled 208 wells which qualify for Section 29 tax credits. The Company was the managing general partner of this Section 29 Limited Partnership and had broad latitude in conducting its operations. Prior to a defined payout, the limited partner was entitled to receive a preferential distribution of a specified quantity of available production from this Section 29 Limited 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 was entitled to receive only 1% of ongoing production of this Section 29 Limited Partnership. The historic production allocable to the limited partner has been deducted from the Company's reserve and production statistics. Effective December 1997, the Company purchased the limited partner's interest in this Section 29 Limited Partnership.

Texas Severance Tax Reduction

Natural gas produced from wells that have been certified as tight formations or deep wells by the Texas Railroad Commission ("high cost wells") and that 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. Such exemption ends August 31, 2001. The natural gas production

from wells drilled on certain of the Company's properties, primarily in the Austin Chalk, West Texas and 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 until the later of 180 days after first production or the 45th day of approval by the Texas Railroad Commission to obtain a high cost gas certification without incurring a 10% tax penalty. 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 reductions received equals 50% of the total drilling and completion costs.

Environmental Regulation

The Company's operations are subject to extensive federal, state, provincial and local environmental laws and regulations governing the protection of the environment. The Company is in compliance, in all material respects, with applicable environmental requirements. Although future environmental obligations are expected to have a material impact on the results of operations or financial condition of the Company, there is 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 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 operator 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 the definition of hazardous substance, many state laws affecting the Company's operations impose clean-up liabilities regarding petroleum and petroleum related products. In addition, although RCRA classifies certain oil production 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 on the oil and gas industry in general. See "Other Matters—Environmental Costs."

Oil Spills. Under the Oil Pollution Act of 1990 ("OPA"), owners and operators of onshore facilities, 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 the 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. Therefore, the financial responsibility requirements applicable under laws existing prior to OPA still apply to

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 for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties. In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. In addition to replacing a variety of older statutes which related to environmental matters, AEPEA also imposes certain 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 1,907 employees as of December 31, 1997, 22 of whom were not full time employees. The Company believes that its relations with its employees are good.

Other Business Matters

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

Item 2. Properties

Proved Reserves

The following table sets forth the proved developed and undeveloped reserves of natural gas, natural gas liquids and crude oil of the Company as of December 31, 1997. 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. Ryder Scott Company Petroleum Engineers ("Ryder Scott") has provided an opinion with respect to the Company's estimate of its proved reserves as of December 31, 1997. Such opinion states that on a total Company basis, Ryder Scott is in agreement with the Company's estimate of proved reserves for the properties which they reviewed. For further information concerning Ryder Scott's review of the proved reserves of the Company as of December 31, 1997, see Ryder Scott's letter, dated February 27, 1998, included as Exhibit 99 to this Annual Report on Form 10-K.

Category of Reserves	As of December 31, 1997			
	Natural Gas (Bcf)	Natural Gas Liquids (MMBbl)	Crude Oil (MMBbl)	Total (Bcfe)
Proved developed	2,217.0	103.3	93.9	3,400.2
Proved undeveloped	403.3	14.6	34.9	700.2
Total proved reserves	<u>2,620.3</u>	<u>117.9</u>	<u>128.8</u>	<u>4,100.4</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, 1997.

Business Unit	Total Acres	
	Gross	Net
	(In thousands)	
Austin Chalk	31	1
Rockies ¹	3,253	3,253
South Texas/Plains/Canada ¹	5,316	4,921
Gulf Onshore/Offshore	215	7
East Texas	46	1
West Texas	690	23
Total fee acreage	<u>9,551</u>	<u>8,504</u>

¹ The fee mineral acreage associated with the Land Grant is included in Rockies and South Texas/Plains/Canada business units

7,912 7,72

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, including the Land Grant, is primarily undeveloped.

Leasehold. The Company's leasehold acreage by business unit as of December 31, 1997 is set forth below.

Business Unit	Acres					
	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
Austin Chalk	959	732	1,667	1,396	2,626	2,128
Rockies	117	69	215	154	332	223
South Texas/Plains/Canada	429	205	1,010	639	1,439	844
Gulf Onshore/Offshore	314	285	461	261	775	546
East Texas	266	137	561	327	827	464
West Texas	232	141	162	132	394	273
Total leasehold acreage	<u>2,317</u>	<u>1,569</u>	<u>4,076</u>	<u>2,909</u>	<u>6,393</u>	<u>4,478</u>

Total Leasehold and Fee Mineral. The total leasehold and fee mineral acreage by business unit as of December 31, 1997 is set forth below.

Business Unit	Total Acres	
	Gross	Net
	(In thousands)	
Austin Chalk	2,657	2,139
Rockies	3,585	3,475
South Texas/Plains/Canada	6,755	5,766
Gulf Onshore/Offshore	990	619
East Texas	873	476
West Texas	1,084	511
Total leasehold and fee acreage	<u>15,944</u>	<u>12,986</u>

Drilling Activity and Producing Well Summary

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

	Years Ended December 31,					
	1997		1996		1995	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	685	478.6	575	413.4	679	505.7
Dry	59	46.2	35	25.7	18	7.7
Exploration wells:						
Productive	35	19.1	16	8.5	6	2.8
Dry	38	22.1	29	18.2	22	10.7
Total wells	<u>817</u>	<u>566.0</u>	<u>655</u>	<u>465.8</u>	<u>725</u>	<u>526.9</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, 1997, the Company owned a working interest in 6,043 gross gas wells (3,574 net) and 2,763 gross oil wells (1,636 net). Gross wells include 611 wells with multiple completions. The Company operated 61% of the gross wells in which it owned an interest.

Gas Processing Assets

A listing of the Company's processing plants and their gross design capacity is provided below. Generally each of the processing plants has an extensive gathering system. Average throughput in such processing plants for 1997 was approximately 83% of such processing plants' design capacity.

Gas Plants	As of December 31, 1997		Average Gross Volumes Year Ended December 31, 1997	
	Working Interest Percent	Design Capacity (MMcfd)	Natural Gas Throughput (MMcfd)	Natural Gas Liquids Produced (MMbbl)
Rockies				
*Anschutz Ranch East	12	650	370	17.3
Brady ¹	50	0	63	2.4
*Painter	19	260	248	13.2
Pineview	49	15	2	0.2
*Whitney Canyon	19	235	176	7.2
South Texas/Plains/Canada				
Bledsoe	100	2	1	—
*Caroline	7	300	340	31.0
Mt. Pearl	52	11	11	0.4
Silo	100	5	2	0.3
GPM				
A&M ²	55	50	49	4.6
Brookeland	80	100	80	6.4
Bryan	55	60	58	10.2
Conroe	100	65	33	0.8
East Carlsbad ³	100	23	24	2.3
East Texas Plant Complex ^{4,5}	90	660	653	39.6
*Echo Springs	34	240	233	16.3
Emigrant Trail	100	60	37	1.9
Gulf Plains ^{4,6}	100	110	82	5.3
Hulldale ³	100	18	11	1.6
Masters Creek ⁷	62	100	47	4.3
Ozona ⁴	63	120	113	11.8
Patrick Draw ^{4,8}	100	120	25	1.7
Sonora ^{4,3}	100	68	62	5.6
S.W. Ozona	100	90	68	7.5
Yellow Creek ⁴	100	80	30	0.2
Total		<u>3,442</u>	<u>2,818</u>	<u>192.1</u>

* Nonoperated

¹ This plant ceased processing gas in August 1997; however, this plant continues to treat sour gas. This plant's average natural gas throughput and natural gas liquids produced are set forth for the period January through August 1997.

² This plant was shut down February 1998.

³ This plant is one of several plants acquired in the purchase of Highlands effective as of August 1997.

⁴ Includes fractionation facilities.

⁵ This plant's design capacity during 1997 was 660 MMcfd. This plant's design capacity is expected to increase by an additional 12 MMcfd to 780 MMcfd beginning in March 1998.

⁶ This plant's design capacity is expected to increase by 50 MMcfd in mid-year 1998.

⁷ This plant became operational in August 1997 with 100 MMcfd; this plant's design capacity is expected to increase to 200 MMcfd in February 1998. Natural gas throughput and natural gas liquids produced represent averages for the period August through December 1997.

⁸ This plant's design capacity was expanded from 30 MMcfd to 120 MMcfd during December 1997.

Pipeline Assets

A listing of the Company's pipeline assets is provided below.

Pipeline System by Geographic Area	As of December 31, 1997			
	Working Interest %	Products Shipped	Line Size (in inches)	Number of Miles
Eastern Texas and Louisiana				
Jasper Pipeline	100	NGL	6	19
*Ferguson-Burleson gathering	55	Gas	2 - 18	1,509
*Black Lake Pipeline	50	NGL	6 - 8	317
Eastern Texas—Carthage				
East Texas Gas Systems	90	Gas	10 - 12	121
San Jacinto Pipeline	90	NGL	4 - 8	35
Panola Products Pipeline	90	NGL	8 - 10	195
Eastrans Ltd. Pipeline	90	Gas	8 - 12	33
Southern Texas				
Stratton Crude/Condensate Pipeline	100	Crude/ Condensate	3 - 4	32
Stratton Butane/Natural Gasoline	100	Butane/ Nat. Gasoline	2 - 6	38
Stratton Propane	100	Propane	3	10
Wyoming				
Emigrant Trail	100	NGL	4	8
Overland Trail	99	Gas	4 - 16	305
Wahsatch Pipeline	100	Gas	4 - 10	40
Western Texas				
Transwestern Pipeline System	100	Gas	2 - 8	52
Sonora/Fin Tex Pipeline	100	NGL	8 - 10	384
Crockett Pipeline	90	NGL	8	25
Ozona Pipeline	100	NGL	6	23

* Nonoperated

Item 3. Legal Proceedings

Mineral Reservation Litigation

In August 1994, the surface owners (McCormick, et al.) 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 State District Court, Weld County, Colorado, to quiet title to minerals, including crude oil (in some of the lands) and natural gas. The State District Court heard arguments on the Company's motion for summary judgment on May 23, 1997. On June 23, 1997, the District Court granted the Company's motion holding as a matter of law that the mineral reservations at issue were unambiguous and included all valuable nonsurface substances, including oil and gas. A final judgment was entered on August 5, 1997. Thereafter, such surface owners filed a notice of appeal to the Colorado Court of Appeals on September 17, 1997.

Royalty Litigation

The Company is a defendant in a number of lawsuits in which plaintiffs allege that the Company underpaid their royalties on crude oil and natural gas production. In addition, certain of such suits allege that the Company has violated antitrust laws and other similar laws. None of this litigation articulates a theory of recovery or specific amounts of damages. This litigation against the Company and others in the oil and gas industry suggests that more suits of this type will be filed against the Company, including perhaps, suits by other types of interest owners and suits in other jurisdictions. The Company intends to defend vigorously against such litigation, as well as any similar lawsuits subsequently brought against the Company. In the opinion of management of the Company, the outcome of these matters should not have a materially adverse effect on the consolidated financial condition, cash flows or results of operations of the Company.

General

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 contract claims, personal injury claims and environmental claims. While management of the Company cannot predict the outcome of such litigation and other proceedings, management does not expect these matters to have a materially adverse effect on the consolidated financial condition, cash flows or results of operations of the Company.

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

There were no matters submitted to a vote of security holders during the fourth quarter ended December 31, 1997.

Executive Officers of the Registrant

The names, positions and ages of executive officers of the Company are set forth below:

<u>Name</u>	<u>Position</u>	<u>Age</u>
Jack L. Messman ¹	Chairman and Chief Executive Officer	58
George Lindahl III ²	President and Chief Operating Officer	51
V. Richard Eales ³	Executive Vice President	62
Thomas R. Blank ⁴	Vice President—State, Regulatory and Public Affairs	45
Anne M. Franklin ⁵	Vice President—People	41
Joseph A. LaSala, Jr. ⁶	Vice President, General Counsel and Secretary	43
Donald W. Niemiec ⁷	Vice President—Marketing	51
Morris B. Smith ⁸	Vice President and Chief Financial Officer	53
John B. Vering ⁹	Vice President—Canada	48

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 Union Pacific Resources Company ("UPRC") from May 1991 through October 1995.

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.

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 Mr. Blank has held his current position with the Company since August 1997. He was Communications Director for the Speaker of the House of Representatives for the United States from February 1997 to August 1997. From January 1994 to February of 1997, he was President of Hager Sharp, Inc. Prior thereto, he was the Senior Vice President of Hager Sharp, Inc.

⁵ 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.

- ⁶ Mr. LaSala has held his current position with the Company since January 1996 and assumed the role of Secretary in June 1997. Mr. LaSala joined UPRC as Assistant General Counsel in 1995. Prior to joining UPRC, he was Vice President—Government and Regulatory Affairs of USPCI, Inc., a former subsidiary of Union Pacific Corporation ("UPC"), from May 1993 until December 1994 and, prior thereto, Vice President—External Relations of USPCI, Inc.
- 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 March 1998. From October 1996 until March 1998 he was Vice President—Exploration and Production Services of the Company. 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 ("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 of Common Stock, as reported on the New York Stock Exchange Composite Tape, as well as the dividends declared on the Common Stock, is set forth under Selected Quarterly Data on page 63.

As of February 27, 1998, there were 251,043,100 shares of Common Stock outstanding and approximately 50,400 shareholders of record. The closing price of the Common Stock on the New York Stock Exchange on February 27, 1998 was \$22³/₈.

The Company has paid quarterly cash dividends of \$0.05 per share of Common Stock since its initial public offering in October, 1995. The Company currently intends to continue to pay quarterly cash dividends on its outstanding shares of Common Stock. The determination of the amount of future cash dividends, if any, to be declared and paid by the Company will depend upon, among other things, the Company's financial condition, funds from operations, the level of its capital and 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 February 1997, the Board of Directors adopted a stock purchase program which authorizes the Company to purchase up to \$50 million of its Common Stock outstanding in any given fiscal year. In December 1997, the Board of Directors approved a resolution to allow the Company to purchase an additional \$50 million of its Common Stock outstanding in 1998. As of December 31, 1997, the Company had purchased 2,013,400 shares of its Common Stock under this program for approximately \$49.9 million.

Item 6. Selected Financial Data

The following table contains selected historical financial data for each of last five fiscal years.

