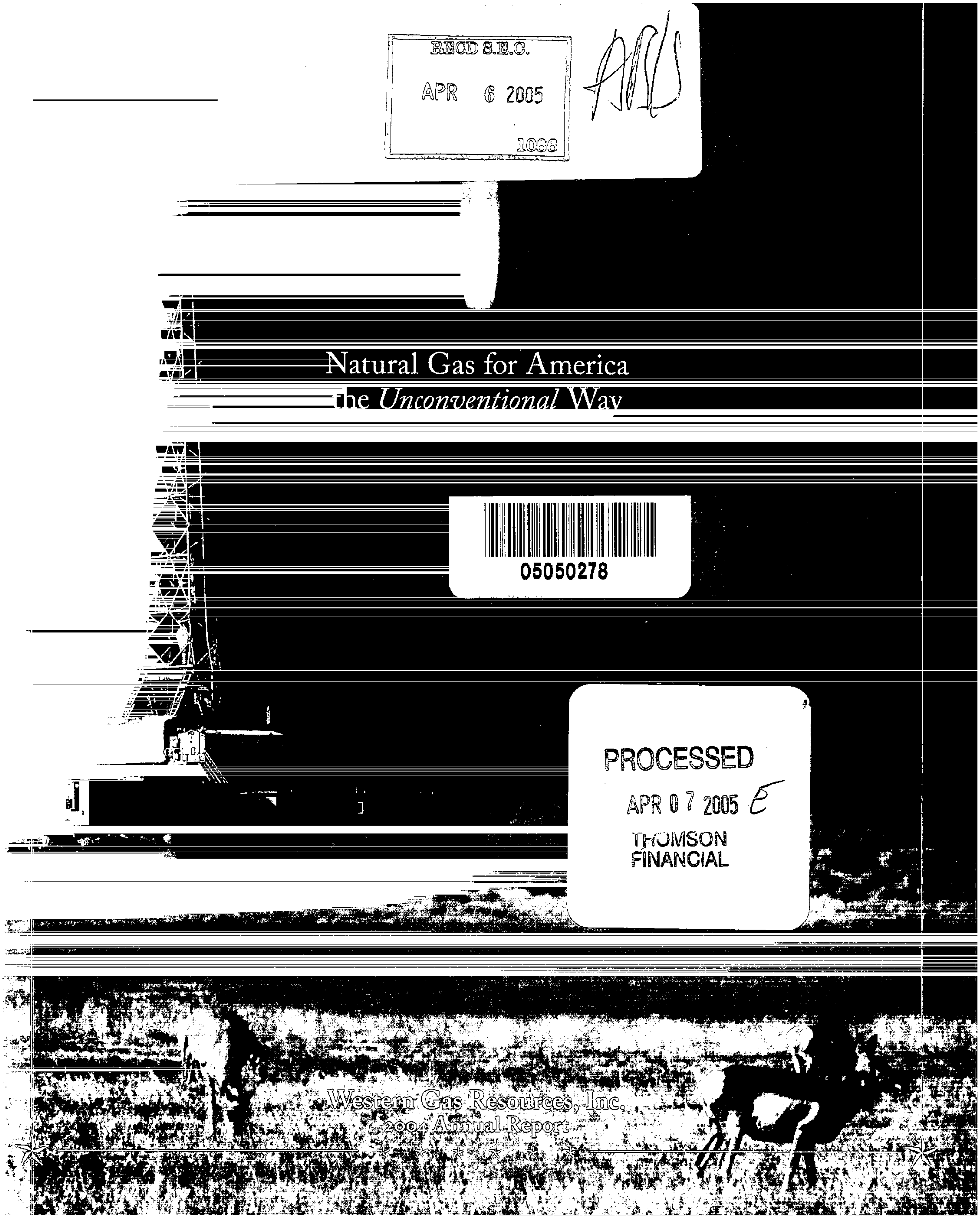


Natural Gas for America the *Unconventional* Way

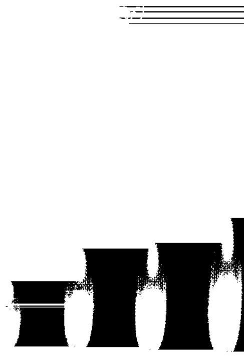
Western Gas Resources, Inc.
2004 Annual Report

