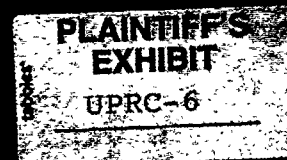


Union Pacific Resources Group Inc.
Annual Employees' Report to Shareholders 1998



New Places, New Faces.

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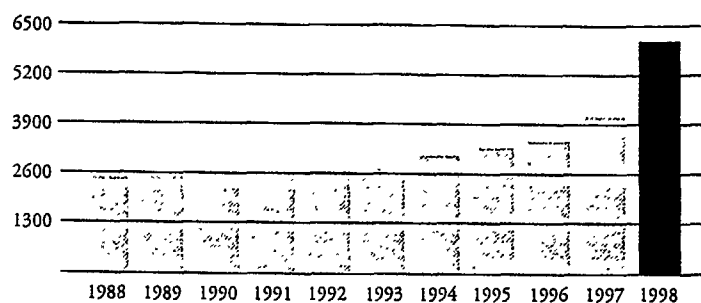
Annual Report on Form 10K

New Places, New Faces

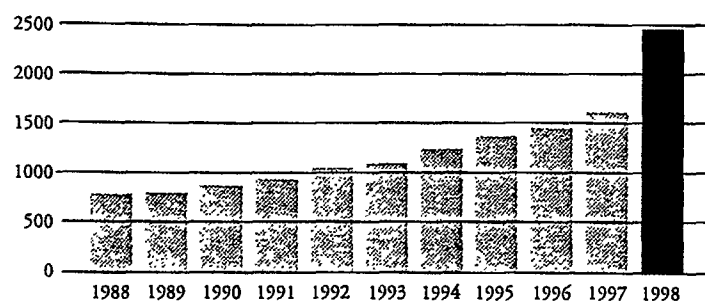
The title of our Annual Report, "New Places, New Faces," refers to the most important change that occurred at UPR in 1998: the acquisition of Norcen Energy Resources, its valuable and high-potential oil and gas properties, and the skilled, dedicated people who manage and operate them.

The combination of new and existing assets and people makes UPR an even more formidable presence in the oil and gas exploration and production industry than in the past. Amid many changes in our company and our industry, UPR's determination to achieve competitive advantage and increase shareholder value remains unchanged.

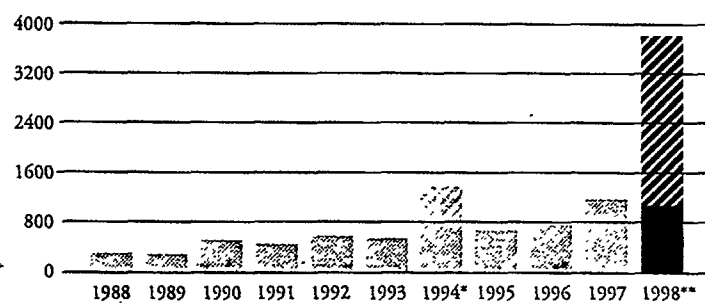
Proved Reserves (Bcfe)



Daily Production (MMcfe)



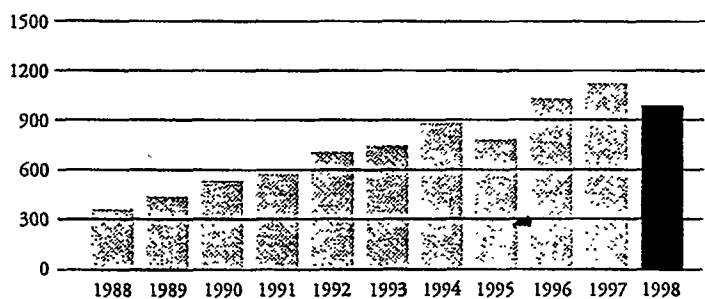
Capital & Exploratory Expenditures (\$ millions)



*Includes \$725 million for the Amax Oil & Gas, Inc., acquisition.

**Includes \$2,634 million for the Norcen acquisition, not including assumed debt.

Discretionary Cash Flow (\$ millions) *



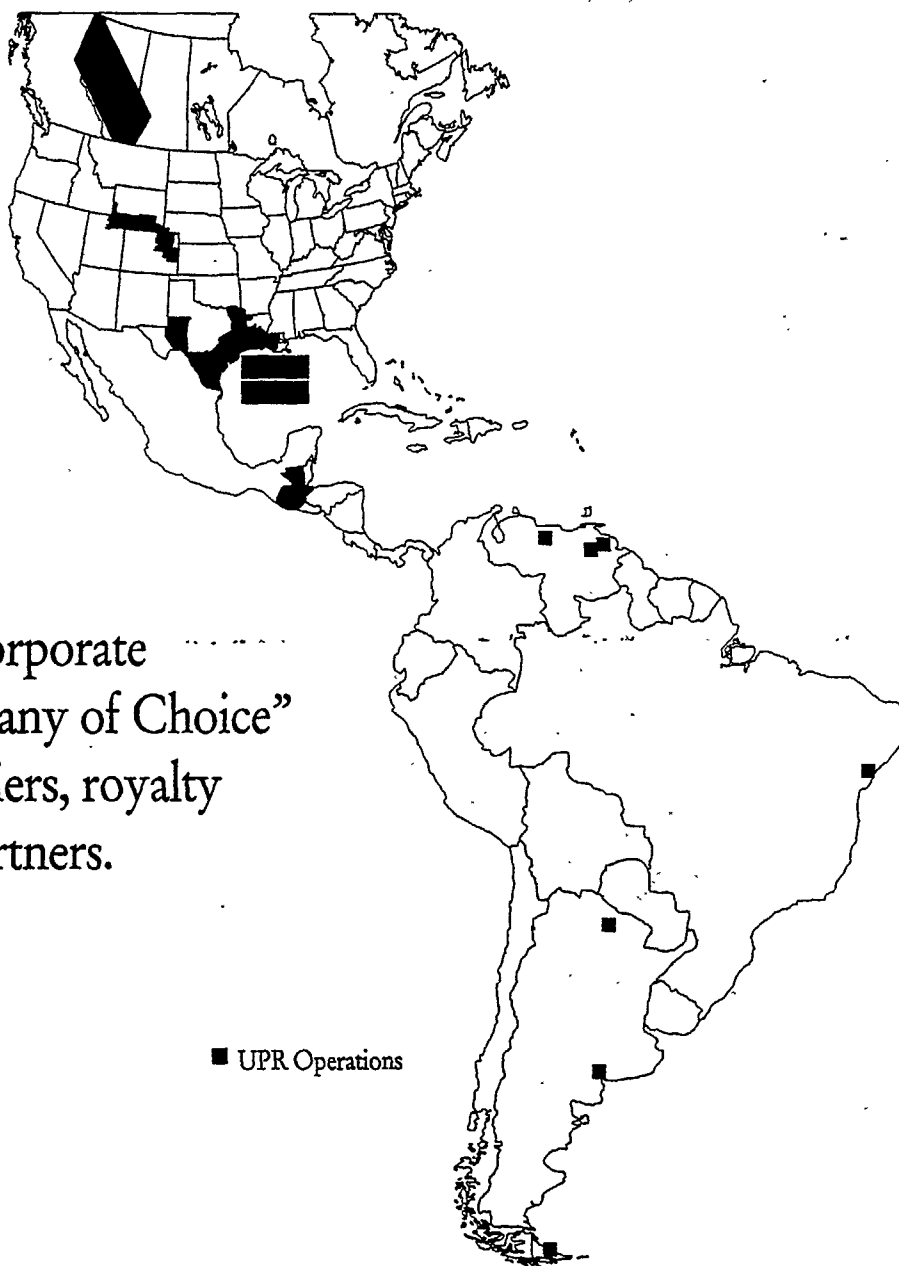
*As adjusted to give pro forma effect to the Company's initial public offering and to exclude certain non-recurring amounts.

Company Profile

Union Pacific Resources Group Inc. is one of the largest North American independent oil and gas exploration and production companies and has important operations in Latin America. Our hard minerals business supports oil and gas operations by providing steady income and cash flow.

The most active driller in the United States for the past seven years, UPR is known as a leader in applying technology to produce oil and gas at the lowest possible cost.

UPR is the home of a corps of employees who put their skills and creativity to work in a nationally recognized corporate culture. It is the "Company of Choice" for its employees, suppliers, royalty owners and industry partners.



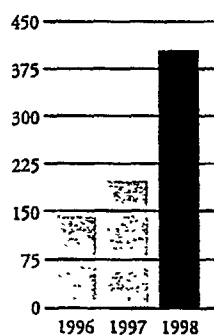
Financial and Operating Highlights

Union Pacific Resources Group Inc.

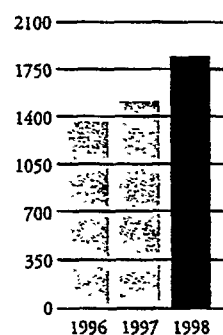
<i>Millions, except where noted</i>	Years Ended December 31	
	1998	1997
Operating Revenues	\$ 1,841.0	\$ 1,518.0
Operating Income (loss)	\$ (1,193.2)	\$ 433.9
Income (loss) from Continuing Operations	\$ (883.1)	\$ 303.1
Net Income (loss)	\$ (898.7)	\$ 333.0
Income (loss) from Continuing Operations Per Share - Diluted	\$ (3.57)	\$ 1.21
Earnings (loss) Per Share - Diluted	\$ (3.63)	\$ 1.33
Discretionary Cash Flow *	\$ 922.2	\$ 1,122.7
Discretionary Cash Flow Per Share	\$ 3.72	\$ 4.47
Capital and Exploratory Expenditures	\$ 3,828.8	\$ 1,188.4
Operating Data		
Producing Properties		
Average Daily Production (MMcfed)	2,467.0	1,615.7
Average Sales Prices (per Mcfe)	\$ 1.71	\$ 2.19
Average Production Costs (per Mcfe)	\$.49	\$.51
As of December 31		
Proved Reserves (Bcfe)	6,124.0	4,100.0
Total Assets	\$ 7,642.4	\$ 4,313.7
Average Number of Shares of Common Stock Outstanding - Diluted	247.7	250.9
Capital Structure		
Debt Due Within One Year	\$ 853.8	\$ —
Long-Term Debt	\$ 3,744.9	\$ 1,230.6
Shareholders' Equity	\$ 728.2	\$ 1,760.7
Total Capitalization	\$ 5,326.9	\$ 2,991.3
Debt as a Percent of Capitalization	86.3%	41.1%

* The sum of net income; depletion, depreciation and amortization; deferred taxes; and exploration expenses, including exploration overhead.

Reserve Replacement
(percent)



Operating Revenues
(millions)

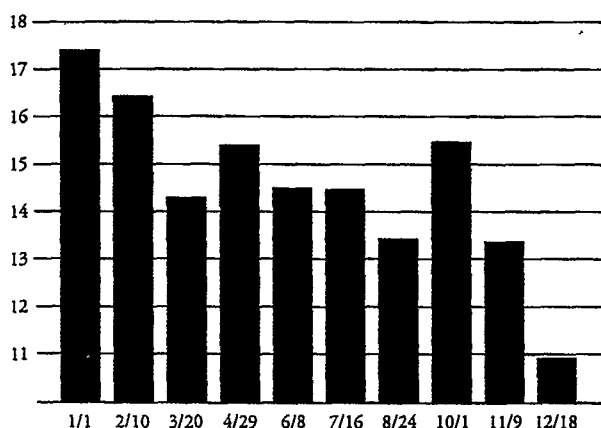


Employees' Letter to Shareholders

Low commodity prices have stunned our industry, but UPR's strengths and strategies will enable us to ride out current conditions and capitalize on improving prices later on.

The year 1998 will go down in UPR history as one of record growth, fundamental change and a redefinition of business strategies and core areas. It was a year in which we welcomed aboard a new cadre of seasoned professionals, experts in their Canadian and Latin American regions — the New Places and New Faces that are now so important to UPR's future. And it was a year of strangely conflicting accomplishments and results: record volume growth and continuing operational achievement versus a large after-tax net loss and unsatisfactory stock performance. What caused this odd conjunction? Collapsing commodity prices, particularly oil prices.

NYMEX Oil Prices—1998
(\$ per barrel)



The lowest oil prices in 50 years rocked our industry, damaging profitability, driving oil and gas company stock prices down dramatically and accelerating a trend toward industry consolidation. Throughout the industry, plans for growth and for capital expenditures to increase reserves, production and volumes were turned on their head. The rig count in the United States declined to a near-record low in 1998 — and broke the record in early 1999. The emphasis changed to weathering the price storm, being profitable by reducing the costs of doing business, reexamining business processes, looking for economies of scale and decreasing risk.

At the beginning of 1998, UPR was a domestic exploration and production powerhouse with a large midstream gas business. At a glance, we looked great. But after careful analysis, we concluded that an almost exclusive reliance on the domestic upstream and a mature midstream business was not consistent with our view of industry trends.

UPR recognized the need for growth early on and acted, acquiring Norcen Energy Resources of Canada in early 1998. Growth and increased profitability are business imperatives. They required that UPR become what it is today: a North American mega-independent exploration and production company with some international midstream interests. Our strategy was right. The timing, admittedly, was off, as commodity prices plummeted at about the same time we completed the Norcen transaction. Debt associated with the acquisition of Norcen aggravated the price-related problems we would have faced in any case in 1998, and it will limit our flexibility in 1999, or until the price environment improves.

1998 Performance

A large cash acquisition and a sudden, unanticipated price decline were largely responsible for our disappointing stock price and financial performance in 1998, and for after-tax, non-cash charges against earnings totaling over \$800 million.

In 1998, we recorded a loss of \$899 million, even as production increased by 53 percent. Proved reserves increased by 49 percent, and we achieved a reserves replacement rate of 403 percent. In the same year, we took a \$760 million after-tax, non-cash asset impairment charge, or a writedown of the value of our reserves, to conform to commodity prices in the new market environment. Discretionary cash flow totaled \$922 million for the year, a 17 percent decrease from 1997, as crude oil prices declined 43 percent to \$10.48 per barrel, down from the 1997 average of \$18.36.

Our stock price declined 63 percent, the result, first, of investor caution during our acquisition phase, then of concern about our high debt level, and finally, of the market's loss of enthusiasm for our industry in the face of a precipitous commodity price decline.

In 12 months, from first quarter 1998 to first quarter 1999, we successfully executed a daunting series of tasks:

- Completed the \$3.6 billion acquisition of Norcen and rapidly integrated our new Canadian, Gulf of Mexico and Latin American assets with our already strong domestic asset base.
- Held onto our ranking as the most active driller in the United States for the seventh consecutive year, even as we reduced capital spending and lowered our rig count by two-thirds.
- Put together a plan, strategies and budget with which to operate profitably in a low-price environment in 1999 and beyond, and to thrive when the commodities markets return to something more nearly resembling normal conditions.
- Completed a program to reduce debt by selling non-core domestic and Canadian upstream assets, as well as our domestic gas gathering, processing and marketing business.
- Embarked on a stringent, across-the-board cost-reduction program, including a two-part work force reduction.
- Earned the distinction of being selected as one of the "100 Best Companies to Work for" in separate surveys conducted by *Fortune* and *Working Mother* magazines and as one of *Fortune's* "Most Admired Companies."

Properties and Plans

Our new assets have been integrated and we are carrying out a balanced program of resource development and selective exploration in the United States, Canada and Latin America.

We have improved the quality of our assets, which now total over \$7.5 billion. Our natural gas-to-oil reserve ratio favors gas, 56 percent to 44 percent. The combination of newly acquired properties and the sale of mature, non-core properties has given UPR higher ownership percentages, a higher level of operatorship — two essential elements of our business model — and a higher-quality portfolio of diversified drill site opportunities.

We have retained our leading position in drilling and technological expertise, our outstanding corps of employees, our 7.5 million net acres of Land Grant property, and our initiative to become the Company of Choice, the company anyone who works with or for our industry looks to first.

We boast a strong minerals business unit, with properties in Wyoming, that provides a stable source of income and cash flow for UPR.

Our already large total acreage position has grown even larger, to more than 19 million net acres. We have a dominant position in numerous giant fields and a large drill site inventory that has increased in both size and quality.

Our strategy in 1999 is to concentrate on profitably finding and producing gas in Canada and the United States, and to increase the size

and importance of our international

operations by developing our positions in Guatemala and Venezuela. Our development and exploration programs should allow us to maintain production volumes in 1999 at about 2.2

billion cubic feet of

gas equivalent per day (Bcfed), just slightly below the 1998 rate, while reducing finding and development costs and continuing to increase our reserves to production ratio. We will hold onto most of our stockpile of oil exploration opportunities until the market signals that it is ready for new oil at reasonable prices.

UPR Leadership Position*

	Industry Ranking
Austin Chalk	#1
East Texas	#1
West Texas	#1
Western Region	#3
Guatemala	#1
Offshore	#15
Canada	#19
Venezuela	#7

*Based on production.

1999 Capital Spending

Our capital budget of about \$500 million for 1999 is down 57 percent from 1998's \$1.16 billion for exploration and production. We are watching oil and gas price movements, and therefore, cash flow, very carefully and we will be making appropriate adjustments to the budget as the year progresses. About 90 percent of the budget will be devoted to development projects, with the remainder earmarked for high-impact exploration. The budget is divided into five roughly equal parts distributed among Canada, Latin America, the Gulf of Mexico, the Austin Chalk and other domestic projects.

Debt Reduction

UPR is well on the way to meeting the goal we announced in early 1998 of reducing debt by \$2 billion within two years. We will have reduced debt by about \$1.7 billion with proceeds from the sale of non-core exploration and production assets that accounted for about 10 percent of total production and

reserves, and from the anticipated sale of our midstream gas gathering, processing and marketing business, scheduled to close March 31, 1999. We intend to apply about \$250 million of cash flow from operations in 1999 to further reduce debt, which will bring us to our target of \$2 billion in total debt reduction. Despite our high debt-to-book equity ratio, after reducing debt by \$2 billion, UPR's cash coverage ratios should be strong and allow UPR to grow again once prices recover.

Cost Reduction

UPR has earned a well-deserved reputation over the years as a consistent low-cost operator. That reputation slipped a little in 1998, when our finding and development costs jumped from a five-year average of \$1.00 per thousand cubic feet of gas equivalent (Mcf) to \$1.26 because of some expensive exploration failures. It will not happen again. We plan to record finding and development costs in 1999 of less than \$1.00 per Mcf.

We instituted a work force reduction in 1998 and reduced contract services. By the end of first quarter, 1999 a series of other actions undertaken in early 1999 will have reduced UPR's work force by nearly 30 percent from its 1998 high.

We have initiated a company-wide reexamination of our business processes, emphasizing once again our corporate culture's commitment to the notion that we must do more than accept change — we must cause it. We cannot raise prices, but we can drive down costs.

Operational Reports

Our Annual Report last year was organized around our various business units in the United States. This year, our first as a North American mega-independent with large and important interests in Latin America, domestic operations take up only about a third of the operational section, with the rest divided between introductions to our New Places — Canadian and Latin American operations.

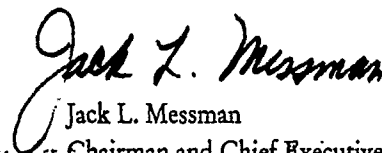
History's Reassurance

It is important to remember that while the oil industry and UPR are experiencing a period of upheaval, it is not by any means unprecedented. Our industry is cyclical, and price shocks seem to hit us once in each decade. The last sudden price decline occurred in 1986, when oil and gas prices fell 46 percent and 18 percent, respectively. As Dan Yergin wrote in *The Prize*, his classic history of the industry, "The results were devastating to the American oil industry...." But, as history has shown, there is usually a significant upturn in prices following a sudden decline.

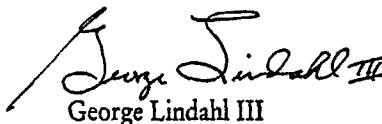
In 1986, UPR was a wholly owned subsidiary of Union Pacific Corporation called Champlin Petroleum Company. In that year, Champlin reported a loss of \$464 million, wrote down \$900 million in reserves and assets, embarked on a program to sell mature and non-core exploration and production assets, reduced its work force by 16 percent as part of a stringent cost-cutting campaign, and cut capital expenditures nearly in half. In Union Pacific's 1986 Annual Report, Champlin management said its "low-cost strategy (for 1987) is designed to make an acceptable profit at \$15-a-barrel oil and to improve profits very substantially at \$18 and \$20 a barrel." It all sounds very familiar.

The strategy worked. In 1987, prices were mixed: Crude oil prices rose, while the price of natural gas fell. Champlin, newly renamed Union Pacific Resources Company, reported a profit of \$205 million. We believe our strategy, which contains many of the elements in UPR's 1987 approach, can work again. We can make a profit at our budgeted oil and gas prices of \$13.50 per barrel and \$2.05 per thousand cubic feet (Mcf) NYMEX, respectively, and improve profits substantially at higher price levels in 1999.

Granted, circumstances today are not the same as they were in 1987. World economics, geopolitics and supply and demand equations are uncertain in ways different from 1986-87, and our industry has changed and continues to change. But there are some certainties: The market will adjust, prices will again rise — and UPR will continue to be one of the strongest competitors among the independents.


Jack L. Messman

Chairman and Chief Executive Officer


George Lindahl III

President and Chief Operating Officer

March 1999

Recognition

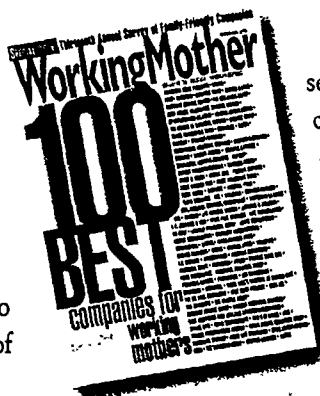
UPR was the only oil and gas company to make three prestigious rankings: the two top lists of the best companies to work for in America — and *Fortune's* list of America's most admired companies.

The views of UPR held by outsiders, industry experts and our own employees put us in select company in 1998-99: among "The 100 Best Companies to Work For" and "America's Most Admired Companies."

Two national magazines, *Working Mother* and *Fortune*, chose UPR for the first time for inclusion on their lists of "100 Best Companies to Work For." Then *Fortune*, with the publication of its annual "Most Admired Companies" issue, ranked UPR among the Top 10 in its category.

Working Mother chose the companies on its list after reviewing corporate cultures and surveying benefits policies and programs, with particular emphasis on how "family friendly" the candidates' practices were. The magazine points out that such policies enhance recruitment, reduce turnover and encourage a more loyal, focused work force, which, in turn, can have a real effect on financial performance and operational efficiency.

Fortune chose UPR for its "100 Best..." list after a review of our policies and programs similar to that of *Working Mother*, but with an added element: employee surveys. Over 200 randomly selected employees received lengthy questionnaires on their experience as UPR employees. Their responses counted heavily in *Fortune's* decision.



The *Fortune* "Most Admired Companies" selection depended on the application of eight criteria — innovation, quality of management, employee talent, quality of products/services, long-term investment value, financial soundness, social responsibility and use of corporate assets — to companies in their industries by selected executives, directors and analysts. Our industry's experts — peers, competitors and critical observers — gave UPR an unsolicited but welcome review, placing us ninth on a list of the Top 10 in the category of Mining, Crude Oil. These selections by so diverse a group of people from inside and outside our industry and our Company would be pleasing at any time, but they are especially gratifying during this difficult period in the oil and gas industry.

We believed the corporate culture change process we instituted several years ago would positively influence our employees and affect our overall performance. It is good to see that expectation ratified by the opinions and observations of so many people, some intimately involved in our work and some far removed.

We thank those who spoke so highly of us — especially our employees, on whom UPR's future depends.

Review of Operations

New Places and New Faces added immediate benefits and promising new opportunities to UPR's already strong inventory of domestic assets.

The integration of new Canadian, Gulf of Mexico and Latin American assets into UPR's existing operations was the big story of 1998, with production and proved reserves increased by half and reserves replaced at a rate of 403 percent. A high-grade development and exploration program in 1999 will keep production and other operational performance measures close to 1998 levels, despite a greatly reduced capital budget of approximately \$500 million.

Canada

Operating and Financial Statistics

	1998
Producing Properties Volumes (MMcfd)	519
Proved Reserves (Bcfe)	1,731
Capital and Exploratory Expenditures (millions)*	\$198
Gross Wells Drilled	273

*Excludes acquisition of Norcen.



Union Pacific Resources Inc. (UPRI) operates in western Canada and is UPR's largest business segment, contributing approximately 25 percent of the Company's reserves, production and cash

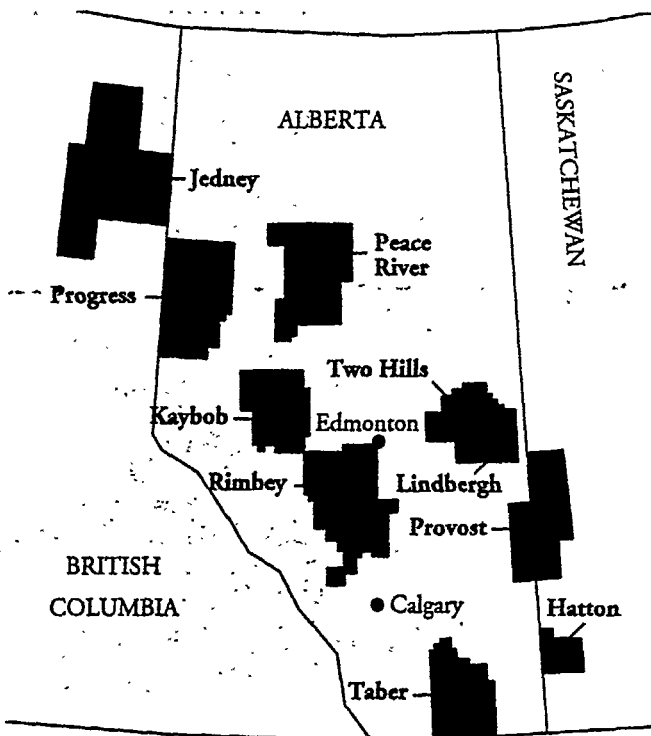
flow. The Canadian operations, distributed among 10 core operating areas, are geologically and geographically diverse, providing a balanced commodity mix (54 percent natural gas and 46 percent oil and natural gas liquids), as well as a long reserve life asset portfolio. Proved reserves in Canada total 1.7 trillion cubic feet of gas equivalent (Tcfe).

The quality and diversity of the Canadian assets offer strong future exploration and development potential. With access to 3.1 million net acres in Canada, an inventory of about 1,000 low-risk drill sites and exposure to potential high-impact exploration opportunities, the Canadian operations are poised for future growth.

As with all of UPR, 1998 was a year of transition and integration for the Canadian operations as UPRI combined the Norcen Canadian asset base with UPR's existing interests in western Canada and responded to the low crude oil price environment.

Total UPRI and Norcen capital expenditures decreased 36 percent from 1997 as a result of reductions in heavy and conventional oil exploration in response to lower crude prices.

UPRI drilled 161 net wells in 1998 and achieved an 85 percent success rate. Of these, 24 were shallow gas development wells drilled in the Hatton area. Average production of 519 million cubic feet of natural gas equivalent per day (MMcfd) in 1998 was generated from high working interests in approximately 5,500 gross producing wells, of which UPRI operates 4,200. This represents an eight percent increase in production over 1997. Natural gas volumes remained flat at 285 million cubic feet per day (MMcfd) in 1998, largely due to volume growth in the Jedney and Kaybob areas that offset natural declines. Natural gas liquids production rose 21 percent to 4 thousand barrels per day (Mbbld) as a result of increased production at Kaybob and Rimbey. Conventional oil and condensate production remained flat at roughly 21 Mbbld



UPRI's 10 core operating areas are located across the Western Canadian Sedimentary Basin in Alberta, southwest Saskatchewan, and northeast British Columbia.

with conventional oil increases in Taber and higher production of field condensates in Rimbey, Progress and Jedney offset by natural declines. Heavy oil production increased 31 percent in 1998 to 14 thousand barrels of oil equivalent per day (Mbbled) in the Lindbergh and Provost areas, mainly as a result of significant drilling activity in these areas in 1997.

1999 Plans

- UPRI is currently pursuing very high-grade drilling prospects that will maximize new production growth and generate rapid payouts. In the Rimbey area, UPRI led new exploration and development of two large gas plays in 1998, Open Lake and Telfordville. As we are ahead of other players in this region, UPRI's momentum offers a significant competitive advantage in the future development of these fields. UPRI has an ongoing aggressive outlook for gas development in the Rimbey area and plans for additional land acquisition and aggressive seismic and drilling activity in this region.
- The Company expects to continue its shallow gas development in the Hatton region of southwest Saskatchewan and plans to drill over 300 gross wells in this area in 1999, which will add substantial new gas production. With further down-spacing, the potential exists for an additional 1,000 future Hatton drilling locations.
- In addition to working on these and other high-quality development projects in the Canadian core areas, UPRI will continue to pursue certain new exploration opportunities in 1999. For example, with a farm-in in the Sullivan Creek area of southwest Alberta, UPRI has committed to drilling a horizontal reentry of an existing suspended well, which, if successful, will earn UPRI a 60 percent working interest in the entire surrounding structure. UPRI will apply horizontal drilling technology to revisit this play, which has an expected reserve potential of about half a trillion cubic feet of gas.

U.S. Operations

Operating and Financial Statistics

	1997	1998
Producing Properties Volumes (MMcfed)	1,566	1,692
Proved Reserves (Bcfe)	3,934	3,466
Capital and Exploratory Expenditures (millions)*	\$1,156	\$821
Gross Wells Drilled	811	318

*Excludes acquisition of Norcen.