	Years Ended December 31,				
	1997	1996	1995	1994	1993
	(Millions of dollars, except per share amounts)				
Income Statement Data:					
Operating revenues	\$1,924.7	\$1,831.0	\$1,476.7 ^(a)	\$1,332.9	\$1,277.1
Operating income	495.2	526.6	470.1 ^(a)	351.3	382.9
Net income.....	333.0	320.8	350.7 ^(a)	390.0 ^(b)	243.8
Per share:					
Net income—basic ^(d)	1.33	1.29	n/a	n/a	n/a
Net income—diluted ^(d)	1.33	1.28	n/a	n/a	n/a
Dividends.....	0.20	0.20	0.05 ^(e)	n/a	n/a
Cash Flow Data:					
Capital and exploratory expenditures	\$1,531.7 ^(f)	\$ 880.3	\$ 686.4	\$1,389.3 ^(g)	\$ 560.4
Cash provided by operations	968.8	990.4	829.4	821.0	567.5
	As of December 31,				
	1997	1996	1995	1994	1993
Financial Position Data:					
Properties—net	\$3,665.4 ^(h)	\$2,972.4	\$2,764.3	\$2,600.1 ^(g)	\$1,780.2
Total assets	4,472.2	3,648.9	3,308.9	3,247.0	2,714.1
Long-term debt	1,230.6 ^(h)	670.9 ^(b)	101.5	37.7	45.6
Shareholders' equity	1,760.7	1,514.3	1,312.4	1,884.9	1,596.1

(Footnotes continued on next page.)

- (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 ("Columbia settlement") (see Note 4 to the Consolidated Financial Statements).
- (b) In March 1994, the Company sold its interest in the Wilmington field and Harbor Cogeneration Plant to the Port of Long Beach, California. Such sale resulted in a \$159.2 million pre-tax (\$100 million after-tax) gain.
- (c) 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.
- (d) Earnings per share prior to 1996 have been omitted as the Company was a wholly owned subsidiary of UPC until the Company's initial public offering ("Offering") in October 1995; therefore, net income per share is not applicable for periods prior to the fourth quarter of 1995.
- (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 1997, the Company increased debt by issuing commercial paper to fund its capital spending, including the acquisition of producing properties and Highlands.
- (h) 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 2 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 Annual Report on Form 10-K. The consolidated statements of income for previous periods include certain reclassifications that were made to conform to the current presentation. Such reclassifications affect 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, 1997 Compared to Year Ended December 31, 1996

Summary Financial Data

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Operating revenues	\$1,924.7	\$1,831.0
Operating expenses	1,429.5	1,304.4
Operating income	495.2	526.6
Net income	333.0	320.8

The Company reported net income of \$333 million for the year ended December 31, 1997 compared to \$320.8 million in 1996. Earnings per share on a diluted basis increased by 4% to \$1.33 from \$1.28 in 1996. Improvements were achieved from increased producing property volumes and prices and royalty income from mineral operations. In addition, the Company experienced higher other income and one-time tax benefits. These improvements were offset by a \$60.1 million increase in exploration expenses, reduced margins for gathering, processing and marketing ("GPM") operations, one-time costs of \$17.8 million relating to the Company's unsuccessful attempt to acquire Pennzoil Company and higher operating costs.

Operating income declined \$31.4 million (6%) from 1996 due to reduced margins for GPM operations, a \$60.1 million increase in exploration expenses and higher general and administrative costs, which more than offset improvements from producing properties and minerals operations.

Summary of Segment Financial Data

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Segment operating income:		
Producing properties	\$344.4	\$328.7
Gathering, processing and marketing	94.6	150.1
Minerals	135.5	120.0
Corporate/general and administrative	(79.3)	(72.2)
Total operating income.....	<u>\$495.2</u>	<u>\$526.6</u>

Producing Property Operations

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Operating revenues.....	\$1,281.2	\$1,133.3
Other oil and gas revenues.....	53.5	65.0
Total operating revenues	1,334.7	1,198.3
Operating expenses:		
Production	292.6	259.5
Exploration	204.7	144.6
Depreciation, depletion and amortization	493.0	465.5
Total operating expenses	<u>990.3</u>	<u>869.6</u>
Operating income	<u>\$ 344.4</u>	<u>\$ 328.7</u>

Total operating revenues for producing property operations increased by \$136.4 million during 1997. The improvement in operating revenues was primarily due to prices, which were higher by \$0.07 per Mcfe from 1996 to \$2.20 per Mcfe in 1997. The higher prices provided an incremental \$104.5 million to operating revenues. Additional sales volume growth of 10% provided an incremental \$43.4 million to operating revenue.

	Years Ended December 31,			
	1997 (without hedging)	1996	1997 (with hedging)	1996
Average price realizations—producing properties:				
Natural gas (per Mcf)	\$ 2.19	\$ 1.94	\$ 2.00	\$ 1.86
Natural gas liquids (per Bbl)	11.20	11.39	11.20	11.39
Crude oil (per Bbl)	18.80	20.09	18.36	18.84
Average (per Mcfe).....	2.34	2.23	2.20	2.13

	Years Ended December 31,	
	1997	1996
Production volumes—producing properties:		
Natural gas (MMcfd)	1,102.3	980.3
Natural gas liquids (MBbld)	29.9	28.5
Crude oil (MBbld).....	52.9	50.6
Total (MMcfd)	<u>1,598.8</u>	<u>1,454.9</u>

Natural gas volumes increased 122 MMcfd (12%) over 1996 primarily due to the extensive drilling programs in several business units and a lower distribution of preferential volumes related to the Company's Section 29 Limited Partnership (57.1 MMcfd). Gas volumes from the South Texas/Plains/Canada business unit were up 22.6 MMcfd primarily due to the drilling program in southern Texas. The East Texas business unit's volumes increased by 19.9 MMcfd primarily due to the acquisition and development of properties acquired from Castle Energy. The West Texas business unit's gas volumes improved 15.1 MMcfd due to continued success with its horizontal drilling program. In addition, the Gulf Onshore/Offshore business unit gas volumes rose 14 MMcfd primarily due to its drilling program in the southern Louisiana area. The Austin Chalk business unit's gas volumes increased 10.8 MMcfd due to its success in the deep Giddings field. These improvements were partially offset by a 17.1 MMcfd reduction in Rockies business unit's gas volumes caused by production declines. Crude oil volumes increased by 2.3 MBbld (5%) primarily due to drilling successes in the Masters Creek field in Louisiana. Natural gas liquids volumes rose 1.4 MBbld (5%) with most of the improvement attributable to the East Texas business unit.

Production costs increased \$33.1 million to \$292.6 million for 1997, primarily due to a \$30.6 million increase in lease operating expenses. Such increase reflects the impact of higher volumes, as well as increased costs for workovers, maintenance and salt water disposal, primarily in the Austin Chalk business unit. Total production expenses per Mcfe increased to \$0.50 in 1997 from \$0.49 in 1996.

Exploration expenses were up \$60.1 million to \$204.7 million compared to 1996 reflecting the Company's expanded exploration programs. Surrendered lease costs were higher by \$24.1 million as a result of more leasing activity in the East Texas and the Austin Chalk business units. Delay rentals rose \$10.4 million, primarily in Austin Chalk and the Gulf Onshore/Offshore business units. In addition, geological and geophysical costs were higher by \$16.2 million, primarily in the Gulf Onshore/Offshore business unit, while dry hole costs were up by \$8.4 million, primarily in the East Texas and Gulf Onshore/Offshore business units.

Producing property depreciation, depletion and amortization expense increased \$27.5 million due to higher production volumes. This increased expense, was partially offset by a lower unit of production rate. There were write-downs of assets of \$24.4 million in the South Texas/Plains/Canada business unit relating to Moca Dome in 1997 and \$26.4 million in the Rockies and Gulf Onshore/Offshore business units in 1996.

Gathering, Processing and Marketing Operations

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Operating revenues.....	\$443.3	\$503.8
Gas purchases	161.3	167.0
Operating margin	282.0	336.8
Other oil and gas revenues.....	6.9	—
Operating expenses:		
Operating costs	123.9	123.0
Depreciation, depletion and amortization.....	70.4	63.7
Total operating expenses	194.3	186.7
Operating income	<u>\$ 94.6</u>	<u>\$150.1</u>

Margins for the GPM operations declined \$54.8 million to \$282 million in 1997. Plant margins were down \$26.2 million resulting from lower sales prices (\$15.2 million), higher gas purchase costs and lower gas plant fees despite a 6% improvement in volumes (\$11.9 million). Pipeline margins declined \$3.7 million from 1996 reflecting lower throughput at Ferguson-Burleson and Wahsatch pipelines. This lower throughput was partially offset by higher volumes provided by the acquisition of Highlands. Marketing margins declined by \$24.9 million as a result of higher crude oil purchase costs and reduced margins for natural gas and natural gas liquids. Such higher costs and reduced margins were partially offset by additional margins on volumes from the acquisition of Highlands.

Other oil and gas revenues in 1997 primarily reflect a \$6.4 million gain on the sale of the Company's investment in the Frontier Pipeline.

	Years Ended December 31,	
	1997	1996
Average price realizations—plants:		
Natural gas (per Mcf)	\$ 2.40	\$ 2.01
Natural gas liquids (per Bbl)	11.91	13.16
Average (per Mcfe)	2.03	2.18
Sales Volumes—plants:		
Natural gas (MMcfd)	30.5	26.7
Natural gas liquids (MBbld)	41.7	39.8
Total (MMcfd)	280.5	265.4

Plant gas volumes increased by 3.8 MMcfd over the volumes in 1996, due to the Highlands acquisition (8.3 MMcfd) and the Masters Creek plant start-up. These volume increases were partially offset by lower inlet volumes at the Brookeland plant (5.1 MMcfd). Plant natural gas liquids volumes increased by 1.9 MBbld primarily due to the Highlands acquisition (2.2 MBbld) and the Masters Creek start-up.

GPM operating costs increased by \$0.9 million to \$123.9 million for 1997. Higher costs relating to the assets acquired from Highlands; plant start-ups and the addition of support staff, more than offset the absence of the \$17 million 1996 asset impairment adjustment for the Wahsatch pipeline.

Depreciation, depletion and amortization for the GPM operations increased \$6.7 million, primarily due to the higher asset base resulting from plant expansions and the acquisition of Highlands.

Minerals Operations

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Operating revenues	\$139.8	\$128.9
Operating expenses	3.4	8.0
Depreciation, depletion and amortization	0.9	0.9
Operating income	<u>\$135.5</u>	<u>\$120.0</u>

Minerals operating income increased by \$15.5 million over the income in 1996, primarily due to higher lease bonus and royalty income (\$15.4 million) as a result of higher soda ash volumes and prices. Operating expenses for the minerals operations declined compared to 1996, primarily due to the shutdown of the Company's ballast operations.

General and Administrative Expenses

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
General and administrative expenses	\$(75.5)	\$(68.4)
Depreciation, depletion and amortization	(3.8)	(3.8)
Corporate/general and administrative	<u>\$(79.3)</u>	<u>\$(72.2)</u>

General and administrative expenses were \$7.1 million higher than 1996, due to costs associated with the implementation of employee ownership and culture change programs, increased costs for upgrades and maintenance of the Company's computer systems and higher personnel costs related to additional hiring. General and administrative expenses per Mcfe remained flat at \$0.11 per Mcfe from 1996 to 1997.

Other Income

Other income of \$24.3 million was \$27.7 million higher than 1996, due to a \$23 million reserve reduction relating to oil and gas properties in Wilmington, California which were sold in 1994. Such reserves were reduced due to the expiration of certain indemnification obligations and a reduction of other exposure. Other income also includes a \$7.2 million gain on the sale of securities held for investment and \$10 million in environmental insurance settlements. These items were partially offset by \$17.8 million in costs relating to the unsuccessful bid to acquire Pennzoil Company.

Income Taxes

Income taxes of \$133.4 million were \$18.4 million lower than 1996, reflecting lower income before taxes, \$9.9 million in prior period state and federal tax adjustments and an increase in Section 29 tax credits. In contrast, 1996 included a \$3 million unfavorable state tax adjustment. Excluding these adjustments, the effective tax rate for 1997 would have been 30.7% (including \$18.8 million of Section 29 tax credits), compared to 31.5% for 1996 (including \$15.6 million of Section 29 tax credits).

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

Summary Financial Data

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

The Company reported net income of \$320.8 million for the year ended December 31, 1996, compared to \$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 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 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), net income for 1996 would have been \$4.6 million above pro forma net income for 1995 (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 settlement. These gains were offset partially by property write-downs, cost increases associated with expanded exploration activity and increased administrative expenses associated with being an independent public company.

Summary of Segment Financial Data

	Years Ended December 31,	
	1996	1995
	(Millions of dollars)	
Segment operating income:		
Producing properties	\$328.7	\$307.7
Gathering, processing and marketing	150.1	107.8
Minerals	120.0	107.1
Corporate/general and administrative	(72.2)	(52.5)
Total operating income.....	<u>\$526.6</u>	<u>\$470.1</u>

Producing Property Operations

	Years Ended December 31,	
	1996	1995
	(Millions of dollars)	
Operating revenues	\$1,133.3	\$ 851
Other oil and gas revenues	65.0	157
Total operating revenues	1,198.3	1,011
Operating expenses:		
Production	259.5	211
Exploration	144.6	87
Depreciation, depletion and amortization	465.5	40
Total operating expenses	869.6	70
Operating income	<u>\$ 328.7</u>	<u>\$ 30</u>

Total operating revenues for producing property operations increased by \$187.6 million to \$1,198.3 million in 1996. Production volume increases of 83.9 MMcf added \$39.6 million in revenues while higher prices \$0.42 per Mcfe added \$240.1 million in revenues.

Other oil and gas revenues declined by \$92.1 million in 1996 reflecting the absence of the Columbia settlement (\$122.5 million), lower preferential volumes distributed to an investor in a Section 29 Limited Partnership (\$10.1 million) and lower net gains on property sales. Such decline was partially offset by reduction of reserves for the Columbia settlement in 1996 and the absence of a hedging loss in 1995 of \$8.1 million.

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

	Years Ended December 31	
	1996	1995
Production volumes—producing properties:		
Natural gas (MMcfd)	980.3	935.6
Natural gas liquids (MBbld)	28.5	23.1
Crude oil (MBbld)	50.6	52.8
Total (MMcfd)	1,454.9	1,411.5

Natural gas volumes increased by 64.7 MMcfd to 980.3 MMcfd with increases from development drilling programs in the Austin Chalk (79.6 MMcfd) and West Texas (17.6 MMcfd) business units and a distribution of preferential volumes related to the Section 29 Limited Partnership (22.4 MMcfd). Offsetting increases were declines in Gulf Onshore/Offshore business unit (31.6 MMcfd) resulting largely from depletion of several offshore wells, and declines in the Rockies business unit (13.2 MMcfd) resulting from production problems. Natural gas liquids volumes from producing properties increased by 5.4 MBbld to 28.5 MBbld primarily due to ethane recovery in the Rockies and South Texas/Plains/Canada business unit and additional lease gas being processed in the Austin Chalk business unit by the expanded Brookeland plant. Crude oil volumes were 2.2 MBbld lower at 50.6 MBbld as a result of production declines in the Texas/Plains/Canada and Rockies business units and the sale of certain non-core properties, partially offset by property acquisitions and drilling in the Austin Chalk business unit.