2004 Performance Highlights

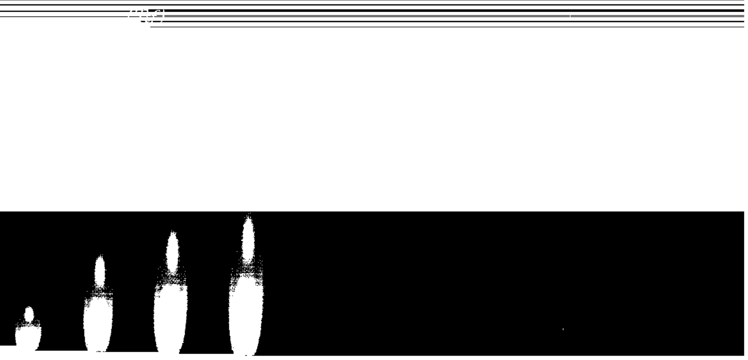
- Achieved shareholder return of 25 percent.
- Realized record net income of $119.2 million or $1.61 per diluted share.
- Reduced debt to capitalization ratio to 36 percent.
- Increased proved reserves 19 percent to 812 Bcfe.
- Increased net production five percent to 55.5 Bcfe.
- Replaced 346 percent of equity gas produced.
- Increased gathering and processing throughput volumes.
- Achieved midstream operating costs of $0.19 per Mcf.
- Acquired additional leasehold, production and gathering assets in the Rockies.

Western continues to help meet the energy needs of America in an environmentally sound manner. Water produced from CBM wells benefit buffalo, livestock and wildlife in the arid Powder River Basin.

Unconventional U.S. Gas Production



U.S. CBM Production



Western Gas Resources

✯ ✯ ✯ ✯ ✯ ✯

un · con · ven · tion · al

adj. not conforming to convention, unusual

At Western, we bring a whole new meaning to unconventional. From the unconventional natural gas reservoirs we produce to our fully integrated business model, our unconventional approach delivers results.

As a premier developer of unconventional natural gas in the Rocky Mountain region, our leasehold in the Powder River Basin and the Pinedale Anticline represent low-risk, low-cost and high-return reserves that are expected to fuel long-term growth and increase shareholder value.

One of our unique strengths is our fully integrated business model. The integration of our upstream activities with our significant midstream assets and marketing services is less common in our industry. We link the wellhead to the marketplace, which provides us with a strategic advantage to maximize profits and access new growth opportunities.

Americans use natural gas because it is safe, reliable and more environmentally friendly than other energy sources. Unconventional natural gas use continues to rise and now accounts for approximately 32 percent of our nation's supply.

We're proud to provide clean burning domestic natural gas for America—the *unconventional* way.

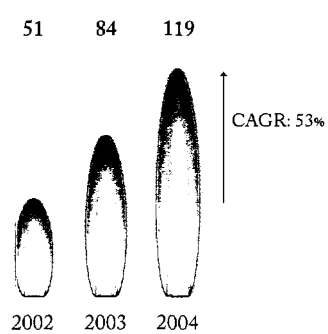
Selected Financial and Segment Operating Data

★ ★ ★ ★ ★ ★

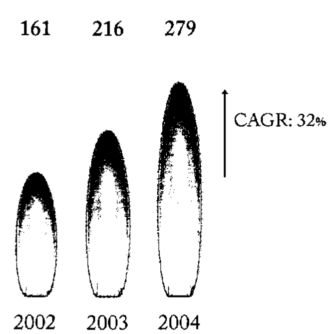
Selected Financial Data *(Dollars in thousands, except share and per share amounts)*	Year ended December 31, 2004	2003	2002
Revenues	**$ 3,069,713**	$ 2,874,010	$ 2,489,698
Net income	**119,215**	84,219	50,589
Earnings per share of stock—assuming dilution	**$ 1.61**	$ 1.13	$ 0.62
Weighted average shares of common stock outstanding— assuming dilution	**73,494,747**	74,694,420	67,215,120
Total assets	**1,840,112**	1,460,524	1,302,144
Long-term debt	**382,000**	339,000	359,933
Stockholders' equity	**682,028**	562,509	483,068
Cash flow before working capital adjustments[1]	**278,927**	215,666	161,071
Capital expenditures (excluding acquisitions)	**224,400**	153,100	140,637

[1]See page 79 after the 10-K for reconciliation to net income.