To reduce costs, increase efficiency and more accurately reflect the new balance among domestic, Canadian and Latin American operations, UPR reorganized its domestic operations in early 1999, consolidating five business units into two: onshore and offshore operations.

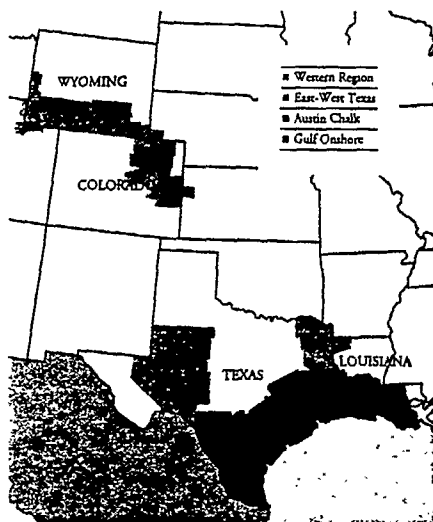
Onshore Business Unit

The domestic onshore business unit comprises UPR's operations and holdings in Texas, Louisiana, Wyoming, Utah, Kansas and Colorado. Approximately 40 percent of UPR's total capital expenditures for exploration and production in 1999 is allocated to domestic onshore activities.

The Austin Chalk, UPR's second largest area of operations after Canada, will receive about half the capital expenditures for domestic onshore operations in 1999, an acknowledgment of UPR's past successes in the Chalk and of its continuing potential for the development of low-risk, high- and fast-return projects.

The Austin Chalk is an exceptionally productive source of oil and natural gas stretching from western Louisiana to southwest Texas. It was UPR's largest area of operations until the Norcen acquisition reduced the Company's reliance on Chalk production. Nevertheless, the Chalk still accounted for 24 percent of UPR's total production in 1998 and 20 percent of total reserves at year-end.

In 1998, UPR maintained its ranking as the number one producer in the Chalk, even as lower commodity prices caused an overall decrease in activity in the last months of the year. With an average of 15 operated rigs working, compared to 26 in 1997, the unit effectively high graded drilling opportunities to produce record volumes — 581 MMcfed — and reserves additions — 252 billion cubic feet of natural gas equivalent (Bcfe). The Chalk replaced 100 percent of reserves, for total proved remaining net reserves of 708 Bcfe.



UPR extended its record as the nation's leading driller to seven straight years in 1998. With a total acreage position of over 19 million net acres, UPR has a large, high-quality drill site inventory.

Two noteworthy achievements in the Chalk were the drilling of five successful wells into the Edwards formation, along with the completion of 60 MMcfd-capacity facilities to gather and process sour gas from the Edwards development, and the drilling of the Glaeser #1 well in the Deep Giddings, which produced 5 billion cubic feet of natural gas (Bcf)

in its first five months of production and continues flowing at 60 MMcfd. The Glaeser #1 well extended the Deep Giddings play further south, setting up 1999 drilling projects. The Deep Giddings delivered a total of five high-volume wells with aggregate initial production volumes of 140 MMcfd.

UPR leads the industry in production in the areas of *East-West Texas* where it operates. The Carthage and Oak Hill fields in east Texas and the Ozona gas field in the Permian Basin of west Texas account for 16 percent of UPR's total proved reserves and 13 percent of production. Overall, the East-West Texas properties increased production by five percent in 1998, while continuing to drive down operating costs.

The East-West Texas fields, generally called "mature," are good examples of properties that benefit from UPR's low-cost application of advanced development and drilling technology. Three-D seismic evaluations of prospective acreage, the introduction of horizontal drilling techniques to older fields and in-fill drilling in established but underdeveloped fields will allow UPR to continue to add to its record of success in Texas.

The *Gulf Onshore* area includes UPR's interests in south Louisiana and south Texas. In Louisiana, exclusive of the Austin Chalk, UPR is actively marketing its non-core properties while concentrating on the evaluation of approximately 750 square miles of 3-D seismic shot on nearly 200,000 acres of land over which UPR and its partners have leases or control options. UPR has developed an inventory of prospects and selected prospect-specific leases from among the optioned acreage blocks. By recruiting partners to reduce both risk and

cost, UPR hopes to drill as many as eight high-potential wells this year. In south Texas, UPR completed the sale of non-strategic, higher-cost properties in January 1999. UPR was very active in 1998, acquiring attractive new properties and large amounts of 3-D seismic data, and working with partners to redevelop older fields and drill wells in new areas. The Alltex-Savage #2 well, in Matagorda County's Wadsworth field, for example, recorded initial production of 70 MMcfd and produced over 7 Bcf in its first six months of operation.

UPR is the number three producer in the *Western Region*, where the Company owns approximately 8.6 million fee mineral acres, primarily in Wyoming, Colorado and Utah, as well as production and acreage in several other mid-continent states. In 1998, UPR participated in 215 wells and produced 500 MMcfd. UPR's fee mineral position allows the Company to drive much of the activity in southwest Wyoming and southeast Colorado.

In Wyoming's Green River Basin, UPR participated in two major multi-well drilling programs. With the application of advanced technology and concentrated cost-reduction efforts, the basin will continue to be an active and profitable area for future development. The Company was chosen by the Department of Energy to drill an experimental horizontal well in the basin to test horizontal drilling technology's potential to unlock new gas reserves there.

UPR holds a 33 percent interest in most of the Whitney Canyon sour gas field, located in the Overthrust area of southwest Wyoming, where an active in-fill drilling program increased 1998 production from 150 MMcfd to over 180 MMcfd.

In southeast Colorado, UPR built a 35 MMcfd gas processing and liquefied helium plant, since included in the properties being sold to Duke Energy Field Services, Inc., which opened up new markets for natural gas that had once been considered unprofitable. UPR operated an aggressive two-rig drilling program throughout the year, which now allows the Company to supply natural gas to the plant.

Offshore Business Unit

Offshore operations grew significantly in 1998, primarily as a result of the acquisition of Norcen. The combined assets of the two companies make UPR the fifteenth-largest operator of production in the Gulf of Mexico. The number of operated platforms rose from 11 to 57, and operated producing wells increased from 11 to 129. Net volume doubled and lease inventory more than doubled.

UPR divested non-core properties in 1998 to consolidate operations. As a result, the offshore property mix is now about 90 percent operated and located almost exclusively on the central Louisiana Shelf.

Drilling activity slowed in 1998 due to the Norcen acquisition and low commodity prices. UPR participated in 13 gross exploration and development wells on the Shelf, 11 of which were successful. Reserves at year-end were 358 Bcfe, a 32 percent increase over the previous year. Production volumes increased 94 percent, to an average of about 182 MMcfe.

The deep-water Gomez prospect, first discovered in 1997, continues to deliver promising results. A delineation well completed early in the first quarter of 1999 was successful, and a second delineation well is planned.

1999 Plans

Onshore

- Focus on gas prospects in the Deep Giddings and other gas-rich areas.
- Maintain existing leaseholds in areas where oil predominates and prepare for increased activity when prices rebound.
- Continue programs of innovation and cost reduction.
- Test several high-potential exploratory prospects in the Gulf onshore area.

Offshore

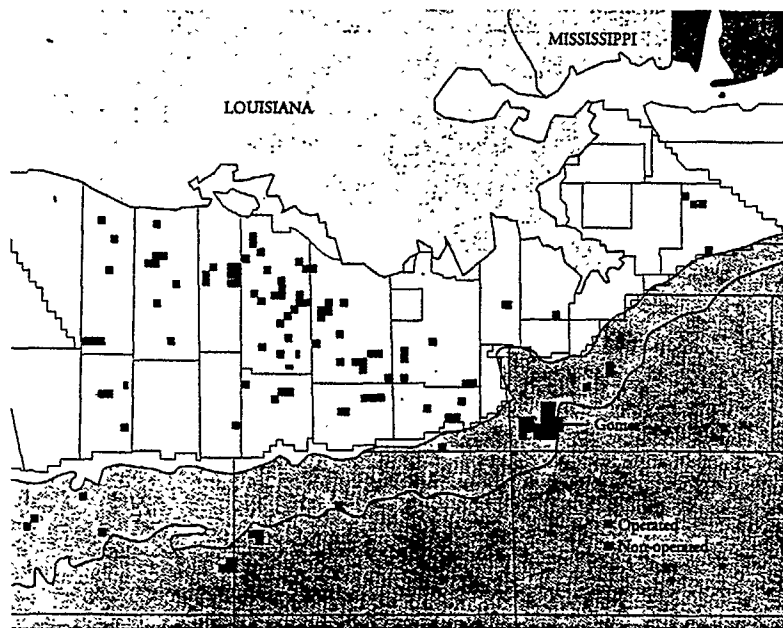
- Delineate sufficient reserves to begin the development phase of the deep-water Gomez prospect.
- Conserve capital without sacrificing volume and cash flow.
- Concentrate on developmental work – recompletions and exploitation drilling – within existing fields on the Gulf Shelf.

Minerals Business Unit

The minerals business unit turned in another impressive performance in 1998, recording earnings of \$134 million.

UPR's Wyoming Land Grant acreage is home to the world's largest deposit of trona, the raw material of soda ash, as well as to large deposits of low-sulphur coal and industrial minerals. UPR receives royalties from mining operations on the Land Grant. The Company also owns a 49 percent interest in soda ash producer OCI of Wyoming and a 50 percent interest in the Black Butte Coal Company.

UPR expects the minerals business to continue to contribute strong earnings and cash flow in 1999.



The integration of Norcen's offshore Gulf assets into UPR's existing operations doubled production and increased reserves by one third. Delineation work on UPR's 1997 deep-water Gomez discovery is a major 1999 project.

International

Operating and Financial Statistics*

	1998
Producing Properties Volumes (MMcfed)	256
Proved Reserves (Bcfe)	927
Capital and Exploratory Expenditures (millions)**	\$144
Gross Wells Drilled	45

* First year under UPR.

** Excludes acquisition of Norcen.

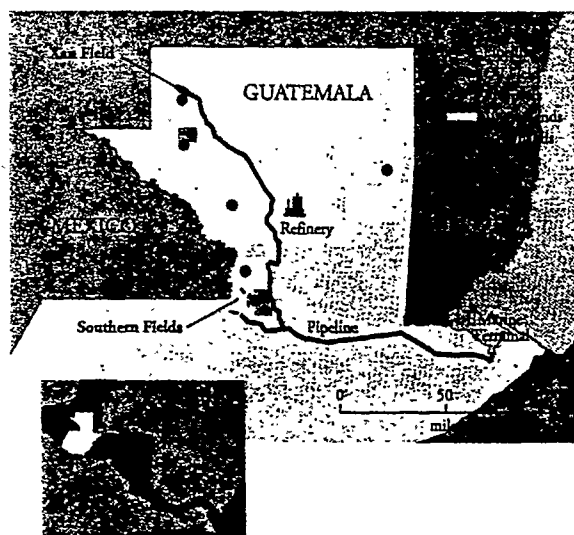
The acquisition of substantial production, development and exploration assets and acreage in Guatemala and Venezuela in 1998 made Latin America a core business area for UPR. Crude oil dominates UPR's Latin American asset portfolio. The Company's 1999 program will concentrate on maintaining existing production and lowering operating expenses while continuing a limited exploration program in the two countries.

Guatemala



UPR's purchase of Norcen included the assets of the wholly owned subsidiary Basic Resources International (Bahamas) Limited located in the Republic of Guatemala. The coming

of peace to Guatemala after a long civil war, combined with a strong government initiative to become self-sufficient in petroleum production, has created a favorable environment for petroleum investments in the country.



Guatemala is a country with enormous oil potential. In today's oil price environment, UPR will concentrate on drilling to test new exploratory concepts and modeling to identify new development drilling opportunities.

UPR currently produces 25 Mbd of oil from two contract areas. The majority comes from the Xan field in northwest Guatemala. The Company also controls gathering and processing facilities at each producing field, an asphalt refinery, 285 miles of pipeline with seven pump stations and a 420,000-barrel capacity shipping terminal on the Caribbean coast. With the exception of about 2 Mbd of asphalt produced at the refinery for Guatemalan road construction, all production is exported to the United States for upgrading and refining.

UPR holds a 100 percent working interest in six exploration blocks and is negotiating for an additional two blocks. In total, UPR controls approximately 1.9 million gross acres.

UPR undertook an aggressive seismic program in 1998 to evaluate exploration and development opportunities on its extensive land holdings, shooting and processing about 573 kilometers of proprietary 2-D seismic data. UPR also completed a 200-square-kilometer 3-D program covering the Xan field and adjacent exploration acreage. The 3-D survey was only the second shot in Guatemala.

Infrastructure improvements included the completion of a seventh pipeline pumping station and greater storage capacity at the port. Most drilling activity took place in the first half of the year, when seven in-fill wells were completed at Xan.

The program for 1999 includes the drilling of four wells, one of them near Xan, to test new exploratory concepts utilizing new seismic data. Successful imaging and modeling of the Xan field could identify targets for further development drilling as well as separate similar pools in the area.

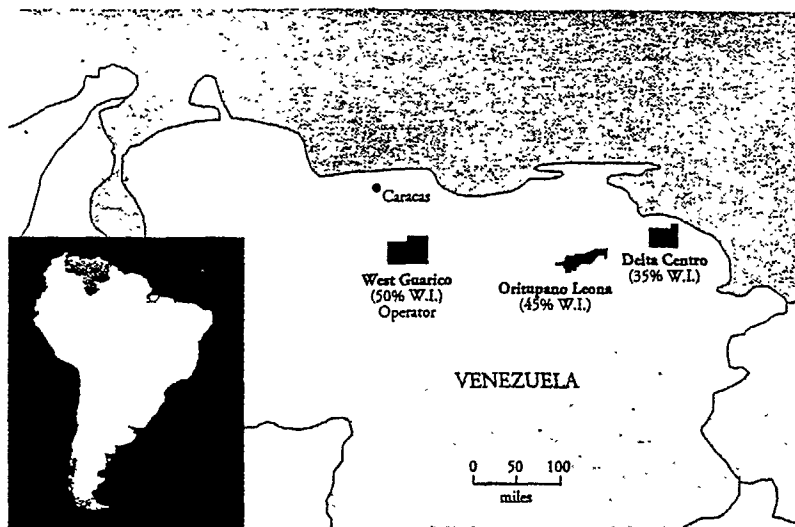
Venezuela



Venezuela is a cornerstone of UPR's growth strategy in Latin America. UPR has a land position of nearly 1.8 million gross acres in the eastern Venezuela Basin, which covers some of the largest

reserve areas in the world. Advanced technology applied to these underdeveloped areas is expected to continue a trend of production increases.

UPR is the seventh largest producer in the country with net production of 21 Mbd of oil from two producing field reactivation projects: Oritupano Leona and West Guarico. A third block, Delta Centro, is an exploration area. The steady production growth of Oritupano Leona, plus the potential of the underdeveloped West Guarico property and the highly prospective Delta Centro block, provide significant growth opportunities.



UPR's assets in Venezuela offer a complete range of opportunities: existing oil production, low-risk field development projects and highly prospective exploration possibilities.

Oritupano Leona

The Oritupano Leona block, located in the south-central portion of the eastern Venezuela Basin, covers approximately 433,000 acres, only 22,000 of which have been developed. It had gross production of 46 Mbbl of oil in December 1998, with cumulative production of 305 MMbbl of oil. Original oil in place is estimated at over 3.5 billion barrels.

A consortium in which UPR holds a 45 percent interest acquired the Oritupano Leona block in 1993 and began operations the following year. Since 1994, it has drilled 124 wells and recompleted or reactivated 245 more, increasing production from 8 Mbbl to 46 Mbbl of oil. All six of the exploration prospects drilled thus far have resulted in new discoveries. The consortium has not drilled a dry hole since it took over the block in 1994.

In 1999, UPR will concentrate on two important projects: commingling reservoirs with a common aquifer and increasing water-handling capabilities.

West Guarico

The West Guarico block sits on the western edge of the eastern Venezuela Basin, approximately 100 miles southeast of Caracas. The block covers 809,000 acres, of which only 31,000 acres have been developed. Production from the block, in which UPR has a 50 percent operated interest, is about 700 Bbl of oil.

The project is in the beginning stages of redevelopment. A 430-square-kilometer 3-D program was shot in 1998. At year-end, two of three wells drilled from 3-D leads had

shown commercial pay and were awaiting completion. A multi-well drilling program in 1999, targeting different play concepts, will evaluate the potential of the 3-D survey. Additional seismic will be shot during the year to set up future drilling programs.

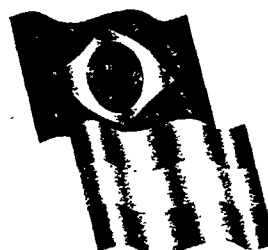
Delta Centro

The 500,000-acre Delta Centro block, located in the highly prospective delta of the Orinoco River, is on trend with Oritupano Leona.

A consortium in which UPR has a 35 percent non-operated interest acquired the block in 1996 and shot a large 3-D and 2-D seismic program in 1997. Plans for 1999 include the drilling of a 15,500-foot prospect in the northern portion of the surveyed area to test the Oficina formation. The prospect is estimated to contain 60 million to 150 million barrels of oil. If results are positive, a

delineation test is planned for later in the year.

Brazil and Argentina



Latin America's two largest countries hold great promise for the discovery and development of oil and gas fields. UPR is active in Brazil, where it is developing a block in the Sergipe Alagoas Basin, and in Argentina, where it holds six blocks in three major basins.



Directors and Officers

Board of Directors



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Of Counsel
Womble, Carlye,
Sandridge & Rice
Law



Lynne V. Cheney
Distinguished Fellow
American Enterprise
Institute
Public policy research



**Preston M. "Pete"
Geren III**
Attorney-at-Law
Law



Lawrence M. Jones
Retired Chairman and
Chief Executive Officer
The Coleman Company, Inc.
*Home and recreational
products*



Drew Lewis
Retired Chairman and
Chief Executive Officer
Union Pacific
Corporation
Transportation



Claudine B. Malone
President
Financial & Management
Consulting, Inc.
Management consulting



Jack L. Messman
Chairman and Chief
Executive Officer
Union Pacific Resources
Group Inc.
Oil and gas



**John W. Poduska, Sr.,
Ph.D.**
Chairman
Advanced Visual Systems,
Inc.
Visualization software



Michael E. Rossi
Chairman
Shorestein Realty Service
Real Estate



Samuel K. Skinner
Co-Chairman and
Partner
Hopkins and Sutter
Law



James R. Thompson
Chairman, Chairman of
the Executive Committee
and Partner
Winston & Strawn
Law

Officers

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Chairman and Chief
Executive Officer

George Lindahl III
President and Chief
Operating Officer

V. Richard Eales
Executive Vice President

Thomas R. Blank
Vice President—State, Regulatory
and Public Affairs

Anne M. Franklin
Vice President—People

Joseph A. LaSala, Jr.
Vice President—General Counsel
and Secretary

Donald W. Niemiec
Vice President—Marketing
President—Union Pacific Fuels, Inc.

Morris B. Smith
Vice President and
Chief Financial Officer

John B. Vering
Vice President—Canada

Audit Committee

Claudine B. Malone, Chair
Samuel K. Skinner
H. Jesse Arnelle
Lynne V. Cheney

Compensation and Corporate Governance Committee

James R. Thompson, Chair
Preston M. Geren III
John W. Poduska, Sr., Ph.D.
Michael E. Rossi

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Drew Lewis, Chair
Lawrence M. Jones
Jack L. Messman
Michael E. Rossi
James R. Thompson

Finance Committee

Lawrence M. Jones, Chair
Michael E. Rossi
Drew Lewis
Jack L. Messman

Corporate Information

Union Pacific Resources
Group Inc.
777 Main Street
Fort Worth, Texas 76102
(817) 321-6000

Common Stock Prices and Dividends

The range of New York Stock Exchange trading prices for UPR common stock and dividends declared per share during 1998 was as follows:

Quarter Ended	High	Low	Last	Dividends
Mar. 31	24½	20⅞	23⅞	\$0.05
June 30	25¼	16⅞	17⅞	\$0.05
Sept. 30	18⅞	8⅞	12⅞	\$0.05
Dec. 31	14½	8¼	9⅞	\$0.05

Common Stock Listing

New York Stock Exchange
Ticker Symbol: UPR

Shareholders

The Company estimates that, as of December 31, 1998, the number of shareholders of Union Pacific Resources Group Inc. common stock was approximately 145,000.

Transfer Agent and Registrar of Stock

Harris Trust & Savings Bank
Attn: Shareholder Services
P.O. Box A3504
Chicago, Illinois 60690-3504
Internet: www.harrisbank.com

Annual Meeting

The annual meeting of shareholders is scheduled to be held on May 18, 1999, at 10:00 a.m. (Central Standard Time), at the Worthington Hotel, Fort Worth, Texas. Information with respect to the annual meeting is contained in the Proxy Statement.

Company Contacts

Shareholder Information:

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Assistant Corporate Secretary
(817) 321-7100

Investor Relations:

David Larson,
Director-Investor Relations
(817) 321-7294

Media Relations:

Dan Sullivan,
Director-Public Affairs
(817) 321-6527

On the Internet:

www.upr.com

Information Sources

For prompt assistance with shareholder change of address, consolidation of multiple accounts or related matters, please contact the Shareholder Services Division, Harris Trust & Savings Bank, at (312) 461-3309, (800) 335-6918 or for the hearing impaired (312) 461-5633 on weekdays between 8:30 a.m. and 5:00 p.m. (Central Standard Time).

Additional copies of the Annual Employees' Report to Shareholders 1998 and copies of the 1998 Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained from UPR's Investor Relations department.

This Annual Report, other than historical financial information, contains forward-looking statements regarding budgeted capital expenditures, estimated reserves, expected drilling activity and construction, expected production and other matters subject to a number of risks and uncertainties, which are detailed in the Company's Annual Report on Form 10-K for the year ended December 31, 1998. Additionally, all financial information contained herein should be read in conjunction with the Annual Report on Form 10-K, incorporated herein by reference.

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, 1998

Commission file number 1-13916

Union Pacific Resources Group Inc.

(Exact name of registrant as specified in its charter)

Utah
(State or other jurisdiction of
incorporation or organization)

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

777 Main Street
Fort Worth, Texas
(Address of principal executive offices)

76102
(Zip Code)

Registrant's telephone number, including area code: (817) 321-6000

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

Title of each class

Name of each exchange
on which registered

Common Stock

New York Stock Exchange, Inc.

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

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

As of February 28, 1999, the aggregate market value of the registrant's common stock held by non-affiliates (using the New York Stock Exchange closing price) was approximately \$2.2 billion.

The number of shares outstanding of the registrant's common stock as of February 28, 1999 was 252,150,993.

Certain portions of the registrant's definitive Proxy Statement for the annual meeting of shareholders to be held on May 18, 1999 (the "Proxy Statement") are incorporated in Part III by reference.

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

PART I

ITEM 1. *Business*

General

Union Pacific Resources Group Inc. (a Utah corporation) and subsidiaries (collectively, the "Company" or "UPR"), is engaged primarily in the exploration for and the development and production of natural gas, natural gas liquids ("NGLs") and crude oil in several major producing basins in the United States, Canada, Guatemala, Venezuela and other international areas. 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 holdings in Wyoming. The Land Grant consists of land that passes through the states of Colorado and Wyoming and into Utah, which was granted by the federal government to a predecessor of the Company in the mid-1800s. In the Land Grant, the Company has fee ownership of the mineral rights under approximately 7.9 million acres. At December 31, 1998, over 79 percent of the revenues, 49 percent of fixed assets and 57 percent of reserves of the Company are generated or located in the United States.

In 1998, the Company acquired Norcen Energy Resources Limited ("Norcen") for a purchase price of \$2.634 billion, and also assumed long-term debt obligations of Norcen totaling approximately \$1 billion. Norcen was a major Canadian oil and gas exploration and production company with primary operations in western Canada, the Gulf of Mexico, Guatemala and Venezuela. The acquisition significantly increased the Company's drill site inventory and expanded the Company's operations beyond its historical domestic focus. See additional discussion in Note 2 to the Consolidated Financial Statements.

In 1998, the Company's Board of Directors authorized management to proceed with a deleveraging program, including the sale of approximately \$600 million of producing properties, and to pursue potential monetization of the Company's gathering, processing and marketing ("GPM") business segment. In November 1998, the Company executed a merger and purchase agreement to sell the GPM segment to Duke Energy Field Services, Inc. ("Duke") for \$1.35 billion, with the sale expected to close in the first quarter of 1999. See "Deleveraging Program — Property Sales," "Significant Events and Corporate Reorganization — Property Sales and GPM Divestiture" and Note 3 to the Consolidated Financial Statements for additional discussion.

Business Strategy

In each of its core areas, the Company continues to focus on the exploration for and development of natural gas and crude oil resources, in combination with efforts to increase margins through reductions in drilling and operating costs. The Company's long-term strategy is to increase production by expanding its drill site inventory and enhancing well results through the application of economies of scale, its operating experience in its core geographic areas and its expertise in advanced drilling and completion technologies. The Company keeps its drilling inventory high to supply its drilling operations, striving to maintain a three-year inventory of drill sites in its core areas through development of its existing properties, exploration, farm-in agreements and acquisitions of properties and companies. However, in the current depressed price environment, the Company is holding its exploration drilling inventory for the future. The Company maintains a high working interest in its core areas and typically serves as operator, which allows it to control the timing and cost of exploration and development activities and to enhance its ability to apply its expertise to these properties.

In 1999, the Company anticipates spending approximately \$500 million in capital and exploratory expenditures, with a focus on high-return, quick-payout projects. Approximately 20 percent of the capital will be directed to each of the following areas: Canada, the Austin Chalk trend in Texas and Louisiana, other U.S. Onshore, U.S. Offshore and Latin America. As a result of reduced capital spending, the Company may not increase production in 1999. See "Outlook and Other Matters."

Exploration and Production Operations

In the first quarter of 1999, the Company announced the reorganization of its exploration and production operations into four primary business units: the U.S. Offshore business unit and the Canada business unit, both unchanged from the previous structure, the Latin America business unit, comprised of Guatemala, Venezuela and other international operations, and the U.S. Onshore business unit, which will consist of the consolidation of all other domestic business units under the previous structure. As this reorganization is not yet fully in place, the following discussion will address the structure of the Company's exploration and production operations in place during 1998.

During 1998, the Company's oil and gas activities were concentrated in five core geographic areas in the United States and four core areas for international operations. The core areas in the United States were comprised of the following business units: (1) the Austin Chalk trend in Texas and Louisiana, (2) East/West Texas, (3) the Western Region, consisting of the Land Grant area in Colorado, Wyoming and Utah, as well as additional properties in Kansas, (4) Gulf Coast Onshore, covering the onshore coastal plain of Texas and Louisiana, and (5) Offshore, which covers the Company's Gulf of Mexico operations. International core areas were (1) Canada, (2) Guatemala, (3) Venezuela and (4) Other International.

The following table sets forth 1998 capital spending excluding the Norcen Acquisition (hereinafter defined), proved reserves as of December 31, 1998, and 1998 production information with respect to each of the Company's business units. Natural gas constituted 56% of the Company's total proved reserves of 6.1 Tcfe as of December 31, 1998, and 58% of the Company's sales volumes of 2.467 Bcfe for the year then ended. Production from properties sold in 1998 is included in producing property volumes for each business unit through the effective date of each sale. See "Deleveraging Program — Property Sales" for additional information.

<u>Business Unit</u>	<u>Total Capital Spending (Millions)</u>	<u>Percent of Total</u>	<u>Total Proved Reserves (Bcfe)</u>	<u>Percent of Total</u>	<u>Producing Property Volumes (MMcfe)</u>	<u>Percent of Total</u>
Austin Chalk	\$ 380	33%	708	11%	581	24%
East/West Texas	104	9	969	16	308	13
Western Region	69	6	1,322	22	500	20
Gulf Coast Onshore	114	10	109	2	121	5
Offshore	154	13	358	6	182	7
Total USA	821	71	3,466	57	1,692	69
Canada	198	17	1,731	28	519	21
Guatemala	40	3	357	6	125	5
Venezuela	100	9	480	8	100	4
Other International	3	—	90	1	31	1
Total	<u>\$1,162</u>	<u>100%</u>	<u>6,124</u>	<u>100%</u>	<u>2,467</u>	<u>100%</u>

United States Operations

Austin Chalk Business Unit. The Austin Chalk business unit manages the Company's oil and gas activities in the Austin Chalk trend, which extends 700 miles from southern Texas through central and eastern Texas into Louisiana. At present, the Company's Austin Chalk production is located primarily in three fields: Giddings, Brookeland and Masters Creek. The Masters Creek field in Louisiana and the Giddings field in Texas are currently the most active. Since 1988, the Company has participated in the drilling of over 1,500 wells and has made aggregate capital expenditures over \$2.4 billion in the Austin Chalk, including spending of \$380 million in 1998. The Company controls nearly 1.9 million developed and undeveloped net acres in the Austin Chalk and has increased its volumes from 37 MMcfe in January 1990 to an average of 581 MMcfe during 1998. During 1998, 90 percent of the Austin Chalk business unit's production was attributable to Company-operated properties.