Production expenses increased by \$49 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 million) and an unfavorable 1996 ad valorem tax adjustment (\$4.5 million). Lease operating costs were higher by \$16.1 million primarily in the Austin Chalk, East Texas and West Texas business units as a result of increased production volumes and greater workover costs. Production overhead was higher by \$4 million in 1996. Production expenses on a per Mcfe basis of \$0.49 were \$0.07 per 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 southern Louisiana, offshore, and North and South Dakota. The surrendered lease costs provision was \$29.1 million higher in 1996 than surrendered lease costs in 1995 reflecting a write-down of North and South Dakota leasehold (\$9.1 million) as well as increases in Austin Chalk and Gulf Onshore/Offshore business units leasing activity. Exploration overhead was \$5.4 million higher in 1996 than exploration overhead in 1995.

Depreciation, depletion and amortization expense increased by \$62.4 million to \$465.5 million in 1996 as a result of asset impairment adjustments related to certain properties in the Rockies and Gulf Onshore/Offshore business units (\$17.4 million), several offshore property write-downs (\$9 million), higher producing property volumes (\$25.8 million), and an unfavorable unit of production rate (\$11 million). On a per Mcfe basis, depreciation, depletion and amortization, excluding write-downs, increased \$0.02 per Mcfe to \$0.83 per Mcfe in 1996.

Gathering, Processing and Marketing Operations

	Years Ended December 31,	
	1996	1995
	(Millions of dollars)	
Operating revenues.....	\$503.8	\$339.9
Gas purchases	167.0	94.2
Operating margin	336.8	245.7
Other oil and gas revenues.....	—	9.8
Operating expenses:		
Operating costs	123.0	94.8
Depreciation, depletion and amortization	63.7	52.9
Total operating expenses	186.7	147.7
Operating income	<u>\$150.1</u>	<u>\$107.8</u>

Gathering, processing and marketing margins increased by \$91.1 million (37%) to \$336.8 million in 1996. Increased plant volumes of 36.3 MMcfed (16%) added \$21.2 million in plant revenues while higher prices of \$0.62 per Mcfe (40%) added \$59.8 million in plant revenues. Pipeline revenue increases of \$63.9 million in 1996 were primarily attributable to increased throughput and higher prices at the Ferguson-Burleson pipeline in the Austin Chalk area and the Ozona pipeline in western Texas. Revenues from the Wahsatch pipeline in the Rockies area were down due to lower throughput and tariff rates. Gas purchase costs were higher by \$72.8 million as a result of increased throughput and higher prices paid by the Ozona, Peachridge and Ferguson-Burleson pipelines and certain plants in the Austin Chalk area.

Marketing margins increased by \$24.6 million in 1996 primarily as a result of improved natural gas and natural gas liquids margins, additional marketed volumes and increased natural gas storage activity.

	Years Ended December 31,	
	1996	1995
Average price realizations—plants:		
Natural gas (per Mcf)	\$ 2.01	\$ 1.51
Natural gas liquids (per Bbl)	13.16	9.38
Average (per Mcfe)	2.18	1.56
Sales volumes—plants:		
Natural gas (MMcfd)	26.7	23.9
Natural gas liquids (MBbld)	39.8	34.2
Total (MMcfd)	265.4	229.

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

Gathering, processing and marketing expenses increased by \$28.2 million (30%) in 1996 due to an asset impairment adjustment related to the Wahsatch pipeline (\$17 million) and higher marketing expenses (\$9.6 million) associated with system development, legal and other operating costs. GPM depreciation, depletion and amortization costs increased \$10.8 million in 1996, primarily due to a higher asset base of plants and pipelines.

Minerals Operations

	Years Ended December 31,	
	1996	1995
	(Millions of dollars)	
Operating revenues	\$128.9	\$116.
Operating expenses	8.0	8
Depreciation, depletion and amortization	0.9	0
Operating income	<u>\$120.0</u>	<u>\$107</u>

Minerals operating income increased by \$12.9 million (12%) to \$120 million in 1996, as a result of \$6.7 million in higher soda ash joint venture income, an increase in ballast income, higher coal royalty income associated with more tons mined on the Company's leases and decreased operating expenses.

General and Administrative Expenses

	Years Ended December 31,	
	1996	1995
	(Millions of dollars)	
General and administrative expenses	\$(68.4)	\$(50)
Depreciation, depletion and amortization	(3.8)	(3)
Corporate/general and administrative	<u>\$(72.2)</u>	<u>\$(53)</u>

General and administrative expenses increased by \$19.7 million (38%) in 1996 as a result of increased costs associated with being a stand-alone public company and costs of completing information and accounting system conversions. On a pro forma basis, general and administrative expenses increased by \$0.01 per Mcfe to \$0.11 Mcfe. (See Note 2 to the Consolidated Financial Statements for pro forma income information).

Interest Expense and Other Income

Interest expense increased by \$31.5 million to \$50.6 million in 1996, while other income-net declined by \$10.4 million. These changes principally reflect the effects of the debt restructuring (higher debt balances and lower interest-earning advances to UPC) that occurred at the time of the Offering.

Income Taxes

Income taxes increased by \$44.5 million to \$151.8 million in 1996 due to higher income before taxes, a \$22.3 million decrease in Section 29 tax credits, a \$3 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).

LIQUIDITY AND CAPITAL RESOURCES

Cash provided by operations for 1997 was \$968.8 million, down by \$21.6 million from 1996. The decrease principally relates to unfavorable working capital changes due primarily to a reduction in accrued taxes payable, partially offset by favorable changes in deferred income taxes.

The Company expects to increase its oil and gas volumes in 1998 while growing its reserves. Sales volume growth is anticipated primarily in the Gulf Onshore/Offshore, South Texas/Plains/Canada and Austin Chalk business units. The Company expects to remain one of the most active drillers in the United States in 1998 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, volumes in the GPM business unit are anticipated to increase 15% as a result of the Company's acquisition of Highlands and recent expansions of Patrick Draw and Masters Creek plants.

Prices for oil, gas and natural gas liquids for 1998 are expected to be lower than the average for the previous years. Increased production from OPEC countries, including sales by Iraq, along with the decline in several Asian countries' economies has altered the balance between supply and demand for oil, sending recent oil prices 20% lower than in previous years. The recent mild weather in the United States resulting from the El Niño effect has also resulted in a downward trend in gas prices. The Company expects to experience price fluctuations and manages some price risk with hedging activities. Lower prices could materially affect expected future net income, cash flows and capital spending.

The Company owns a nonoperating 50% interest in Black Butte, a partnership which operates a surface coal mine complex in southwestern Wyoming ("Black Butte"). During 1997, Black Butte's sales to its largest customer under an amended coal supply contract accounted for \$59.3 million, or 12%, of the Company's consolidated operating income. This contract was amended in 1997 to accelerate the shipments from the year 2001 into the years 1998, 1999 and 2000, at which time the financially beneficial terms of this contract 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 of its competition. The Company does not expect to be able to replace the operating income it currently receives under the contract with incremental coal sales after the year 2000.

Capital spending increased by \$651.4 million (74%) to \$1,531.7 million in 1997, compared to \$880.3 million for 1996. The Company's ability to maintain and improve its operating income and cash flow is dependent upon continued capital spending, among other things. The following table summarizes capital expenditures for 1997 and 1996.

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Producing properties:		
Production	\$ 621.8	\$429.5
Exploration	399.3	237.5
Property acquisitions	130.6	85.7
Total producing properties	<u>1,151.7</u>	<u>752.7</u>
Gathering, processing and marketing	364.2	118.1
Minerals and other	15.8	9.5
Total capital expenditures	<u>\$1,531.7</u>	<u>\$880.3</u>

Producing property capital spending was up by \$399 million (53%) in 1997 as a result of higher lease acquisition costs of \$95.8 million, primarily in the Austin Chalk and East Texas business units and increased exploratory and development drilling (\$222.3 million). Drilling accounted for \$682.9 million (45%) of capital expenditures in 1997, with \$207.8 million in the Austin Chalk business unit. Property acquisitions totaling \$130.6 million were completed in 1997 compared to \$85.7 million in 1996. The Company expanded its GPM operations and increased its capital spending by \$246.1 million in 1997. The increase in GPM capital spending was related to the completion of the Masters Creek plant in Louisiana, expansion of the East Texas plant and the acquisition of Highlands.

The Company expects its capital spending in 1998 to be in the range of \$1.5 to \$1.8 billion, including projected spending associated with the Norcen acquisition. The Company plans to focus such spending primarily on exploration and development activities in the Austin Chalk, Gulf Onshore/Offshore, western Canada and Guatemala business units or areas. Such spending in the Gulf Onshore/Offshore business unit includes capital to drill two or three additional wells in the Gulf of Mexico in 1998 to further delineate the extent of the discovery in the Mississippi Canyon Block 755 deepwater prospect. In addition, the Company plans to acquire producing properties and expand its GPM operations.

As a result of continued increase in the worldwide demand for soda ash, the Company, along with its partner Oriental Chemical Industries, Inc. ("OCI") plans to expand the OCI Wyoming LP's 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 has made an additional investment and expects expansion costs to be primarily funded by a \$100 million credit facility of OCI Wyoming LP guaranteed by OCI 51% and the Company 49%.

As of December 31, 1997 and 1996, the total capitalization of the Company was as follows:

	As of December 31,	
	1997	1996
	(Millions of dollars)	
Commercial paper, net	\$ 663.1	\$ 99.6
7% Notes due 2006	200.0	200.0
7.5% Debentures due 2026	200.0	200.0
7.5% Debentures due 2096	150.0	150.0
Tax exempt revenue bonds	20.1	24.0
Discount on notes and debentures	(2.6)	(2.6)
Total long-term debt	1,230.6	670.0
Shareholders' equity	1,760.7	1,514.0
Total capitalization	<u>\$2,991.3</u>	<u>\$2,185.0</u>
Debt to total capitalization	<u>41.1%</u>	<u>30.0%</u>

None of the Company's Notes and Debentures are redeemable prior to maturity or subject to any sinking fund requirements. In addition, the Company has an effective Shelf Registration Statement on file with the Securities and Exchange Commission ("SEC"), which would permit the Company to offer up to \$900 million in debt and equity securities.

The Company has a \$600 million revolving credit agreement that expires in August 2001 and a \$300 million revolving credit agreement which expires in November 1998. Borrowings under these agreements, at the Company's election, bear interest either at a spread over London Interbank Offered Rate ("LIBOR") or at 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 0.06% to 0.15% also depending on the Company's senior debt rating. As a result of the Norcen acquisition, the covenants for these agreements have been modified. Under these agreements debt can not exceed 75% of the total of the Company's debt and shareholders' equity (and 65% after 18 months) and requires the combined EBITDAX (the sum of operating income; depreciation, depletion and amortization; and exploration expenses) of the Company and its Principal Subsidiaries (as defined in the agreements) to be at least 80% of the Company's consolidated EBITDAX. These agreements also impose certain restrictions on the Company regarding the creation of liens, incurrence of indebtedness, transactions with affiliates, sales of the stock of UPRC and certain merger consolidations and asset sales. As of December 31, 1997, there were no borrowings outstanding under the credit facilities although borrowing capacity is reduced by outstanding commercial paper. The Company had

capacity to borrow \$900 million, less commercial paper outstanding, under these agreements as of December 31, 1997.

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 issuance of commercial paper and term financings. In addition, the Company could borrow under the credit agreements.

As a result of the Norcen acquisition, the Company will increase its debt by \$3.6 billion, including \$2.7 billion acquisition debt and approximately \$900 million of existing commercial paper and debentures of Norcen. In addition to the covenants described above, the \$2.7 billion acquisition facility entered into by the Company includes a mandatory prepayment provision and a series of "prepayment events." The mandatory prepayment provision requires that \$1.35 billion be repaid prior to March, 1999. In addition, 75% of the net proceeds resulting from any prepayment events should be applied to reduce the indebtedness under the acquisition facility. Prepayment events include sales of assets in excess of \$10 million and debt and equity issuances. This increased debt is expected to raise the Company's debt to total capitalization ratio from 41% at December 31, 1997 to approximately 72% as of March 1998. The Company plans to pursue an aggressive deleveraging program, which may include asset and financial divestitures and the issuance of equity securities.

The Company paid cash dividends of \$50 million in 1997, which represents a \$0.05 per share quarterly cash dividend on its outstanding shares of Common Stock. On January 26, 1998, the Board of Directors declared a \$0.05 per share quarterly cash dividend for shareholders of record on March 11, 1998, payable April 1, 1998. 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 purchased \$52.3 million of its Common Stock during 1997. In November 1997, the Board of Directors authorized the purchase of an additional \$50 million of Common Stock during 1998.

The Company believes that cash from operations, additional available financing and proceeds from asset and financial divestitures will enable it to fund its ongoing capital expenditures, dividends and working capital requirements for the foreseeable future.

Item 7a. Risk Management

The Company has established policies and procedures for managing risk within its organization. These policies and procedures incorporate internal controls and are governed by a risk management committee. The level of risk assumed by the Company is based on its objectives and earnings, and its capacity to manage risk. Limits are established for each major category of risk, with exposures monitored and managed by Company management and reviewed by the risk management committee.

Commodity Price Risk—Non-Trading Activities

The Company uses derivative financial instruments for non-trading purposes in the normal course of business to manage and reduce risks associated with contractual commitments, price volatility, and other market variables. These instruments are generally put in place to limit risk of adverse price movements, however, these instruments usually limit future gains from favorable price movements. Such risk management activities are generally accomplished pursuant to exchange-traded contracts or over-the-counter options.

Recognition of realized gains/losses in the Consolidated Statement of Income and option premium payments/receipts are deferred until the underlying physical product is purchased or sold. Unrealized gains/losses on derivative financial instruments are not recorded. Margin deposits, deferred gains/losses on derivative financial instruments and net premiums are included in other current assets or liabilities in the Consolidated Statement of Financial Position. The cash flow impact of derivative and other financial instruments is reflected as cash flows from operating activities in the Consolidated Statement of Cash Flows.

As a result of the various hedging transactions for natural gas, natural gas liquids and crude oil, the Company realized \$28.1 million and \$45.5 million of pre-tax losses in 1997 and 1996, respectively. Since these transactions were hedges on production, these losses were included in sales and other operating revenue and were reflected in the average sales price of the associated products.

The following table summarizes the Company's open positions as of December 31, 1997.