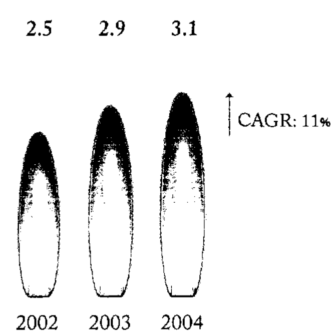
Net Income
($ in millions)



Cash Flow Before Working Capital Adjustments
($ in millions)



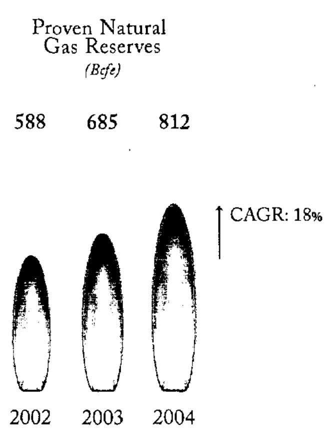
Revenues
($ in billions)

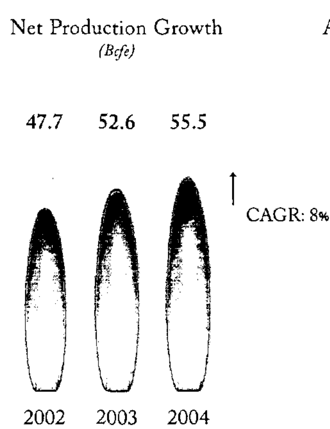


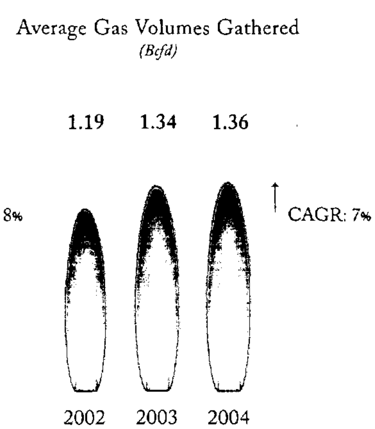
CAGR: Compound Annual Growth Rate

Segment Operating Data *(Operating Profit—Dollars in thousands)*	Year ended December 31, 2004	 2003	 2002
Producing Properties			
Equity gas reserves (Bcfe)	**812**	685	588
Gas production volumes sold (MMcfed)	**153**	149	134
Average wellhead gas prices ($/Mcfe)	**$ 3.97**	$ 3.47	$ 1.69
Operating profit[1]	**$156,141**	$114,232	$74,126
Gas Gathering and Processing			
Average gas volumes gathered (MMcfd)	**1,361**	1,343	1,188
Average plant gas sales (MMcfd)	**344**	473	444
Average plant NGL sales (MGald)	**1,386**	1,354	1,417
Operating profit[1]	**$168,877**	$127,249	$93,554
Transportation			
Gas transportation volumes (MMcfd)	**152**	166	192
Operating profit[1]	**$ 10,974**	$ 11,625	$16,326
Marketing			
Average gas sales (MMcfd)	**1,225**	1,361	1,988
Average NGL sales (MGald)	**1,641**	1,634	2,010
Average gas prices ($/Mcf)	**$ 5.59**	$ 4.94	$ 2.92
Average NGL prices ($/Gal)	**$ 0.75**	$ 0.58	$ 0.42
Average gas sales margin ($/Mcf)	**$ 0.04**	$ 0.05	$ 0.04
Average NGL sales margin ($/Gal)	**$ 0.011**	$ 0.009	$ 0.008
Operating profit[1]	**$ 24,621**	$ 30,691	$36,410

[1] *Operating profit represents total revenues less product purchases, plant and transportation operating expense and oil and gas exploration and production expense.*







Dear Shareholders

★ ★ ★ ★ ★ ★

Western and its shareholders had another excellent year in 2004 while supplying the United States with clean burning natural gas, which is critical to a healthy environment, jobs, economic growth and a secure nation. We benefited from strong commodity prices, increased drilling activity, a low-cost structure and the exceptional efforts of our employees. The Company achieved the highest net income and cash flow before working capital adjustments in our 27-year history of $119.2 million and $278.9 million, respectively. As a result, shareholder return was 25 percent for 2004 and 90 percent for the last three years.