East/West Texas Business Unit. The East/West Texas business unit manages the Company's oil and gas activities in two major northeastern Texas producing areas, the Carthage and Oakhill fields, as well as the Company's oil and gas activities in western Texas, principally in the Ozona field in the Permian Basin area. In East Texas, in addition to its production operations, the Company has conducted exploration activities in the Cotton Valley Pinnacle Reef Trend where 3-D seismic has identified over 100 drilling prospects. In West Texas, the Company has drilled over 980 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 applied its horizontal expertise in the West Texas area and drilled 67 horizontal wells. During 1998, the Company directed \$104 million of capital into the East/West Texas business unit, and recognized a 5 percent improvement in production volumes, to 308 MMcfed. At December 31, 1998, approximately 90 percent of the producing wells in the East/West Texas business unit were Company operated and 84 percent of the 1998 production was attributable to Company-operated properties.

Western Region Business Unit. The Western Region business unit manages the Company's oil and gas activities in the Land Grant area in Colorado, Wyoming and Utah, and the Hugoton/Panoma field in Kansas. This business unit is the second largest in terms of reserves, and ranked third in production volumes in 1998, while absorbing only \$69 million (6%) of consolidated capital expenditures. The Company's operations in the Western Region are concentrated in the Green River Basin and the Overthrust area. The Company currently controls approximately 8.9 million developed and undeveloped net acres in the Western Region, principally attributable to its Land Grant ownership. Production volumes from the Western Region business unit were 500 MMcfed in 1998, with 29 percent of the production attributable to Company-operated properties.

Gulf Coast Onshore Business Unit. The Gulf Coast Onshore business unit manages the Company's operations on the onshore coastal plain of Texas and Louisiana. In 1998, production volumes improved 30 percent to 121 MMcfed. In addition to its producing activities, this business unit conducts exploration activities in these areas, and is evaluating 3-D seismic to identify the areas of highest drilling potential. 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 1998, the Company spent \$114 million of capital in the Gulf Coast Onshore business unit, and 80 percent of production volume was attributable to Company-operated properties.

Offshore Business Unit. The Offshore business unit manages the Company's oil and gas activities in the Gulf of Mexico, including operations added in the Norcen Acquisition in 1998. 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 and will continue to delineate the discovery during 1998 and 1999, with first production anticipated in 2002. In 1998, the Company spent \$154 million of capital in the Offshore business unit, both related to the Mississippi Canyon discovery and to further develop other prospects, including those acquired as part of Norcen. Production volumes of 182 MMcfed during 1998, represent a 94 percent improvement over 1997, with 74 percent of the production attributable to Company-operated properties.

International Operations

Canada. The Company's Canadian operations principally include properties from the Norcen Acquisition, which were combined with the Company's previous interests in western Canada to form a new business unit. Operations in ten core areas are centered in the province of Alberta, with additional properties in northeastern British Columbia and southwestern Saskatchewan. Canada currently represents the Company's largest business unit in terms of reserve base, and was second in production volumes (519 MMcfed) and in capital spending (\$198 million) in 1998. Canada provides a balanced commodity mix of 46 percent crude oil and NGLs and 54 percent natural gas, as well as an asset portfolio with long reserve life. Approximately 40 percent of Canadian oil production is heavy oil. In Canada, UPR has working interests in approximately 5,500 gross producing wells, and operates about 4,200 of these.

Guatemala. The Company's Guatemalan operations are comprised of the former Basic Resources International that was also acquired as part of Norcen. The majority of activity is currently from the Xan area,

producing heavy to medium quality crude oil. The Company also owns a 100 percent working interest in several exploration blocks and is focusing on an aggressive seismic acquisition strategy to evaluate exploration and development opportunities. Capital spending in 1998 in Guatemala was \$40 million, with daily production volumes of 125 MMcfed. The Company owns, controls and operates infrastructure in Guatemala which includes gathering and processing facilities at each producing field, an asphalt refinery, 285 miles of pipeline with seven pump stations and a 420 MBbl capacity shipping terminal on the Caribbean coast. The combination of these assets provides the Company with an integrated network of facilities from producing fields to the port.

Venezuela. The Company's Venezuelan operations consist of the Oritupano-Leona block, the West Guarico farm-in agreement and the Delta Centro exploration block. The Oritupano-Leona block, in which UPR has a 45 percent working interest, covers 433,000 acres and has approximately 200 producing wells. Most of the activity in the block has been driven by a 3-D seismic program conducted in prior years. The West Guarico block covers over 800,000 acres and is operated by the Company, which has a 50 percent working interest. The project is in the beginning stages of redevelopment, focusing on seismic, drilling, recompletions and the improvement of infrastructure. The Company has a 35 percent working interest in Delta Centro, where the block covers 500,000 acres. No wells have yet been drilled, and the primary activity has been seismic evaluation to identify future drilling opportunities. During 1998, the Company spent \$100 million of capital in Venezuela, producing average volumes of 100 MMcfed.

Other International. Other international operations include interests in six fields in Argentina, two non-operated platforms in Australia and an interest in a non-operated property in Egypt. In addition, the Company is trying to strengthen its presence in Brazil.

Volumes, Prices and Production Costs

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

	Years Ended December 31,		
	1998	1997	1996
Producing Properties:			
Average daily production:			
Natural gas (MMcfed)	1,441.1	1,108.5	988.9
Natural gas liquids (MBbld)	33.1	31.7	30.5
Crude oil (MBbld)	137.9	52.9	50.6
Total (MMcfed)	2,467.0	1,615.7	1,475.3
Average sales prices:			
Natural gas (per Mcf)	\$ 1.74	\$ 2.00	\$ 1.85
Natural gas liquids (per Bbl)	7.88	11.23	11.48
Crude oil (per Bbl)	10.48	18.36	18.84
Production costs (per Mcfe) (a)	0.49	0.51	0.49

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

Minerals

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

Company reinvests the cash flow from its hard minerals operations into its oil and gas business units. The Minerals business unit generated \$133.5 million of operating income during 1998, as follows:

	1998 Operating Income	
	Amount	Percent
	(Millions of dollars)	
Royalties:		
Soda ash(a)	\$ 31.8	24%
Coal(b)	15.5	12
Total royalties	47.3	36
Nonoperated joint ventures:		
Soda ash(c)	3.7	3
Coal(d)	86.0	64
Total joint ventures	89.7	67
Overhead/other	(3.5)	(3)
Total operating income	<u>\$133.5</u>	<u>100%</u>

- (a) Includes properties leased to five soda ash producers, estimated to contain resources sufficient to support over 30 years of production at current production levels.
- (b) The Company leases coal resources to six operating mines. In 1998, 60 percent 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.
- (c) Represents a 49 percent interest in OCI Wyoming LP, a non-operated joint venture.
- (d) Represents the Company's 50 percent non-operating interest in Black Butte Coal Company ("Black Butte"). In 1998, \$79.3 million of operating income is attributable to a single coal supply contract, which terminates at the end of 2000. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 8 to the Consolidated Financial Statements.

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

The world's largest deposit of trona, constituting 90 percent of the world's known trona resources, is located in the Green River Basin in southwestern Wyoming. Approximately 40 percent of this trona deposit lies within the Land Grant and is therefore owned by the Company. Natural soda ash, which is produced by refining trona ore, is used primarily in the production of glass for containers and flat glass, in the paper and water treatment industries and in the manufacture of certain chemicals and detergents. Natural soda ash from Wyoming contributes 32 percent of the world soda ash supply with the remainder principally from synthetic processes. In 1998, the Company, along with its partner, Oriental Chemical Industries, Inc. ("OCI"), completed process improvement projects and construction of additional refining capacity at the OCI Wyoming LP soda ash facility that increased the plant's nameplate capacity to 3.1 million tons per year. This facility is now ranked second in soda ash capacity among domestic producers.

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. In 1998, some consolidation within the industry occurred, as companies combined their strengths and financial resources to improve overall stability during the current period of low oil and gas prices. 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.

Government Regulation

The Company's natural gas, NGL and crude oil exploration, development and production operations are subject to extensive rules and regulations promulgated by federal, provincial, state and local authorities and foreign governmental entities.

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. In 1998, the MMS adopted financial responsibility regulations under the Oil Pollution Act of 1990. See "Environmental Regulation — Oil Spills."

Currently, there are no federal, state or local laws that regulate the price for sales of natural gas, NGLs and crude oil by the Company. However, the rates charged and terms and conditions for the movement of gas in interstate commerce through certain intrastate pipelines and production area hubs are subject to regulation under the Natural Gas Policy Act of 1978 ("NGPA"). Pipeline and hub 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.

Through many interstate pipeline specific orders, FERC has revised its policy regarding jurisdiction over gathering facilities and services. 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 FERC's policy. As a result of the court's 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 Railroad Commission initiated a rulemaking and ultimately issued new regulations regarding gathering activities. 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 activities.

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 that may be removed from these 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 liabilities 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 phaseout 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 \$16.4 million of Section 29 tax credits in 1998. 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 liabilities 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.

Texas Severance Tax Reduction

Natural gas produced from wells that have been certified as deep wells or geologic formations certified as tight formations 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 percent severance tax in Texas on natural gas and NGLs produced by such wells. Such exception ends August 31, 2001. The natural gas production from wells drilled on certain of the Company's properties, primarily in the Austin Chalk and East/West 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 percent 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 equal 50 percent of the total drilling and completion costs.

Environmental Regulation

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

Air Emissions. The primary legislation affecting the Company's air emissions is the Federal Clean Air Act and its 1990 Amendments (the "CAA"). Among other things, the CAA requires all major sources of air emissions to obtain operating permits. The amendments also revised the definition of a "major source" such that additional equipment involved in oil and gas production are now covered by the permitting requirements.

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

Oil Spills. Under the Oil Pollution Act of 1990 ("OPA"), owners and operators of onshore facilities and pipelines and lessees or permittees of an area in which an offshore facility is located ("Responsible Parties") are strictly liable on a joint and several basis for removal costs and damages that result from a discharge of oil into United States waters. OPA limits the strict liability of Responsible Parties for removal costs and damages that result from a discharge of oil from \$10 million to \$150 million in the case of onshore facilities and from \$35 million to \$150 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, issued a final rule in August 1998 implementing OPA requirements. 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 new environmental responsibilities on oil and natural gas operators in Alberta and, in certain instances, imposes greater penalties for violations. In British Columbia, regulations affecting the oil and gas industry are administered by the Ministry of Energy, Mines and Petroleum Resources.

Employees

The Company had 2,900 employees as of December 31, 1998, 75 of which were not full-time. Included were approximately 450 employees of the Company's GPM segment, which is to be sold to Duke at the end of the first quarter of 1999.

Also included in the December 31, 1998 employee level above were approximately 140 employees who were terminated by January 31, 1999, in connection with a reduction in force announced in December 1998. In February 1999, the Company announced a second program for a reduction in force, with the program expected to be complete by the end of the first quarter of 1999. This program includes a voluntary retirement incentive program as well as a second reduction in force. Approximately 250 employees will be affected, and in connection with the program, the Company will take a pretax charge to income, the amount of which will be determined late in the first quarter of 1999.

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 NGLs, 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 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 could 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 otherwise already reserved.

ITEM 2. Properties

Proved Reserves

The following table sets forth the proved developed and undeveloped reserves of natural gas, NGLs and crude oil of the Company as of December 31, 1998. In connection with the Norcen Acquisition in the first quarter of 1999, the Company used four independent firms to review Norcen estimates of essentially all of the reserves to be acquired by the Company. Reserve estimates as of December 31, 1998, were prepared by the Company's engineers and utilized information from these independent reviews. 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 ("SEC").

Category	Reserves as of December 31, 1998			
	Natural Gas (Bcf)	Natural Gas Liquids (MMBbl)	Crude Oil (MMBbl)	Total (Bcfe)
Proved developed	2,968	79	252	4,956
Proved undeveloped	471	12	104	1,168
Total proved reserves	<u>3,439</u>	<u>91</u>	<u>356</u>	<u>6,124</u>
Percent of total	56%	9%	35%	100%

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. Reservoir 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, 1998. The Company holds royalty interests of varying percentages in the approximately one million gross acres of the Land Grant that are subject to exploration and production agreements with third parties. The Company's fee mineral acreage is primarily undeveloped.

Business Unit	Total Acres	
	Gross	Net
	(In thousands)	
Austin Chalk	33	13
East/West Texas	746	260
Western Region	8,570	8,161
Gulf Coast Onshore	221	74
Offshore	—	—
Total USA	9,570	8,508
Canada	—	—
Guatemala	—	—
Venezuela	—	—
Other International	—	—
Total fee acreage	<u>9,570</u>	<u>8,508</u>
Land Grant (included in Western Region above)	<u>7,912</u>	<u>7,722</u>

Leasehold. The Company's leasehold acreage by business unit as of December 31, 1998, is set forth below.

<u>Business Unit</u>	<u>Developed Acres</u>		<u>Undeveloped Acres</u>		<u>Total Acres</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
	(In thousands)					
Austin Chalk	1,095	813	1,325	1,048	2,420	1,861
East/West Texas	477	265	713	489	1,190	754
Western Region	450	208	1,013	550	1,463	758
Gulf Coast Onshore	154	71	160	70	314	141
Offshore	284	136	418	312	702	448
Total USA	2,460	1,493	3,629	2,469	6,089	3,962
Canada	1,657	958	5,613	2,185	7,270	3,143
Guatemala	26	25	1,834	1,788	1,860	1,813
Venezuela	57	25	1,710	758	1,767	783
Other International	465	85	2,227	648	2,692	733
Total leasehold acreage	<u>4,665</u>	<u>2,586</u>	<u>15,013</u>	<u>7,848</u>	<u>19,678</u>	<u>10,434</u>

Total Leasehold and Fee Mineral. The total leasehold and fee mineral acreage by business unit as of December 31, 1998, is set forth below.

<u>Business Unit</u>	<u>Total Acres</u>	
	<u>Gross</u>	<u>Net</u>
	(In thousands)	
Austin Chalk	2,453	1,874
East/West Texas	1,936	1,014
Western Region	10,033	8,919
Gulf Coast Onshore	535	215
Offshore	702	448
Total USA	15,659	12,470
Canada	7,270	3,143
Guatemala	1,860	1,813
Venezuela	1,767	783
Other International	2,692	733
Total leasehold and fee acreage	<u>29,248</u>	<u>18,942</u>

Drilling Activity and Producing Well Summary

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

	<u>Years Ended December 31,</u>					
	<u>1998</u>		<u>1997</u>		<u>1996</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Development wells:						
Productive	511	357.8	685	478.6	575	413.4
Dry	39	27.2	59	46.2	35	25.7
Exploration wells:						
Productive	64	46.1	35	19.1	16	8.5
Dry	22	18.0	38	22.1	29	18.2
Total wells	<u>636</u>	<u>449.1</u>	<u>817</u>	<u>566.0</u>	<u>655</u>	<u>465.8</u>

The number of wells drilled is not a valid measure or indicator of the relative success or value of a drilling program because the significance of the reserves and their economic potential may vary widely for each

project. As of December 31, 1998, the Company owned a working interest in 9,504 gross gas wells (7,323 net) and 4,446 gross oil wells (3,160 net). Gross wells include 2,404 wells with multiple completions. The Company operated 66 percent of the gross wells in which it owned an interest.

Deleveraging Program — Property Sales

In 1998, the Company's Board of Directors authorized management to proceed with a deleveraging program designed to reduce the Company's debt in order to maintain a strong investment grade credit rating. The program included plans to sell approximately \$600 million of producing properties. The Company announced in January 1999 that sales of nearly \$700 million of properties had been completed, with over \$400 million of this amount having closed by December 31, 1998. These sales represent a different mix of properties being sold than was originally designated. A summary of properties that have been sold is as follows:

<u>Property Sale Package</u>	<u>Business Unit</u>	<u>Sales Price (Millions)</u>
DJ Basin	Western Region	\$ 41
Matagorda Island Blocks	Offshore	158
Rockies Package	Western Region	46
Eugene Island Blocks	Offshore	8
Canadian Package	Canada	145
Caroline — Swan Hill(a)	Canada	108
South Texas Package(a)	Gulf Coast Onshore	138
Superior Propane	Canada	48
Total		<u>\$692</u>

(a) Sale closed in January 1999.

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. On June 23, 1997, the State District Court granted the Company's motion for summary judgment, holding as a matter of law that the mineral reservations at issue were unambiguous and included all valuable nonsurface substances, including oil and gas. The Colorado Court of Appeals affirmed the decision of the State District Court in granting the Company's motion for summary judgment on December 10, 1998. The surface owners filed a motion for rehearing, which is pending.

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 material adverse effect on the consolidated results of operations, financial condition or cash flows 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 material adverse effect on consolidated results of operations, financial condition or cash flows of the Company.

ITEM 4. *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to a vote of security holders during the quarter ended December 31, 1998.

Executive Officers of the Registrant

<u>Name</u>	<u>Position</u>	<u>Age</u>
Jack L. Messman(a)	Chairman and Chief Executive Officer	59
George Lindahl III(b)	President and Chief Operating Officer	52
V. Richard Eales(c)	Executive Vice President	63
Thomas R. Blank(d)	Vice President — State, Regulatory and Public Affairs	46
Anne M. Franklin(e)	Vice President — People	42
Joseph A. LaSala, Jr.(f)	Vice President, General Counsel and Secretary	44
Donald W. Niemiec(g)	Vice President — Marketing	52
Morris B. Smith(h)	Vice President and Chief Financial Officer	54
John B. Vering(i)	Vice President — Canada	49

- (a) 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 during the past five years. He was President, Chief Executive Officer and a Director of Union Pacific Resources Company ("UPRC") through October 1995.
- (b) 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. Prior thereto, he was Vice President — Operations for UPRC.
- (c) 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.
- (d) 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. Prior thereto, he was President of Hager Sharp, Inc.
- (e) Ms. Franklin has held her current position with the Company since August 1995. Prior thereto, she was Director of Executive Leadership and Development for Ameritech, Inc.
- (f) Mr. LaSala has held his current position as Vice President, General Counsel with the Company since January 1996 and assumed the role of Secretary in June 1997. Mr. LaSala joined UPRC as Assistant General Counsel in January 1995. Prior thereto, he was Vice President — Government and Regulatory Affairs of USPCI, Inc., a former subsidiary of Union Pacific Corporation ("UPC").
- (g) 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 Union Pacific Fuels, Inc. ("UP Fuels") since 1990.
- (h) 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. Prior thereto, he served as Vice President — Finance of USPCI, Inc.
- (i) 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.

PART II

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

The common stock of the Company is traded on the New York Stock Exchange under the symbol "UPR." Information with respect to the quarterly high and low sales prices per share for the Company common stock, as reported on the New York Stock Exchange Composite Tape, as well as the dividend declared on such stock, is set forth under Selected Quarterly Data on page 80. At February 28, 1999, there were 252,150,993 shares of outstanding common stock and approximately 145,000 shareholders of record. At that date, the closing price of the common stock on the New York Stock Exchange was \$8.9375.

The Company has paid quarterly cash dividends of \$0.05 per share 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. The Company has no current plans to increase or decrease its dividend.

ITEM 6. Selected Financial Data

Five-Year Financial Summary

	1998 (a)	1997	1996	1995	1994
	(Millions, except per share amounts)				
Income Statement Data:					
Operating revenues	\$ 1,841.0	\$1,518.0	\$1,369.2	\$1,166.8(d)	\$1,107.9
Operating income (loss)	(1,193.2)	433.9	408.5	380.3(d)	299.3
Income (loss) from continuing operations	(883.1)	303.1	253.7	294.2(d)	358.7(f)
Net income (loss)	(898.7)	333.0	320.8	350.7(d)	390.0(f)
Per share:					
Income (loss) from continuing operations — basic(b)	(3.57)	1.21	1.02	n/a	n/a
Income (loss) from continuing operations — diluted(b)	(3.57)	1.21	1.01	n/a	n/a
Net income (loss) — basic(b)	(3.63)	1.33	1.29	n/a	n/a
Net income (loss) — diluted(b)	(3.63)	1.33	1.28	n/a	n/a
Dividends	0.20	0.20	0.20	0.05(e)	n/a
Financial Position Data:					
Properties — net	\$ 6,093.3	\$2,901.1	\$2,404.7	\$2,238.4	\$2,105.2
Total assets	7,642.4	4,313.7	3,531.6	3,265.7	2,532.1
Total debt	4,598.7	1,230.6	670.9	101.5	37.7
Shareholders' equity	728.2	1,760.7	1,514.3	1,312.4	1,834.9
Cash Flow Data:					
Capital and exploratory expenditures	\$ 3,828.8(c)	\$1,188.4	\$ 773.0	\$ 603.0	\$1,069.5(g)
Cash provided by operations	1,031.1	856.2	772.5	719.0	710.7

(a) In 1998, the Company recorded a \$760 million after-tax charge related to asset impairments in accordance with Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" ("SFAS No. 121").

(b) 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.

(c) In March 1998, the Company acquired Norcen for a purchase price of \$2.634 billion.

(d) In November 1995, the Company recorded a \$122.5 million pretax (\$78.5 million after-tax) gain resulting from the Columbia Gas Transmission Company bankruptcy settlement.

(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 prior periods.

(f) In March 1994, the Company sold its interest in the Wilmington Field and Harbor Cogeneration Plant to the Port of Long Beach, California. The Wilmington sale resulted in a \$159.2 million pretax (\$100 million after-tax) gain.

(g) In March 1994, the Company acquired Amax Oil & Gas, Inc., for a purchase price of \$725 million.

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

The following information should be read in conjunction with the information contained in the Consolidated Financial Statements and the notes thereto included in Item 8 of this report. The Consolidated Statements of Income for previous periods have been restated to present the Company's GPM segment as discontinued operations.

SIGNIFICANT EVENTS AND CORPORATE REORGANIZATION

Norcen Acquisition

In March 1998, the Company acquired Norcen for an aggregate purchase price of \$2.634 billion, and also assumed long-term debt obligations of Norcen totaling approximately \$1.0 billion. The acquisition was accounted for as a purchase effective March 3, 1998, and, therefore, Norcen's financial results have been consolidated into the Company's results beginning in March 1998. See Note 2 to the Consolidated Financial Statements.

Property Sales and GPM Divestiture

In 1998, the Company's Board of Directors authorized management to proceed with a deleveraging program designed to reduce the Company's debt in order to maintain a strong investment grade credit rating. The program included the Company's plans to sell approximately \$600 million of producing properties. The Company announced in January 1999 that sales of nearly \$700 million of properties had been completed, with over \$400 million of this amount having closed by December 31, 1998. These sales represent a different mix of properties sold than was originally designated. Closed sales in 1998 include properties located in the Denver Julesburg Basin of the Western Region (the "DJ Basin properties"), the Matagorda Island Block 623 Field and surrounding blocks (the "Matagorda property"), other Offshore and Western Region properties and various Canadian properties originally identified for divestiture. In addition, completed sales in 1999 include interests in certain south Texas properties for \$138 million and the Caroline property in Canada for \$108 million. All of the producing properties sold or identified for sale in the aggregate represent approximately 13 percent of the Company's total proved reserves as of December 31, 1998, and approximately 6 percent of the production volumes for 1998.

In connection with this deleveraging program, the Board of Directors also authorized management to pursue potential monetization of the Company's GPM segment. On November 20, 1998, the Company entered into a Merger and Purchase Agreement ("Agreement") with Duke to sell the GPM segment for \$1.35 billion with the sale expected to close at the end of the first quarter of 1999.

Hydrocarbon Sales Price Pressures

During 1998, prices for oil and natural gas declined and are expected to remain at low levels through 1999 as a result of several factors. These factors include, but are not limited to, high production levels from members of the Organization of Petroleum Exporting Countries ("OPEC") and other countries, generally mild weather conditions, the economic weakness in several Asian countries and excessive natural gas storage levels. Because of these factors, the 1999 NYMEX price strip for crude oil was \$13.02/Bbl and \$2.03/Mcf for natural gas on December 31, 1998. These prices were 29 percent and 10 percent, respectively, below the corresponding price strips on December 31, 1997.

Impairment of Long-Lived Assets

The Company recorded a pretax charge of \$1.23 billion (\$760.1 million after tax) in the fourth quarter of 1998, as required by SFAS No. 121. The non-cash asset impairment charge to earnings was recorded as depreciation, depletion and amortization ("DD&A") expense of \$1.17 billion and surrendered lease expense of \$54.5 million in the Company's Consolidated Statement of Income. As noted above, the current and anticipated low hydrocarbon prices — particularly their effect on the value of the Company's heavy oil

properties in Canada and Guatemala — and reserve revisions following a comprehensive review of reserves completed in December 1998, are the principal factors contributing to the impairment. Most of the reserve revisions are associated with properties in Canada and Offshore that were acquired by the Company in 1998. The revisions are primarily due to comprehensive reserve reviews and disappointing well performance from recent discoveries that were not on production at the time of the Norcen Acquisition.

Corporate Reorganization and Reduction in Force

Also as a result of the current low price environment and the resulting reduction in cash flows generated by the Company's operations, the Company recorded a pretax charge in 1998 of \$17 million (\$11 million after tax) to cover the cost of a workforce reduction at its Fort Worth, Texas headquarters and other domestic locations, and costs associated with offshore rig commitments.

The Company has announced a second reorganization to occur in the first quarter of 1999, which will include an additional reduction in force and a voluntary retirement incentive program. As a result of the workforce reductions and a reduced capital spending program, the Company has reorganized its operations into five primary business areas: (1) U.S. Onshore, (2) U.S. Offshore, (3) Canada, (4) Latin America and (5) Minerals. Other business areas and all overhead operations have been similarly streamlined to improve cost efficiencies and to reflect lower capital spending plans.

In connection with the reorganizations, the Company believes that the reductions in force and other cost reduction programs will better align staffing levels with expected capital spending and operating activity levels, provide an improved cost structure and create a more effective organization in the current economic environment.

RESULTS OF OPERATIONS

Year Ended December 31, 1998 Compared to December 31, 1997

Summary Financial Data

	Years Ended December 31,	
	1998	1997
	(Millions of dollars)	
Total operating revenues	\$ 1,841.0	\$1,518.0
Total operating expenses	3,034.2	1,084.1
Operating income (loss)	(1,193.2)	433.9
Income (loss) from continuing operations	(883.1)	303.1
Net income (loss)	(898.7)	333.0
Earnings (loss) from continuing operations per share — diluted	(3.57)	1.21
Earnings (loss) per share — diluted	(3.63)	1.33

The Company recorded a net loss of \$898.7 million in 1998, or a loss of \$3.63 per share, compared to net income of \$333.0 million, or \$1.33 per share, in 1997. The decrease is primarily due to the impact of the SFAS No. 121 asset impairment of \$1.23 billion (\$760.1 million after tax), the majority of which affected continuing operations, and lower product prices.

RESULTS OF CONTINUING OPERATIONS

In 1998, the Company reported a net loss from continuing operations of \$883.1 million, compared to income from continuing operations of \$303.1 million in 1997. Included in 1998 results was a charge of \$1.22 billion (\$756.0 million after tax) related to the asset impairment. The additional volumes from the Norcen Acquisition added revenues of \$456.7 million. The increased revenues were offset by depressed product prices that reduced revenues from non-Norcen properties by more than \$200 million as average prices declined 22 percent. Additional factors that impacted income, primarily driven by the Norcen Acquisition, were \$273.9 million of higher production, exploration and administrative expenses and \$210.3 million of higher interest expense. Included in administrative expenses was a restructure charge of \$17.0 million related to a reduction in force of the Company's domestic operations. The Company realized a \$140.0 million improvement to operating income as a result of gains on the sale of various properties.

The operating loss was \$1,193.2 million in 1998 compared to operating income of \$433.9 million in 1997. Exploration and production operating income, excluding the portion of the fourth quarter asset impairment charged to such properties, declined \$355.1 million to \$18.3 million. These results reflect lower prices for all products and increased operating, exploration and DD&A costs, which offset higher volumes and the gains on the sale of various properties. Minerals operating income dropped slightly to \$133.5 million due to a \$14.3 million reserve established for a legal settlement and a \$4.0 million asset impairment but was partially offset by increased operating income due to an amended coal supply agreement at Black Butte. General and administrative ("G&A") costs, excluding the restructure charge, increased \$35.5 million primarily due to increased administrative costs associated with expanded Canadian and international operations and an \$8.2 million charge related to the settlement of various crude royalty and tax issues.

Summary of Segment Financial Data

	Years Ended December 31,	
	1998	1997
	(Millions of dollars)	
Segment operating income (loss):		
Exploration and production	\$(1,199.2)	\$373.4
Minerals	133.5	135.5
Corporate/general and administrative	(127.5)	(75.0)
Total	<u>\$(1,193.2)</u>	<u>\$433.9</u>

Exploration and Production Operations

	Years Ended December 31,	
	1998	1997
	(Millions of dollars)	
Exploration and production revenues	\$ 1,539.2	\$1,293.5
Other oil and gas revenues	160.7	84.7
Total operating revenues	1,699.9	1,378.2
Production expense	444.3	300.8
Exploration expense	339.0	204.7
Depreciation, depletion and amortization	2,115.8	499.3
Total operating expenses	<u>2,899.1</u>	<u>1,004.8</u>
Operating income (loss)	<u>\$(1,199.2)</u>	<u>\$ 373.4</u>

Operating Revenues

Exploration and production revenues increased by \$245.7 million (19%) to \$1,539.2 million, \$456.7 million of which were associated with properties added in the Norcen Acquisition. Excluding the Norcen Acquisition properties, volumes were essentially flat to 1997 production levels; however, product price declines

reduced revenues by \$211.0 million. Other revenues increased \$76.0 million from higher gains on property sales, principally the sales of the Matagorda and DJ Basin properties.