Product	Contract Type	Contract Time Period	Volume	Weighted Avg. Prices Per Mcf	Fair Value (Millions of Dollars)	Unrecognized Gain (Loss) (Millions of Dollars)
Gas	Future/swaps	Feb-Mar 1998	449 MMcfd	\$2.33	\$ 3.7	\$ 3.
Gas	Future/swaps	Apr-Oct 1998	369 MMcfd	\$2.08	(4.3)	(4.)
Gas	Future/swaps	Nov-Dec 1998	100 MMcfd	\$2.17	(1.5)	(1.)
Gas	Calls sold	Feb-Mar 1998	405 MMcfd	\$3.20	0.1	3.
Gas	Net calls sold	Apr-Oct 1998	96 MMcfd	\$2.58	1.1	0.
Gas	Puts purchased	Feb-Mar 1998	450 MMcfd	\$2.21	5.5	1.
Gas	Puts purchased	Apr-Oct 1998	166 MMcfd	\$2.04	5.0	(0)
Gas	Fixed price	Feb 1998-Jun 2008	62.6 Bcf	\$2.98	28.1	28
						<u>\$31</u>

Additionally, the Company had previously sold near-term futures contracts and swaps for February through December 1998 with respect to notional natural gas volumes of 47 MMcfd, then subsequently offset these positions by purchasing corresponding volumes through futures contracts and swaps for the same periods. The unrealized gain at December 31, 1997 relating to these transactions was \$0.6 million. The Company periodically enters into financial contracts in conjunction with transportation, storage, and customer programs. The unrecognized mark-to-market loss associated with such contracts as of December 31, 1997, was \$0.5 million.

The Company had a total unrecognized mark-to-market present value gain of \$31.5 million relating to the financial and fixed price sales contracts described above. This gain consists of \$28.1 million net gain on term fixed price sales contracts and \$3.4 million net gain on financial derivative instruments. Unrecognized mark-to-market gains and losses were determined based on current market prices, as quoted by market dealers, assuming round lot transactions and using a mid-market convention without regard to market liquidity. The actual gains or losses ultimately realized by the Company from such hedges may vary significantly from the foregoing amounts due to the volatility of the commodity markets.

Commodity Price Risk-Trading Activities

Periodically, the Company may enter into transactions involving a wide range of energy related financial transactions that are not the result of hedging activities. These instruments are generally put in place based on the Company's analysis and expectations with respect to price movement or changes in other variables. As of December 31, 1997 and 1996, there were no commodity price risk-trading activities outstanding.

Interest Rate Swaps

The Company periodically enters into rate swaps and contracts to hedge certain interest rate transactions. As of December 31, 1997 and 1996, there were no interest rate contracts outstanding which materially affect the results of operations or financial condition of the Company.

Foreign Currency Contracts

The Company periodically enters into foreign currency contracts to hedge specific currency exposures on commercial transactions. As of December 31, 1997 and 1996, there were no foreign currency contracts outstanding.

Credit Risk

Credit risk is the risk of loss as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. Because the loss can occur at some point in the future, a potential exposure is added to the current replacement value, to arrive at a total expected credit exposure. The Company has established methodologies to establish limits, monitor and report creditworthiness and concentrations of credit to reduce such credit risk. At December 31, 1997, the Company's largest credit risk associated with any single counterparty, represented by the net fair value of open contracts with such counterparty was less than \$1 million.

Performance Risk

Performance risk results when a counterparty fails to fulfill its contractual obligations such as commodity pricing or volume commitments. Typically, such risk obligations are defined within the trading agreements. The Company utilizes its credit risk methodology to manage performance risk.

OTHER MATTERS

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 seven 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, 1997, long and short-term liabilities totaling \$75.7 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 \$37.8 million for the obligation to participate in the remediation of the Wilmington, California 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 \$14.7 million in 1997 and \$11.4 million in 1996. In 1998, the Company anticipates spending a total of \$20 million for remediation and control, including \$9 million relating to the Wilmington, California properties. The majority of accrued environmental liability as of December 31, 1997 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.

Year 2000 Issue

The Company has adopted a Year 2000 Readiness Program and an implementation plan. The Company is in the process of conducting a comprehensive evaluation and assessment of the business risks and exposures related to the coming change in the century. These business risks and exposures relate to the problem present in certain

software and embedded logic control devices to recognize the change in the century. If not corrected, such software and devices could fail or create erroneous results by or at the year 2000.

Since 1993, the Company has replaced all major information systems with Year 2000 compliance as criterion; therefore, the Company does not currently expect to incur any material amount of expense associated with its remediation of its major information systems. With respect to the risks and exposures related to the Company's customers, partners, suppliers, financial institutions and other constituencies and the resulting potential impact on the Company's business operations and financial condition, the Company has initiated formal communications with its customers, partners, suppliers, financial institutions and other constituencies to mitigate or prevent such risks and exposures. The extent of such risks and exposures will be assessed and evaluated.

The evaluation and assessment of the extent of the risks and exposures related to the Company's information systems, including embedded logic devices, and the Company's customers, partners, suppliers, financial institutions, and other constituencies, should be substantially completed during 1998. The Company has retained a consultant to advise the Company in the evaluation and assessment phase of the implementation plan. The costs associated with the Year 2000 Readiness Program and its implementation are not currently expected to be material. Until the evaluation and assessment is completed, the Company can not have a reasonable basis to conclude that the risks and exposures related to the Year 2000 will not materially affect future financial results or cause reported financial information not to reflect fairly the future operating results, cash flows 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 SEC (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, production volumes, hydrocarbon reserves, hydrocarbon prices, hedging activities and the results thereof, liquidation, 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 which 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 and 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 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; 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, 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:

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

	<u>Page</u>
Responsibilities for Financial Statements	33
Independent Auditors' Report	34
Consolidated Statements of Income for the Years Ended December 31, 1997, 1996 and 1995	35
Consolidated Statements of Financial Position as of December 31, 1997 and 1996	36
Consolidated Statements of Cash Flows for the Years Ended December 31, 1997, 1996 and 1995 ...	37
Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 1997, 1996 and 1995	38
Business Segment Information	39
Notes to Consolidated Financial Statements.....	40
Supplementary Information (Unaudited)	59

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

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, 1997 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, 1997. 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, 1997 and 1996, and the results of operations and its cash flows for each of the three years in the period ended December 31, 1997 in conformity with generally accepted accounting principles.

DELOITTE & TOUCHE LLP

Fort Worth, Texas
January 26, 1998

UNION PACIFIC RESOURCES GROUP INC.
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 1997, 1996 and 1995

	<u>1997</u>	<u>1996</u>	<u>1995</u>
	(Millions, except per share amounts)		
Operating revenues: (Note 5)			
Oil and gas operations:			
Producing properties	\$1,281.2	\$1,133.3	\$ 853.6
Gathering, processing and marketing	443.3	503.8	339.9
Other oil and gas revenues (Note 4)	60.4	65.0	166.9
Total oil and gas operations	1,784.9	1,702.1	1,360.4
Minerals (Note 12)	139.8	128.9	116.3
Total operating revenues	<u>1,924.7</u>	<u>1,831.0</u>	<u>1,476.7</u>
Operating expenses:			
Production	292.6	259.5	210.5
Exploration	204.7	144.6	89.4
Gathering, processing and marketing	285.2	290.0	189.0
Minerals (Note 12)	3.4	8.0	8.8
Depreciation, depletion and amortization	568.1	533.9	458.6
General and administrative	75.5	68.4	50.3
Total operating expenses	<u>1,429.5</u>	<u>1,304.4</u>	<u>1,006.6</u>
Operating income	495.2	526.6	470.1
Other income (expense)—net (Notes 3 and 4)	24.3	(3.4)	7.0
Interest expense—net (Notes 3 and 8)	(53.1)	(50.6)	(19.1)
Income before income taxes	466.4	472.6	458.0
Income taxes (Note 7)	(133.4)	(151.8)	(107.3)
Net income (Note 2)	<u>\$ 333.0</u>	<u>\$ 320.8</u>	<u>\$ 350.7</u>
Earnings per share—basic (see Significant Accounting Policies—Earnings Per Share)	\$ 1.33	\$ 1.29	
Earnings per share—diluted	\$ 1.33	\$ 1.28	
Weighted average shares outstanding—diluted	250.9	250.1	
Cash dividends per share	\$ 0.20	\$ 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, 1997 and 1996

	<u>1997</u>	<u>1996</u>
	(Millions of dollars)	
ASSETS		
Current assets:		
Cash and temporary investments	\$ 70.6	\$ 118.9
Accounts receivable (net of allowance for doubtful accounts of \$3.9 million in 1997 and \$4.5 million in 1996)	385.4	351.6
Inventories	53.1	29.4
Other current assets	<u>67.7</u>	<u>86.4</u>
Total current assets	<u>576.8</u>	<u>586.3</u>
Properties: (Notes 6 and 18)		
Cost	7,414.4	6,190.0
Accumulated depreciation, depletion and amortization	<u>(3,749.0)</u>	<u>(3,217.6)</u>
Total properties	3,665.4	2,972.4
Intangible and other assets (Note 12)	<u>230.0</u>	<u>90.2</u>
Total assets	<u>\$ 4,472.2</u>	<u>\$ 3,648.9</u>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 426.7	\$ 407.4
Accrued taxes payable	59.3	134.1
Other current liabilities	<u>71.7</u>	<u>71.3</u>
Total current liabilities	557.7	612.8
Long-term debt (Notes 8 and 18)	1,230.6	670.9
Deferred income taxes (Note 7)	552.9	434.7
Retiree benefits obligations (Note 10)	147.7	151.4
Other long-term liabilities (Notes 12, 13, 14 and 15)	222.6	264.8
Shareholders' equity (see page 38)	<u>1,760.7</u>	<u>1,514.1</u>
Total liabilities and shareholders' equity	<u>\$ 4,472.2</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, 1997, 1996 and 1995

	1997	1996	1995
	(Millions of dollars)		
Cash provided by operations:			
Net income	\$ 333.0	\$ 320.8	\$ 350.7
Non-cash charges to income:			
Depreciation, depletion and amortization	568.1	533.9	458.6
Deferred income taxes (Note 7)	119.7	37.0	(18.3)
Other non-cash charges (credits)—net	(35.0)	8.0	(65.8)
Exploratory expenditures	76.9	51.6	36.0
Changes in current assets and liabilities	(93.9)	39.1	68.2
Cash provided by operations	<u>968.8</u>	<u>990.4</u>	<u>829.4</u>
Investing activities:			
Capital and exploratory expenditures (Note 17)	(1,352.3)	(880.3)	(686.4)
Acquisition of Highlands Gas Corporation (Note 4)	(179.4)	—	—
Proceeds from sales of assets (Note 4)	44.6	30.2	111.1
Other investing activities—net	(17.7)	(2.8)	(7.5)
Cash (used) by investing activities	<u>(1,504.8)</u>	<u>(852.9)</u>	<u>(582.8)</u>
Financing activities:			
Dividends paid (Note 2)	(50.0)	(49.8)	(1,713.9)
Debt financings (Note 8)	563.5	646.9	68.0
Debt repaid	(3.9)	(77.5)	(47.4)
Repurchase of common stock	(52.3)	(3.5)	—
Proceeds from initial public offering (Note 2)	—	—	843.9
Advances from (to) Union Pacific Corporation (Notes 2 and 3)	—	(567.8)	627.1
Other financings—net (Note 8)	30.4	5.5	(3.4)
Cash provided (used) by financing activities	<u>487.7</u>	<u>(46.2)</u>	<u>(225.7)</u>
Net change in cash and temporary investments	(48.3)	91.3	20.9
Balance at beginning of year	118.9	27.6	6.7
Balance at end of year	<u>\$ 70.6</u>	<u>\$ 118.9</u>	<u>\$ 27.6</u>
Changes in current assets and liabilities:			
Accounts receivable	\$ (33.9)	\$(111.5)	\$ 4.0
Inventories	(23.7)	38.1	(9.2)
Other current assets	18.8	(1.6)	79.7
Accounts payable	19.2	60.4	10.0
Accrued taxes payable	(74.7)	46.7	22.4
Short-term debt	—	—	(43.2)
Other current liabilities	0.4	7.0	4.5
Total	<u>\$ (93.9)</u>	<u>\$ 39.1</u>	<u>\$ 68.2</u>
Supplemental cash flow disclosure:			
Interest paid	\$ 56.3	\$ 43.4	\$ 20.0
Income taxes paid	129.7	79.0	29.7

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

UNION PACIFIC RESOURCES GROUP INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
For the Years Ended December 31, 1997, 1996 and 1995

	1997	1996	1995
	(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
Asset restructuring (Note 2)	—	—	(4.5)
Balance at end of year	—	—	—
Common stock, no par value; authorized 400,000,000 shares:			
251,888,575 shares issued and outstanding at December 31, 1997 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	872.9	860.2	421.5
Asset restructuring (Note 2)	—	—	(421.5)
Initial public offering (Note 2)	—	—	843.1
Conversion, award, forfeiture and appreciation of retention shares (Note 11)	5.1	15.9	9.1
Issuance of ESOP shares (Note 11)	107.3	—	—
Exercise of Stock Options	5.5	0.5	—
Other	0.4	(3.7)	—
Balance at end of year	991.2	872.9	860.1
Retained earnings:			
Balance at beginning of year	674.4	472.9	1,421.5
Net income	333.0	320.8	35.1
Total	1,007.4	793.7	1,456.6
Dividends declared on common stock (Note 2)	(50.0)	(49.8)	(1,711.5)
Pension asset adjustment (Note 10)	—	(69.5)	—
Asset restructuring (Note 2)	—	—	4.1
Balance at end of year	957.4	674.4	—
Unearned compensation:			
Balance at beginning of year	(17.5)	(9.2)	—
Conversion, award, appreciation and amortization of retention shares—net (Note 11)	5.7	(8.3)	—
Balance at end of year	(11.8)	(17.5)	—
Deferred foreign exchange adjustment:			
Balance at beginning of year	(12.0)	(11.5)	—
Foreign currency translation adjustment	(5.3)	(0.5)	—
Balance at end of year	(17.3)	(12.0)	—
ESOP (Note 11):			
Balance at beginning of year	—	—	—
Issuance of ESOP shares	(107.3)	—	—
Release of ESOP shares	5.3	—	—
Balance at end of year	(102.0)	—	—
Treasury stock:			
Balance at beginning of year	(3.5)	—	—
Treasury stock, at cost	(52.3)	(3.5)	—
Balance at end of year 2,379,625 shares at December 31, 1997	—	—	—
154,417 shares at December 31, 1996	(55.8)	(3.5)	—
Minimum pension liability	(1.0)	—	—
Total shareholders' equity	\$1,760.7	\$1,514.3	\$1,456.6

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, 1997, 1996 and 1995

	1997	1996	1995
	(Millions of dollars)		
Revenues: ^{1,2}			
Exploration and production	\$1,334.7	\$1,198.3	\$1,010.7
Gathering, processing and marketing	450.2	503.8	349.7
Minerals	139.8	128.9	116.3
Total revenues	<u>\$1,924.7</u>	<u>\$1,831.0</u>	<u>\$1,476.7</u>
Depreciation, depletion and amortization:			
Exploration and production	\$ 493.0	\$ 465.5	\$ 403.1
Gathering, processing and marketing	70.4	63.7	52.9
Minerals	0.9	0.9	0.4
Corporate	3.8	3.8	2.2
Total depreciation, depletion and amortization	<u>\$ 568.1</u>	<u>\$ 533.9</u>	<u>\$ 458.6</u>
Operating income: ³			
Exploration and production	\$ 344.4	\$ 328.7	\$ 307.7
Gathering, processing and marketing	94.6	150.1	107.8
Minerals	135.5	120.0	107.1
Corporate	(79.3)	(72.2)	(52.5)
Total operating income	<u>\$ 495.2</u>	<u>\$ 526.6</u>	<u>\$ 470.1</u>
Fixed assets—net:			
Exploration and production	\$2,695.7	\$2,227.4	\$2,049.9
Gathering, processing and marketing	843.4	637.8	610.7
Minerals	23.6	21.9	23.6
Corporate	102.7	85.3	80.1
Total fixed assets—net	<u>\$3,665.4</u>	<u>\$2,972.4</u>	<u>\$2,764.3</u>
Capital and exploratory expenditures:			
Exploration and production	\$1,151.7	\$ 752.7	\$ 577.9
Gathering, processing and marketing	364.2	118.1	106.5
Minerals	1.4	0.8	0.2
Corporate	14.4	8.7	1.8
Total capital and exploratory expenditures	<u>\$1,531.7</u>	<u>\$ 880.3</u>	<u>\$ 686.4</u>

The Company's reportable segments are strategic business units or an aggregation of business units with similar operations and management objectives. The reportable segments are managed separately because each segment requires different operational assets, technology and management strategies.