We further improved the balance sheet in 2004 to the strongest level in years. We converted or redeemed all of our preferred stock and redeemed $155 million of 10 percent senior subordinated notes. A two-for-one stock split was also completed, while effectively doubling our dividend for the quarters after the split.

Western continued to solidify and expand its position as a premier explorer, developer, gatherer and processor of unconventional natural gas, particularly in Rocky Mountain resource plays. In total, Western has approximately 1.6 million net acres under lease in eight Rockies basins. We initiated new unconventional gas resource opportunities in the Rockies, Canada and other select areas of the United States. In 2004, we further developed our well established positions in two of the most prolific discoveries in the onshore United States in recent years, the Powder River Basin coal bed methane (CBM) play and the Pinedale Anticline in the Green River Basin of Wyoming. Additionally, we positioned the Company in several new areas including the San Juan, eastern Green River and Uinta Basins and began drilling to evaluate our Niobrara acreage in northeastern Colorado. We have also acquired nearly 500,000 net acres in a new unconventional gas play and expect to begin exploring its potential in mid to late 2005.

Net production, proved, probable and possible reserves as determined by our outside reservoir engineers and exploration and production segment-operating profit increased once again in 2004. Net production increased five percent to 55.5 billion cubic feet equivalent (Bcfe) and proved reserves increased 19 percent to 812 Bcfe. Probable and possible reserves in two consolidated fields increased 13 percent to 2.4 trillion cubic feet (Tcf). Segment-operating profit from our exploration and production activities increased 37 percent from 2003.

Segment-operating profit from our midstream operations increased 33 percent in 2004 as we expanded gathering and processing operations in most of our operating areas, while maintaining our low-cost structure and excellent safety record. We continue this momentum into 2005 with expected record drilling in most operating areas and a projected eight percent increase in gas throughput volumes to be gathered or processed by our midstream assets. Our marketing expertise provided optimum prices and risk management strategies in 2004.

We have increased our 2005 capital expenditure plans by 38 percent from 2004, excluding acquisitions, to pursue our significant drilling and midstream growth opportunities. From our low-risk 10 to 15-year drilling inventory, we plan to drill 1,031 gross wells in 2005, a 22 percent increase from last year.

I want to thank our employees for their commitment and dedication to bring much needed natural gas supplies to America and for their efforts and contributions in our communities. Through participation in Mile High United Way, low-income energy assistance and their part in the worldwide Tsunami relief fund in 2004, Western and its employees are always willing to lend a caring hand. We also extend our gratitude to those courageous men and women in the Armed Services who protect our country and freedom.

We at Western appreciate the continued trust and financial commitment afforded us by our shareholders as we strive to grow the Company and deliver new shareholder value.

Sincerely,

Peter A. Dea

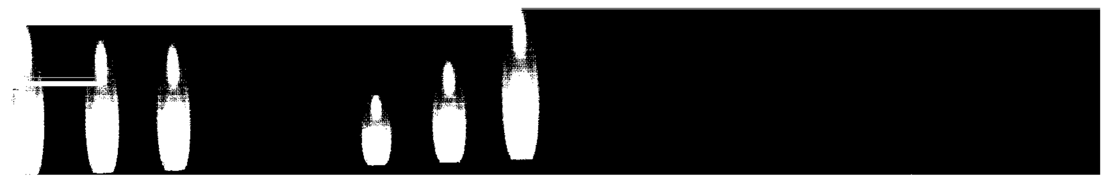
Peter A. Dea
President & CEO

Debt to Capitalization

(at year end)

Capital Expenditures

($ in millions)



The dedication, perseverance and integrity
of our employees are the driving force
behind our growth and success.
Their experience and enthusiasm
enable us to leverage our core competencies
to develop new and existing
unconventional natural gas projects.

CEO Perspective

Western's extensive leasehold position and large base of unconventional gas reserves in the Rockies provide the Company with significant organic growth potential for many years and leverage to new areas.

Q: **Why is natural gas important to America?**

A: Natural gas is directly linked to the sustainability of the American quality of life and a healthy economy. It is the most dependable, clean-burning and environmentally friendly fossil fuel. Over 61 percent of American homes rely on natural gas for heating, cooling, cooking and electricity. Natural gas liquids, such as ethane and propane, are used to produce various plastics for many purposes such as medical supplies and clothing such as fleece and water repellent fabrics for all of us outdoor enthusiasts. Propane is also used for rural heating and crop drying and butane is blended into motor gasoline. Natural gas is also the primary source of hydrogen used in fuel cells—the hope of future energy. Consumption of natural gas is expected to steadily increase even with much needed advancements in energy efficiency, conservation and renewable energy. Natural gas is the perfect complement to wind and solar power given its cleanliness and dependability as a fuel for the future of America.