	Years Ended December 31,			
	1998	1997	1998	1997
	(without hedging)		(with hedging)	
Average price realizations — exploration and production:				
Natural gas (per Mcf)	\$ 1.77	\$ 2.19	\$ 1.74	\$ 2.00
Natural gas liquids (per Bbl)	7.88	11.23	7.88	11.23
Crude oil (per Bbl)	10.37	18.80	10.48	18.36
Average price (per Mcfe)	1.72	2.34	1.71	2.19

	<u>Years Ended December 31,</u>	
	<u>1998</u>	<u>1997</u>
Production volumes — exploration and production:		
Natural gas (MMcfd)	1,441.1	1,108.5
Natural gas liquids (MBbld)	33.1	31.7
Crude oil (MBbld)	137.9	52.9
Total (MMcfed)	2,467.0	1,615.7

Exploration and production volumes improved 851.3 MMcfed to 2,467.0 MMcfed in 1998. Canadian volumes were 481.0 MMcfed higher than last year, while other international volumes increased 244.1 MMcfed, in both cases primarily due to properties added in the Norcen Acquisition. Production from domestic properties increased 126.2 MMcfed including 103.9 MMcfed added in Offshore from the Norcen Acquisition. Offshore production from non-Norcen properties decreased largely due to the sale of the Matagorda property. All other domestic profit centers realized increased volumes in 1998.

Natural gas volumes increased 332.6 MMcfd (30%). Canadian volumes increased by 263.6 MMcfd and Offshore production was up 64.1 MMcfd, largely due to properties added in the Norcen Acquisition. Gulf Coast Onshore production was 23.2 MMcfd higher from continued drilling success in the Roleta Field and Wadsworth Southeast area. Western Region and East/West Texas volumes improved 8 MMcfd each due to development drilling. Partially offsetting these improvements was a 39 MMcfd decline in Austin Chalk volumes where the drilling success achieved in Washington County in 1997 was not duplicated.

Natural gas liquids volumes increased 1.4 MBbld (4%) to 33.1 MBbld. Production improvements included 2.9 MBbld in the Austin Chalk resulting from the processing of gas through newly expanded facilities and 2.5 MBbld in Canada largely due to the Norcen Acquisition. These increases were partially offset by 4.8 MBbld of lower volumes from the Western Region as a result of the decision to reject ethane and bypass gas due to low NGL prices.

Crude oil volumes were 85.0 MBbbl higher in 1998 primarily from properties added in the Norcen Acquisition and a 7.5 MBbbl improvement from the Austin Chalk due to higher volumes in Louisiana. Canadian production was 33.7 MBbbl higher for the period, while production from Guatemala and Venezuela was 20.8 MBbbl and 16.7 MBbbl, respectively.

Operating Expenses

Production expenses, which include lease operating costs, production overhead and production taxes, increased \$143.5 million while production costs on a per unit basis were \$0.49 per Mcfe, 4 percent less than last year's \$0.51 per Mcfe. Total lease operating expenses rose \$141.3 million, of which \$135.4 million was attributable to Norcen Acquisition properties. The remainder of the lease operating expense increase largely reflects higher personnel costs associated with other producing property purchases and higher salt water disposal costs in East/West Texas, Austin Chalk and Gulf Coast Onshore. Lease operating expenses on a per unit basis were up 22 percent to \$0.34 per Mcfe which reflects higher operating expenses associated with the production of heavy crude oil in Guatemala, Venezuela and Canada. Production overhead costs were up \$2.6 million largely because of increased personnel costs due to the expanded international operations.

Exploration expenses increased \$134.3 million over last year, including \$54.5 million of surrendered lease costs that were part of the SFAS No. 121 asset impairment. Excluding the effect of the asset impairment, activity related to properties added in the Norcen Acquisition contributed \$72.8 million to the increase. For domestic operations, exploration expenses were up 3 percent to \$210.8 million, excluding the surrendered lease asset impairment. The increase was primarily the result of a \$30.1 million increase in other surrendered lease costs, related to the Cotton Valley Reef and other properties in East/West Texas, and increased leasing activity in Gulf Coast Onshore. Other domestic exploration expenses were down \$23.1 million reflecting reduced activity. Dry hole expenses, geological and geophysical costs and delay rentals were down \$10.4 million, \$9.1 million and \$4.2 million, respectively, while exploration overhead was essentially flat with 1997 levels.

DD&A increased by \$1,616.5 million, including \$1,163.1 million related to the SFAS No. 121 asset impairment. On a per unit basis, DD&A expense, excluding the impairment, rose \$0.21 per Mcfe to \$1.06 per Mcfe. Properties added in the Norcen Acquisition contributed \$377.4 million, excluding the asset impairment. The remaining variance from non-Norcen Acquisition properties, \$76.0 million, is associated with higher volumes that caused \$11.3 million of the total increase in DD&A, while a higher per unit rate added \$64.7 million.

Minerals Operations

	Years Ended December 31,	
	1998	1997
	(Millions of dollars)	
Operating Income		
Coal	\$101.5	\$ 83.3
Soda ash	35.5	49.5
Other	(3.5)	2.7
Total	<u>\$133.5</u>	<u>\$135.5</u>

Minerals operating income decreased by \$2.0 million. Contributing to the decline was \$14.0 million of lower operating income from soda ash operations, reflecting lower royalties, lower equity income from the Company's soda ash joint venture and the inclusion of a lease bonus in 1997 results. Also affecting 1998 performance was a \$14.3 million accrual for a legal settlement and a \$4.0 million asset impairment charge on certain industrial mineral and uranium properties. In addition, ballast operating income decreased due to the shutdown of operations in 1997. Partly offsetting these items were \$19.7 million of higher equity income from Black Butte reflecting the amendment of a coal supply contract and a \$2.0 million gain from a property sale.

General and Administrative and Other

G&A and other expenses increased \$52.5 million to \$127.5 million, principally reflecting \$21.1 million related to expanded international operations and the \$17.0 million restructuring charge. Also contributing to the increase was an \$8.2 million charge related to the settlement of various crude royalty and tax issues, \$3.3 million of additional rent expense, \$2.4 million in higher professional and temporary costs, and a \$1.9 million rise in DD&A expense for domestic overhead. On a per unit basis, excluding the restructuring charge, G&A expenses were flat to 1997 at \$0.12 per Mcfe.

Other income/expense was \$69.8 million lower than 1997 results. The reduction reflects a \$46.5 million foreign currency exchange rate loss and a \$14.3 million charge related to the expiration of interest rate lock contracts intended to hedge such rates for a contemplated bond issuance. In addition, 1997 results included the benefit of a \$23.0 million partial reduction of reserves associated with the 1994 sale of the Wilmington, California oil field, due to the reduction of environmental remediation exposure, a \$7.2 million gain on the sale of securities held for investment and \$6.7 million of higher environmental insurance settlements. Partly offsetting these declines were an \$11.0 million gain on the closure of a foreign exchange contract entered into

in connection with the Norcen Acquisition, and the inclusion in 1997 of \$17.8 million of costs related to the unsuccessful bid to acquire Pennzoil Company.

Interest expense increased \$210.3 million to \$249.8 million. This increase reflects the borrowings made in connection with the Norcen Acquisition and capital spending programs. Interest expense allocated to discontinued operations was \$21.1 million in 1998 and \$13.6 million in 1997.

Income taxes declined \$721.0 million compared to last year to a benefit of \$605.2 million, primarily the result of the pretax net loss in 1998. Included in 1998 results was a \$22.5 million benefit due to foreign currency gains on deferred tax liabilities in Venezuela and Guatemala. Section 29 tax credits in 1998 were \$16.4 million compared to \$18.8 million in 1997. The effective tax rate in 1998 was 40.6 percent versus 28.6 percent in 1997 largely due to the effect of the acquisition and expansion of operations outside the United States where higher tax rates exist. Also, Section 29 tax credits were additive to the effective rate when recording the overall tax benefit in 1998 but reduced the effective tax rate when the overall 1997 tax expense was recorded.

RESULTS OF DISCONTINUED OPERATIONS

Gathering, Processing and Marketing Operating Results

Results from discontinued operations generated a net loss of \$15.6 million for 1998, compared to income of \$29.9 million in 1997. The segment reported an operating loss of \$1.0 million for 1998 versus operating income of \$61.3 million in 1997.

Operating margins were down more than \$45 million from last year due to low product prices that were not offset by lower gas purchase prices. Operating revenues were down \$66.7 million from 1997 largely due to the \$35.2 million (\$23.0 million after tax) charge related to firm transportation contracts that were marked to market in connection with the GPM disposition, and lower product prices. Volumes were up 2 percent largely due to the purchase of Highlands Gas Corporation ("Highlands") in the third quarter of 1997, and recently expanded or constructed facilities. Another benefit to income was the \$30.0 million pretax gain on the settlement of a gas supply agreement. Operating expenses were down \$17.9 million due to lower gas purchase costs which more than offset higher facility operating expenses and overhead costs due to expanded operations.

RESULTS OF OPERATIONS

Year Ended December 31, 1997 Compared to December 31, 1996

Summary Financial Data

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Total operating revenues	\$1,518.0	\$1,369.2
Total operating expenses	1,084.1	960.7
Operating income	433.9	408.5
Income from continuing operations	303.1	253.7
Net income	333.0	320.8
Earnings from continuing operations per share — diluted	1.21	1.01
Earnings per share — diluted	1.33	1.28

The Company reported net income of \$333.0 million, or \$1.33 per share, for 1997 compared to \$320.8 million, or \$1.28 per share, for 1996.

RESULTS OF CONTINUING OPERATIONS

Income for continuing operations increased 19 percent to \$303.1 million in 1997, and 20 percent on a per share basis, to \$1.21. Exploration and production operating income was up 4 percent to \$373.4 million due to increased volumes and higher product prices partly offset by a \$60.1 million increase in exploration expenses and higher production costs. Minerals contributed strong operating income of \$135.5 million, up 13 percent from 1996, largely due to increased royalty income. In addition, the Company realized higher other income despite one-time costs associated with the unsuccessful attempt to acquire Pennzoil Company.

Summary of Segment Financial Data

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Segment operating income:		
Exploration and production	\$373.4	\$359.1
Minerals	135.5	120.0
Corporate/general and administrative	(75.0)	(70.6)
Total	<u>\$433.9</u>	<u>\$408.5</u>

Exploration and Production Operations

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Exploration and production revenues	\$1,293.5	\$1,148.2
Other oil and gas revenues	84.7	92.1
Total operating revenues	1,378.2	1,240.3
Production expense	300.8	263.2
Exploration expense	204.7	144.6
Depreciation, depletion and amortization	499.3	473.4
Total operating expenses	<u>1,004.3</u>	<u>881.2</u>
Operating income	<u>\$ 373.4</u>	<u>\$ 359.1</u>

Operating Revenues

Exploration and production revenues increased by \$145.3 million (13%) largely due to a 10 percent increase in volumes and increased product prices of \$0.06 per Mcfe.

	Years Ended December 31,			
	1997	1996	1997	1996
	(without hedging)		(with hedging)	
Average price realizations — exploration and production:				
Natural gas (per Mcf)	\$ 2.19	\$ 1.94	\$ 2.00	\$ 1.85
Natural gas liquids (per Bbl)	11.23	11.48	11.23	11.48
Crude oil (per Bbl)	18.80	20.14	18.36	18.84
Average price (per Mcfe)	2.34	2.23	2.19	2.13

	Years Ended December 31,	
	1997	1996
Production volumes — exploration and production:		
Natural gas (MMcfd)	1,108.5	988.9
Natural gas liquids (MBbld)	31.7	30.5
Crude oil (MBbld)	52.9	50.6
Total (MMcfd)	1,615.7	1,475.3

Volumes improved 140.4 MMcfd to 1,615.7 MMcfd for 1997, principally on the strength of higher natural gas production.

Natural gas volumes increased 119.6 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). East/West Texas business unit gas volumes improved 35.4 MMcfd from continued success with horizontal drilling programs and production from, and further development of, properties acquired from Castle Energy. The Gulf Coast Onshore business unit showed an improvement of 31.1 MMcfd reflecting successful drilling programs in southern Texas and southern Louisiana. Austin Chalk gas volumes were up 11.0 MMcfd from success in the deep Giddings field. These improvements were partially offset by a 14.8 MMcfd decline in Western Region gas volumes caused by production declines.

Natural gas liquids volumes increased 1.2 MBbld (4%) with most of the improvement attributable to the East/West Texas business unit. Crude oil volumes increased by 2.3 MBbld (5%) primarily from drilling successes in the Masters Creek field in Louisiana.

Operating Expenses

Production costs increased \$37.6 million to \$300.8 million for 1997, primarily due to a \$27.9 million rise in lease operating expenses. This 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 \$0.51 in 1997 compared to \$0.49 in 1996.

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

Exploration and production DD&A expense increased \$25.9 million due to higher production volumes, partially offset by a lower unit of production rate. Included in 1997 was \$24.4 million of writedowns of various properties, while 1996 contained \$26.4 million of writedowns, primarily in the Western Region, Gulf Coast Onshore and Offshore business units.

Minerals Operations

	Years Ended December 31,	
	1997	1996
	(Millions of dollars)	
Operating Income		
Coal	\$ 83.3	\$ 76.5
Soda ash	49.5	40.2
Other	2.7	3.3
Total	<u>\$135.5</u>	<u>\$120.0</u>

Minerals operating income increased by \$15.5 million over 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 minerals operations declined \$4.6 million compared to 1996, due to the shutdown of the Company's ballast operations.

General and Administrative and Other

G&A expenses in 1997 were \$4.4 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 associated with increased activity levels. G&A expenses per unit were \$0.12 per Mcfe in both 1997 and 1996.

Other income/expense was \$28.0 million higher than 1996 from a \$23 million reserve reduction reflecting lower environmental remediation exposure related to oil and gas properties in Wilmington, California that were sold in 1994. Other income/expense also included 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 related to the unsuccessful bid to acquire Pennzoil Company.

Interest expense increased \$0.6 million to \$39.5 million. Interest expense allocated to discontinued operations was \$13.6 million in 1997 and \$11.7 million in 1996.

Income taxes of \$115.8 million were \$3.4 million higher than 1996, reflecting higher income before taxes, \$9.9 million in favorable prior period state and federal tax adjustments recorded in 1997 and an increase of \$3.2 million in Section 29 tax credits. In contrast, 1996 included a \$3 million unfavorable state tax adjustment.

RESULTS OF DISCONTINUED OPERATIONS

Gathering, Processing and Marketing Operating Results

Results from discontinued operations generated income of \$29.9 million for 1997, a drop of \$37.2 million from income of \$67.1 million in 1996. Operating income declined \$56.8 million to \$61.3 million for 1997.

Operating margins in 1997 were down more than \$45 million from 1996 due to low sales prices and higher gas purchase prices. Operating revenues were down \$55.1 million from 1996 largely due to lower product sales prices despite an 8 percent volume increase. The volume increase was largely due to the Highlands acquisition and the start-up of the Masters Creek plant. Also included in 1997 results was a \$6.4 million gain on the sale of the Company's investment in the Frontier Pipeline. Included in 1996 results was a \$17 million asset impairment for the Wahsatch pipeline.

LIQUIDITY AND CAPITAL RESOURCES

The Company's primary sources of cash during 1998 were cash provided by operations, debt financing, a forward sale and the sales of assets associated with the Company's deleveraging program. Cash outflows for 1998 include the purchase of Norcen, capital and exploratory expenditures, interest, dividends and the repurchase of common stock by the Company.

Cash provided by operations for 1998 of \$1.03 billion increased \$174.9 million (20%) compared to 1997, as the benefit of significantly higher production volumes was offset by lower sales prices for the Company's oil and gas products, higher costs of expanded production operations and higher interest expense associated with higher debt levels. Cash from operations also included two non-recurring items: the collection of an acquired note receivable related to Norcen's 1997 partial sale of Superior Propane (\$85.4 million) and the closure of certain commodity and foreign currency financial contracts (\$63.9 million) also acquired in the Norcen Acquisition.

Cash used in investing activities for 1998 rose \$1.90 billion over 1997, primarily reflecting the \$2.63 billion purchase price for Norcen. This increase was partially offset by over \$400 million of higher

proceeds from sales of producing properties and investments, associated with the Company's deleveraging program. In 1998, this included proceeds from the sales of the Matagorda properties (\$158 million), the DJ Basin properties (\$41 million), a package of Canadian properties (\$145 million), a package of Western Region business unit properties (\$46 million) and the sale of the remaining investment in Superior Propane (\$48 million). Cash provided by discontinued GPM operations of \$50.4 million was \$272.2 million higher than 1997. Included in 1997 were an aggressive capital expenditure program and the acquisition of Highlands. Results in 1998 reflect lower capital expenditures, tighter margins from the GPM operations, and a forward sale agreement that provided \$171 million. The forward sale initially provided \$250 million; however, in November the Company began settling the obligation, and made payments of \$79 million by the end of the year, with the remaining amount to be settled in the first quarter of 1999.

Capital expenditures for continuing operations, excluding the cost of the Norcen Acquisition, were up \$6.1 million compared to last year. The amounts below include capital expenditures for Norcen properties beginning in March 1998.

	1998	1997
	(Millions of dollars)	
Exploration and production		
Exploration	\$ 286.3	\$ 399.3
Production	764.9	642.7
Property purchases	110.7	130.6
Total exploration and production	1,161.9	1,172.6
Minerals, G&A and other	32.6	15.8
Sub-total continuing operations	1,194.5	1,188.4
Norcen purchase price	2,634.3	—
Continuing operations	<u>\$3,828.8</u>	<u>\$1,188.4</u>
Gathering, processing and marketing	\$ 143.8	\$ 163.9
Highlands acquisition	—	179.4
Discontinued operations	<u>\$ 143.8</u>	<u>\$ 343.3</u>

Exploration and production capital spending was down \$10.7 million to \$1.16 billion. Drilling expenditures of \$731.4 million accounted for 61 percent of capital expenditures for continuing operations in 1998. The Austin Chalk was responsible for \$288.3 million of drilling expenditures while Canada and Offshore spent \$114.2 million and \$105.7 million, respectively. Development drilling was concentrated in the Austin Chalk, Canada, East/West Texas and the Western Region while exploratory drilling was focused in the Offshore, Canada and Gulf Coast Onshore areas. Production facility capital expenditures of \$135.1 million largely reflect spending on properties added in the Norcen Acquisition to support production operations.

Property purchases of \$110.7 million completed in 1998 include purchases in the Western Region, Austin Chalk and Gulf Coast Onshore. Minerals, G&A and other capital was up \$16.8 million, primarily related to expenditures for relocating the Fort Worth headquarters. Expenditures for discontinued operations were down \$20.1 million, excluding \$179.4 million associated with the 1997 Highlands acquisition, due to a reduction in plant expansion and construction in 1998.

At year-end 1998 and 1997, the total capitalization of the Company was as follows:

	December 31, 1998	December 31, 1997
	(Millions of dollars)	
Long- and short-term debt:		
Commercial paper and other, net	\$2,351.9	\$ 663.1
Notes and debentures	2,225.0	550.0
Capital lease obligations	17.4	—
Tax exempt revenue bonds	—	20.1
(Discount) premium on notes and debentures — net	4.4	(2.6)
Total debt	4,598.7	1,230.6
Shareholders' equity	728.2	1,760.7
Total capitalization	<u>\$5,326.9</u>	<u>\$2,991.3</u>
Debt to total capitalization	86.3%	41.1%

During the first quarter of 1998, in connection with the Norcen Acquisition, the Company issued commercial paper supported by a \$2.7 billion 364-day Competitive Advance/Revolving Credit Agreement (the "Norcen Acquisition Facility"), and also assumed the net debt of Norcen.

In October 1998, the Company replaced its eight existing facilities (the Norcen Acquisition Facility, its \$600 million and \$300 million revolving credit agreements and five Canadian facilities), which totaled approximately U.S. \$2.9 billion. The facilities were replaced with three new facilities totaling an aggregate of U.S. \$2.5 billion. These new facilities are comprised of a \$1.0 billion 364-day Competitive Advance/Revolving Credit Agreement (the "Bridge Facility"), a \$750 million 364-day Competitive Advance/Revolving Credit Agreement and a \$750 million Five-Year Competitive Advance/Revolving Credit Agreement (collectively the "Facilities"). Each of the Facilities contain a covenant stipulating that the ratio of consolidated debt to consolidated EBITDAX — the sum of operating income (before adjustments for income taxes, interest expense or extraordinary gains or losses), DD&A and exploration expenses — cannot exceed 3.25:1.00. This covenant replaced the consolidated debt to total capitalization ratio covenant applicable under previous facilities. The 1998 consolidated debt to consolidated EBITDAX covenant calculation uses pro forma EBITDAX results. The Company was in compliance with this covenant provision at year-end 1998.

The Bridge Facility also contains mandatory reduction provisions whereby it will be permanently reduced by 75 percent of the net proceeds from specified asset sales (certain identified exploration and production assets and the Company's GPM segment). At December 31, 1998, the Bridge Facility had not been reduced pursuant to this provision as none of the specified sales had yet occurred. The Facilities also place other restrictions on the Company regarding the creation of liens, incurrence of additional indebtedness or subsidiaries, transactions with affiliates, sales of stock of Union Pacific Resources Company (a wholly-owned subsidiary of the Company) and certain mergers, consolidations and asset sales.

Debt maturities through 2003, excluding capital leases, are \$851.9 million of commercial paper and bankers acceptances in 1999 and \$250 million of term debt in 2002. At December 31, 1998, \$1.5 billion of commercial paper and bankers acceptances had been classified as long-term, supported by the \$750 million Five-Year and the \$750 million 364-day Competitive Advance/Revolving Credit Agreements. This classification reflects the Company's intent and ability to maintain these borrowings on a long-term basis, through the issuance of additional commercial paper and/or new term financings.

The Company utilizes letters of credit to support certain financing instruments, performance contract and insurance policies. The fair value of the letters of credit at December 31, 1998 and 1997 was \$58.6 million and \$10.7 million, respectively. The Company has guaranteed a portion of the OCI Wyoming, L.P. debt facility. At December 31, 1998, OCI Wyoming, L.P. had an outstanding debt facility balance of \$49 million of which the Company has guaranteed \$24.0 million.

During 1998, the Company purchased \$26.7 million of its common stock. In 1998, the Board of Directors authorized the purchase of an additional \$50 million of common stock in 1999. During 1998, the Company paid quarterly cash dividends of \$0.05 per share on its outstanding common stock, and on October 29 declared a \$0.05 per share dividend that was paid on January 2, 1999. 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.

OUTLOOK AND OTHER MATTERS

The Company expects to realize a decrease in its oil and gas production in 1999 but anticipates that reserve additions will more than replace 1999 production. Average annual volumes, adjusted for property sales, are expected to drop approximately 5 percent because of the reduced capital spending program that reflects lower activity levels due to the current forecast of low product prices at least through year-end 1999. Production growth is expected, however, in Canada, when adjusted for property sales, and Venezuela. The Company will continue to search for properties and reserves that will supplement its drill site inventory.

Prices for crude oil, natural gas and NGLs for 1999 are expected to remain at their current depressed levels. Increased production from members of OPEC along with the decline in several Asian countries' economies has altered the balance between supply and demand for oil, sending 1998 NYMEX crude oil prices 30 percent lower than 1997 with little optimism for a price rebound in 1999. Natural gas prices have been similarly affected due to the recent mild winter weather that has resulted in excessive natural gas storage levels and the ability of consumers to switch between oil and natural gas. The Company expects to experience price fluctuations and manages a portion of its price risk with hedging activities; however, lower prices could affect expected future net income, cash flows and capital spending.

In 1999, the Company anticipates spending approximately \$500 million for exploration and development projects and will be funded through cash provided by operations. The focus will be on high-return, quick-payout programs with almost 90 percent of the capital budget devoted to development projects that generate more immediate cash flow. Approximately 20 percent of the capital will be directed to each of the following areas: Canada, Austin Chalk, other U.S. Onshore, U.S. Offshore and Latin America. The Company may adjust its capital spending as commodity prices and cash flows change. The extent and timing of capital spending may also be affected by changes in business, financial and operating conditions as well as by the timing and availability of suitable investment opportunities.

The Company owns a non-operating 50 percent interest in Black Butte, a partnership which operates a surface coal mine complex in southwestern Wyoming. During 1998, Black Butte's sales to its largest customer under an amended coal supply contract contributed \$79.3 million to 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 this agreement will terminate. Operating income under the contract is expected to be approximately \$74 million in both 1999 and 2000. 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, primarily mines located in the Powder River Basin of Wyoming and Montana. The Company does not expect to be able to replace the operating income it receives currently under the amended contract with incremental coal sales after 2000.

The Agreement associated with the sale of the GPM business segment to Duke included an obligation for the Company to sell the majority of its domestic natural gas and existing NGL production to Duke for a five-year period beginning on the closing date of the sale. Natural gas volumes dedicated to the Agreement include existing and future production that is available at specific delivery points as listed in the Agreement. Prices received for the natural gas and NGL production will be tied to current market prices. Additionally, as a result of the Agreement, the Company agreed to reimburse Duke for losses incurred under certain transportation contracts for up to ten years. The Company established a reserve based on the fair value of

these contracts at December 31, 1998, of \$88.7 million, which is included in other current and long-term liabilities on the Consolidated Statement of Financial Position.

As part of the Agreement, Duke was allowed to conduct an environmental audit and, based on the results, assert claims for the cost to remediate environmental conditions discovered during the audit. Duke has concluded the environmental audit and asserted claims under the Agreement. Under the terms of the Agreement, asserted claims will not affect or delay the close of the transaction; however, following the close of the transaction the Company has the right to contest any environmental claims through arbitration. If it is determined through arbitration that there are valid environmental claims in excess of \$40 million, then the Company is obligated to make payment to Duke for such excess. While the Company is still analyzing Duke's environmental claims, at this time it is the Company's view that there are substantial defenses to the Duke claims.

In 1997, Union Pacific Resources Inc. ("UPRI"), the Company's wholly-owned Canadian subsidiary, received a reassessment concerning the deductibility of certain expenses and foreign exchange losses claimed for income tax purposes during the period 1989 through 1993 in the amount of \$81.1 million. In spite of UPRI's disagreement and appeal, the reassessment was fully funded in 1997 and recorded as a deferred tax benefit. As a result of the Norcen Acquisition, the Company recorded a valuation allowance against this benefit as part of the purchase price allocation. The carryforward benefit net of the valuation allowance is approximately \$15.8 million. On March 8, 1999, the Company entered into an agreement with Canadian tax authorities to settle the claims out of court. Under the terms of the settlement, the Company will receive a refund of approximately \$50 million.

The financial statements of the Company's Canadian subsidiary use the Canadian dollar as their functional currency. Latin American subsidiaries generally use the U.S. dollar as their functional currency. To the extent that business transactions in these countries are not denominated in the respective country's functional currency, the Company is exposed to foreign currency exchange rate risk. In addition, in these subsidiaries, certain asset and liability balances are denominated in currencies other than the subsidiary's functional currency. These asset and liability balances must be remeasured in the preparation of the subsidiary financial statements using a combination of current and historical exchange rates, with any resulting remeasurement adjustments included in net income. See additional discussion in "Item 7A. Risk Management: Foreign Currency Risk."

ITEM 7A. Risk Management

The Company has established policies and procedures for managing risk within its organization, including internal controls and governance 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.

As a result of the Norcen Acquisition, the Company's risk exposure has changed during 1998. With higher production volumes, the Company is able to enter into hedges covering a greater amount of production in its non-trading activities. In addition, the additional debt incurred and the acquired foreign operations increase the Company's exposure to changes in interest rates and foreign currency exchange rates. At December 31, 1997, the Company's primary risk exposure was related to commodity price risk — non-trading activities, where futures, swaps and option contracts for natural gas were in place for an average of 554 MMcfd for the year 1998. These positions had an unrecognized gain of \$3.3 million at December 31, 1997. In addition, fixed price contracts were in place for 62.6 Bcf of natural gas for 1998 through 2008, with an unrecognized gain of \$28.1 million. No other material positions were outstanding at December 31, 1997.

Unrecognized mark-to-market gains and losses were determined based on current market prices, as quoted by recognized 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 — 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 the risk of adverse price movements; however, these same instruments may also limit future gains from favorable price movements. Risk management activities are generally accomplished pursuant to exchange-traded futures contracts or over-the-counter swaps and options.

Recognition of realized gains/losses and option premium payments/receipts in the Consolidated Statement of Income is deferred until the underlying physical product is purchased or sold. Unrealized gains/losses on derivative financial instruments are not recorded. The cash flow impact of derivative and other financial instruments is reflected as cash flows from operations in the Consolidated Statement of Cash Flows. 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. At December 31, 1998, the Company had margin deposits of \$3.2 million.

The Company's oil and gas revenues can be higher or lower than what would be reported if the hedging program were not in place. As a result, revenues were lower by \$9 million in 1998 and by \$86 million in 1997. Since these transactions were hedges on oil and gas production volumes, these impacts were also reflected in the average sales price of the associated products.