¹ The exploration and production segment sells a significant portion of its oil and gas volumes to the Company's wholly owned marketing subsidiary, Union Pacific Fuels, Inc. at market prices. See "Significant Accounting Policies—Revenue Recognition."

² 1997, 1996 and 1995 revenues include income from equity affiliates of \$0.7 million, \$0.8 million and \$0.7 million, respectively, for the gathering, processing and marketing segment and \$74.5 million, \$74.5 million and \$68.2 million, respectively for the minerals segment.

³ Segment operating income for the corporate segment consists primarily of general and administrative expense.

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 (collectively, the "Company"), including its principal operating subsidiary Union Pacific Resources Company ("UPRC"). The Company accounts for investments in affiliated companies (20% to 50% owned) on the equity method of accounting and consolidates the proportionate share of such investments. All significant 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 a 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, 1997 and 1996 was \$7.7 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 aggregated 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 or 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 profit center or 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 (see Note 16).

Environmental Expenditures. Environmental expenditures related to treatment or cleanup are expensed when incurred, while environmental expenditures which extend the life of the property or prevent future contamination are capitalized in accordance with generally accepted accounting principles. Liabilities for future expenditures are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated, based on current law and existing technologies. Environmental accruals are recorded at undiscounted amounts and exclude claims for recoveries from insurance or other third parties (see Note 13).

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Goodwill. Intangible and other assets includes 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 of \$90.7 million, acquired subsequent to 1971, is being amortized on a straight-line basis over a 20 year period. Amortization of goodwill was \$2 million for 1997. The value of goodwill is periodically evaluated based on the expected future undiscounted operating cash flows to determine whether any potential impairment exists (see Note 12).

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 gathering, processing and marketing revenues is recorded net of the cost of hydrocarbons purchased.

Derivative Financial Instruments. Unrealized gains/losses on derivative financial instruments are not recorded. Recognition of realized gains/losses and option premium payments/receipts are deferred and recorded in the Consolidated Statement of Income when the underlying physical product is purchased or sold. Margin deposits, realized gains/losses on derivative financial instruments and net premiums are included in other current assets or liabilities in the Consolidated Statement of Financial Position. The cash flow impact of derivative and other financial instruments is reflected in cash provided by operations in the Consolidated Statement of Cash Flows.

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 or state 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 common stock of the Company ("Common 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. In 1997, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 128, "Earnings Per Share" ("EPS") which established new standards for computing and presenting EPS. SFAS No. 128 replaced the presentation of primary EPS with a presentation of basic EPS. Basic EPS excludes dilution and is computed by dividing income available to common shareholders by the weighted-average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. EPS amounts for 1997 and 1996 have been presented and, where appropriate, restated to conform to the SFAS No. 128 requirements (see Note 11).

EPS for the year ended December 31, 1995 has 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 EPS (see Note 2) are based upon 249.7 million average common shares outstanding during the period from completion of the Offering (hereinafter defined) until December 31, 1995.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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 59).

Recently Issued Accounting Standards. In June 1997, the FASB issued SFAS No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income and its components (revenues, expenses, gains and losses) in a full set of general-purpose statements. It requires (a) classification of items of other comprehensive income by their nature in a financial statement and (b) display of the accumulated balance of other comprehensive income separate from retained earnings and additional paid-in surplus in the equity section of the Statement of Financial Position. The Company plans to adopt SFAS No. 130 for the quarter ended March 31, 1998.

In June 1997, the FASB issued SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," which established standards for reporting information about operating segments in annual financial statements and requires selected information about operating segments in interim financial reports issued to shareholders. SFAS No. 131 also establishes standards for related disclosures about products and services, geographic areas and major customers. The Company has adopted SFAS No. 131 for the year ended December 31, 1997 (See Business Segment Information beginning on page 39).

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 in several major basins in the United States and Canada. The Company owns and operates significant assets, in proximity to its principal producing properties, dedicated to "gas value chain" activities, which consist of gathering, processing, transportation and marketing 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 minerals 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 free distribution (the "Distribution"). On October 15, 1996, the Distribution was consummated.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

2. Spinoff from Union Pacific Corporation—(Continued)

Prior to the Offering (1) UPC caused the Company to own all the rights and assets historically employed by the natural resources business segment of UPC in connection with the operations presented in the Consolidated Financial Statements and (2) the Company declared dividends to UPC totaling \$1,621 million consisting of (i) a cash dividend of \$912 million payable promptly after the completion of the Offering, (ii) a \$650 million note payable to UPC bearing interest at 8.5% per annum payable within 90 days of the Distribution and (iii) a \$59 million receivable from UPC. 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 for 1995 are not directly comparable to results for the years ended December 31, 1996 and 1997. The following pro forma information reflects adjustments to the historical 1995 Consolidated Statement of Income necessary to give effect to the Asset Restructuring and the Offering as if such transactions had occurred at the beginning of 1995.

	Year Ended December 31, 1995		
	Historical	Pro Forma Adjustments	Pro Forma
	(Millions of dollars, 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-diluted			<u>\$ 1.27</u>
Weighted average shares outstanding-diluted ^(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 million of pension expense representing one quarter of approximately \$8 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

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

3. Related Party Transactions—(Continued)

long-term debt and commercial paper (see Note 8). Intercompany interest income related to amounts receivable from UPC was \$9.6 million in 1995, 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 \$32.6 million in 1996 and \$14.5 million in 1995 which is included in interest expense in the Company's Consolidated Statements of Income.

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 1997, 1996 and 1995 related to such agreements were \$2.9 million, \$2.7 million and \$0.9 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 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 1997 and 1996, the Company reached settlements and took default judgment with respect to a number of royalty owners named in the suit. In 1997 and 1996, the Company recognized \$18 million and \$31.3 million in other oil and gas revenues related to a reduction in litigation and contingencies accrual pertaining to the Columbia payment (see Note 15).

Highlands Gas Corporation. In August 1997, the Company acquired 100% of the outstanding stock of Highlands Gas Corporation ("Highlands") for an adjusted purchase price of approximately \$179.4 million, plus the assumption of certain liabilities. Highlands is in the business of gathering, purchasing, processing and transporting natural gas and natural gas liquids. The acquisition included three natural gas processing plants, five gathering systems with over 700 miles of gas and natural gas liquids gathering pipeline and 400 miles of transportation pipeline located in western Texas and eastern New Mexico. Results of operations for Highlands from August through December 1997 are included in the Consolidated Statement of Income.

5. Financial Instruments

Hedging. The Company has established policies and procedures for managing risk within its organization. It is balanced by internal controls and governed by a risk management committee. The level of risk assumed by the Company is based on its objectives and earnings, and its capacity to manage risk. Limits are established for each major category of risk, with exposures monitored and managed by Company management, and reviewed semi-annually by the risk management committee. Major categories of the Company's risk are defined as follows:

Commodity Price Risk—Non-Trading Activities. The Company uses derivative financial instruments for non-trading purposes in the normal course of business to manage and reduce risks associated with contract commitments, price volatility, and other market variables. These instruments are generally put in place to

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

5. Financial Instruments—(Continued)

risk of adverse price movements, however, these same instruments usually limit future gains from favorable price movements. Such risk management activities are generally accomplished pursuant to exchange-traded contracts or over-the-counter options.

Recognition of realized gains/losses and option premium payments/receipts are also deferred in the Consolidated Statement of Income until the underlying physical product is sold. Unrealized gains/losses on derivative financial instruments are not recorded. Margin deposits, deferred gains/losses on derivative financial instruments and net premiums are included in other current assets or liabilities in the Consolidated Statement of Financial Position. The cash flow impact of derivative and other financial instruments is reflected as cash flows provided from operations in the Consolidated Statement of Cash Flows.

Commodity Price Risk—Trading Activities. Periodically, the Company may enter into transactions involving a wide range of energy related derivative financial transactions that are not the result of hedging activities. These instruments are generally put into place based on the Company's analysis and expectations with respect to price movement or changes in other market variables. As of December 31, 1997 and 1996, there were no commodity trading activity-based contracts outstanding.

Interest Rate Swaps. The Company periodically enters into rate swaps and contracts to hedge certain interest rate transactions. As of December 31, 1997 and 1996, there were no material interest rate contracts outstanding which materially affect the results of operation or financial condition of the Company.

Foreign Currency Contracts. The Company periodically enters into foreign currency contracts to hedge specific currency exposures from commercial transactions. As of December 31, 1997 and 1996, there were no foreign currency contracts outstanding.

Credit Risk. Credit risk is the risk of loss as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. Because the loss can occur at some point in the future, a potential exposure is added to the current replacement value to arrive at a total expected credit exposure. The Company has established methodologies to establish limits, monitor and report creditworthiness and concentrations of credit to reduce such credit risk. At December 31, 1997, the Company's largest credit risk associated with any single counterparty, represented by the net fair value of open contracts with such counterparty was less than \$1 million.

Performance Risk. Performance risk results when a counterparty fails to fulfill its contractual obligations such as commodity pricing or volume commitments. Typically, such risk obligations are defined within the trading agreements. The Company utilizes its credit risk methodology to manage performance risk.

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 1997 and 1996, revenues were \$86 million and \$52 million lower, respectively, while during 1995, revenues were \$27 million higher as a result of hedging activities.

Fair Value of Financial Instruments. At December 31, 1997, 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 were as follows:

	As of December 31,	
	1997	1996
	(Millions of dollars)	
Producing properties	\$5,155.9	\$4,311.3
Non-producing properties	449.5	371.3
Gathering, processing and marketing	1,240.5	1,010.7
Construction in progress	392.6	348.8
Other	175.9	147.9
Total	<u>\$7,414.4</u>	<u>\$6,190.0</u>

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

	As of December 31,	
	1997	1996
	(Millions of dollars)	
Producing properties	\$3,090.9	\$2,604.1
Non-producing properties	123.6	142.7
Gathering, processing and marketing	443.5	396.0
Other	91.0	74.8
Total	<u>\$3,749.0</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 1997 and 1996, the Company adjusted the net book value of such properties to their fair value, determined using a discounted cash flow approach, with charges to operations of \$20.2 million and \$34.4 million, respectively.

Fixed asset additions included capitalized interest of \$3.8 million in 1997, \$0.2 million in 1996 and \$1 million in 1995.

7. Income Taxes

Components of income tax expense were as follows:

	For the Years Ended December 31,		
	1997	1996	1995
	(Millions of dollars)		
Current:			
Federal	\$ 8.1	\$105.8	\$130
State	5.6	9.0	(4)
Total current	<u>13.7</u>	<u>114.8</u>	<u>126</u>
Deferred:			
Federal	121.7	33.0	(2)
State	(2.0)	4.0	
Total deferred	<u>119.7</u>	<u>37.0</u>	<u>(1)</u>
Total	<u>\$133.4</u>	<u>\$151.8</u>	<u>\$10</u>

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

7. Income Taxes—(Continued)

Deferred tax liabilities (assets) include the following:

	As of December 31,	
	1997	1996
	(Millions of dollars)	
Excess tax over book items, including depreciation and exploration costs	\$686.0	\$561.0
State taxes—net	—	11.4
Long-term liabilities	—	(40.7)
Alternative minimum tax	(73.2)	(56.6)
Pension and other retirement benefits	(57.4)	(60.0)
Other	(2.5)	19.6
Net deferred tax liability	<u>\$552.9</u>	<u>\$434.7</u>

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

	For the Years Ended December 31,		
	1997	1996	1995
Statutory tax rate	35.0%	35.0%	35.0%
State taxes—net	1.3	1.8	(0.3)
Section 29 tax credits	(4.3)	(3.3)	(8.3)
Tax settlements	(1.5)	—	(2.2)
Other	(1.9)	(1.4)	(0.8)
Effective tax rate	<u>28.6%</u>	<u>32.1%</u>	<u>23.4%</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 \$18.8 million, \$15.6 million and \$39.9 million of Section 29 tax credits in 1997, 1996 and 1995, respectively. The federal tax law provides for the use of these credits against regular federal income tax liability. Accordingly, the Company utilized \$27.4 million of Section 29 tax credits on its 1996 tax return. Of the \$27.4 million utilized on the 1996 tax return, \$10.7 million was due to the utilization of prior year alternative minimum tax credit carry forwards. It is anticipated that all of the 1997 tax credits will increase the alternative minimum tax credit carry forwards and apply against future tax years' regular tax liability.

During 1997, the Company recognized a \$6 million favorable adjustment to state income taxes representing the settlement of a California state audit. The Company also had favorable tax adjustments of \$3.3 million resulting from a tax allocation refund from UPC to settle 1996 federal income taxes and \$2.7 million relating to prior year federal tax returns.

All tax years prior to 1979 have been closed with the Internal Revenue Service ("IRS"). On behalf of the Company, 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 the Company's returns for 1990 through 1994 in connection with the IRS' examination of UPC's returns. 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

The total debt of the Company is summarized below:

	As of December 31,	
	1997	1996
	(Millions of dollars)	
Commercial paper, net of discount, average of 6% at December 31, 1997	\$ 663.1	\$ 99.6
Notes, 7%, due 2006	200.0	200.0
Debentures, 7.5%, due 2026	200.0	200.0
Debentures, 7.5%, due 2096	150.0	150.0
Tax exempt revenue bonds, 4.25%, due 2012	20.1	24.0
Discount on notes and debentures	(2.6)	(2.6)
Total debt	1,230.6	670.0
Less current portion	—	—
Total long-term debt	<u>\$1,230.6</u>	<u>\$670.0</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 issuance of commercial paper and through new term financings.