Q: **Why unconventional natural gas?**

A: Unconventional gas, found in coal seams, low-permeability sandstones and shale, has become the largest source of new natural gas supply in the United States. The National Petroleum Council states that future growth in our nation's gas supply will depend on the domestic production of unconventional gas. The largest increase of domestic natural gas production in the lower 48 states is expected to come from unconventional reservoirs, like those Western pursues, develops and produces in the gas-rich Rockies.

Q: **Why is Western Gas Resources focused on unconventional natural gas?**

A: For nearly a decade, Western has focused the majority of its exploration, production and gathering efforts on unconventional gas reservoirs. Unconventional gas resource plays provide Western with a repeatable low-risk, low-cost, high-return and long-term drilling inventory to drive reserve and production growth in a gas manufacturing-type process. Equally important is the full integration of our gathering, compression, processing and marketing expertise in these expansive fairway plays.

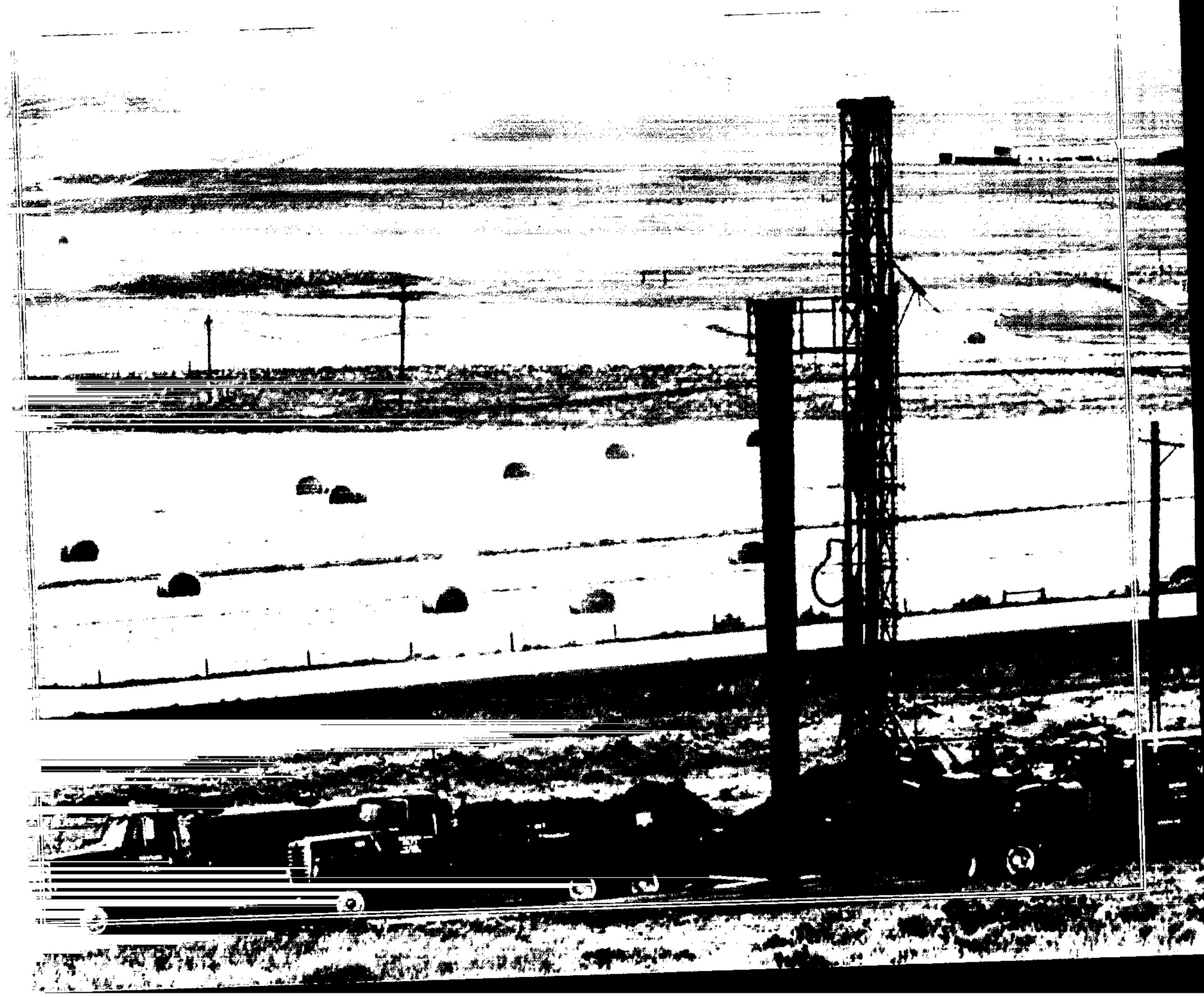
Q: **How extensive is Western's potential in unconventional natural gas?**