The following table summarizes the Company's open positions as of December 31, 1998, which hedge the Company's future oil and gas production:

Product	Type	Contract Time Period	Volume	Weighted Avg. Prices Per Mcf or Bbl	Fair Value (Millions)	Unrecognized Gain (Loss) (Millions)
Gas	Puts purchased	Feb-Mar 1999	1.0 Bcfd	\$2.15	\$ 15.3	\$ 6.7
Gas	Puts purchased	Apr-Oct 1999	0.35 Bcfd	1.90	8.6	(2.5)
Gas	Calls sold	Apr-Oct 1999	1.0 Bcfd	2.54	3.1	18.8
Gas	Swaps	Feb-Mar 1999	0.8 Bcfd	Var	(5.0)	(5.0)
Gas	Swaps	Apr-Oct 1999	0.8 Bcfd	Var	(18.5)	(18.5)
Gas	Futures	Apr-Oct 1999	0.1 Bcfd	2.00	0.9	0.9
Gas	Fixed price	Feb 99-Dec 99	6.6 Bcfd	1.81	0.8	0.8
Gas	Fixed price	Jan 00-Dec 00	6.7 Bcfd	1.83	0.7	0.7
Gas	Fixed price	Jan 01-Oct 01	3.0 Bcfd	1.91	(0.6)	(0.6)
Oil	Swaps	Feb 99-Dec 99	2.0 Mbd	8.45	(1.4)	(1.4)
Oil	Swaps	Jan 00-Dec 00	2.0 Mbd	8.45	(1.3)	(1.3)
Oil	Fixed price	Feb 99-Mar 99	10.0 Mbd	5.27	(2.3)	(2.3)
Oil	Fixed price	Feb 99-Aug 99	2.0 Mbd	5.78	(0.9)	(0.9)
					<u>\$ (0.6)</u>	<u>\$ (4.6)</u>

In connection with purchase accounting for the Norcen Acquisition, an asset was recorded representing the fair value of acquired futures contracts, to be amortized over the terms of the applicable contracts. At December 31, 1998, excluding the \$4.0 million remaining unamortized value of the asset, the Company's unrecognized loss related to hedges of oil and gas production was \$8.0 million.

UP Fuels enters into financial contracts in conjunction with transportation, storage and customer service programs. The following table summarizes UP Fuels' open positions as of December 31, 1998, which are part of the assets of the Company's GPM segment held for sale:

<u>Product</u>	<u>Type</u>	<u>Contract Time Period</u>	<u>Volume</u>	<u>Weighted Avg. Price Per Mcf</u>	<u>Fair Value (Millions)</u>	<u>Unrecognized Gain (Loss) (Millions)</u>
Gas	Futures/swaps purchased	Feb 99-Dec 01	121.6 Bcf	\$2.12	\$(38.3)	\$(38.3)
Gas	Futures/swaps sold	Feb 99-Jan 00	38.4 Bcf	2.25	12.6	12.6
Gas	Fixed price	Feb 99-Jun 11	229.9 Bcf	2.88	77.1	77.1
					<u>\$ 51.4</u>	<u>\$ 51.4</u>

In connection with purchase accounting for the Norcen Acquisition, an asset was recorded representing the fair value of acquired fixed price positions, to be amortized over the terms of the applicable contracts. At December 31, 1998, excluding the \$66.9 million remaining unamortized value of the asset, the Company's unrecognized gain related to UP Fuels open fixed price positions was \$10.7 million.

As a result of the sales agreement with Duke, the Company has agreed to reimburse Duke under a keep whole agreement for losses incurred under certain transportation contracts for up to ten years. The fair value of these contracts at December 31, 1998, was a loss of \$88.7 million, which is included in other current liabilities and other liabilities on the Consolidated Statement of Financial Position. The fair value of these obligations are summarized as follows:

<u>Year</u>	<u>Undiscounted (Millions)</u>	<u>Discounted (Millions)</u>
1999	\$ 17.4	\$16.7
2000	14.8	12.9
2001	13.2	10.4
2002	12.1	8.7
2003	15.6	10.1
2004-2009	60.6	29.9
	<u>\$133.7</u>	<u>\$88.7</u>

Trading Activities

The Company periodically enters into financial contracts in conjunction with market-making or trading activities with the objective of achieving profits through successful anticipation of movements in commodity prices and changes in other market variables. Market-making positions are marked-to-market and gains and losses are immediately included as revenue in the Consolidated Statement of Income. In addition, the fair value of unsettled positions is immediately included in the Consolidated Statement of Financial Position as a current asset or current liability. The net pretax loss recorded in the Consolidated Statement of Income related to these activities for the year ended December 31, 1998, was \$1.8 million. The following table summarizes the Company's open positions as of December 31, 1998:

<u>Product</u>	<u>Type</u>	<u>Contract Time Period</u>	<u>Volume</u>	<u>Weighted Avg. Price Per Mcf or Bbl</u>	<u>Fair Value (Millions)</u>
Gas	Futures/swaps purchased	Jan 99-Dec 99	8.2 Bcf	\$ 2.28	\$ (3.2)
Gas	Futures/swaps sold	Jan 99-Dec 99	8.3 Bcf	2.13	3.0
Oil	Futures/swaps purchased	Jan 99-Jun 99	512 MBbl	16.74	(2.0)
Oil	Futures/swaps sold	Jan 99-Jun 99	543 MBbl	17.13	2.4
					<u>\$ 0.2</u>

Interest Rate Risk and Interest Rate Swaps

The table below summarizes maturities for the Company's fixed and variable rate debt. Variable rate debt consists of commercial paper and bankers acceptances that are generally tied to the London Interbank Offered Rate ("LIBOR"). If interest rates on the Company's variable rate debt increase or decrease by one percentage point, the Company's annual pretax income would decrease or increase by \$23.5 million.

	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>Thereafter</u>
	(in millions)					
Variable Rate	\$851.9	—	—	—	—	\$1,500.0
Fixed Rate	<u>1.9</u>	<u>\$2.0</u>	<u>\$2.1</u>	<u>\$252.3</u>	<u>\$2.4</u>	<u>1,986.1</u>
Total	<u>\$853.8</u>	<u>\$2.0</u>	<u>\$2.1</u>	<u>\$252.3</u>	<u>\$2.4</u>	<u>\$3,486.1</u>

The Company periodically enters into rate swaps and contracts to hedge certain interest rate transactions. As of December 31, 1998, the Company had no interest rate swap positions open. During 1998, the Company entered into rate lock contracts to hedge interest rates related to a contemplated bond issuance. The bonds were not issued and the Company recognized a \$14.3 million pretax loss in 1998 associated with these contracts.

Foreign Currency Risk

The Company's Canadian subsidiary uses the Canadian dollar as its functional currency, and the Latin American subsidiaries use the U.S. dollar as their functional currency. To the extent that business transactions in these countries are not denominated in the respective country's functional currency, the Company is exposed to foreign currency exchange rate risk. In addition, in these subsidiaries, certain asset and liability balances are denominated in currencies other than the subsidiary's functional currency. These asset and liability balances must be remeasured in the preparation of the subsidiary financial statements using a combination of current and historical exchange rates, with any resulting remeasurement adjustments included in net income.

At December 31, 1998, the Company's Canadian subsidiary had outstanding \$650 million of fixed rate notes and debentures denominated in U.S. dollars. During 1998, the Company recognized a \$46.5 million pretax non-cash loss associated with remeasurement of this debt. The potential foreign currency remeasurement impact on earnings from a five percent change in the year-end Canadian exchange rate would be approximately \$32 million.

At December 31, 1998, Latin American subsidiaries had foreign deferred tax liabilities denominated in the local currency, equivalent to \$159.6 million in Venezuela and \$58.0 million in Guatemala. During 1998, the Company recognized deferred tax benefits of \$15.2 million and \$7.3 million after tax, respectively, associated with remeasurement of the Venezuelan and Guatemalan deferred tax liabilities. The potential foreign currency remeasurement impact on net earnings from a five percent change in the year-end Latin American exchange rates would be approximately \$11 million.

The Company periodically enters into foreign currency contracts to hedge specific currency exposures from commercial transactions. The following table summarizes the Company's open foreign currency positions at December 31, 1998:

<u>Year</u>	<u>Notional Amount (US\$ Millions)</u>	<u>Forward Rate</u>	<u>Fair Value (US\$ Millions)</u>
1999	\$168.0	C\$1.3578	\$(18.5)
2000	8.0	C\$1.3750	(0.8)
2004	<u>70.0</u>	<u>C\$1.3630</u>	<u>(6.0)</u>
	<u>\$246.0</u>		<u>\$(25.3)</u>

As a result of the Norcen Acquisition, the Company acquired foreign currency forward exchange contracts with a \$643 million notional amount and maturities through October 2004, and recorded a \$15.5 million deferred liability representing the fair value of these contracts. This liability will be amortized over the terms of the applicable contracts. The unrecognized loss on foreign currency contracts at December 31, 1998, excluding the \$6.8 million remaining unamortized deferred liability, was \$18.5 million.

Credit Risk

Credit risk is the risk of loss as a result of nonperformance by counterparties 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 determine limits, monitor and report creditworthiness and concentrations of credit to reduce such credit risk. At December 31, 1998, the Company's largest credit risk associated with any single financial counterparty, represented by the net fair value of open contracts, was \$2.6 million.

In connection with the sale of the GPM segment, the Company entered into a long-term sales agreement with Duke, which obligates the Company to sell the majority of its domestic natural gas and NGLs to Duke for a five-year period beginning on the closing date of the sale. Prices received will be tied to the current market price for each product. As a result, a significant portion of the Company's credit risk will be with a single customer. Duke is currently considered a good credit risk; however, periodic credit evaluations will continue. Further, due to certain agreements with Duke, letter of credit and/or other assurances can be demanded under certain circumstances.

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, local, provincial and international 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, 1998, long and short-term liabilities totaling \$74.7 million had been accrued for future costs of all sites where the Company's obligation is probable and where such costs can be reasonably estimated; however, the ultimate cost could be lower or 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 \$37.0 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 liabilities. 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 \$17.0 million in 1998 and \$14.7 million in 1997. In 1999, the Company anticipates spending a total of \$17.0 million for remediation, control and prevention, including \$8.0 million relating to the Wilmington, California properties. The majority of the accrued environmental liability as of December 31, 1998, 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 established a formal Year 2000 Readiness Program to address the Company's issues relating to the Year 2000. Program activities are directed by a Program Management Office staffed with a Year 2000 Program Manager, several senior Information Technology ("IT") and engineering project managers and representatives from key internal functions including exploration and production, operations, purchasing, finance and legal. The Program Management Office operates under the oversight of a Year 2000 Executive Steering Committee and the Audit Committee of the Board of Directors. The Company has engaged CSC Consulting ("CSC") during the inventory and assessment phases of the program and continues to make use of CSC services for program management recommendations and reviews. The Company has also engaged the law firm of Morgan, Lewis & Bockius LLP for legal advice on Year 2000 related issues.

The general phases for the Company's Year 2000 Readiness Program are (1) inventory of Year 2000 items; (2) assessment of business criticality and compliance status of inventory items; (3) remediation and verification planning for items determined to be material to the company; (4) remediation (including repairing, retiring, replacing or preparing work-arounds) of material items that are determined not to be Year 2000 compliant; (5) verification that material items are Year 2000 compliant; and (6) deployment of corrected items into the ongoing business environment.

The Company's Year 2000 Readiness Program is organized around the following major areas:

- IT infrastructure
- Information systems
- Process control and embedded technology
- Third party suppliers, partners, customers and governmental entities

In the IT infrastructure area, 17 readiness projects have been designated as having a "high" criticality. Fourteen of these 17 projects (82%) have completed the remediation and verification phases. Thirteen of these 17 (76%) have completed the deployment phase as well. The Company anticipates that the "high" criticality readiness projects in this area will be completed during the first quarter of 1999. Remaining activity in this area primarily involves installing and testing upgrades and software releases supplied by vendors.

In the information systems program area, forty-one systems have been designated as having "high" criticality. The remediation, verification and deployment phases have been completed for thirty-five (85%) of these systems. One system is currently being upgraded to a new release, already received from the vendor. The remaining 5 critical systems are awaiting version upgrades from a single vendor. Remaining effort in this area primarily involves installing and testing new releases of application software packages when they are made available by software vendors. The Company anticipates that the remaining systems in this area will be complete by June 30, 1999.

In the process control and embedded technology area, project teams and vendors are in the process of completing the remediation and verification planning phases and have commenced the remediation phase. Remaining activity in this area primarily involves implementing software upgrades to selected equipment and verifying the Year 2000 readiness of process control and embedded technology equipment. The Company anticipates completion by mid-1999 of both the remediation and verification phases at each location.

In the third-party suppliers, partners, customers and governmental entities program area, the Company is continuing the process of monitoring and assessing the readiness of third parties. Approximately 400 third-

party entities have been contacted in writing concerning their Year 2000 plans and readiness. The Company has also begun the process of monitoring SEC mandated disclosures of third parties. Remaining work includes follow-up evaluations of the readiness of "mission critical" third-party dependencies. Emphasis in this area has also shifted to begin formal business contingency planning.

In the fourth quarter of 1998, the Company began a formal process for business contingency planning that spans all of the above readiness program areas. This process includes, for each business area, (i) identifying critical dependencies, (ii) assessing exposures, (iii) identifying controllable vs. non-controllable factors and (iv) developing proactive prevention plans and reactive response plans. The Company anticipates completing such business contingency plans by mid-year 1999. To incorporate the changes in status information available from third parties, periodic updates of these contingency plans are scheduled for September and November, 1999.

The total cost of the Company's Year 2000 Readiness Program is not expected to be material to the Company's financial position. Not including the cost of replacing its information systems between 1993 and 1997, the Company anticipates spending a total of between \$2.5 million and \$3.0 million dollars during 1998 and 1999 for Year 2000 related modifications and testing. This estimate does not include the Company's potential share of Year 2000 costs that may be incurred by partnerships and joint ventures in which the Company participates but is not the operator.

Due to the general uncertainty inherent in the Year 2000 problem, resulting in large part from the uncertainty of the Year 2000 readiness of third-party suppliers, partners and customers, the Company is unable to determine at this time whether the consequences of Year 2000 failures will have a material impact on the Company's results of operations, liquidity or financial condition. The Company's Year 2000 Readiness Program is expected to significantly reduce the Company's level of uncertainty about Year 2000 issues. The Company believes that, with the completion of the Year 2000 Readiness Program, the possibility of significant interruptions of normal operations should be reduced.

The Company believes that the "most reasonably likely worst case" scenarios are as follows: (i) unanticipated Year 2000 induced failures in information systems could cause a reliance on manual contingency procedures and significantly reduce efficiencies in the performance of certain normal business activities; (ii) unanticipated failures in embedded technology or process control systems due to Year 2000 causes could result in temporarily suspending operations at certain operating facilities with consequent loss of revenue; and (iii) slow downs or disruptions in the third party supply chain due to Year 2000 causes could result in operational delays and reduced efficiencies in the performance of certain normal business activities.

FORWARD LOOKING INFORMATION

Certain information included in this report, 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 projections and 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 (including the timing of the completion of the Company's deleveraging program), development activities, cost savings efforts, production activities and volumes, hydrocarbon reserves, hydrocarbon prices, hedging activities and the results thereof, liquidity, regulatory matters and competition. Such forward looking statements generally are accompanied by words such as "estimate," "expect," "predict," "anticipate," "goal," "should," "assume," "believe" or other words that convey the uncertainty of future events or outcomes.

Such forward looking information is based upon management's current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward looking statements made by or on behalf of the Company. The risks and

uncertainties include generally the volatility of oil, gas and hydrocarbon-based financial derivative prices; basis risk and counterparty credit risk in executing hydrocarbon price risk management activities; economic, political, judicial and regulatory developments; competition in the oil and gas industry as well as competition from other sources of energy; the economics of producing certain reserves; demand and supply of oil and gas; the ability to find or acquire and develop reserves of natural gas and crude oil; and the actions of customers and competitors. Additionally, unpredictable or unknown factors not discussed herein could have material adverse effects on actual results related to matters which are the subject of forward looking information.

With respect to expected capital expenditures and drilling activity, additional factors such as oil and gas prices and the ability to achieve debt repayment objectives, 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 the Company's deleveraging program, factors such as the ability to identify qualified buyers, the buyer's ability to obtain financing (if necessary), successful negotiation of contract terms and completion of due diligence may affect the success and timing of the completion of the program. With respect to expected growth in production and sales volumes and estimated reserve quantities, factors such as the extent of the Company's success in finding, developing and producing reserves, the timing of capital spending, deleveraging 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 and the ability to reduce debt, factors such as changes in oil and gas prices, the Company's success in acquiring properties or divesting producing properties, the GPM segment or other assets, environmental matters and other contingencies, hedging activities and the Company's credit rating and debt levels may affect the Company's ability to generate expected cash flows. With respect to contingencies, factors such as changes in environmental and other governmental regulation, and uncertainties with respect to legal matters may affect the Company's expectations regarding the potential impact of contingencies on the operating results or financial condition of the Company. Certain factors, such as changes in oil and gas prices and underlying demand and the extent of the Company's success in exploiting its current reserves and acquiring or finding additional reserves may have pervasive effects on many aspects of the Company's business in addition to those outlined above.

ITEM 8. *Financial Statements and Supplementary Data*

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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RESPONSIBILITIES FOR FINANCIAL STATEMENTS

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

The integrity and objectivity of data in these financial statements and accompanying notes, including estimates and judgments related to matters not concluded by year-end, are the responsibility of management, as is all other information in this report. Management devotes ongoing attention to the 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 the selection and development of qualified financial personnel; programs to further timely communication and monitoring of policies, standards and delegated authorities; and evaluation by independent auditors during their examinations of the annual financial statements.

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

Jack L. Messman
Chairman and Chief Executive Officer

Morris B. Smith
Vice President and Chief Financial Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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

We have audited the accompanying consolidated statement of financial position of Union Pacific Resources Group Inc. (a Utah Corporation) and subsidiaries ("the Company") as of December 31, 1998, and the related consolidated statements of income and comprehensive income, changes in shareholders' equity and cash flows for the year then ended. 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 audit.

We conducted our audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1998, and the results of its operations and its cash flows for the year then ended in conformity with generally accepted accounting principles.

We have also audited the adjustments related to discontinued operations described in Note 3 that were applied to restate the 1997 and 1996 financial statements. In our opinion, such adjustments are appropriate and have been properly applied.

ARTHUR ANDERSEN LLP
Fort Worth, Texas
January 25, 1999

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 the related consolidated statements of income, changes in shareholders' equity and cash flows for each of the two years in the period ended December 31, 1997 (which have been restated and are no longer presented herein). 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 the results of its operations and its cash flows for each of the two 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 AND COMPREHENSIVE INCOME
For the Years Ended December 31, 1998, 1997 and 1996

	1998	1997	1996
	(Millions, except per share amounts)		
Operating revenues:			
Producing properties	\$ 1,539.2	\$1,293.5	\$1,148.0
Other oil and gas revenues	160.7	84.7	92.0
Minerals (Note 8)	141.1	139.8	128.0
Total operating revenues	<u>1,841.0</u>	<u>1,518.0</u>	<u>1,369.0</u>
Operating expenses:			
Production	444.3	300.8	263.0
Exploration	339.0	204.7	144.0
Minerals (Note 8)	3.5	3.4	8.0
Depreciation, depletion and amortization (Note 6)	2,125.6	504.0	478.0
General and administrative	104.8	71.2	66.0
Restructuring charge (Note 4)	17.0	—	—
Total operating expenses	<u>3,034.2</u>	<u>1,084.1</u>	<u>960.0</u>
Operating income (loss)	(1,193.2)	433.9	408.0
Other income (expense) — net (Notes 3 and 17)	(45.3)	24.5	(3.0)
Interest expense — net (Notes 3 and 10)	(249.8)	(39.5)	(38.0)
Income (loss) from continuing operations before income taxes	(1,488.3)	418.9	366.0
Income tax (expense) benefit (Note 9)	605.2	(115.8)	(112.0)
Income (loss) from continuing operations	(883.1)	303.1	253.0
Income (loss) from discontinued operations (Note 3)	(15.6)	29.9	67.0
Net income (loss)	<u>\$ (898.7)</u>	<u>\$ 333.0</u>	<u>\$ 320.0</u>
Other comprehensive income, net of tax: (Note 16)			
Foreign currency translation adjustments	\$ (67.1)	\$ (5.3)	\$ (0.0)
Minimum pension liability	(3.9)	(1.0)	—
Comprehensive income (loss)	<u>\$ (969.7)</u>	<u>\$ 326.7</u>	<u>\$ 320.0</u>
Earnings (loss) per share — basic: (Note 16)			
Continuing operations	\$ (3.57)	\$ 1.21	\$ 1.00
Discontinued operations	(0.06)	0.12	0.20
Total	<u>\$ (3.63)</u>	<u>\$ 1.33</u>	<u>\$ 1.20</u>
Earnings (loss) per share — diluted: (Note 16)			
Continuing operations	\$ (3.57)	\$ 1.21	\$ 1.00
Discontinued operations	(0.06)	0.12	0.20
Total	<u>\$ (3.63)</u>	<u>\$ 1.33</u>	<u>\$ 1.20</u>
Weighted average shares outstanding — diluted	247.7	250.9	250.0
Cash dividends per share	\$ 0.20	\$ 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, 1998 and 1997

ASSETS

	<u>1998</u>	<u>1997</u>
	<u>(Millions of dollars)</u>	
Current assets:		
Cash and temporary investments	\$ 8.8	\$ 67.1
Accounts receivable (net of allowance for doubtful accounts of \$9.8 million in 1998 and \$1.9 million in 1997)	261.0	252.1
Inventories	64.6	16.8
Other current assets	107.0	60.6
Total current assets	<u>441.4</u>	<u>396.6</u>
Properties: (Note 6)		
Cost	11,078.2	6,268.7
Accumulated depreciation, depletion and amortization	(4,984.9)	(3,367.6)
Total properties	6,093.3	2,901.1
Intangible and other assets (Note 8)	180.8	138.2
Net assets of discontinued operations (Note 3)	926.9	877.8
Total assets	<u>\$ 7,642.4</u>	<u>\$ 4,313.7</u>

LIABILITIES AND SHAREHOLDERS' EQUITY

Current liabilities:		
Accounts payable	\$ 270.5	\$ 274.7
Accrued taxes payable	64.9	59.5
Other current liabilities	157.5	68.3
Short-term debt	853.8	—
Total current liabilities	1,346.7	402.5
Long-term debt (Note 10)	3,744.9	1,230.6
Deferred income taxes (Note 9)	1,291.6	552.9
Retiree benefits obligations (Note 12)	142.9	147.7
Other long-term liabilities (Notes 13, 14 and 15)	388.1	219.3
Shareholders' equity (see page 43)	728.2	1,760.7
Total liabilities and shareholders' equity	<u>\$ 7,642.4</u>	<u>\$ 4,313.7</u>

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

UNION PACIFIC RESOURCES GROUP INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
For Years Ended December 31, 1998, 1997 and 1996

	1998	1997	1996
	(Millions of dollars)		
Cash provided by operations:			
Net income	\$ (898.7)	\$ 333.0	\$ 320.
Non-cash charges to income:			
Depreciation, depletion and amortization	2,125.6	504.0	478.
Deferred income taxes (Note 9)	(659.3)	110.9	(21.)
(Income) loss from discontinued operations (Note 3)	15.6	(29.9)	(67.)
Other non-cash charges (credits) — net	240.7	(29.4)	7.
Exploratory expenditures	115.2	76.9	51.
Changes in current assets and liabilities	92.0	(109.3)	2.
Cash provided by operations	<u>1,031.1</u>	<u>856.2</u>	<u>772.</u>
Investing activities:			
Capital and exploratory expenditures (Note 7)	(1,194.5)	(1,188.4)	(773.)
Acquisition of company (Note 2)	(2,634.3)	—	—
Proceeds from sales of assets (Note 3)	436.6	37.3	30.
Proceeds from sales of investments	48.4	—	—
Cash provided (used) by discontinued operations	50.4	(221.8)	113.
Other investing activities — net	—	(17.7)	(2.)
Cash (used) by investing activities	<u>(3,293.4)</u>	<u>(1,390.6)</u>	<u>(632.)</u>
Financing activities:			
Dividends paid	(49.6)	(50.0)	(49.)
Proceeds from long-term debt issuance (Note 10)	1,025.0	—	550.
Other debt financing — net (Note 10)	1,294.5	559.6	(80.)
Repurchase of common stock	(26.7)	(52.3)	(3.)
Repayment of advances to Union Pacific Corporation	—	—	(567.)
Other financings — net (Note 10)	(39.2)	30.4	105.
Cash provided (used) by financing activities	<u>2,204.0</u>	<u>487.7</u>	<u>(46.)</u>
Net change in cash and temporary investments	(58.3)	(46.7)	94.
Balance at beginning of year	67.1	113.8	19.
Balance at end of year	<u>\$ 8.8</u>	<u>\$ 67.1</u>	<u>\$ 113.</u>
Changes in current assets and liabilities:			
Accounts receivable	\$ 215.8	\$ (33.2)	\$ (82.)
Inventories	(17.8)	(1.5)	17.
Other current assets	3.2	21.6	1.
Accounts payable	(153.4)	(21.4)	13.
Accrued taxes payable	3.5	(73.4)	47.
Other current liabilities	40.7	(1.4)	5.
Total	<u>\$ 92.0</u>	<u>\$ (109.3)</u>	<u>\$ 2.</u>
Supplemental cash flow disclosure:			
Interest paid:			
Continuing operations	\$ 216.0	\$ 42.7	\$ 31
Discontinued operations	21.1	13.6	11
Income taxes paid (recovered):			
Continuing operations	81.0	121.0	97
Discontinued operations	(35.0)	8.7	(18)

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, 1998, 1997 and 1996

	1998	1997	1996
	(Millions of dollars)		
Common stock, no par value; authorized 400,000,000 shares:			
250,685,204 shares issued and outstanding at December 31, 1998			
251,888,575 shares issued and outstanding at December 31, 1997			
250,058,019 shares issued and outstanding at December 31, 1996			
Balance at beginning and end of year.....	\$ —	\$ —	\$ —
Paid-in surplus:			
Balance at beginning of year	991.2	872.9	860.2
Conversion, award, forfeiture and appreciation of retention shares (Note 16)	0.5	5.1	15.9
Issuance of ESOP shares (Note 16)	—	107.3	—
Exercise of stock options	0.6	5.5	0.5
Other	0.3	0.4	(3.7)
Balance at end of year	<u>992.6</u>	<u>991.2</u>	<u>872.9</u>
Retained earnings:			
Balance at beginning of year	957.4	674.4	472.9
Net income (loss)	(898.7)	333.0	320.8
Total	58.7	1,007.4	793.7
Dividends declared on common stock	(49.6)	(50.0)	(49.8)
Pension asset adjustment	—	—	(69.5)
Balance at end of year	<u>9.1</u>	<u>957.4</u>	<u>674.4</u>
Unearned compensation:			
Balance at beginning of year	(11.8)	(17.5)	(9.2)
Conversion, award, appreciation and amortization of retention shares — net (Note 16)	5.8	5.7	(8.3)
Balance at end of year	<u>(6.0)</u>	<u>(11.8)</u>	<u>(17.5)</u>
ESOP (Note 16):			
Balance at beginning of year	(102.0)	—	—
Issuance of ESOP shares	—	(107.3)	—
Release of ESOP shares	6.3	5.3	—
Balance at end of year	<u>(95.7)</u>	<u>(102.0)</u>	<u>—</u>
Treasury stock:			
Balance at beginning of year	(55.8)	(3.5)	—
Treasury stock repurchased, at cost	(26.7)	(52.3)	(3.5)
Balance at end of year 3,666,913 shares at December 31, 1998			
2,379,625 shares at December 31, 1997			
154,417 shares at December 31, 1996.....	<u>(82.5)</u>	<u>(55.8)</u>	<u>(3.5)</u>
Comprehensive income:			
Deferred foreign exchange adjustment:			
Balance at beginning of year	(17.3)	(12.0)	(11.5)
Foreign currency translation adjustment.....	(67.1)	(5.3)	(0.5)
Balance at end of year	<u>(84.4)</u>	<u>(17.3)</u>	<u>(12.0)</u>
Minimum pension liability (Note 12)	(4.9)	(1.0)	—
Total comprehensive income	<u>(89.3)</u>	<u>(18.3)</u>	<u>(12.0)</u>
Total shareholders' equity	<u>\$ 728.2</u>	<u>\$1,760.7</u>	<u>\$1,514.3</u>

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

UNION PACIFIC RESOURCES GROUP INC.
BUSINESS SEGMENT INFORMATION
For the Years Ended December 31, 1998, 1997 and 1996

	1998	1997	1996
	(Millions of dollars)		
Revenues(a):			
Exploration and production	\$ 1,699.9	\$1,378.2	\$1,240.3
Minerals	141.1	139.8	128.9
Total revenues	<u>\$ 1,841.0</u>	<u>\$1,518.0</u>	<u>\$1,369.2</u>
Depreciation, depletion and amortization:			
Exploration and production	\$ 2,115.8	\$ 499.3	\$ 473.4
Minerals	4.1	0.9	0.9
Corporate	5.7	3.8	3.7
Total depreciation, depletion and amortization	<u>\$ 2,125.6</u>	<u>\$ 504.0</u>	<u>\$ 478.0</u>
Operating income(b):			
Exploration and production	\$(1,199.2)	\$ 373.4	\$ 359.1
Minerals	133.5	135.5	120.0
Corporate	(127.5)	(75.0)	(70.6)
Total operating income (loss)	<u>\$(1,193.2)</u>	<u>\$ 433.9</u>	<u>\$ 408.5</u>
Fixed assets — net:			
Exploration and production	\$ 5,988.8	\$2,827.1	\$2,336.2
Minerals	10.2	14.1	16.9
Corporate	94.3	59.9	51.6
Total fixed assets — net	<u>\$ 6,093.3</u>	<u>\$2,901.1</u>	<u>\$2,404.7</u>
Capital and exploratory expenditures:			
Exploration and Production	\$ 3,796.2	\$1,172.6	\$ 763.5
Minerals	0.1	1.4	0.8
Corporate	32.5	14.4	8.7
Total capital and exploratory expenditures	<u>\$ 3,828.8</u>	<u>\$1,188.4</u>	<u>\$ 773.0</u>

Geographic Information

	1998	1997	1996
	(Millions of dollars)		
Revenues(a):			
United States	\$ 1,455.9	\$1,477.2	\$1,333.4
Canada	259.0	28.9	23.3
Other international	126.1	11.9	12.5
Total revenues	<u>\$ 1,841.0</u>	<u>\$1,518.0</u>	<u>\$1,369.2</u>
Fixed assets — net:			
United States	\$ 2,965.2	\$2,800.9	\$2,290.8
Canada	1,854.0	89.8	96.4
Other international	1,274.1	10.4	17.5
Total fixed asset — net	<u>\$ 6,093.3</u>	<u>\$2,901.1</u>	<u>\$2,404.7</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.