The Company has a \$600 million revolving credit agreement that expires in August 2001 and a \$300 million revolving credit agreement which expires in November 1998. Borrowings under these agreements, at the Company's election, bear interest either at a spread over London Interbank Offered Rate ("LIBOR") or at 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 0.06% to 0.15% also depending on the Company's senior debt rating. Under these agreements debt can not exceed 65% of the total of the Company's debt and shareholders' equity and requires the combined EBITDAX (the sum of operating income, depreciation, depletion and amortization, and exploration expenses) of the Company and its Principal Subsidiaries (as defined in these agreements) to be at least 80% of the Company's consolidated EBITDAX. These agreements also impose certain restrictions on the Company regarding the creation of new debt, incurrence of indebtedness, transactions with affiliates, sales of the stock of UPRC and certain mergers, consolidations and asset sales. As of December 31, 1997, there were no borrowings outstanding under these agreements, although borrowing capacity is reduced by outstanding commercial paper. The Company had the capacity to borrow \$900 million, less commercial paper outstanding, under these agreements as of December 31, 1997. In addition, the Company could borrow funds under the credit agreements.

None of the Company's Notes and Debentures are redeemable prior to maturity and none are subject to sinking fund requirements. The Company has an effective shelf registration statement on file with the SEC which permits the Company to offer up to \$900 million in debt and equity securities.

In March 1998, the Company borrowed \$2.7 billion to purchase the capital stock of Norcen Energy Resources Limited ("Norcen") and guaranteed the \$900 million outstanding public debt held by Norcen Energy Resources Limited (Note 18 for additional information about the transactions).

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 lease terms which are not subject to being cancelled in excess of one year were as follows:

	<u>As of December 31, 1997</u> (Millions of dollars)
1998	\$ 59.0
1999	47.5
2000	38.5
2001	31.5
2002	29.5
Later years	<u>16.4</u>
Total minimum payments	<u>\$222.4</u>

Rent expense, net of sublease income, for operating leases with terms exceeding one month was \$22.4 million in 1997, \$27.2 million in 1996 and \$31 million in 1995. Sublease income for the next five years is \$28.5 million in 1998, \$28.4 million in 1999, \$28.1 million in 2000, \$28.1 million in 2001, \$28.1 million in 2002 and \$14.7 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 an employee's 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>For the Years Ended</u> <u>December 31,</u>		
	<u>1997</u>	<u>1996</u>	<u>1995</u>
	(Millions of dollars)		
Service cost—benefits earned during the period	\$ 5.5	\$ 4.4	\$ 5.3
Interest on projected benefit obligation	13.4	13.3	14.4
Return on assets:			
Actual (gain) loss	(30.8)	(41.7)	(49.5)
Deferred gain (loss)	13.7	22.1	30.0
Net amortization costs	<u>(5.7)</u>	<u>(3.7)</u>	<u>(2.4)</u>
Net pension credit	<u>\$ (3.9)</u>	<u>\$ (5.6)</u>	<u>\$ (2.2)</u>

The projected benefit obligation was determined using a discount rate of 7.25% in 1997 and 7.5% in 1996. The estimated rate of salary increase approximated 5.25% in 1997 and 5.5% in 1996. The expected long-term rate of return on plan assets was 9% in 1997 and 8% in 1996. The portion of the funded plan's assets held in fixed-income and short-term securities was approximately 34% and 29% as of December 31, 1997 and 1996, respectively, with the remainder primarily in equity securities.

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

10. Retirement Plans—(Continued)

The funded status of the plans was as follows:

	As of December 31, 1997			
	Funded Pension Plan		Unfunded Supplemental Pension Plan	
	1997	1996	1997	1996
	(Millions of dollars)			
Plan assets at fair value	\$ 240.9	\$ 221.3	\$ —	\$ —
Actuarial present value of benefit obligations:				
Vested benefits	165.0	152.9	6.1	4.5
Non-vested benefits	7.0	6.4	0.4	0.2
Accumulated benefit obligation	172.0	159.3	6.5	4.7
Additional benefits based on estimated future salaries	22.8	17.4	1.3	2.5
Projected benefit obligation	194.8	176.7	7.8	7.2
Plan assets (over) under projected benefit obligation	(46.1)	(44.6)	7.8	7.2
Unamortized net transition asset (obligation)	18.4	21.0	(0.5)	(1.1)
Unrecognized prior service cost	(4.5)	(5.2)	(3.3)	(3.8)
Unrecognized net gain (loss)	102.3	105.0	(2.3)	(2.2)
Minimum liability	—	—	4.8	4.6
Pension liability	<u>\$ 70.1</u>	<u>\$ 76.2</u>	<u>\$ 6.5</u>	<u>\$ 4.7</u>

The Company is in the process of conducting a voluntary compliance review of its pension plan. The results of the review are not expected to have a material impact on the funded status of the plans.

Other Postretirement Benefits. Postretirement health and life insurance benefit costs included the following components:

	For the Years Ended December 31,		
	1997	1996	1995
	(Millions of dollars)		
Service cost—benefits earned during the period	\$ 0.8	\$ 1.0	\$ 1.2
Interest costs on accumulated benefit obligation	3.3	3.4	4.3
Net amortization costs	(2.4)	(2.3)	(1.5)
Charge to operations	<u>\$ 1.7</u>	<u>\$ 2.1</u>	<u>\$ 4.0</u>

The liability for other postretirement benefit plans was as follows:

	For the Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Accumulated postretirement benefit obligation ("APBO"):		
Retirees	\$30.8	\$35.5
Fully eligible active employees	2.3	1.9
Other active employees	9.8	7.7
Total APBO	42.9	45.1
Unrecognized prior service gain	3.4	4.4
Unrecognized net gain	27.0	25.1
Postretirement benefits liability	<u>\$73.3</u>	<u>\$74.6</u>

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

10. Retirement Plans—(Continued)

The APBO was determined using a discount rate of 7.25% in 1997 and 7.5% in 1996. The health care cost trend rate is assumed to gradually decrease from 8.5% for 1997 to 5% for 2005 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 \$0.4 million and the APBO would rise by \$3.6 million. The Company does not currently pre-fund health care and life insurance benefit costs. Cash payments for these benefits were \$3 million in 1997 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, 8,785,684 and 9,215,933 shares of Common Stock were available as either options to purchase Common Stock or as awards of retention stock at December 31, 1997 and 1996, respectively, for grant to employees and directors. Options to purchase Common Stock 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 eleven years from grant date. Option grants have been made to directors, officers and employees and vest over a period up to ten years from the grant date.

Retention stock is awarded under the plan to eligible employees, subject to forfeiture if employment terminates during the prescribed restriction period, generally one to five years from date of grant. Multi-year retention stock awards also have been made, with vesting two to five years from date of grant.

Multi-year grants of stock options and retention stock made in 1994 also required that designated Company stock prices be met to be exercisable. These performance conditions were achieved during 1995 for the stock options and during 1996 for the 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 stock options, ISOs and retention stock of the Company, respectively. The converted options and retention stock retain the same exercise dates and vesting requirements as the UPC options and retention stock for which they were exchanged.

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

	Company Shares	Weighted Average Exercise Price
Stock options:		
Balance at December 31, 1994	—	\$ —
Conversion of UPC stock options	3,702,443	15.87
Granted	88,695	25.88
Exercised	(1,500)	15.18
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	5,216,074	19.97
Granted	1,111,750	25.63
Exercised	(351,723)	16.05
Expired/surrendered	(91,615)	24.75
Balance at December 31, 1997	<u>5,884,486</u>	21.20
Exercisable December 31:		
1995	2,235,470	\$16.26
1996	3,035,905	16.81
1997	3,853,035	18.72

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

11. Shareholders' Equity—(Continued)

	<u>Regular</u>	<u>Performance</u>
Retention stock:		
1995		
Awarded	33,585	14,1
Conversion of UPC retention stock	389,880	310,6
Unvested at December 31, 1995	423,465	324,7
1996		
Awarded	604,530	
Conversion of UPC retention stock	2,610	18,6
Achievement of performance conditions	301,066	(301,0
Vested	(124,733)	
Forfeited, surrendered and other	(2,376)	(42,4
Unvested at December 31, 1996	1,204,562	
1997		
Awarded	209,114	
Vested	(376,295)	
Forfeited, surrendered and other	(34,693)	
Unvested at December 31, 1997	1,002,688	

Weighted-average grant-date fair value of stock options granted and retention stock awarded:

	<u>Options(b)</u>	<u>Retent Shares</u>
1995	\$8.31	\$25.8
1996	9.15	27.8
1997	8.74	25.6

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

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

	<u>1997</u>	<u>1996</u>	<u>19</u>
Expected volatility	28%	26%	2
Expected dividend yield	0.8%	0.7%	0.
Expected option term	4 years	5 years	5 ye
Risk-free rate of return	5.7%	6.3%	5.

(c) Represents market value on grant date.

Options to purchase Common Stock outstanding were as follows:

<u>As of December 31, 1997</u>					
<u>Options Outstanding</u>			<u>Options Exercisable</u>		
<u>Range of Exercise Prices</u>	<u>Number of Shares</u>	<u>Weighted Average Years to Expiration</u>	<u>Weighted Average Exercise Price</u>	<u>Number of Shares</u>	<u>Weighted Average Exercise Price</u>
\$ 9.49-\$15.29	1,913,601	5.89	\$14.75	1,913,601	\$14.60
\$17.14-\$20.94	1,242,963	5.59	19.01	1,242,963	19.06
\$23.78-\$29.44	2,727,922	8.34	26.73	696,471	27.06
\$ 9.49-\$29.44	<u>5,884,486</u>	6.96	21.20	<u>3,853,035</u>	18.72

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

11. Shareholders' Equity—(Continued)

Since the Company applies the intrinsic value method in accounting for its stock option and retention stock plans, it generally records no compensation cost for its stock option plans. Compensation cost recognized relating to retention stock was \$11.6 million, \$7.4 million and \$0.7 million in 1997, 1996 and 1995, respectively. If compensation cost for the Company's stock option plan had 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 \$8 million in 1997, \$3 million in 1996 and \$3.4 million in 1995, essentially all of which relates to option conversion at the Offering. Basic and diluted EPS would have been reduced by \$0.03 per share in 1997 and \$0.01 per share both in 1996 and 1995.

Earnings Per Share. The reconciliation between basic EPS and diluted EPS for the years ended December 31, 1997 and 1996 is as follows:

	For the Years Ended December 31,		
	Income (Millions of dollars)	Average Shares (Millions)	Per Share
1997			
Basic EPS			
Income available to common shareholders	\$333.0	250.1	\$1.33
Effect of Dilutive Options	—	0.8	—
Diluted EPS			
Income available to common shareholders plus assumed conversion	<u>\$333.0</u>	<u>250.9</u>	<u>\$1.33</u>
1996			
Basic EPS			
Income available to common shareholders	\$320.8	249.2	\$1.29
Effect of Dilutive Options	—	0.9	(0.01)
Diluted EPS			
Income available to common shareholders plus assumed conversion	<u>\$320.8</u>	<u>250.1</u>	<u>\$1.28</u>

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. Scheduled principal and interest requirements are \$8.6 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 EPS 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

11. Shareholders' Equity—(Continued)

As of December 31, 1997, allocated and unallocated shares in the ESOP are 197,395 and 3,502,605, respectively. The fair value of unallocated ESOP shares is \$85.8 million at December 31, 1997. During 1997, compensation cost related to the allocation of ESOP shares to participants' accounts was \$5.3 million.

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 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, 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.

In 1997, the Company announced a program to repurchase up to \$50 million of its Common Stock in 1997 and another \$50 million of Common Stock in 1998. During 1997, 2,013,400 shares of Common Stock were repurchased at a cost of \$49.9 million.

12. Intangible and Other Assets

Goodwill. Goodwill consists 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. During 1997, goodwill of \$90.7 million was recorded as a result of the purchase of Highlands and is being amortized on a straight-line basis over a 20 year period. Amortization of goodwill was \$2 million for 1997.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

12. Intangible and Other Assets—(Continued)

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 is as follows:

	As of and for the Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Current assets	\$ 27.5	\$ 39.8
Non-current assets	37.9	46.4
Current liabilities	17.1	20.2
Non-current liabilities and equity (see Note 13)	48.3	66.0
Sales	159.7	192.4
Operating income	112.4	137.0
Partners' income	113.6	137.0

During 1997, Black Butte's sales to its largest customer under an amended coal supply contract accounted for \$59.3 million, or 12%, of the Company's consolidated operating income. This coal supply contract was amended during 1997 to accelerate shipments in the years 1998, 1999 and 2000, at which time the financially beneficial terms of the contract 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 supply. The Company does not expect to be able to replace the operating income it currently receives under the contract with incremental coal sales.

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, 1997 and 1996 were \$50.4 million and \$54.3 million, of which the Company's share is \$25.2 million and \$27.2 million, respectively. The majority of cash expenditures for reclamation are expected to be incurred from five to ten years in the future.

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 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 seven 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.

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. As part of the Wilmington sales agreement, the

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

13. Environmental Exposure—(Continued)

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, up to a maximum of \$105.5 million. As a result, a provision of \$50.5 million for future environmental costs and \$55 million for future site preparation costs was established (\$91.5 million in total remaining at December 31, 1997) and is categorized as other current liabilities and long-term liabilities (see Note 15). The majority of cash outlays for these liabilities is expected to occur over the next five years.

As of December 31, 1997 and 1996, long and short-term liabilities totaling \$75.7 million and \$94.3 million, respectively 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 \$37.8 million for the obligation to participate in the remediation of the Wilmington, California 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 of environmental exposures required spending of \$14.7 million in 1997 and \$11.4 million in 1996. In 1998, the Company anticipates spending a total of \$20 million for remediation, control and prevention, including \$9 million relating to the Wilmington properties. The majority of the December 31, 1997 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.

14. Commitments and Contingencies

UP Fuels is a party to a long-term firm transportation agreement with Kern River Gas Transmission Company ("Kern River") 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. Ten years remain on the primary term of the agreement, and the current transportation rate is \$0.69 Mcf. This rate will be in effect through at least mid-1998. Thereafter, this rate can change, based on Kern River's cost of service and upon rate regulation policies of the Federal Energy Regulatory Commission ("FERC"). Under a 1993 ruling of the FERC, UP Fuels is obligated to pay all of the fixed costs included in the transportation rate, whether or not UP Fuels actually uses Kern River's pipeline to transport gas. Those fixed costs presently amount to \$0.6878 per Mcf. The undiscounted amount of the ten-year fixed cost commitment, assuming no future changes in the rate, is \$177 million. The 1993 FERC ruling was issued notwithstanding a provision in the transportation agreement between Kern River and UP Fuels in which the parties agreed that a portion of the fixed costs would be paid by UP Fuels only if and to the extent that UP Fuels uses the pipeline. In light of recent changes in the regulatory policies of FERC, UP Fuels is seeking reinstatement of the contractually agreed rate structure, but there is no assurance that such efforts will be successful. UP Fuels is a party to an additional agreement under which it may acquire in 2001, at its option, an additional 25 MMcfd of transportation rights on the Kern River Pipeline system beginning in 2002.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

14. Commitments and Contingencies—(Continued)

UP Fuels is a party to a long-term firm transportation agreement with Texas Gas Transmission Corporation that expires in 2008. Under the transportation agreement UP Fuels has the rights to transport 90 MMBtu per day of gas from the Company's East Texas plant. UP Fuels is obligated to pay a fixed transportation rate of \$0.331 per MMBtu regardless of the volumes transported under the agreement. The undiscounted amount of this commitment is \$116 million.