(a) 1998, 1997 and 1996 revenues include income from equity affiliates of \$89.7 million, \$74.4 million and \$74.5 million, respectively, for the minerals segment.

(b) 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., a Utah Corporation, 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. The Company also consolidates its pro-rata share of oil and gas joint ventures. All significant intercompany transactions are eliminated. The consolidated financial statements for previous periods include certain reclassifications that were made to conform to the current presentation. Such reclassifications have no effect on previously reported net income. Refer to the accompanying notes to the financial statements for additional disclosure of the Company's significant accounting policies.

As a result of the Company's announcement to sell its gathering, processing and marketing business ("GPM") segment, the GPM segment has been accounted for as a discontinued operation. GPM results of operations have been excluded from continuing operations in the consolidated statements of income and cash flows. GPM net assets have been segregated from continuing operations in the accompanying statements of financial position and reported as net assets of discontinued operations. Some prior year amounts have been restated to conform to the current presentation.

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 71).

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, exploration costs (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. Costs to drill exploratory wells that result in additions to reserves are also 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 two to 15 years. Potential impairment of producing properties and significant unproved properties is assessed annually on a field-by-field basis; all other unproved properties are assessed annually on an aggregate basis (see Note 6).

Costs of future site restoration, dismantlement and abandonment for producing properties are accrued as part of depreciation, depletion and amortization expense for tangible equipment by assuming no salvage value in the calculation of the unit of production rate. Additional costs are accrued for offshore and Canadian wells

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

based on internal engineering estimates using the unit of production method with a charge to depreciation, depletion and amortization expense. The balance of the abandonment accrual at December 31, 1998 and 1997 was \$62.1 million and \$11.6 million, respectively. The increase was due primarily to the acquisition of Norcen.

Gains or losses on retired, sold or abandoned properties that constitute part of an amortization base are deferred by charging or crediting, 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 and significant nonoperating assets are recorded in other income. Gains and losses from all other dispositions of operating assets are recognized in other oil and gas revenues.

Goodwill. Intangible and other assets 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. The value of goodwill is periodically evaluated to determine whether any potential impairment exists.

Income Taxes. Deferred taxes are established for all temporary differences between the book and tax bases of assets and liabilities. In addition, deferred tax balances must be adjusted to reflect tax rates that will be in effect in the years in which the temporary differences are expected to reverse. Non-U.S. subsidiaries compute taxes at rates in effect in the various countries. Earnings of these subsidiaries may also be subject to additional income and withholding taxes when they are distributed as dividends. Deferred tax liabilities are not recognized on profits that are expected to be permanently reinvested by the local subsidiaries and thus not considered available for distribution to the parent Company. As of December 31, 1998, the Company's non-U.S. subsidiaries have not recognized operating profits and, therefore, no undistributed earnings are available.

Revenue Recognition. Sales from producing gas wells are recognized on the entitlement method of accounting which defers recognition of sales 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 are recorded to reflect the full net revenue interest. The Company's net gas imbalance at December 31, 1998 was immaterial. Crude marketing revenue, included in other oil and gas revenue is recorded net of the cost of crude oil purchased.

Recently issued accounting standards. In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), which is effective for fiscal years beginning after June 15, 1999. This statement requires that all derivatives be recognized on the balance sheet and measured at fair value. If certain conditions are met, a derivative may be specifically designated as a hedge and be eligible for special accounting treatment. However, the special accounting treatment afforded hedge transactions may delay the recognition of a portion of the gain or loss on the derivative, which would later be recorded concurrent with the gain or loss on the item being hedged. For derivatives not designated as hedges, gains or losses are recognized in earnings in the period of change. The impact of the statement on the Company will depend upon price volatility and the level of open derivative positions at the end of a reporting period. The Company plans to adopt SFAS No. 133 for the first quarter of the year ending December 31, 2000 and is currently evaluating the effects of this pronouncement. Adoption will require the Company to begin recording unrealized gains and losses in the statement of financial position and in comprehensive income.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

1. Nature of Operations

The Company is an independent oil and gas company engaged primarily in the exploration for and development and production of natural gas and crude oil in several major basins in the United States, Canada, Guatemala, Venezuela and other international areas. The Company markets all of its crude oil production together with significant volumes of crude oil produced by others. In 1998, the Company marketed a substantial portion of its natural gas and natural gas liquids ("NGLs"); however, the Company will enter into a long-term gas sales agreement to sell a substantial portion of its natural gas and NGLs to another company in connection with the pending sale of the GPM segment (see Note 3). In addition, the Company engages in the hard minerals business through non-operated joint venture and royalty interests in several coal and trona (natural soda ash) mines.

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. Acquisitions

Norcen Energy Resources Limited. On January 25, 1998, the Company and Union Pacific Resources Inc. ("UPRI"), an Alberta corporation and a wholly-owned subsidiary of the Company, entered into a pre-acquisition agreement ("Pre-acquisition Agreement") with Norcen Energy Resources Limited ("Norcen"). Under the Pre-acquisition Agreement, the Company and UPRI agreed to make an offer (the "Tender Offer") for up to 100 percent of the common shares of Norcen, subject to certain conditions. On March 3, 1998, the Company announced the closing of the Tender Offer. In total, 95.5 percent of the outstanding common shares of Norcen were tendered at a purchase price of U.S. \$13.65 per share.

On March 5, 1998, UPRI completed the compulsory acquisition of the remaining common shares outstanding which were not tendered. (The closing of the Tender Offer and completion of the compulsory acquisition is referred to as the "Norcen Acquisition.") The aggregate purchase price for the Norcen Acquisition, including non-recurring transaction costs of \$28.1 million, was \$2.634 billion. In addition, the Company assumed the long-term debt obligations of Norcen.

Norcen operations primarily consisted of oil and gas exploration and development operations in western Canada, the Gulf of Mexico, Guatemala and Venezuela.

The Company funded the purchase price of the Norcen Acquisition through the issuance of commercial paper, supported by a U.S. \$2.7 billion 364-day Competitive Advance/Revolving Credit Agreement dated March 2, 1998. In accordance with Accounting Principles Board Opinion No. 16, "Business Combinations," the Norcen Acquisition was accounted for as a purchase effective March 3, 1998.

The following table represents the revised preliminary allocation of the total purchase price of the assets acquired and liabilities assumed, based upon their fair values on the date of the Norcen Acquisition and pushed down to the acquired Company. In accordance with SFAS 109, a deferred tax liability was recognized for the differences between the allocated values and the tax bases of the acquired assets and liabilities. Any

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

additional adjustments to the allocation of the purchase price are not anticipated to be material to the consolidated financial statements of the Company.

	(Millions of dollars)
Working capital	\$ 114.4
Property, plant and equipment	4,931.2
Other assets	228.2
Long-term debt	(1,012.0)
Deferred taxes	(1,495.7)
Other non-current liabilities	(131.8)
Total purchase price	<u>\$ 2,634.3</u>

The following table presents unaudited pro forma condensed consolidated statements of income of the Company for the twelve months ended December 31, 1998 and 1997, as though the Norcen Acquisition had occurred on January 1, 1997. Certain adjustments were made to the financial information to conform to the accounting policies and financial statement presentation of the Company. Prior year amounts have been restated to reflect the Company's current presentation for discontinued operations.

	Twelve Months Ended December 31,	
	1998	1997
	(Millions of dollars, except per share amounts)	
Revenues	\$ 1,940.8	\$2,169.3
Costs and expenses	3,165.2	1,810.4
Operating income (loss)	(1,224.4)	358.9
Interest expense	(284.3)	(240.1)
Other income (expense) — net	(45.3)	24.5
Income (loss) before income taxes	(1,554.0)	143.3
Income tax benefit (expense)	629.4	(24.5)
Income (loss) from continuing operations	<u>\$ (924.6)</u>	<u>\$ 118.8</u>
Earnings (loss) per share — basic and diluted		
Continuing operations	\$ (3.73)	\$ 0.47

The unaudited pro forma condensed consolidated information presented above is not necessarily indicative of the results of operations which would have occurred had the Norcen Acquisition been consummated on January 1, 1997, nor is it necessarily indicative of future results of operations of the Company.

Norcen Summarized Financial Information. Shortly after the Norcen Acquisition, Norcen was amalgamated with UPRI (the "Amalgamation"). Prior to the Amalgamation, UPRI's operations primarily consisted of oil and gas operations in western Canada. After the Amalgamation, certain non-Canadian international assets were or will soon be distributed or contributed from UPRI to other subsidiaries of the Company.

As a result of the Amalgamation, UPRI assumed the obligations of Norcen, including the public debt obligations of Norcen (the "Debt Securities"). The Debt Securities include 6.8% Debentures due July 2, 2002, in the aggregate principal amount of \$250 million, 7% Debentures due May 15, 2006, in the aggregate principal amount of \$250 million and 7.8% Debentures due July 2, 2008 in the aggregate principal amount of \$150 million, each of which have been fully and unconditionally guaranteed by the Company.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table presents summarized financial information for UPRI (as successor to Norcen) as of and for the two months ended February 28, 1998, and ten months ended December 31, 1998. This summarized financial information is being provided pursuant to Section G of Topic 1 of Staff Accounting Bulletin No. 53 — "Financial Statement Requirements in Filings Involving the Guarantee of Securities by a Parent." The Company will continue to provide such summarized financial information for UPRI as long as the Debt Securities remain outstanding and guaranteed by the Company.

	Two Months Ended February 28, 1998 (a) (Millions of dollars)	Ten Months Ended December 31, 1998 (b) (Millions of dollars)
Summarized Statement of Income Information:		
Operating revenues	\$ 104.0	\$ 357.2
Operating income (loss)	4.0	(784.5)
Net loss	\$ (30.0) (c)	\$ (508.3) (d)
Summarized Statement of Financial Position Information:		
Current assets	\$ 275.6	\$ 53.7
Non-current assets	2,456.2	1,882.3
Current liabilities	182.6	279.8
Non-current liabilities and equity	\$2,549.2	\$1,656.2

- (a) Results for Norcen as of and for the two months ended February 28, 1998. Results have not been restated in accordance with U.S. generally accepted accounting principles ("GAAP") and reflect the full cost method for accounting for oil and gas operations.
- (b) Results for UPRI as of and for the ten months ended December 31, 1998, include adjustments to reflect U.S. GAAP and the successful efforts method of accounting. Adjustments to reflect the application of the purchase method of accounting for the Norcen Acquisition are included effective March 3, 1998.
- (c) Net loss includes \$40 million in costs incurred by Norcen in connection with the Norcen Acquisition which were not reimbursed by the Company.
- (d) Results reflect the impairment and writedown of certain oil and gas properties.

3. Divestitures

Deleveraging Program. In April 1998, the Company's Board of Directors authorized a deleveraging program which was designed to reduce debt and maintain a strong investment grade credit rating for the Company's outstanding indebtedness. The deleveraging program, which was initiated following the completion of the Norcen Acquisition, included sales of the GPM segment and non-strategic oil and gas producing properties. The completed sales undertaken as part of the Company's deleveraging program include:

Wattenberg Properties. In May 1998, the Company completed the sale of its interest in certain oil and gas producing properties located in the Wattenberg area of the Denver-Julesburg Basin of Colorado to United States Exploration, Inc. for a cash sales price of \$41 million. The Company has retained a royalty interest in these properties.

Superior Propane Income Fund. In May 1998, UPRI sold a 10 percent ownership interest in Superior Propane Income Fund (the "Superior Fund"), together with rights under a management agreement with Superior Propane Inc., ("Superior Propane") and rights under an administration and advisory agreement among the Company, Superior Propane and the Superior Fund, to Superior Management Services Limited Partnership for a cash sales price of \$48 million.

Matagorda Island Properties. In August 1998, the Company completed the sale of its 19 percent non-operated interest in the Matagorda Island Block 623 Field and surrounding blocks, all located in the Gulf of Mexico (off the shore of Texas), to Enron Oil & Gas Company for a cash sales price of \$158 million.

Rockies Properties. In the fourth quarter 1998, the Company completed the sale of certain oil and gas producing properties located in Wyoming, oil producing properties in Utah and oil producing properties in

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

North Dakota and Montana. The aggregate proceeds from the sales of these oil and gas producing properties were approximately \$46 million.

Canadian Properties. In December 1998, the Company completed sales of certain oil and gas producing properties located in western Canada. The aggregate proceeds from the sales of these oil and gas producing properties were approximately \$145 million.

In January 1999, the Company announced the completion of several other large asset sales. The Company sold several of its non-core southern Texas properties for \$138 million and its Canadian Caroline-Swan Hill for \$108 million. Proceeds from these sales will primarily be used to reduce the Company's debt obligations.

Discontinued Operations. In November 1998, the Company entered into a Merger and Purchase Agreement ("Agreement") with Duke Energy Field Services, Inc. ("Duke") to sell its gathering, processing and marketing ("GPM") segment for \$1.35 billion in cash. The proposed sale consists primarily of the Company's pipelines, gathering systems, natural gas processing plants and natural gas and NGL marketing assets and operations, including interests in 19 natural gas processing plants (together with approximately 7,200 miles of pipelines that support these processing plants), as well as two non-operated NGL fractionation plants. The Company will retain its crude oil marketing business. The Company expects to record a gain on the sale of the GPM segment, which is expected to be completed in March 1999.

As part of the Agreement, Duke was allowed to conduct an environmental audit and, based on the results, assert claims for the cost to remediate environmental conditions discovered during the audit. Duke has concluded the environmental audit and asserted claims under the Agreement. Under the terms of the Agreement, asserted claims will not affect or delay the close of the transaction; however, following the close of the transaction, the Company has the right to contest any environmental claims through arbitration. If it is determined through arbitration that there are valid environmental claims in excess of \$40 million, then the Company is obligated to make payment to Duke for such excess. The Company is analyzing Duke's environmental claims. At this time, it is the Company's view that there are substantial defenses to the Duke environmental claims.

The GPM segment has been reported as a discontinued operation and the GPM net assets which are being sold have been segregated from continuing operations in the accompanying consolidated statement of financial position. The GPM segment results of operations and cash flows have been excluded from continuing operations in the consolidated statements of income and cash flows for all periods presented and have been reported as discontinued operations in the accompanying consolidated statements of income and cash flows.

Summarized information relating to discontinued results of operations for the years ended December 31, 1998, 1997 and 1996 are as follows:

	1998	1997	1996
	(Millions of dollars)		
Operating revenues	\$ 340.0	\$ 406.7	\$ 461.8
Operating expenses	(263.4)	(281.3)	(287.8)
Depreciation depletion and amortization	(77.6)	(64.1)	(55.9)
Operating income (loss)	(1.0)	61.3	118.1
Other income (expense) — net	—	(0.2)	0.1
Interest expense(a)	(21.1)	(13.6)	(11.7)
Income (loss) before taxes	(22.1)	47.5	106.5
Income taxes (benefit)	(6.5)	17.6	39.4
Net income (loss) from discontinued operations	<u>\$ (15.6)</u>	<u>\$ 29.9</u>	<u>\$ 67.1</u>

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

- (a) The Company allocated interest expense to the GPM segment based on the ratio of net assets of discontinued operations to total Company net assets, excluding \$3.6 billion of debt associated with the Norcen Acquisition.

Summarized information relating to net assets of discontinued operations at December 31, 1998 and 1997 are as follows:

	1998	1997
	(Millions of dollars)	
Current Assets:		
Cash and temporary investments	\$ 5.7	\$ 3.5
Accounts receivable — net	152.8	133.3
Inventories	46.8	36.3
Other current assets	5.2	7.1
Total current assets	210.5	180.2
Properties-net of accumulated depreciation	851.3	764.3
Intangible and other assets	154.8	91.8
Total assets	<u>\$1,216.6</u>	<u>\$1,036.3</u>
Current Liabilities:		
Accounts payable	\$ 158.0	\$ 152.0
Advance payment(b)	126.7	—
Other current liabilities	2.0	3.2
Total current liabilities	286.7	155.2
Other long-term liabilities	3.0	3.3
Total liabilities	<u>\$ 289.7</u>	<u>\$ 158.5</u>
Net assets of discontinued operations	<u>\$ 926.9</u>	<u>\$ 877.8</u>

- (b) In June 1998, the Company entered into a third party forward sales arrangement covering a total of 567 MMcf of gas per day. At the time of the arrangement, the Company received \$250 million and became obligated to deliver gas from October 1998 through March 1999. The Company recorded the obligation associated with this transaction as an advance payment included in net assets of discontinued operations. This current liability will be amortized as part of discontinued operations, as the gas is delivered over the remaining term of the contract.

4. Restructuring Charge

As a result of depressed hydrocarbon prices, the Company announced a workforce reduction for its domestic operations and implemented programs to reduce overhead and other costs in November 1998. As a result of this process, a \$17 million restructuring charge was recorded in the fourth quarter of 1998. The restructuring charge included \$7.6 million for workforce reductions of approximately 140 U.S. employees. The charge also included \$5 million for a long-term drilling rig commitment and \$4.4 million for excess office space commitments. At December 31, 1998, the remaining reserve relating to the restructuring charge totaled \$14.6 million.

Subsequent to year-end, the Company reorganized into five operating groups, announced further workforce reductions for its Canadian and U.S. operations and established a voluntary retirement incentive program. Another restructuring charge will be recorded in the first quarter of 1999 associated with these additional workforce reductions.

5. Financial Instruments

Hedging. The Company has established policies and procedures for managing risk within its organization, including internal controls and governance by a risk management committee. The level of risk assumed

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

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 contractual commitments, price volatility, and other market variables. These instruments are generally put in place to limit risk of adverse price movements; however, these same instruments may also limit future gains from favorable price movements. Risk management activities are generally accomplished pursuant to exchange-traded contracts or over-the-counter swaps and options.

Recognition of realized gains/losses and option premium payments/receipts relating to non-trading activities are deferred in the consolidated statement of income until the underlying physical product is sold. Unrealized gains/losses are not recorded. Margin deposits, deferred gains/losses and net premiums are included in other current assets or liabilities in the consolidated statement of financial position. The cash flow impact is reflected in cash flows provided from operations in the consolidated statement of cash flows.

The Company's oil and gas revenues can be higher or lower than what would be reported if the hedging program was not in place. As a result, revenues in 1998, 1997 and 1996 were \$9 million, \$86 million and \$52 million lower, respectively. Since these transactions were hedges on production, these impacts were also reflected in the average sales price of the associated products.

Commodity Price Risk — Trading Activities. The Company periodically enters into financial contracts in conjunction with market-making or trading activities with the objective of achieving profits through successful anticipation of movements in commodity prices and changes in other market variables. Market-making positions are marked-to-market and gains and losses are immediately included as revenue in the consolidated statement of income. In addition, the fair value of unsettled positions is immediately included in the consolidated statement of financial position as a current asset or current liability. As of December 31, 1998, there were no transactions in place which would materially affect the results of operations or financial condition of the Company.

Interest Rate Swaps. The Company periodically enters into rate swaps and contracts to hedge certain interest rate transactions. As of December 31, 1998 and 1997, there were no interest rate contracts outstanding which materially affect the results of operations or financial condition of the Company. During 1998, the Company entered into rate lock contracts to hedge interest rates related to a contemplated bond issuance. The bonds were not issued and the Company recognized a \$14.3 million pretax loss in 1998 associated with these contracts.

Foreign Currency. The financial statements of foreign subsidiaries, except those subsidiaries located in countries which have highly inflationary economies, utilize the local currency as their functional currency. The financial statements of foreign subsidiaries located in countries which have highly inflationary economies utilize the U.S. dollar as their functional currency. Monetary assets and liabilities denominated in a currency other than the functional currency are remeasured into the functional currency with the corresponding gains/losses included in the consolidated statement of income. The financial statements of those foreign subsidiaries which do not utilize the U.S. dollar as their functional currency are translated into the U.S. dollar. Assets and liabilities are translated at the current exchange rate, while revenues and expenses are translated at the average exchange rate for the reporting period. Translation gains/losses are not included in net income but are recorded in a separate section of shareholders' equity and comprehensive income. The Company's Canadian subsidiary's functional currency is the Canadian dollar. Generally, the Company's other foreign subsidiaries' functional currency is the U.S. dollar.

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At December 31, 1998, the Company's Canadian subsidiary had outstanding \$650 million of fixed rate notes and debentures denominated in U.S. dollars. During 1998, the Company recognized a \$46.5 million pretax non-cash loss associated with remeasurement of this debt. The potential foreign currency remeasurement impact on earnings from a five percent change in the year-end Canadian exchange rate would be approximately \$32 million.

At December 31, 1998, the Company's Latin American subsidiaries had foreign deferred tax liabilities denominated in the local currency of the respective countries of \$159.6 million in Venezuela and \$58.0 million in Guatemala. During 1998, the Company recognized deferred tax benefits of \$15.2 million and \$7.3 million after tax, respectively, associated with remeasurement of the Venezuelan and Guatemalan deferred tax liabilities. The potential foreign currency remeasurement impact on net earnings from a five percent change in the year-end Latin American would be approximately \$11 million.

The Company may periodically enter into foreign currency contracts to hedge specific currency exposures from commercial transactions. As a result of the Norcen Acquisition, the Company acquired foreign currency forward exchange contracts with a \$643 million notional amount and maturities between March 1998 and December 1999, for which a \$15.5 million deferred liability was recorded on the Consolidated Statement of Financial Position representing the fair value of these contracts. These contracts were deemed to be hedges of UPRI's future U.S. dollar denominated hydrocarbon sales. This deferred liability will be amortized over the contract terms. The unrecognized loss on such contracts at December 31, 1998, excluding the \$6.8 million remaining unamortized deferred liability recorded in purchase accounting, was \$18.5 million.

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, 1998, the Company's largest credit risk associated with any single counterparty, represented by the net fair value of open contracts with such counterparty, was \$2.6 million.

In connection with the sale of its GPM business segment, the Company will enter into a long-term sales agreement with Duke. The long-term sales agreement obligates the Company to sell the majority of its domestic natural gas and NGLs to Duke for a five-year period subsequent to the closing of the sale. Prices received for the natural gas and NGLs will be tied to the current market price for each product. As a result, a significant portion of the Company's credit risk will be with a single customer. Duke is currently considered a good credit risk; however, periodic credit evaluations will continue. Further, due to certain agreements with Duke, letters of credit and/or other assurances can be demanded under certain circumstances.

Performance Risk. Performance risk results when a counterparty fails to fulfill its contractual obligations with respect to 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.

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. The Company derives a significant amount of its revenues from international operations. 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,	
	1998	1997
	(Millions of dollars)	
Producing properties	\$ 9,429.9	\$5,296.8
Non-producing properties	1,241.5	449.5
Construction in progress	143.4	346.5
Other	263.4	175.9
Total	<u>\$11,078.2</u>	<u>\$6,268.7</u>

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

	As of December 31,	
	1998	1997
	(Millions of dollars)	
Producing properties	\$4,642.1	\$3,153.0
Non-producing properties	233.1	123.6
Other	109.7	91.0
Total	<u>\$4,984.9</u>	<u>\$3,367.6</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 due to lower hydrocarbon prices and downward revisions in reserve estimates. In 1998, the Company adjusted the net book value of such properties to their fair value, determined using a discounted cash flow approach, with a charge to depreciation, depletion and amortization of \$1.2 billion. In 1997, the Company recorded an impairment charge of \$20.2 million. Fixed asset additions included capitalized interest of \$0.9 million and \$2.0 million in 1998 and 1997, respectively.

7. Capital and Exploratory Expenditures

Capital and exploratory expenditures include the following:

	For the Years Ended		
	1998	1997	1996
	(Millions of dollars)		
Capital expenditures:			
Producing properties	\$3,056.9	\$ 773.3	\$526.0
Non-producing properties	506.6	200.7	149.8
Exploratory drilling	117.5	121.7	36.1
Other	32.6	15.8	9.5
Total capital expenditures	3,713.6	1,111.5	721.4
Exploratory expenditures:			
Expensed geological and geophysical costs	63.1	35.2	19.0
Expensed dry hole costs	52.1	41.7	32.6
Total exploratory expenditures	115.2	76.9	51.6
Total capital and exploratory expenditures	<u>\$3,828.8</u>	<u>\$1,188.4</u>	<u>\$773.0</u>

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

8. Investment in Unconsolidated Affiliate

The Company has a 50 percent 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:

	Years Ended and as of December 31,	
	1998	1997
	(Millions of dollars)	
Current assets	\$ 30.4	\$ 27.5
Non-current assets	26.2	37.9
Current liabilities	21.0	17.1
Non-current liabilities and equity	35.7	48.3
Sales	\$254.5	\$159.7
Operating income	183.4	112.4
Partners' income	183.2	113.6

During 1998, Black Butte's sales to its largest customer under an amended coal supply contract accounted for \$79.3 million 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 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 supplies. 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, 1998 and 1997 were \$52.0 million and \$50.4 million, of which the Company's share is \$26 million and \$25.2 million, respectively. The majority of cash expenditures for reclamation are expected to be incurred from five to ten years in the future (see Note 13).

A supplier of coal to Black Butte has been assessed by the State of Montana Department of Revenue for underpayment of production taxes related to coal previously sold to Black Butte. The supplier is contesting this claim; however, should the claim be successful, the supplier will claim reimbursement from Black Butte. In 1998, the Courts ruled in favor of the State of Montana. The supplier is appealing to the Montana State Supreme Court; however, the Company recorded \$14.3 million during 1998 as its proportionate share of the Montana Department of Revenue assessment related to coal production taxes. Additionally, this supplier of coal to Black Butte has been assessed by the Minerals Management Service of the United States Department of the Interior for underpayment of royalties related to coal previously sold to Black Butte. The liability for underpaid royalties to the Minerals Management Service, if any, could range from zero to \$12 million.

9. Income Taxes

Income (loss) from continuing operations before taxes is as follows:

	For the Years Ended December 31,		
	1998	1997	1996
	(Millions of dollars)		
Domestic	\$ (239.7)	\$405.9	\$356.9
Foreign	(1,248.6)	13.0	9.2
Total	<u><u>\$ (1,488.3)</u></u>	<u><u>\$418.9</u></u>	<u><u>\$366.1</u></u>

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Components of income tax expense (benefit) for continuing operations, were as follows:

	For the Years Ended December 31,		
	1998	1997	1996
	(Millions of dollars)		
Current:			
U.S. federal	\$ 43.2	\$ (0.4)	\$123.4
U.S. state	6.8	5.1	10.0
Foreign	4.1	0.2	0.3
Total current	<u>54.1</u>	<u>4.9</u>	<u>133.7</u>
Deferred:			
U.S. federal	(155.7)	113.4	(22.1)
U.S. state	3.4	(2.5)	0.8
Foreign	(507.0)	—	—
Total deferred	<u>(659.3)</u>	<u>110.9</u>	<u>(21.3)</u>
Total income tax expense (benefit)	<u><u>\$ (605.2)</u></u>	<u><u>\$115.8</u></u>	<u><u>\$112.4</u></u>

Deferred tax liabilities (assets) were as follows:

	As of December 31,	
	1998	1997
	(Millions of dollars)	
Excess tax over book items, including depreciation and exploration costs	\$1,528.2	\$686.0
State taxes — net	(15.0)	—
Long-term liabilities	(19.6)	—
Alternative minimum tax	(72.6)	(73.2)
Pension and other retirement benefits	(52.6)	(57.4)
Net operating losses	(93.1)	—
Other	16.3	(2.5)
Net deferred tax liability	<u><u>\$1,291.6</u></u>	<u><u>\$552.9</u></u>

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

	For the Years Ended December 31,		
	1998	1997	1996
U.S. statutory federal tax rate	35.0%	35.0%	35.0%
Section 29 credits	1.1	(4.3)	(3.3)
State taxes — net	(0.4)	1.3	1.8
Foreign rate differentials	1.8	—	—
Foreign currency remeasurement	1.5	—	—
Non taxable entity	1.0	—	—
Tax settlements	—	(1.5)	—
Other	0.6	(1.9)	(1.4)
Effective tax rate	<u><u>40.6%</u></u>	<u><u>28.6%</u></u>	<u><u>32.1%</u></u>

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 \$16.4 million, \$18.8 million and \$15.6 million of Section 29 tax credits in 1998, 1997 and 1996, respectively. The federal tax law provides for the use of these credits against regular federal income tax liability. Accordingly, the Company utilized \$5.1 million of Section 29 tax credits on its 1997 tax return. It is anticipated that all of the 1998 tax credits will increase the alternative minimum tax credit carry forward and will be applied against future tax years' regular tax liability.

The Company recognized favorable tax adjustments relating to prior year federal tax returns in the amount of \$4 million for 1998 and \$2.7 million for 1997. During 1997, the Company also recognized a \$6 million favorable adjustment to state income taxes representing the settlement of a California state audit and a favorable adjustment of \$3.3 million resulting from a tax refund from Union Pacific Corporation ("UPC").

UPC has informed the Company that all material deficiencies prior to 1986 have been settled with the Internal Revenue Service ("IRS"). UPC is negotiating with the IRS 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.

While the operations of the Company in Guatemala are subject to local income taxes, no liability has arisen in recent years, as sufficient unrecovered costs carried forward from previous years, have been available to offset current taxable income. Guatemalan tax benefits which can be carried forward indefinitely were \$59.5 million at December 31, 1998. All other carryforward benefits due to net operating losses are expected to be utilized in 1999.

In 1997, UPRI (formally Norcen), received a reassessment concerning the deductibility of certain expenses and foreign exchange losses claimed for income tax purposes during the period 1989 through 1993 in the amount of \$81.1 million. In spite of UPRI's disagreement and appeal, the reassessment was fully funded in 1997 and recorded as a deferred tax benefit. As a result of the Norcen Acquisition, the Company recorded a valuation allowance against this benefit as part of the purchase price allocation. The carryforward benefit, net of the tax valuation allowance, is approximately \$15.8 million. On March 8, 1999, the Company entered into an agreement with Canadian tax authorities to settle the claims out of court. Under the terms of the settlement, the Company will receive a refund of approximately \$50 million dollars.

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

10. Debt

The total debt of the Company is summarized below:

	Interest Rate	As of December 31,	
		1998	1997
		(Millions of dollars)	
Commercial Paper and Bankers Acceptances (Average of 5.98% at December 31, 1998)		\$2,351.9	\$ 663.1
Debentures due July 2, 2002	6.8%	250.0	—
Notes due May 15, 2005	6.50%	200.0	—
Debentures due May 15, 2006	7.375%	250.0	—
Notes due October 15, 2006	7.0%	200.0	200.0
Notes due May 15, 2008	6.75%	200.0	—
Debentures due July 2, 2008	7.8%	150.0	—
Debentures due May 15, 2018	7.05%	200.0	—
Debentures due October 15, 2026	7.5%	200.0	200.0
Debentures due May 15, 2028	7.15%	425.0	—
Debentures due November 1, 2096	7.5%	150.0	150.0
Capital lease obligations (Note 11)		17.4	—
Tax exempt revenue bond due 2012	4.25%	—	20.1
(Discount) Premium on notes and debentures		4.4	(2.6)
Total debt		4,598.7	1,230.6
Less: current portion		853.8	—
Total long-term debt		<u>\$3,744.9</u>	<u>\$1,230.6</u>

During the first quarter of 1998, in connection with the Norcen Acquisition, the Company issued commercial paper supported by a \$2.7 billion 364-day Competitive Advance/Revolving Credit Agreement (the "Norcen Acquisition Facility") and also assumed the outstanding debt of Norcen. The debt assumed includes 6.8% Debentures due July 2, 2002, in the aggregate principal amount of \$250 million, 7% Debentures due May 15, 2006, in the aggregate principal amount of \$250 million and 7.8% Debentures due July 2, 2008, in the aggregate principal amount of \$150 million, each of which have been unconditionally guaranteed by the Company. Additionally, the Company assumed \$351 million in bankers acceptances.

In October 1998, the Company replaced its eight existing facilities (the Norcen Acquisition Facility, its \$600 million and \$300 million revolving credit agreements and five Canadian facilities, which totaled approximately U.S. \$2.9 billion) with three new facilities totaling an aggregate of U.S. \$2.5 billion. These new facilities are comprised of a \$1.0 billion 364-day Competitive Advance/Revolving Credit Agreement (the "Bridge Facility"), a \$750 million 364-day Competitive Advance/Revolving Credit Agreement and a \$750 million Five-Year Competitive Advance/Revolving Credit Agreement (collectively the "Facilities"). Each of the Facilities contain a covenant stipulating that the ratio of consolidated debt to consolidated EBITDAX — the sum of operating income (before adjustments for income taxes, interest expense or extraordinary gains or losses), depreciation, depletion and amortization and exploration expenses — cannot exceed 3.25:1.00. This covenant replaced the consolidated debt to total capitalization ratio covenant applicable under previous facilities. The 1998 consolidated debt to consolidated EBITDAX covenant calculation uses pro forma EBITDAX results. The Company was in compliance with this covenant provision at year-end 1998.

The Bridge Facility also contains mandatory reduction provisions whereby it will be permanently reduced by seventy-five percent of the net proceeds from specified asset sales (certain identified exploration and production assets and the Company's GPM segment). At December 31, 1998, the Bridge Facility had not been reduced because none of the specified asset sales had occurred. The Facilities also place other restrictions

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

on the Company regarding the creation of liens, incurrence of additional indebtedness by subsidiaries, transactions with affiliates, sales of stock of UPRC and certain mergers, consolidations and asset sales.

Debt maturities through 2003, excluding capital leases, are \$851.9 million of commercial paper in 1999 and \$250 million of Debentures due July 2, 2002. At December 31, 1998, \$1.5 billion of commercial paper and bankers acceptances had been classified as long-term, supported by the \$750 million Five-Year and the \$750 million 364-day Competitive Advance/Revolving Credit Agreements. This classification reflects the Company's intent and ability to maintain these borrowings on a long-term basis through the issuance of additional commercial paper and/or new term financings.

The fair value of the Company's long-term debt, excluding commercial paper and bankers acceptances, debt discount/premium and capital lease obligations was approximately \$2,088 million at December 31, 1998 and \$580 million at December 31, 1997. The fair value was estimated using quoted market prices. These fair values were \$137 million less than the carrying values at December 31, 1998 and \$30 million more than the carrying value at December 31, 1997. The change in the fair value during 1998 resulted primarily from the deterioration in general market conditions for energy industry related fixed income securities and the reduction in the Company's long-term credit rating. As a result of the Norcen Acquisition, the Company recorded a \$31.5 million debt premium, representing the excess of the fair value over the carrying value of the debt acquired. The premium is being amortized over the life of the acquired debt.

The 2005 Notes, 2008 Notes, 2018 Debentures and 2028 Debentures will be redeemable as a whole or in part, at the option of the Company at any time. The redemption price is equal to the greater of (i) 100% of the principal amount of the Securities to be redeemed and (ii) the sum of the present values of the remaining scheduled payments thereon, discounted to the redemption date on a semi-annual basis at the Treasury Rate plus 15 basis points in the case of the 2005 Notes and the 2008 Notes, 20 basis points in the case of the 2018 Debentures and 25 basis points in the case of the 2028 Debentures plus, in each case, accrued interest on the principal amount being redeemed to the redemption date. There are no other notes and debentures redeemable prior to maturity. None of the Company's notes and debentures is subject to sinking fund requirements. At December 31, 1998, the Company had an effective shelf registration statement on file with the Securities and Exchange Commission that would permit the Company or certain identified subsidiaries to offer up to \$1.0 billion in debt and/or equity securities.

The Company utilizes letters of credit to support certain financing instruments, performance contracts and insurance policies. The fair value of the letters of credit at December 31, 1998 and 1997 was \$58.6 million and \$10.7 million, respectively.

The Company has guaranteed a portion of the OCI Wyoming, L.P. debt facility. At December 31, 1998, OCI Wyoming, L.P. had an outstanding debt facility balance of \$49 million, of which the Company has guaranteed \$24 million. The debt is carried as an investment in affiliate on the consolidated statement of financial position.

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

11. Lease Commitments

The Company leases several office buildings, certain production platforms and other property under operating leases. In 1998, the Company entered into a capital lease for furniture and walls in its Fort Worth offices. Future minimum lease payments for operating and capital leases with initial non-cancelable lease terms in excess of one year as of December 31, 1998, were as follows:

	As of December 31, 1998		
	Capital leases	Operating leases	Total
1999	\$ 2.8	\$ 50.8	\$ 53.6
2000	2.8	44.8	47.6
2001	2.8	45.3	48.1
2002	2.8	33.4	36.2
2003	2.8	31.8	34.6
Later years	7.2	10.9	18.1
Total future minimum lease payments	\$21.2	<u>\$217.0</u>	<u>\$238.2</u>
Less: amounts representing interest	(3.8)		
Present value of minimum capital lease obligations	<u>17.4</u>		
Less: Short-term portion of capital lease obligations	(1.9)		
Long-term portion of capital lease obligations	<u>\$15.5</u>		

Rent expense, net of sublease income, for operating leases with terms exceeding one month was \$59.8 million in 1998, \$19.2 million in 1997, and \$13.2 million in 1996. Sublease income for the next five years will be \$30.2 million in 1999, \$29.9 million in 2000, \$29.2 million in 2001, \$29.2 million in 2002, \$28.1 million in 2003 and \$0.3 million thereafter. Capital leases included in corporate fixed assets were \$17.4 at December 31, 1998.

12. Retirement Plans

The Company provides pension, health care and life insurance benefits to all eligible retirees in the U.S. and pension benefits to all eligible retirees in Canada. No such pension or other benefits are provided to employees of other foreign subsidiaries.

U.S. Pension Benefits. Pension benefits for U.S. employees are based on years of service and compensation during the last years of employment. Contributions to the plans are calculated on the Projected Unit Credit actuarial funding method and are not less than the minimum funding standards set forth in the Employees Retirement Income Security Act of 1974, as amended. The portion of the funded plan's assets held in fixed-income and short-term securities was approximately 32 percent and 34 percent as of December 31, 1998 and 1997, respectively, with the remainder primarily in equity securities.

Other U.S. Postretirement Benefits. Postretirement health and life insurance benefits are provided to all eligible U.S. retirees. The Company does not currently pre-fund health care and life insurance benefit costs.

Canadian Pension Benefits. Included in the Norcen Acquisition were Norcen's pension plans covering most Canadian employees. Benefits provided under the defined benefit plan are based on years of service and highest compensation over a specified number of consecutive years. The provisions under the defined benefit plan were modified to provide employees with a defined contribution plan option, which has been retroactively elected by substantially all active employees. Under the defined contribution plan, the Company matches a stated percentage of employee contributions to the plan. Both the defined benefit payments and the defined contribution company match obligation are paid from assets held in trust. The Company will make

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

contributions to the plans, if necessary, to maintain adequate assets in trust. Contributions are not expected to be necessary for several years.

The following pension credits and funded status are based on historical actuarial valuations.

	U.S. Pension Benefits		Other U.S. Benefits		Canadian Pension Benefits
	1998	1997	1998	1997	1998
	(Millions of dollars)				
Change in benefit obligation:					
Benefit obligation at beginning of year	\$202.6	\$183.9	\$42.9	\$45.1	\$ —
Acquisition	—	—	—	—	26.1
Service cost	6.1	5.5	1.0	0.8	0.1
Interest cost	14.3	13.3	3.0	3.3	1.4
Plan amendments	2.4	—	(5.4)	0.3	—
Actuarial gain (loss)	12.6	11.6	0.1	(3.6)	(0.2)
Benefits paid	(17.0)	(11.7)	(1.2)	(3.0)	(1.8)
Benefit obligation at end of year	<u>\$221.0</u>	<u>\$202.6</u>	<u>\$40.4</u>	<u>\$42.9</u>	<u>\$ 25.6</u>
Change in plan assets:					
Fair value of plan assets at beginning of year	\$240.9	\$221.3	\$ —	\$ —	\$ —
Acquisition	—	—	—	—	50.3
Actual return on plan assets	40.0	30.8	—	—	—
Employer contribution(a)	5.8	0.5	1.2	3.0	—
Benefits paid(b)	(17.0)	(11.7)	(1.2)	(3.0)	(2.6)
Fair value of plan assets at end of year	<u>\$269.7</u>	<u>\$240.9</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 47.7</u>
Plan assets (over) under benefit obligation	<u>\$(48.7)</u>	<u>\$(38.3)</u>	<u>\$40.4</u>	<u>\$42.9</u>	<u>\$(22.1)</u>
Unamortized net transition asset	15.8	17.9	—	—	—
Unrecognized prior service gain (cost)	(9.0)	(7.8)	8.0	3.4	—
Unrecognized net gain	<u>105.1</u>	<u>100.4</u>	<u>25.1</u>	<u>27.0</u>	<u>(1.9)</u>
Net amount recognized	<u>\$ 63.2</u>	<u>\$ 72.2</u>	<u>\$73.5</u>	<u>\$73.3</u>	<u>\$(24.0)</u>

(a) Represents payments relating to unfunded plans. The Company periodically settles a portion of the unfunded supplemental plans benefit obligations through the purchase of annuities.

(b) \$0.8 million of Canadian pension benefits paid represent payments to fund the defined contribution Company match.

	U.S. Pension Benefits		Other U.S. Benefits		Canadian Pension Benefits
	1998	1997	1998	1997	1998
	(Millions of dollars)				

Amounts recognized in the Statement of Financial

Position consist of:

Prepaid benefit cost	\$ —	\$ —	\$ —	\$ —	\$(24.0)
Accrued benefit liability	72.0	77.0	73.5	73.3	—
Intangible asset	(3.9)	(3.8)	—	—	—
Accumulated other comprehensive income	(4.9)	(1.0)	—	—	—
Net amount recognized	<u>\$63.2</u>	<u>\$72.2</u>	<u>\$73.5</u>	<u>\$73.3</u>	<u>\$(24.0)</u>

Weighted-average assumptions as of December 31

Discount rate	7.0%	7.25%	7.0%	7.25%	6.5%
Expected return on plan assets	9.0%	9.0%	—	—	6.5%
Rate of compensation increase	5.0%	5.25%	—	—	5.0%

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

For measurement purposes, a 7.8 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for 1998. The rate was assumed to gradually decrease to 5 percent in 2005 and remain at that level thereafter.

	U.S. Pension Benefits			Other U.S. Benefits			Canadian Pension
	1998	1997	1996	1998	1997	1996	1998
	(Millions of dollars)						
Service cost-benefits earned during the period	\$ 6.1	\$ 5.5	\$ 4.4	\$ 1.0	\$ 0.8	\$ 1.0	\$ 0.1
Interest cost	14.3	13.4	13.3	3.0	3.3	3.4	1.4
Expected return on plan assets	(18.6)	(17.1)	(19.6)	—	—	—	(2.7)
Amortization of net transition asset	(2.1)	(2.0)	(2.1)	—	—	—	—
Amortization of unrecognized prior service gain (cost) ..	1.2	1.2	1.2	(0.8)	(0.8)	(0.8)	—
Amortization of unrecognized net gain	(4.1)	(4.9)	(2.8)	(1.7)	(1.6)	(1.5)	—
(Benefit) charge to operations	<u>\$ (3.2)</u>	<u>\$ (3.9)</u>	<u>\$ (5.6)</u>	<u>\$ 1.5</u>	<u>\$ 1.7</u>	<u>\$ 2.1</u>	<u>\$ (1.2)</u>
Other comprehensive (income) loss	<u>\$ 3.9</u>	<u>\$ 1.0</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>

Assumed health care cost trend rates have a significant effect on the amounts reported for the postretirement benefit plan. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1 Percentage Point increase	1 Percentage Point decrease
	(Millions of dollars)	
Effect on total of service and interest cost components	\$0.4	\$ (0.4)
Effect on postretirement benefit obligation	3.6	(3.2)

13. Environmental Exposure

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 these 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.

The Company generates and disposes of hazardous and nonhazardous waste in its current and former operations and is subject to increasingly stringent federal, state, local provincial and international 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 violation 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 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 \$55.0 million for future site preparation costs was established (\$90.7 million in total remaining at December 31, 1998) and is categorized as other current

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

liabilities and long-term liabilities (see Note 15). The majority of cash outlays for these liabilities are expected to occur over the next 5 years.

As of December 31, 1998 and 1997, liabilities totaling \$74.7 million and \$73.3 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 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 million for the obligation to participate in the remediation of the Wilmington field properties. Cost estimates were based on information available for each site, financial viability of other Potentially Responsible Parties ("PRPs") and existing technology, laws and regulations. The Company believes that it has accrued adequately for its share of costs at sites subject to joint and several liabilities. 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 is also involved in reducing emissions, spills and migration of hazardous materials. Remediation of identified sites and control of environmental exposures required spending of \$17 million in 1998 and \$14.7 million in 1997. In 1999, the Company anticipates spending a total of \$17 million for remediation, control and prevention, including \$8 million relating to the Wilmington properties. The majority of the December 31, 1998 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

The Company is a party to several long-term firm gas transportation agreements that support the gas marketing program and GPM segment being sold to Duke. The largest agreements are with Kern River Gas Transportation Company ("Kern River"), Texas Gas Transmission Corporation and Pacific Gas Transmission. Most of the GPM firm long-term transportation contracts are to be transferred to Duke as part of the GPM sale. The Company will keep the Kern River contract and assign the transportation rights to Duke through May 31, 2007. In addition, as part of the GPM sale, the Company has agreed to keep Duke whole if the transportation market value falls below the contract transportation rates and Duke will pay the Company if the market value exceeds the contract transportation rates. This keep-whole agreement will be in effect for the ten-year period subsequent to the closing of the sale. A detailed explanation of the three major firm transportation contracts and keep-whole commitment follows.

The Kern River firm transportation contract expires May 31, 2007. Under the transportation agreement, the Company 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. The current transportation rate is \$0.69 per Mcf; however, Kern River is charging \$0.67 per Mcf pursuant to a rate in effect through at least 2002. 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, the Company is obligated to pay all of the fixed costs included in the transportation rate whether or not the Company actually uses Kern River's pipeline to transport gas. Those fixed costs presently amount to \$0.61 per Mcf. The Company 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 system beginning in 2002.

The Company is a party to a long-term firm transportation agreement with Texas Gas Transmission Corporation that expires October 31, 2008. Under the transportation agreement the Company has the rights to

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

transport 90 MMcf of gas from Carthage, Texas to Lebanon, Ohio. The Company is obligated to pay a fixed transportation rate of \$0.331 per MMBtu regardless of the volumes transported under the agreement.

The Company is party to a long-term firm transportation agreement with Pacific Gas Transmission ("PGT") that expires October 31, 2023. Under the transportation agreement, the Company has the right to transport 25 MMcf of gas from Kingsgate, British Columbia to the California/Oregon border. The Company is obligated to pay a fixed transportation rate of \$0.328 per MMBtu regardless of the volumes transported under the agreement. However, the Company has third-party agreements that reimburse the Company for 90 percent of the firm transportation cost until October 31, 2002. As part of the third-party agreements, the Company assigned 50 percent of the firm transportation capacity.

During 1998, as a result of the Norcen Acquisition, the Company assumed responsibility for additional long-term firm transportation agreements with PGT to transport gas from Kingsgate, British Columbia to the California/Oregon border. Under the transportation agreements, the Company has the rights to transport 106 MMBtu per day of which 47 MMBtu per day will expire on October 31, 2007 and the balance of the contract commitment will expire on October 31, 2023. The Company does have a third party agreement that recovers all the transportation cost for 20 MMBtu per day through June 30, 2011.

Included in the balance sheet of the Company is a reserve for the fair value of the difference between the total rate under the firm transportation agreements and estimated market rates through March 2009. The reserve, which is included in current and other long-term liabilities, was \$88.7 million at December 31, 1998.

In 1997, the Company entered into a letter of intent to negotiate a \$150 million five year agreement with Noble Drilling (U.S.) Inc. beginning in November 1999, for the services of a semisubmersible drilling rig designed for operations in water depths up to 5,000 feet. Under the letter of intent, if a final agreement is negotiated, the Company would share 50 percent of the total rig commitment with another major oil and gas company.

In the last twelve years, the Company has disposed of significant pipeline, refining and producing property assets, including the sale of its 37.5 percent 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 (50 percent sold in March 1987 and the balance in January 1989), Wilmington field (March 1994) and the 1998 deleveraging program sales. 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 certain 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

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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	
	1998	1997
	(Millions of dollars)	
Firm transportation liabilities	\$ 71.2	\$ 8.5
Abandonment provision	58.1	7.7
Environmental	57.2	56.5
Wilmington field site preparation	53.7	53.7
Equity investment — Black Butte	37.8	26.6
Executive incentive compensation	25.9	18.9
Litigation and contingencies	23.4	25.9
Deferred revenue	9.4	5.4
Other	51.4	16.1
Total other long-term liabilities	<u>\$388.1</u>	<u>\$219.3</u>

16. Shareholders' Equity

Stock Option and Retention Stock Plans. Pursuant to the Company's stock option and retention stock plans, 5,999,439 and 8,785,684 shares of Common Stock were available for grant to employees and directors at December 31, 1998 and 1997, respectively. Shares may either be granted as options to purchase Common Stock or as awards of retention stock. Options to purchase Common Stock under the plans are generally granted with an exercise price equal to the fair market value at the date of grant and are exercisable for a period of up to 10 years from grant date. Option grants have been made to directors, officers and employees and vest over periods up to 10 years from the grant date.

Retention stock is awarded under the plans to eligible employees, subject to forfeiture if employment terminates during the prescribed retention period, generally one to five years from grant. Grants of retention stock made in 1994 also required that designated Company stock prices be met to be exercisable. These performance conditions were achieved during 1996.

To become exercisable, 933,000 options from the 1998 stock option grant require that designated Company stock prices be met.

During 1995, UPC non-qualified stock options and certain UPC Incentive Stock Options ("ISOs"), as well as UPC retention shares held by officers and employees of the Company, were converted into non-qualified Company stock options, ISOs and retention shares, respectively. The converted options and retention shares retain the same exercise dates and vesting requirements as the UPC options and retention shares for which they were exchanged.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	<u>Company Shares</u>	<u>Weighted Average Exercise Price</u>
Stock options:		
Balance at December 31, 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	<u>(288,698)</u>	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	<u>(91,615)</u>	24.75
Balance at December 31, 1997	5,884,486	21.20
Granted	2,951,375	17.01
Exercised	(57,487)	9.49
Expired/surrendered	<u>(207,635)</u>	15.18
Balance at December 31, 1998	<u>8,570,739</u>	19.84
Exercisable December 31:		
1996	3,035,905	\$16.81
1997	3,853,035	18.72
1998	4,496,736	19.93
	<u>Regular</u>	<u>Performance</u>
Retention stock:		
Balance at December 31, 1995	423,465	324,796
Awarded	604,530	—
Conversion of UPC retention stock	2,610	18,698 (a)
Achievement of performance conditions	301,066	(301,066)
Vested	(124,733)	—
Forfeited, surrendered and other	<u>(2,376)</u>	<u>(42,428) (a)</u>
Unvested at December 31, 1996	1,204,562	—
Awarded	209,114	—
Vested	(376,295)	—
Forfeited, surrendered and other	<u>(34,693)</u>	—
Unvested at December 31, 1997	1,002,688	—
Awarded	45,580	—
Vested	(531,951)	—
Forfeited, surrendered and other	<u>(19,200)</u>	—
Unvested at December 31, 1998	<u>497,117</u>	—

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	Options(b)	Retention Shares(c)
1996	\$ 9.15	\$ 27.81
1997	8.74	25.63
1998	7.00	17.01

(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:

	1998	1997	1996
Expected volatility	51%	28%	26%
Expected dividend yield	2.25%	0.8%	0.7%
Expected option term	5 years	4 years	5 years
Risk-free rate of return	4.6%	5.7%	6.3%

(c) Represents market value on grant date.

Options to purchase Common Stock were as follows:

Range of Exercise Prices	As of December 31, 1998				
	Options Outstanding			Options Exercisable	
	Number of Shares	Weighted Average Years to Expiration	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
\$10.44-\$15.29	1,909,265	5.01	\$14.72	1,811,515	\$14.86
\$17.04-\$20.94	3,940,273	4.56	17.62	1,222,298	18.89
\$22.50-\$29.44	2,721,201	7.32	26.17	1,462,923	27.05
\$10.44-\$29.44	<u>8,570,739</u>	5.53	19.84	<u>4,496,736</u>	19.93

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. 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. Compensation cost recognized relating to retention stock was \$6.5 million, \$11.6 million and \$7.4 million in 1998, 1997 and 1996, 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 \$13.8 million in 1998, \$8 million in 1997 and \$3 million in 1996. Basic and diluted earnings per share would have been reduced by \$0.06 per share in 1998, \$0.03 per share in 1997 and \$0.01 per share in 1996.

Earnings Per Share. Basic earnings per share ("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

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

common stock were exercised or converted into common stock. The reconciliation between basic earnings per share ("EPS") and diluted earnings per share for the years ended December 31 is as follows:

	For the Years Ended December 31,		
	Income (Millions of dollars)	Average Shares (Millions)	Per Share
1998			
Basic EPS			
Net loss	\$ (898.7)	247.7	\$ (3.63)
Less: loss from discontinued operations	(15.6)	—	(0.06)
Loss from continuing operations available to shareholders	(883.1)		(3.57)
Effect of dilutive options	—	— (a)	—
Diluted EPS			
Loss from continuing operations available to Common shareholders	<u>\$ (883.1)</u>	<u>247.7</u>	<u>\$ (3.57)</u>
1997			
Basic EPS			
Net Income	\$ 333.0	250.1	\$ 1.33
Less: income from discontinued operations	29.9	—	0.12
Income from continuing operations available to shareholders ..	303.1	250.1	1.21
Effect of Dilutive options	—	0.8	—
Diluted EPS			
Income from continuing operations available to Common shareholders plus assumed conversion	<u>\$ 303.1</u>	<u>250.9</u>	<u>\$ 1.21</u>
1996			
Basic EPS			
Net Income	\$ 320.8	249.2	\$ 1.29
Less: income from discontinued operations	67.1	—	0.27
Income from continuing operations available to shareholders ..	253.7		1.02
Effect of dilutive options	—	0.9	(0.01)
Diluted EPS			
Income from continuing operations available to Common shareholders plus assumed conversion	<u>\$ 253.7</u>	<u>250.1</u>	<u>\$ 1.01</u>

(a) 0.5 million average shares of options outstanding, as discussed above, have been excluded from the 1998 calculation of diluted earnings per share because to do so would have been antidilutive.

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 domestic 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 \$7.5 million annually, and will be funded with dividends paid on the unallocated

UNION PACIFIC RESOURCES GROUP INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

ESOP Shares and with cash contributions from the Company. Principal or interest prepayments may be made to ensure that the Company's minimum matching obligation is met.

Shares held by the ESOP will be included in the computation of earnings per share as such ESOP Shares are released from collateral. 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.

As of December 31, 1998, allocated and unallocated shares in the ESOP were 483,216 and 3,216,784, respectively. As of December 31, 1997, allocated and unallocated shares were 197,395 and 3,502,605, respectively. The fair value of unallocated ESOP shares at December 31, 1998 and 1997 is \$29.2 million and \$85.8 million, respectively. During 1998 and 1997, compensation cost related to the allocation of ESOP shares to participants' accounts was \$6.3 million and \$5.3 million, respectively.

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 percent 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 percent 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 percent or more of the Company's outstanding Common Stock.

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

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

In 1998, the Company announced a program to repurchase up to \$50 million of its Common Stock in 1999. Under this program, during 1998 and 1997, the Company repurchased 837,500 and 2,013,400 shares at a cost of \$18.6 million and \$49.9 million, respectively.

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

Comprehensive Income. The Company's comprehensive income is as follows:

	<u>Before-Tax Amount</u>	<u>Tax Benefit</u>	<u>Net-of-Tax Amount</u>
	(Millions of dollars)		
Foreign currency translation adjustment	\$(149.6)	\$82.5	\$(67.1)
Minimum pension liability adjustment	<u>(3.9)</u>	<u>—</u>	<u>(3.9)</u>
Other comprehensive income	<u>\$(153.5)</u>	<u>\$82.5</u>	<u>\$(71.0)</u>

17. Other Income (Expense) — Net

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

	<u>For the Years Ended</u>		
	<u>1998</u>	<u>1997</u>	<u>1996</u>
	(Millions of dollars)		
Insurance settlement proceeds	\$ 3.3	\$ 10.0	\$ —
Excess reserve reductions	—	23.0	1.8
Gain on sales of assets	—	7.2	4.5
Pennzoil Company acquisition costs(a)	(2.0)	(17.8)	—
UPC Spin-off charges	—	—	(5.6)
Interest rate lock cost (Note 5)	(14.3)	—	—
Foreign currency loss — net (Note 5)	(35.5)	—	—
Other — net	<u>3.2</u>	<u>2.1</u>	<u>(4.2)</u>
Total other income (expense) — net	<u>\$(45.3)</u>	<u>\$ 24.5</u>	<u>\$(3.5)</u>

(a) Related to cost incurred with the unsuccessful takeover attempt of Pennzoil Company.

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.