The Company has entered into a letter of intent to enter into a \$150 million five year agreement with Noble Drilling (U.S.) Inc. beginning in July 1999, for the services of a semisubmersible drilling rig designed for operations in water depths up to 5,000 feet. Under this agreement, the Company will share 50% of the total rig commitment with another major oil and gas company.

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, Texas petrochemical complex (July 1987), the Calnev pipeline (October 1988), the Wilmington, California 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, cash flows 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 Annual Report on Form 10-K. The Company intends to defend vigorously against these lawsuits as well as any similar lawsuits. In the opinion of management of the Company, the outcome of these matters should not have a materially adverse effect on the consolidated financial condition, cash flows or results of operations of 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 contract claims, personal injury claims and environmental claims. While management of the Company cannot predict the outcome of such litigation and other proceedings, management does not expect those matters to have a materially adverse effect on the consolidated financial condition, cash flows or results of operations of the Company.

15. Other Long-Term Liabilities

Other long-term liabilities include the following:

	As of December 31,	
	1997	1996
	(Millions of dollars)	
Environmental (Notes 4 and 13).....	\$ 58.5	\$ 74.5
Wilmington field site preparation (Note 14)	53.7	53.7
Litigation and contingencies (Notes 4 and 14)	28.5	73.8
Offshore platform lease accrual	3.6	14.3
Other	<u>78.3</u>	<u>48.5</u>
Total other long-term liabilities	<u>\$222.6</u>	<u>\$264.8</u>

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

16. Other Income—Net

Other income (expense)—net consists of the following:

	For the Years Ended		
	1997	1996	1995
	(Millions of dollars)		
Excess reserve reductions	\$ 23.0	\$ 1.8	\$ 3.2
Insurance settlement proceeds	10.0	—	—
Gain on sales of assets	7.2	4.5	2.2
Pennzoil acquisition costs	(17.8)	—	—
Spinoff charges	—	(5.6)	—
Intercompany interest (Note 2)	—	—	9.6
Other—net	1.9	(4.1)	(8.0)
Total other income—net	<u>\$ 24.3</u>	<u>\$ (3.4)</u>	<u>\$ 7.0</u>

17. Capital and Exploratory Expenditures

Capital and exploratory expenditures include the following:

	For the Years Ended		
	1997	1996	1995
	(Millions of dollars)		
Capital expenditures:			
Producing properties	\$ 752.4	\$515.2	\$482.7
Non-producing properties	200.7	149.8	35.0
Exploratory drilling	121.7	36.1	24.2
Gathering, processing and marketing	364.2	118.1	106.5
Other	15.8	9.5	2.0
Total capital expenditures	1,454.8	828.7	650.4
Exploratory expenditures:			
Expensed geological and geophysical costs	35.2	19.0	22.4
Expensed dry hole costs	41.7	32.6	13.6
Total exploratory expenditures	76.9	51.6	36.0
Total capital and exploratory expenditures	<u>\$1,531.7</u>	<u>\$880.3</u>	<u>\$686.4</u>

18. Subsequent Events (Unaudited)

Norcen Acquisition. In March 1998, the Company purchased the capital stock of Norcen for approximately \$2.6 billion. As a result of the Norcen acquisition, the Company will increase its debt by \$3.6 billion, including \$2.7 billion acquisition debt and approximately \$900 million of existing commercial paper and debentures of Norcen. The \$2.7 billion acquisition debt entered into by the Company includes a mandatory prepayment program and a series of "prepayment events". The mandatory prepayment provision requires that \$1.35 billion be repaid prior to March, 1999. In addition, 75% of the net proceeds applicable to any prepayment events should be applied to reduce the indebtedness under the acquisition facility. Prepayment events include sales of assets in excess of \$10 million and debt and equity issuances. This increased debt is expected to raise the Company's debt to total capitalization ratio from 41% at December 31, 1997 to approximately 72% as of March 1998. The Company plans to pursue an aggressive deleveraging program, which may include asset and financial divestitures and the issuance of equity securities.

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. Ryder Scott Company Petroleum Engineers reviewed the reserves as of December 31, 1997 and indicated in their letter dated February 27, 1998, that the estimated quantities of proved oil and gas reserves were reasonable in the aggregate (see Exhibit 99).

	As of December 31,		
	1997	1996	1995
Natural gas (Bcf): ¹			
Beginning of year	2,378.4	2,173.5	2,126.0
Revisions of previous estimates	9.3	45.7	(122.3)
Extensions, discoveries and other additions	588.3	481.3	518.0
Purchases of reserves-in-place	54.8	52.0	26.7
Sales of reserves-in-place	(3.5)	(5.5)	(32.0)
Production	(407.0)	(368.6)	(342.9)
Total proved, end of year	2,620.3	2,378.4	2,173.5
Proved developed reserves	2,217.0	2,125.4	1,957.1
Natural gas liquids (MMBbl): ¹			
Beginning of year	107.5	100.1	83.8
Revisions of previous estimates	1.9	12.0	9.9
Extensions, discoveries and other additions	21.6	9.1	18.2
Purchases of reserves-in-place	0.9	0.2	0.2
Sales of reserves-in-place	—	(0.4)	(1.0)
Production	(14.0)	(13.5)	(11.0)
Total proved, end of year	117.9	107.5	100.1
Proved developed reserves	103.3	97.7	89.8
Crude oil, including condensate (MMBbl):			
Beginning of year	80.6	83.8	70.9
Revisions of previous estimates	5.1	(0.6)	14.1
Extensions, discoveries and other additions	56.7	14.3	19.1
Purchases of reserves-in-place	5.8	3.6	1.9
Sales of reserves-in-place	(0.1)	(2.0)	(2.9)
Production	(19.3)	(18.5)	(19.3)
Total proved, end of year	128.8	80.6	83.8
Proved developed reserves	93.9	74.1	78.2
Proved reserves equivalent, end of year (Bcfe): ²			
Natural gas	2,620.3	2,378.4	2,173.5
Natural gas liquids	707.4	645.0	600.6
Crude oil, including condensate	772.8	483.6	502.8
Total proved	4,100.5	3,507.0	3,276.9
Proved developed reserves	3,400.2	3,155.8	2,965.1

¹ 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).

² Calculated using the ratio of one Bbl to six Mcf.

B. Drilling Activity ¹

Drilling activity is summarized as follows:

	For the Years Ended December 31,		
	1997	1996	1995
Gross wells	817	655	725
Gross productive wells	720	591	685
Net wells:			
Exploration	41	27	14
Development	525	439	513
Total net wells	566	466	527
Net productive wells:			
Exploration	19	9	3
Development	479	413	506
Total net productive wells	498	422	509

¹ In addition, at December 31, 1997, 138 gross wells (101 net wells) were in the process of being drilled.

C. Average Sales Price and Cost

The average sales prices and costs are set forth below:

	As of Years Ended December 31,		
	1997	1996	1995
Producing properties:			
Natural gas sales price (per Mcf)	\$ 2.00	\$ 1.86	\$ 1.42
Natural gas liquids sales price (per Bbl)	11.20	11.39	8.14
Crude oil sales price (per Bbl)	18.36	18.84	16.08
Production cost (per Mcfe)	0.50	0.49	0.42
Gas plants:			
Natural gas sales price (per Mcf)	2.40	2.01	1.51
Natural gas liquids sales price (per Bbl)	11.91	13.16	9.38

D. Average Daily Production and Sales Volume

The average daily production and sales volumes of the Company are set forth below:

	As of Years Ended December 31,		
	1997	1996	1995
Producing properties:			
Natural gas (MMcfd)	1,102.3	980.3	915.6
Natural gas liquids (MBbld)	29.9	28.5	23.1
Crude oil (MBbld)	52.9	50.6	52.8
Total producing properties (MMcfd)	1,598.8	1,454.9	1,371.0
Plant share of equity gas processed:			
Natural gas (MMcfd)	12.9	26.7	23.9
Natural gas liquids (MBbld)	8.5	8.4	7.1
Total plant share of equity gas (MMcfd)	63.9	77.1	66.5
Total production reflected in estimates of proved reserves (MMcfd)	1,662.7	1,532.0	1,437.5
Plant share of third party gas processed (MBbld)	33.2	31.4	27.1
Total sales (MMcfd)	1,879.3	1,720.2	1,600.1
Plant share of natural gas liquids sales (MBbld):			
Equity gas processed	8.5	8.4	7.1
Third party gas processed	33.2	31.4	27.1
Total	41.7	39.8	34.2

E. Acreage and Wells

Oil and gas leasehold acreage is as follows: ¹

	As of December 31,	
	1997	1996
	(Thousands of acres)	
Gross developed	2,317	2,018
Net developed	1,569	1,179
Gross undeveloped	4,076	4,272
Net undeveloped	2,909	2,935

Productive oil and gas wells are as follows:

	As of December 31,	
	Oil	Gas
	(Wells)	
Gross ²	2,763	6,043
Net	1,636	3,574

¹ 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.

² Approximately 611 wells are multiple completions, 576 of which are gas wells.

F. Capitalized Exploration and Production Costs

Capitalized exploration and production costs are as follows: ¹

	As of December 31,	
	1997	1996
	(Millions of dollars)	
Proved properties	\$ 993.0	\$ 889.5
Unproved properties	449.5	280.9
Wells and related equipment	4,285.5	3,512.2
Uncompleted wells and equipment	182.3	291.6
Gross capitalized costs	5,910.3	4,974.2
Accumulated depreciation, depletion and amortization	(3,214.6)	(2,746.8)
Net capitalized costs	<u>\$2,695.7</u>	<u>\$2,227.4</u>

¹ Excludes gathering, processing and marketing assets.

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:

	For the Years Ended December 31,		
	1997	1996	1995
	(Millions of dollars)		
Costs incurred:			
Proved acreage	\$ 130.6	\$ 85.7	\$ 100.5
Unproved acreage	200.7	149.8	35.0
Exploration costs ¹	236.9	114.6	80.9
Development costs	621.8	429.5	382.2
Total costs incurred ²	<u>\$1,190.0</u>	<u>\$ 779.6</u>	<u>\$ 598.6</u>

¹ Includes allocated exploration overhead costs of \$23.5 million in 1997, \$22.5 million in 1996 and \$17.1 million in 1995, and delay rentals of \$14.8 million in 1997, \$4.4 million in 1996 and \$3.6 million in 1995.

² Excludes capital expenditures relating to gathering, processing and marketing of \$364.2 million in 1997, \$118.1 million in 1996 and \$106.5 million in 1995.

H. Results of Operations for Producing Activities ¹

The results of operations for producing activities is set forth below:

	For the Years Ended December 31,		
	1997	1996	1995
	(Millions of dollars)		
Revenues	\$ 1,334.7	\$ 1,198.3	\$ 1,027.7
Production costs	(292.6)	(259.5)	(217.8)
Exploration expenses	(204.7)	(144.6)	(89.4)
Depreciation, depletion and amortization	(493.0)	(465.5)	(403.1)
Total costs	(990.3)	(869.6)	(710.3)
Pre-tax results	344.4	328.7	317.4
Income taxes	(97.7)	(94.9)	(70.4)
Results of operations	<u>\$ 246.7</u>	<u>\$ 233.8</u>	<u>\$ 247.0</u>

¹ Gathering, processing and marketing and minerals 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 \$18.3 million in 1997, \$3.9 million in 1996 and \$14.2 million in 1995, and the \$122.5 million Columbia bankruptcy settlement in 1995.

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

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves are set forth below:

	As of December 31,		
	1997	1996	1995
	(Millions of dollars)		
Future cash inflows from sales of oil and gas	\$ 9,191.9	\$11,945.7	\$ 5,809.2
Future production and development costs	(2,091.1)	(2,013.1)	(1,747.8)
Future income taxes	(2,042.8)	(3,031.7)	(1,114.6)
Future net cash flows	5,058.0	6,900.9	2,946.8
10% annual discount	(2,011.8)	(2,661.9)	(1,075.5)
Standardized measure of discounted future net cash flows	<u>\$ 3,046.2</u>	<u>\$ 4,239.0</u>	<u>\$ 1,871.3</u>

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

	As of December 31,		
	1997	1996	1995
	(Millions of dollars)		
Beginning of year	\$ 4,239.0	\$ 1,871.3	\$ 1,658.7
Changes due to current year operations:			
Additions and discoveries less related production and other costs	1,000.4	1,135.5	549.7
Sales of oil and gas—net of production costs	(1,078.1)	(961.0)	(716.1)
Development costs	621.8	429.5	382.2
Purchases of reserves-in-place	125.4	181.1	48.8
Sales of reserves-in-place	(3.8)	(48.0)	(49.5)
Changes due to revisions in:			
Price	(2,451.9)	2,763.1	334.0
Development costs	(427.4)	(268.6)	(293.6)
Quantity estimates	86.9	27.9	68.1
Income taxes	638.9	(1,062.9)	(271.5)
Other	(288.7)	(69.6)	(31.8)
Discount accretion	583.7	240.7	192.3
End of year	<u>\$ 3,046.2</u>	<u>\$ 4,239.0</u>	<u>\$ 1,871.3</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. Such weighted average prices for 1997, 1996 and 1995 were \$2.24 Mcfe, \$3.41 Mcfe and \$1.77 Mcfe,

respectively. 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.

J. Selected Quarterly Data

Selected unaudited quarterly data are as follows:

	For the Quarters Ended			
	March 31	June 30	September 30	December 31
	(Millions of dollars, except per share amounts)			
1997				
Operating revenues	\$531.7 ^(a)	\$444.6	\$449.0	\$499.4
Operating income	186.4 ^(a)	115.0	94.5	99.3
Net income—basic and diluted	117.2 ^(a)	74.4	67.2	74.2
Per share:				
Net income	\$ 0.47	\$ 0.30	\$ 0.27	\$ 0.30
Dividends	0.05	0.05	0.05	0.05
Common stock price:				
High	\$ 31 ⁵ / ₈	\$ 29 ⁷ / ₈	\$ 26 ¹⁵ / ₁₆	\$ 27 ¹³ / ₁₆
Low	23 ⁷ / ₈	24 ¹ / ₂	23	23 ¹ / ₄
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—basic and diluted	\$ 0.24	\$ 0.28	\$ 0.31	\$ 0.46
Dividends	0.05	0.05	0.05	0.05
Common stock price:				
High	\$ 26 ⁵ / ₈	\$ 28	\$ 29	\$ 31 ⁵ / ₈
Low	24 ¹ / ₈	24 ¹ / ₄	25 ³ / ₈	25 ³ / ₄

(a) First quarter 1997 and 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 reduction of reserves by \$31.3 million related to Columbia bankruptcy settlement (see Note 4) and operating expenses were impacted by \$43.5 million related to the write-down and impairment of certain oil and gas assets.