	United States	Canada	Other International	Worldwide
Natural gas (Bcf) (b): 1996				
Beginning of year	2,099	75	—	2,174
Revisions of previous estimates	48	(2)	—	46
Extensions, discoveries and other additions	469	12	—	481
Purchases of reserves-in-place	52	—	—	52
Sales of reserves-in-place	(6)	—	—	(6)
Production	(362)	(7)	—	(369)
Total proved, end of year	<u>2,300</u>	<u>78</u>	<u>—</u>	<u>2,378</u>
Proved developed reserves	<u>2,055</u>	<u>70</u>	<u>—</u>	<u>2,125</u>
Natural gas (Bcf) (b): 1997				
Beginning of year	2,300	78	—	2,378
Revisions of previous estimates	13	(4)	—	9
Extensions, discoveries and other additions	574	14	—	588
Purchases of reserves-in-place	55	—	—	55
Sales of reserves-in-place	(3)	—	—	(3)
Production	(401)	(6)	—	(407)
Total proved, end of year	<u>2,538</u>	<u>82</u>	<u>—</u>	<u>2,620</u>
Proved developed reserves	<u>2,157</u>	<u>60</u>	<u>—</u>	<u>2,217</u>
Natural gas (Bcf) (b): 1998				
Beginning of year	2,538	82	—	2,620
Revisions of previous estimates	82	13	—	95
Extensions, discoveries and other additions	277	101	10	388
Purchases of reserves-in-place	210	998	37	1,245
Sales of reserves-in-place	(285)	(97)	—	(382)
Production	(421)	(103)	(3)	(527)
Total proved, end of year	<u>2,401</u>	<u>994</u>	<u>44</u>	<u>3,439</u>
Proved developed reserves	<u>2,079</u>	<u>854</u>	<u>35</u>	<u>2,968</u>
Natural gas liquids (MMBbl) (b): 1996				
Beginning of year	93	7	—	100
Revisions of previous estimates	12	—	—	12
Extensions, discoveries and other additions	9	—	—	9
Purchases of reserves-in-place	—	—	—	—
Sales of reserves-in-place	—	—	—	—
Production	(13)	(1)	—	(14)
Total proved, end of year	<u>101</u>	<u>6</u>	<u>—</u>	<u>107</u>
Proved developed reserves	<u>91</u>	<u>7</u>	<u>—</u>	<u>98</u>

	United States	Canada	Other International	Worldwide
Natural gas liquids (MMBbl) (b): 1997				
Beginning of year	101	6	—	107
Revisions of previous estimates	1	1	—	2
Extensions, discoveries and other additions	21	1	—	22
Purchases of reserves-in-place	1	—	—	1
Sales of reserves-in-place	—	—	—	—
Production	(13)	(1)	—	(14)
Total proved, end of year	<u>111</u>	<u>7</u>	<u>—</u>	<u>118</u>
Proved developed reserves	<u>96</u>	<u>7</u>	<u>—</u>	<u>103</u>
Natural gas liquids (MMBbl): 1998				
Beginning of year	111	7	—	118
Revisions of previous estimates	(10)	5	—	(5)
Extensions, discoveries and other additions	1	1	—	2
Purchases of reserves-in-place	3	18	—	21
Sales of reserves-in-place	(29)	(4)	—	(33)
Production	(10)	(2)	—	(12)
Total proved, end of year	<u>66</u>	<u>25</u>	<u>—</u>	<u>91</u>
Proved developed reserves	<u>55</u>	<u>24</u>	<u>—</u>	<u>79</u>
Crude oil, including condensate (MMBbl): 1996				
Beginning of year	74	7	3	84
Revisions of previous estimates	(1)	—	—	(1)
Extensions, discoveries and other additions	14	1	—	15
Purchases of reserves-in-place	4	—	—	4
Sales of reserves-in-place	(2)	—	—	(2)
Production	(17)	(1)	(1)	(19)
Total proved, end of year	<u>72</u>	<u>7</u>	<u>2</u>	<u>81</u>
Proved developed reserves	<u>66</u>	<u>6</u>	<u>2</u>	<u>74</u>
Crude oil, including condensate (MMBbl): 1997				
Beginning of year	72	7	2	81
Revisions of previous estimates	5	—	—	5
Extensions, discoveries and other additions	57	—	—	57
Purchases of reserves-in-place	6	—	—	6
Sales of reserves-in-place	—	—	—	—
Production	(18)	(1)	(1)	(20)
Total proved, end of year	<u>122</u>	<u>6</u>	<u>1</u>	<u>129</u>
Proved developed reserves	<u>87</u>	<u>6</u>	<u>1</u>	<u>94</u>
Crude oil, including condensate (MMBbl): 1998				
Beginning of year	122	6	1	129
Revisions of previous estimates	(7)	(4)	2	(9)
Extensions, discoveries and other additions	13	5	16	34
Purchases of reserves-in-place	14	115	143	272
Sales of reserves-in-place	(7)	(13)	—	(20)
Production	(22)	(13)	(15)	(50)
Total proved, end of year	<u>113</u>	<u>96</u>	<u>147</u>	<u>356</u>
Proved developed reserves	<u>81</u>	<u>66</u>	<u>105</u>	<u>252</u>

	United States	Canada	Other International	Worldwide
Proved reserves equivalent, end of 1996 (Bcfe) (a)				
Natural gas	2,300	78	—	2,378
Natural gas liquids	603	42	—	645
Crude oil, including condensate	435	39	10	484
Total proved	<u>3,338</u>	<u>159</u>	<u>10</u>	<u>3,507</u>
Proved developed reserves	<u>2,995</u>	<u>151</u>	<u>10</u>	<u>3,156</u>
Proved reserves equivalent, end of 1997 (Bcfe) (a)				
Natural gas	2,538	82	—	2,620
Natural gas liquids	665	42	—	707
Crude oil, including condensate	730	37	6	773
Total proved	<u>3,933</u>	<u>161</u>	<u>6</u>	<u>4,100</u>
Proved developed reserves	<u>3,255</u>	<u>139</u>	<u>6</u>	<u>3,400</u>
Proved reserves equivalent, end of 1998 (Bcfe) (a)				
Natural gas	2,401	994	44	3,439
Natural gas liquids	389	159	—	548
Crude oil, including condensate	676	578	883	2,137
Total proved	<u>3,466</u>	<u>1,731</u>	<u>927</u>	<u>6,124</u>
Proved developed reserves	<u>2,897</u>	<u>1,392</u>	<u>667</u>	<u>4,956</u>

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

(b) Reserves at the end of 1997 and 1996 include the plant share of equity gas processed (natural gas and natural gas liquids, as appropriate, earned by gas processing facilities through the processing of the Company's equity production.)

B. Drilling Activity

Drilling activity is summarized as follows:

	<u>United States</u>	<u>Canada</u>	<u>Other International</u>	<u>Worldwide</u>
For the year ended December 31, 1998(a)				
Gross wells	318	273	45	636
Gross productive wells	290	243	42	575
Net wells:				
Exploration	18	45	1	64
Development	<u>248</u>	<u>115</u>	<u>22</u>	<u>385</u>
Total net wells	<u>266</u>	<u>160</u>	<u>23</u>	<u>449</u>
Net productive wells:				
Exploration	13	32	1	46
Development	<u>232</u>	<u>106</u>	<u>20</u>	<u>358</u>
Total net productive wells	<u>245</u>	<u>138</u>	<u>21</u>	<u>404</u>
For the year ended December 31, 1997				
Gross wells	811	6	—	817
Gross productive wells	714	6	—	720
Net wells:				
Exploration	41	—	—	41
Development	<u>521</u>	<u>4</u>	<u>—</u>	<u>525</u>
Total net wells	<u>562</u>	<u>4</u>	<u>—</u>	<u>566</u>
Net productive wells:				
Exploration	19	—	—	19
Development	<u>475</u>	<u>4</u>	<u>—</u>	<u>479</u>
Total net productive wells	<u>494</u>	<u>4</u>	<u>—</u>	<u>498</u>
For the year ended December 31, 1996				
Gross wells	650	5	—	655
Gross productive wells	586	5	—	591
Net wells:				
Exploration	27	—	—	27
Development	<u>436</u>	<u>3</u>	<u>—</u>	<u>439</u>
Total net wells	<u>463</u>	<u>3</u>	<u>—</u>	<u>466</u>
Net productive wells:				
Exploration	9	—	—	9
Development	<u>410</u>	<u>3</u>	<u>—</u>	<u>413</u>
Total net productive wells	<u>419</u>	<u>3</u>	<u>—</u>	<u>422</u>

(a) In addition, at December 31, 1998, 10 gross wells (5 net wells) were in the process of being drilled.

C. Average Sales Price and Cost

The average producing properties sales prices and costs are set forth below:

	As of Years Ended December 31,		
	1998	1997	1996
Natural gas sales price (per Mcf)			
United States	\$ 1.84	\$ 2.01	\$ 1.87
Canada	1.35	1.58	0.81
Other international	1.39	—	—
Total	1.74	2.00	1.85
Natural gas liquids sales price (per Bbl)			
United States	\$ 8.14	\$11.57	\$11.80
Canada	6.12	5.41	6.79
Other international	—	—	—
Total	7.88	11.23	11.48
Crude oil sales price (per Bbl)			
United States	\$13.23	\$18.37	\$18.93
Canada	8.55	19.85	20.59
Other international	8.09	16.90	15.51
Total	10.48	18.36	18.84
Production cost (per Mcf)			
United States	\$ 0.51	\$ 0.51	\$ 0.49
Canada	0.41	0.29	0.44
Other international	0.54	0.77	0.72
Total production cost	0.49	0.51	0.49

D. Average Daily Production and Sales Volume

The average producing properties daily production and sales volume are set forth below:

	As of Years Ended December 31,		
	1998	1997	1996
Natural gas (MMcfd)			
United States	1,152.8	1,090.9	972.4
Canada	281.2	17.6	16.5
Other international	7.1	—	—
Total natural gas	<u>1,441.1</u>	<u>1,108.5</u>	<u>988.9</u>
Natural gas liquids (MBbld)			
United States	28.8	30.0	28.6
Canada	4.3	1.7	1.9
Other international	—	—	—
Total natural gas liquids	<u>33.1</u>	<u>31.7</u>	<u>30.5</u>
Crude oil (MBbld)			
United States	61.0	49.2	46.7
Canada	35.4	1.7	1.7
Other international	41.5	2.0	2.2
Total crude oil	<u>137.9</u>	<u>52.9</u>	<u>50.6</u>
Total producing properties (MMcfd)			
United States	1,692.0	1,565.8	1,423.8
Canada	519.3	38.3	38.3
Other international	255.7	11.6	13.2
Total producing properties	<u>2,467.0</u>	<u>1,615.7</u>	<u>1,475.3</u>

E. Acreage and Wells

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

	As of December 31,			
	United States	Canada	Other International	Worldwide
	(Thousands of acres)			
1998				
Gross developed	2,460	1,657	548	4,665
Net developed	1,493	958	135	2,586
Gross undeveloped	3,629	5,613	5,771	15,013
Net undeveloped	2,469	2,185	3,194	7,848
1997				
Gross developed	2,200	34	83	2,317
Net developed	1,528	20	21	1,569
Gross undeveloped	3,836	240	—	4,076
Net undeveloped	2,759	150	—	2,909

Productive oil and gas wells are as follows:

	As of December 31, 1998	
	Oil	Gas
	(Wells)	
Gross(b)	4,446	9,504
Net	3,160	7,323

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

(b) Approximately 2,404 are multiple completions, 2,183 of which are gas wells.

F. Capitalized Exploration and Production Costs

Capitalized exploration and production costs are as follows:

	United States	Other International		Worldwide
		Canada	(Millions of dollars)	
1998				
Proved properties	\$ 1,184.9	\$ 459.7	\$ 251.4	\$ 1,896.0
Unproved properties	396.8	389.2	455.5	1,241.5
Wells and related equipment	4,739.5	1,838.6	1,005.7	7,583.8
Uncompleted wells and equipment	142.7	—	—	142.7
Gross capitalized costs	6,463.9	2,687.5	1,712.6	10,864.0
Accumulated depreciation, depletion and amortization	(3,603.2)	(833.5)	(438.5)	(4,875.2)
Net capitalized costs	<u>\$ 2,860.7</u>	<u>\$1,854.0</u>	<u>\$1,274.1</u>	<u>\$ 5,988.8</u>
1997				
Proved properties	\$ 988.9	\$ 3.6	\$ 0.5	\$ 993.0
Unproved properties	438.6	10.9	—	449.5
Wells and related equipment	4,205.0	121.5	29.7	4,356.2
Uncompleted wells and equipment	305.0	—	—	305.0
Gross capitalized costs	5,937.5	136.0	30.2	6,103.7
Accumulated depreciation, depletion and amortization	(3,210.7)	(46.1)	(19.8)	(3,276.6)
Net capitalized costs	<u>\$ 2,726.8</u>	<u>\$ 89.9</u>	<u>\$ 10.4</u>	<u>\$ 2,827.1</u>

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:

	<u>United States</u>	<u>Canada</u>	<u>Other International</u>	<u>Worldwide</u>
		(Millions of dollars)		
1998				
Costs incurred:				
Proved acreage	\$ 424.4	\$1,733.7	\$ 744.7	\$2,902.8
Unproved acreage	45.5	279.1	312.2	636.8
Exploration costs(a)	195.9	43.8	29.5	269.2
Development costs	506.3	136.5	107.8	750.6
Total costs incurred(b)	<u>\$1,172.1</u>	<u>\$2,193.1</u>	<u>\$1,194.2</u>	<u>\$4,559.4</u>
1997				
Costs incurred:				
Proved acreage	\$ 130.6	\$ —	\$ —	\$ 130.6
Unproved acreage	199.7	1.0	—	200.7
Exploration costs(a)	231.9	5.0	—	236.9
Development costs	617.8	4.0	—	621.8
Total costs incurred(b)	<u>\$1,180.0</u>	<u>\$ 10.0</u>	<u>\$ —</u>	<u>\$1,190.0</u>
1996				
Costs incurred:				
Proved acreage	\$ 85.7	\$ —	\$ —	\$ 85.7
Unproved acreage	149.1	0.7	—	149.8
Exploration costs(a)	112.2	2.4	—	114.6
Development costs	426.7	2.8	—	429.5
Total costs incurred(b)	<u>\$ 773.7</u>	<u>\$ 5.9</u>	<u>\$ —</u>	<u>\$ 779.6</u>

(a) Includes allocated exploration overhead costs of \$24.2 million in 1998, \$23.5 million in 1997 and \$22.5 million in 1996, and delay rentals of \$12.3 million in 1998, \$14.8 million in 1997 and \$4.4 million in 1996.

(b) Excludes capital expenditures relating to discontinued operations of \$143.8 million in 1998, \$343.3 million in 1997 and \$107.3 million in 1996.

H. Results of Operations for Producing Activities:(a)

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

	<u>United States</u>	<u>Canada</u>	<u>Other International</u>	<u>Worldwide</u>
		(Millions of dollars)		
For the year ended December 31, 1998				
Revenues	\$ 1,314.6	\$ 259.2	\$ 126.1	\$ 1,699.9
Production costs	(317.0)	(77.3)	(50.0)	(444.3)
Exploration expenses	(267.4)	(25.3)	(46.3)	(339.0)
Depreciation, depletion and amortization	(816.2)	(915.3)	(384.3)	(2,115.8)
Total costs	<u>(1,400.6)</u>	<u>(1,017.9)</u>	<u>(480.6)</u>	<u>(2,899.1)</u>
Pretax results	(86.0)	(758.7)	(354.5)	(1,199.2)
Income taxes (benefit)	(48.3)	(337.7)	(95.0)	(481.0)
Results of operations	<u>\$ (37.7)</u>	<u>\$ (421.0)</u>	<u>\$ (259.5)</u>	<u>\$ (718.2)</u>

	United States	Canada	Other International	Worldwide
		(Millions of dollars)		
For the year ended December 31, 1997				
Revenues	\$ 1,337.3	\$ 28.9	\$ 12.0	\$ 1,378.2
Production costs	(293.4)	(4.1)	(3.3)	(300.8)
Exploration expenses	(197.6)	(4.4)	(2.7)	(204.7)
Depreciation, depletion and amortization	(481.7)	(10.2)	(7.4)	(499.3)
Total costs	(972.7)	(18.7)	(13.4)	(1,004.8)
Pretax results	364.6	10.2	(1.4)	373.4
Income taxes	108.9	—	—	108.9
Results of operations	<u>\$ 255.7</u>	<u>\$ 10.2</u>	<u>\$ (1.4)</u>	<u>\$ 264.5</u>
For the year ended December 31, 1996				
Revenues	\$ 1,204.5	\$ 23.3	\$ 12.5	\$ 1,240.3
Production costs	(253.6)	(6.1)	(3.5)	(263.2)
Exploration expenses	(127.5)	(3.5)	(13.6)	(144.6)
Depreciation, depletion and amortization	(459.8)	(5.9)	(7.7)	(473.4)
Total costs	(840.9)	(15.5)	(24.8)	(881.2)
Pretax results	363.6	7.8	(12.3)	359.1
Income taxes	111.4	—	—	111.4
Results of operations	<u>\$ 252.2</u>	<u>\$ 7.8</u>	<u>\$ (12.3)</u>	<u>\$ 247.7</u>

(a) Gathering, processing and marketing results, general and administrative expenses, other income/expense and interest costs have been excluded in computing these results of operations. Revenues include net gains from sales of assets of \$139.6 million in 1998, \$18.3 million in 1997 and \$3.9 million in 1996. Depreciation, depletion and amortization includes asset impairments of \$1.2 billion in 1998, \$20.2 million in 1997 and \$34.4 million in 1996.

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

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

	United States	Canada	Other International	Worldwide
		(Millions of dollars)		
As of December 31, 1998				
Future cash inflows from sales of oil and gas	\$ 6,210	\$2,642	\$1,128	\$ 9,980
Future production and development costs.....	(1,619)	(998)	(641)	(3,258)
Future income taxes	(942)	(536)	(55)	(1,533)
Future net cash flows	3,649	1,108	432	5,189
10% annual discount	(1,394)	(405)	(165)	(1,964)
Standardized measure of discounted future net cash flows	<u>\$ 2,255</u>	<u>\$ 703</u>	<u>\$ 267</u>	<u>\$ 3,225</u>
As of December 31, 1997				
Future cash inflows from sales of oil and gas.....	\$ 8,822	\$ 355	\$ 15	\$ 9,192
Future production and development costs.....	(2,032)	(55)	(4)	(2,091)
Future income taxes	(1,953)	(86)	(4)	(2,043)
Future net cash flows	4,837	214	7	5,058
10% annual discount	(1,926)	(85)	(1)	(2,012)
Standardized measure of discounted future net cash flows	<u>\$ 2,911</u>	<u>\$ 129</u>	<u>\$ 6</u>	<u>\$ 3,046</u>

	<u>United States</u>	<u>Canada</u>	<u>Other International</u>	<u>Worldwide</u>
	(Millions of dollars)			
As of December 31, 1996				
Future cash inflows from sales of oil and gas.....	\$11,569	\$ 349	\$ 28	\$11,946
Future production and development costs.....	(1,896)	(111)	(6)	(2,013)
Future income taxes	(2,952)	(73)	(7)	(3,032)
Future net cash flows	6,721	165	15	6,901
10% annual discount	(2,590)	(70)	(2)	(2,662)
Standardized measure of discounted future net cash flows	<u>\$ 4,131</u>	<u>\$ 95</u>	<u>\$ 13</u>	<u>\$ 4,239</u>

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

	<u>As of December 31,</u>		
	<u>1998</u>	<u>1997</u>	<u>1996</u>
	(Millions of dollars)		
Beginning of year	\$ 3,046	\$ 4,239	\$ 1,871
Changes due to current year operations:			
Additions and discoveries less related production and other costs	438	1,000	1,135
Sales of oil and gas — net of production costs	(1,160)	(1,078)	(961)
Development costs	751	622	430
Purchases of reserves-in-place	1,712	125	181
Sales of reserves-in-place	(245)	(4)	(48)
Changes due to revisions in:			
Price	(1,110)	(2,452)	2,763
Development costs	(911)	(427)	(269)
Quantity estimates	34	87	28
Income taxes	232	639	(1,063)
Other	38	(289)	(69)
Discount accretion	400	584	241
End of year	<u>\$ 3,225</u>	<u>\$ 3,046</u>	<u>\$ 4,239</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 1998, 1997 and 1996 were \$1.63 per Mcfe, \$2.24 per Mcfe and \$3.41 per 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 percent, 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)			
1998				
Operating revenues	\$408.0	\$501.7	\$558.4	\$ 372.9
Operating income (loss)	61.2	(13.2)	81.2	(1,322.4)
Income (loss) from continuing operations	24.7	(33.8)	(13.1)	(860.9)
Net income (loss)	31.2	(17.3)	(17.3)	(895.4)
Per share:				
Income (loss) from continuing operations	\$ 0.10	\$(0.13)	\$(0.06)	\$ (3.48)
Net income (loss)	0.13	(0.07)	(0.07)	(3.61)
Dividends	0.05	0.05	0.05	0.05
Common stock price:				
High	24 $\frac{1}{2}$	25 $\frac{1}{4}$	18 $\frac{9}{16}$	14 $\frac{1}{2}$
Low	20 $\frac{7}{8}$	16 $\frac{9}{16}$	8 $\frac{5}{16}$	8 $\frac{1}{4}$
1997				
Operating revenues	\$418.3	\$364.0	\$342.2	\$ 393.5
Operating income	162.6	100.5	69.8	101.0
Income from continuing operations	104.3	67.4	53.9	77.5
Net income	117.2	74.4	67.2	74.2
Per share:				
Income from continuing operations	\$ 0.42	\$ 0.27	\$ 0.22	\$ 0.31
Net income	0.47	0.30	0.27	0.30
Dividends	0.05	0.05	0.05	0.05
Common stock price:				
High	31 $\frac{5}{8}$	29 $\frac{7}{8}$	26 $\frac{15}{16}$	27 $\frac{13}{16}$
Low	23 $\frac{7}{8}$	24 $\frac{1}{2}$	23	23 $\frac{1}{4}$

First quarter 1997 results reflect the impact of increases in hydrocarbon prices. Second quarter 1998 results reflect the impact of purchase of Norcen. Fourth quarter 1998 results reflect the decrease in hydrocarbon prices and a \$1.2 billion writedown 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 auditors, 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 each of 1997 and 1996 did not contain an adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principle. During such years and through 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 audit 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 segment of the Proxy Statement and is incorporated herein by reference.

(b) Executive Officers of Registrant.

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

(c) Section 16(a) Compliance.

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

ITEM 11. *Executive Compensation*

Information concerning remuneration received by executive officers and directors is presented in the Compensation of Directors, Compensation Committee Interlocks and Insider Participation and Executive Compensation segments of the Proxy Statement and is incorporated herein by reference.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management*

Information as to the number of shares of equity securities beneficially owned as of March 9, 1999, 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 Executives, Directors 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 in Item 8 of this Form 10-K.

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 on Form 10-K for the year ended December 31, 1996).
3.2	— 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	— Amended and Restated Rights Agreement, dated as of December 1, 1998, between Union Pacific Resources Group Inc. and Harris Trust and Savings Bank, as rights agent (incorporated herein by reference to the Exhibit to the Company's Report on Form 8-A12G/A filed on February 5, 1999).
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(a)	— 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).
4.4(b)	— 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).
4.5(a)	— 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).
4.5(b)	— 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).
4.6(a)	— 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).
4.6(b)	— 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).
4.7	— 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).

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
4.8	— First Supplemental Indenture, dated as of May 22, 1996, to Trust Indenture dated as of May 7, 1996, providing for the issue of 7¾% 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).
4.9	— 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).
4.10	— 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).
4.11	— 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 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).
4.12(a)	— Terms Agreement for \$200,000,000 6.50% Notes due May 15, 2005 (incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on May 26, 1998).
4.12(b)	— Form of 6.50% Note due May 15, 2005 (incorporated herein by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K filed on May 26, 1998).
4.13(a)	— Terms Agreement for \$200,000,000 6.75% Notes due May 15, 2008 (incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on May 26, 1998).
4.13(b)	— Form of 6.75% Note due May 15, 2008 (incorporated herein by reference to Exhibit 4.6 to the Company's Current Report on Form 8-K filed on May 26, 1998).
4.14(a)	— Terms Agreement for \$200,000,000 7.05% Notes due May 15, 2018 (incorporated herein by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on May 26, 1998).
4.14(b)	— Form of 7.05% Debenture due May 15, 2018 (incorporated herein by reference to Exhibit 4.7 to the Company's Current Report on Form 8-K filed on May 26, 1998).
4.15(a)	— Terms Agreement for \$425,000,000 7.15% Notes due May 15, 2028 (incorporated herein by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K filed on May 26, 1998).
4.15(b)	— Form of 7.15% Debenture due May 15, 2028 (incorporated herein by reference to Exhibit 4.8 to the Company's Current Report on Form 8-K filed on May 26, 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).

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
10.3	— Pension Plan Agreement, dated October 1, 1995 by and between Union Pacific Corporation and Union Pacific Resources Group Inc. (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(a)	— 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 Exhibit 4.2 to the Company's Registration Statement on Form S-8, dated February 28, 1997).
*10.7(b)	— Second Amendment, effective January 21, 1999, to 1995 Stock Option and Retention Stock Plan of Union Pacific Resources Group Inc.
*10.8(a)	— 1995 Directors Stock Incentive Plan, as amended and restated, effective July 14, 1998.
*10.8(b)	— First Amendment, effective January 21, 1999, to 1995 Directors Stock Incentive Plan, as amended and restated, effective July 14, 1998.
10.9	— Union Pacific Resources Group Inc. Deferred Compensation Plan for the Board of Directors, as amended and restated, effective September 5, 1997 (incorporated herein by reference to Exhibit 99.2 to the Company's Registration Statement on Form S-8, dated September 15, 1997).
10.10	— Union Pacific Resources Group Inc. Executive Deferred Compensation Plan, effective September 5, 1997 (incorporated herein by reference to Exhibit 99.1 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).
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).

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
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).
10.13(d)	— Form of Agreement relating to Change in Control by and between Union Pacific Resources Group Inc. and Thomas R. Blank, dated July 13, 1998 (incorporated herein by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q/A filed November 12, 1998).
*10.13(e)	— Form of Amendment, dated as of January 21, 1999, to Change in Control Agreements between Union Pacific Resources Group Inc. and Jack L. Messman, George Lindahl III, V. Richard Eales, Donald W. Niemiec, Morris B. Smith, Anne M. Franklin, Joseph A. LaSala, Jr., and John B. Vering, all dated February 4, 1997, and between Union Pacific Resources Group Inc. and Thomas R. Blank dated July 13, 1998.
10.14(a)	— 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).
10.14(b)	— 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 (incorporated herein by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997).
10.14(c)	— 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 (incorporated herein by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997).
10.15(a)	— 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).
10.15(b)	— Amendments to Transportation Agreement dated December 15, 1989, by and between Kern River Gas Transmission Company and Union Pacific Fuels, Inc. (incorporated herein by reference to Exhibit 10.16 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997).
10.16	— Gas Transportation Agreement, dated June 18, 1997, by and between Union Pacific Fuels, Inc. and Texas Gas Transmission Corporation (incorporated herein by reference to Exhibit 10.17 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997).
10.17	— 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).
10.18(a)	— 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).

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
10.18(b)	— 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).
10.19	— U.S. \$25,000,000 Revolving Loan Agreement dated July 14, 1997, between Basic Petroleum International Limited and Royal Bank of Canada (incorporated herein by reference to Exhibit 10.33 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997).
10.20	— U.S. \$1,000,000,000 364-day Competitive Advance/Revolving Credit Agreement, dated as of October 27, 1998, among Union Pacific Resources Group Inc. and Chase Bank of Texas, N.A., as administrative agent and the banks named therein (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q/A filed November 12, 1998).
10.21	— U.S. \$750,000,000 364-day Competitive Advance/Revolving Credit Agreement, dated as of October 27, 1998, among Union Pacific Resources Group Inc. and Chase Bank of Texas, N.A., as administrative agent and the banks named therein (incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q/A filed November 12, 1998).
10.22	— U.S. \$750,000,000 Five-Year Competitive Advance/Revolving Credit Agreement, dated as of October 27, 1998, among Union Pacific Resources Group Inc. and Chase Bank of Texas, N.A., as administrative agent, The Chase Manhattan Bank of Canada, as Canadian sub-agent and the banks named therein (incorporated herein by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q/A filed November 12, 1998).
*10.23(a)	— Merger and Purchase Agreement, dated November 20, 1998, among Union Pacific Resources Company, Union Pacific Fuels, Inc., Duke Energy Field Services, Inc. and DEFS Merger Sub Corp.
*10.23(b)	— Amendment, dated February 1, 1999, to Merger and Purchase Agreement, dated November 20, 1998, among Union Pacific Resources Company, Union Pacific Fuels, Inc., Duke Energy Field Services, Inc. and DEFS Merger Sub Corp.
*12	— Computation of ratio of earnings to fixed charges.
*21	— List of subsidiaries.
*23.1	— Consent of Arthur Andersen LLP dated as of March 15, 1999.
*23.2	— Consent of Deloitte & Touche LLP dated as of March 15, 1999.
*24	— Powers of attorney for Directors.
*27	— Financial data schedules.

(b) Reports on Form 8-K.

On December 4, 1998, the Company filed a Current Report on Form 8-K containing a copy of a press release announcing the execution of a Merger and Purchase Agreement for the sale of the Company's domestic gas gathering, processing and marketing operations to Duke Energy Field Services for \$1.35 billion.

On January 15, 1999, the Company filed a Current Report on Form 8-K containing a copy of a press release making three announcements: (i) the Company will take a \$760 million non-cash charge to earnings in the fourth quarter resulting from asset impairments, (ii) the Company's preliminary capital budget for 1999 of approximately \$500 million and (iii) a continuing cost reduction program.

On January 28, 1999, the Company filed a Current Report on Form 8-K announcing the Company's 1998 annual operating results, net income and certain other financial and statistical information.

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 15th day of March, 1999.

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 15th day of March, 1999, by the following persons on behalf of the registrant and in the capacities indicated.

<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
H. Jesse Arnelle	
*	Director
Lynne V. Cheney	
*	Director
Preston M. Geren III	
*	Director
Lawrence M. Jones	
*	Director
Drew Lewis	
*	Director
Claudine B. Malone	
*	Director
John W. Poduska, Sr., Ph.D.	
*	Director
Michael E. Rossi	
*	Director
Samuel K. Skinner	
*	Director
James R. Thompson	
*By <u>/s/ JOSEPH A. LASALA, JR.</u> (Joseph A. LaSala, Jr., as attorney-in-fact)	

Union Pacific Resources Group Inc., 777 Main Street, Fort Worth, Texas 76102