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

On December 4, 1997, the Company, with the approval of the Audit Committee of the Company's Board of Directors, dismissed Deloitte & Touche LLP ("D&T") as its independent accountants, effective upon D&T's completion of its audit of the Company's financial statements for the fiscal year ended December 31, 1997. The reports of D&T on the financial statements of the Company for either of the two most recent fiscal years did not contain an adverse opinion or disclaimer of opinion and was not qualified or modified as to uncertainty, audit scope or accounting principle. During such years and during the period between December 31, 1996 and the date on which D&T was dismissed, there was no disagreement between the Company and D&T on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of D&T, would have caused D&T to make reference to the subject matter of such disagreement in connection with its report on the Company's financial statements. On December 4, 1997, the Company engaged Arthur Andersen LLP as its new independent auditor effective January 1, 1998.

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 section 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—Section 16(a) Reporting Compliance section 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 16, 1998, 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 32.

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>
2.1	— Pre-acquisition Agreement between Union Pacific Resources Group Inc., Union Pacific Resources Inc. and Norcen Energy Resources Limited, dated January 25, 1998 (incorporated herein by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on March 17, 1998).
3.1	— Amended and Restated Articles of Incorporation of Union Pacific Resources Group Inc. (Exhibit 3.1 to Form S-1 and Exhibit 3.2 to the Company's Annual Report to Form 10-K filed on March 21, 1997).
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	— Terms Agreement, dated as of October 10, 1996, for \$200,000,000 7½% debentures due October 15, 2026 (incorporated herein by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K filed on March 17, 1998).
4.5	— Terms Agreement, dated as of October 10, 1996, for \$200,000,000 7% notes due October 15, 2006 (incorporated herein by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K filed on March 17, 1998).
4.6	— Terms Agreement, dated as of October 31, 1996, for \$150,000,000 7½% debentures due November 1, 2096 (incorporated herein by reference to Exhibit 4.6 to the Company's Current Report on Form 8-K filed on March 17, 1998).
4.7	— Form of 7½% Rate Debenture due October 15, 2026 (incorporated herein by reference to Exhibit 4.7 to the Company's Current Report on Form 8-K filed on March 17, 1998).
4.8	— Form of 7% Rate Note due October 15, 2006 (incorporated herein by reference to Exhibit 4.8 to the Company's Current Report on Form 8-K filed on March 17, 1998).
4.9	— Form of 7½% Rate Note due November 1, 2096 (incorporated herein by reference to Exhibit 4.9 to the Company's Current Report on Form 8-K filed on March 17, 1998).
4.10	— Trust Indenture, dated as of May 7, 1996, providing for the issue of Debt Securities in unlimited principal amount, between Norcen Energy Resources Limited and Montreal Trust Company of Canada, as trustee (incorporated herein by reference to Exhibit 4.10 to the Company's Current Report on Form 8-K filed on March 17, 1998).

**Exhibit
Number**

Description of Exhibit

- 4.11 — First Supplemental Indenture, dated as of May 22, 1996, to Trust Indenture, dated as of May 7, 1996, providing for the issue of 7 $\frac{3}{8}$ % Debentures due May 15, 2006 in aggregate principal amount of U.S. \$250,000,000 between Norcen Energy Resources Limited and Montreal Trust Company of Canada, as trustee (incorporated herein by reference to Exhibit 4.11 to the Company's Current Report on Form 8-K filed on March 17, 1998).
- 4.12 — Second Supplemental Indenture, dated as of June 26, 1996, to Trust Indenture, dated as of May 7, 1996, providing for the issue of 7.8% Debentures due July 2, 2008 in aggregate principal amount of U.S. \$150,000,000 between Norcen Energy Resources Limited and Montreal Trust Company of Canada, as trustee (incorporated herein by reference to Exhibit 4.12 to the Company's Current Report on Form 8-K filed on March 17, 1998).
- 4.13 — Third Supplemental Indenture, dated as of June 26, 1996, to Trust Indenture, dated as of May 7, 1996, providing for the issue of 6.8% Debentures due July 2, 2002 in aggregate principal amount of U.S. \$250,000,000 between Norcen Energy Resources Limited and Montreal Trust Company of Canada, as trustee (incorporated herein by reference to Exhibit 4.13 to the Company's Current Report on Form 8-K filed on March 17, 1998).
- 4.14 — Fourth Supplemental Indenture, dated as of February 27, 1998, to Trust Indenture, dated as of May 7, 1996, providing for the Guarantee of all Securities be Issued or Previously Issued under the Trust Indenture between Norcen Energy Resources Limited, Union Pacific Resources Group Inc., as guarantor and Montreal Trust Company of Canada, as trustee (incorporated herein by reference to Exhibit 4.14 to the Company's Current Report on Form 8-K filed on March 17, 1998).
- 10.1 — Tax Allocation Agreement, dated October 6, 1995 (Exhibit 10.3 to Form S-1).
- 10.2 — Indemnification Agreement, dated October 1, 1995 (Exhibit 10.4 to Form S-1).
- 10.3 — Pension Plan Agreement, dated October 1, 1995 (Exhibit 10.7 to Form S-1).
- 10.4 — 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).
- 10.5 — 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).
- 10.6 — Executive Incentive Plan of Union Pacific Resources Group Inc. as amended and restated June 1, 1997 (incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the period ended March 31, 1997).
- 10.7 — 1995 Stock Option and Retention Stock Plan of Union Pacific Resources Group Inc. as amended and restated, effective June 1, 1997 (incorporated herein by reference to the Company's Registration Statement on Form S-8, dated February 28, 1997).
- 10.8 — 1995 Directors Stock Option Plan, as amended and restated, effective June 1, 1997 (incorporated herein by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the period ended March 31, 1997).
- 10.9 — Directors' Deferred Compensation Plan, as amended and restated, effective September 5, 1997 (incorporated herein by reference to the Company's Registration Statement on Form S-8, dated September 15, 1997).
- 10.10 — Executive's Deferred Compensation Plan, effective September 5, 1997 (incorporated herein by reference to the Company's Registration Statement on Form S-8, dated September 15, 1997).
- 10.11(a) — Conversion Agreement (Exhibit 10.13(a) to Form S-1).
- 10.11(b) — Conversion Agreement for Drew Lewis (Exhibit 10.13(b) to Form S-1).
- 10.11(c) — Conversion Agreement for Jack L. Messman (Exhibit 10.13(c) to Form S-1).

Exhibit
Number

Description of Exhibit

- 10.12 — The Union Pacific Resources Group Inc. Executive Life Insurance Plan, adopted February 26, 1997 (incorporated herein by reference to Exhibit 10.16 to the Company's Annual Report on Form 10-K for the year ended December 31, 1996).
- 10.13(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 (incorporated herein by reference to Exhibit 10.17(a) to the Company's Annual Report on Form 10-K for the year ended December 31, 1996).
- 10.13(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 (incorporated herein by reference to Exhibit 10.17(b) to the Company's Annual Report on Form 10-K for the year ended December 31, 1996).
- 10.13(c) — Form of Agreement relating to Change in Control by and between Union Pacific Resources Group Inc. and each of Anne M. Franklin, Joseph A. LaSala, Jr., Donald W. Niemiec, Morris B. Smith and John B. Vering, dated February 4, 1997 (incorporated herein by reference to Exhibit 10.17(c) to the Company's Annual Report on Form 10-K for the year ended December 31, 1996).
- 10.14 — 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).
- 10.15 — 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).
- *10.16 — Amendments to Transportation Agreement dated December 15, 1989, by and between Kern River Gas Transmission Company and Union Pacific Fuels, Inc.
- *10.17 — Gas Transportation Agreement, dated June 18, 1997, by and between Union Pacific Fuels, Inc. and Texas Gas Transmission Corporation.
- 10.19 — 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).
- 10.20 — Agreement, dated as of August 3, 1995, by and among Union Pacific Resources Group Inc., The Anschutz Corporation, Anschutz Foundation and Mr. Philip F. Anschutz ("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).
- 10.21 — Letter agreement, dated as of January 20, 1997, amending the Anschutz Agreement (incorporated herein by reference to Exhibit 10.25 to the Company's Annual Report on Form 10-K for the year ended December 31, 1996).
- 10.22 — U.S. \$900,000,000 Competitive Advance/Revolving Credit Agreement, dated as of April 16, 1996, among Union Pacific Resources Group Inc., the lenders named therein and Texas Commerce Bank National Association, as administrative agent, as amended through September 13, 1996 (incorporated herein by reference to Exhibit 10 to the Company's Quarterly Report on Form 10-Q for the period ended September 30, 1996.)
- *10.23 — Third Amendment dated March 2, 1998, to the U.S. \$600,000,000 Competitive Advance/Revolving Credit Agreement, dated April 16, 1996, between Union Pacific Resources Group Inc. and Chase Bank of Texas, N.A.
- *10.24 — U.S. \$300,000,000 Competitive Advance/Revolving Credit Agreement, dated as of November 25, 1997, among Union Pacific Resources Group Inc., the lenders named therein and Texas Commerce Bank National Association, as administrative agent.

**Exhibit
Number**

Description of Exhibit

- *10.25 — First Amendment dated March 2, 1998, to the U.S. \$300,000,000 Competitive Advance/Revolving Credit Agreement, dated November 25, 1997 among Union Pacific Resources Group Inc., the lenders named therein and Chase Bank of Texas National Association, as administrative agent.
- *10.26 — U.S. \$2,700,000,000 Competitive Advance/Revolving Credit Agreement, dated as of March 2, 1998, among Union Pacific Resources Group Inc., the lenders named therein and the Chase Manhattan Bank, as administrative agent and Bank of Montreal, as syndication agent.
- *10.27 — Cdn \$200,000,000 Amended and Restated Extendible Revolving Term Credit Facility Agreement, dated May 22, 1997, between Norcen Energy Resources Limited and Canadian Imperial Bank of Commerce.
- *10.28 — Cdn \$100,000,000 Amended and Restated Extendible Revolving Term Credit Facility Agreement, dated May 29, 1997, between Norcen Energy Resources Limited and Royal Bank of Canada.
- *10.29 — Cdn \$100,000,000 Amended and Restated Extendible Revolving Term Credit Facility Agreement, dated May 29, 1997, between Norcen Energy Resources Limited and Toronto-Dominion Bank.
- *10.30 — Cdn \$50,000,000 Amended and Restated Extendible Revolving Term Credit Facility Agreement dated May 29, 1997, between Norcen Energy Resources Limited and Union Bank of Switzerland (Canada).
- *10.31 — Cdn \$50,000,000 Amended and Restated Extendible Revolving Term Credit Facility Agreement dated June 9, 1997, between Norcen Energy Resources Limited and ABN AMRO Bank Canada.
- *10.32 — U.S. \$150,000,000 Demand Credit Facility Agreement, dated November 20, 1997, between Norcen Energy Venezuela, S.A. and Canadian Imperial Bank of Commerce West Indies Offshore Banking Corporation.
- *10.33 — U.S. \$25,000,000 Revolving Loan Agreement, dated July 14, 1997, between Basic Petroleum International Limited and Royal Bank of Canada.
- *10.34 — Cdn \$10,050,000 Revolving Demand Credit Facility Agreement, dated October 16, 1996, between Superior Propane Inc. and Royal Bank of Canada.
- *10.35 — Amendment No. 1 to Amended and Restated 1976 Coal Purchase Contract between Commonwealth Edison Company and Black Butte Coal Company, effective as of January 1, 1996.
- *10.36 — Amendment No. 2 to Amended and Restated 1976 Coal Purchase Contract between Commonwealth Edison Company and Black Butte Coal Company, effective as of January 1, 1997.
- *12 — Computation of ratio of earnings to fixed charges.
- 16 — Letter regarding change in certifying accountant from Deloitte & Touche LLP dated December 1997 (incorporated herein by reference to Exhibit 16.1 to the Company's Current Report on Form 8-K dated December 10, 1997).
- *21 — List of subsidiaries.
- *23(a) — Consent of Deloitte & Touche LLP dated as of March 26, 1998.
- *23(b) — Consent of Ryder Scott Company Petroleum Engineers, dated as of March 9, 1998.
- *24 — Powers of attorney for certain Directors.
- *27 — Financial data schedule.
- *99 — Report from Ryder Scott Company Petroleum Engineers, dated as of February 27, 1998, relating to oil and gas reserves for Union Pacific Resources Group Inc. as of December 31, 1997.

(b) Reports on Form 8-K.

On December 11, 1997, the Company filed a Current Report on Form 8-K concerning changes in the Company's certifying auditors. Deloitte & Touche, LLP, will be dismissed effective with the completion of its annual audit of the Company's financial statements for the fiscal year ended December 31, 1997. The Company also engaged Arthur Andersen LLP as its new independent auditor effective January 1, 1998.

On January 26, 1998, the Company filed a Current Report on Form 8-K containing a copy of two press releases issued by the Company on January 26, 1998. The first press release announced that the Company's Board of Directors and the Board of Directors of Norcen had unanimously approved the acquisition of Norcen by Union Pacific Resources Inc., an Alberta corporation ("UPRI"), the Company's indirect wholly-owned subsidiary. The second press release announced the Company's 1997 annual operating revenues, net income and certain other financial information.

On March 17, 1998, the Company filed a Current Report on Form 8-K containing a copy of two press releases issued by the Company. The first press release issued on March 3, 1998 announced the closing of its tender offer for up to 100% of the common shares of Norcen Energy Resources Limited.

In the second press release, issued on March 6, 1998, UPRI announced that on March 5, 1998, UPRI completed the compulsory acquisition procedures pursuant to section 206 of the Canadian Business Corporation Act to acquire the remaining issued and outstanding common shares of Norcen.

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 26th day of March, 1998.

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 26th day of March, 1998, by the following persons on behalf of the registrant and in the capacities indicated.

<u>Signature</u>	<u>Title</u>
<u>/s/ JACK L. MESSMAN</u> (Jack L. Messman)	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
<u>/s/ MORRIS B. SMITH</u> (Morris B. Smith)	Vice President and Chief Financial Officer (Principal Accounting and Financial Officer)
*	Director
<u>H. Jesse Arnelle</u>	Director
*	Director
<u>Lynne V. Cheney</u>	Director
*	Director
<u>Preston M. Geren III</u>	Director
*	Director
<u>Lawrence M. Jones</u>	Director
*	Director
<u>Drew Lewis</u>	Director
*	Director
<u>Claudine B. Malone</u>	Director
*	Director
<u>John W. Poduska, Sr., Ph.D.</u>	Director
*	Director
<u>Michael E. Rossi</u>	Director
*	Director
<u>Samuel K. Skinner</u>	Director
*	Director
<u>James R. Thompson</u>	
*By <u>/s/ MARK L. JONES</u> Mark L. Jones, as attorney-in-fact	

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