A: Collectively, we control nearly 1.6 million net acres in eight gas-producing basins in the Rocky Mountain region. We have a strategic position in three of the largest natural gas fields discovered in the United States in the last 15 years, all of which are unconventional reservoirs. Our 2.4 Tcfe of probable and possible reserves provide the potential to meaningfully increase our proven reserves over time, and our exploration leasehold provides additional company-building potential. We plan to participate in over 1,000 wells in 2005, all in Rocky Mountain unconventional gas resource plays. This includes new exploration and development in the northeast Denver Basin of Colorado, the Washakie and Red Desert Basins of Wyoming, the San Juan Basin of New Mexico and other select new exploratory plays, all of which will benefit from our midstream expertise with new and existing systems. We've recently hired a team of geologists and reservoir engineers in Calgary, Alberta with considerable experience in the exploration and development of unconventional gas resources in the Western Canadian Sedimentary Basins. We also continue to evaluate gas-rich shale plays in the southern United States.

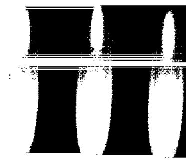
Powder River Basin Coal Bed Methane

Western is an industry leader in the world-class Powder River Basin of Wyoming in the drilling, production, gathering and transportation of coal bed methane. Our extensive leasehold and large midstream infrastructure provide a strategic competitive advantage and position us for long-term growth.

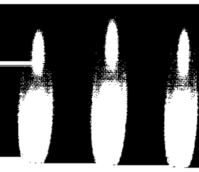
During 2004, Western drilled 752 CBM wells in the Powder River Basin, a 40 percent increase over 2003. The low impact wells are compatible with ranching operations in the basin.



CBM Net Production



CBM Volume Gathered



The Powder River Basin coal bed methane (CBM) development has been one of the leading unconventional natural gas success stories in the last 10 years. The play has produced over one Tcf and development is now transitioning from the mature Wyodak coal to the more prolific Big George fairway to the west. Western and our co-developer remain the largest leaseholder and producer of natural gas in the play. We expect production from our existing leasehold in the Big George fairway to be a major contributor to the Company's production growth in the years ahead.

During 2004, net CBM production totaled 41.7 Bcf. Western drilled 752 gross CBM wells, a 40 percent increase from the previous year. We plan to drill approximately 850 gross wells in 2005, subject to receiving the necessary federal drilling and water discharge permits. These include 730 gross wells in the more prolific Big George fairway and 120 gross wells in the Wyodak fairway. Big George net production nearly doubled from December 2003 to December 2004 and is expected to continue increasing in 2005, although overall net CBM production is expected to be down slightly due to declines in production from the older Wyodak coal. We expect overall net production to increase five to ten percent in 2006 as wells dewater and development expands in the Big George and related coals.

Net proved reserves for the Powder River Basin CBM were 310 Bcf at year-end 2004, or 38 percent of our proved reserve base. Of that total, net reserves attributable to the Big George and related coals were 179 Bcf at year-end 2004, a 25 percent increase from 2003. Western also has significant upside potential from its 2.0 Tcf of probable and possible reserves on its extensive leasehold, of which 97 percent is in the Big George and related coals.

As of February 2005, approximately 4,200 gross CBM wells drilled by Western and its co-developer in the Powder River Basin were producing gas, dewatering or awaiting hookup, including over 1,630 gross wells in the Big George fairway. Of the Big George wells, approximately 730 are producing gas, many of which are in early stages of production and 900 are dewatering or awaiting hookup. The Big George fairway was producing approximately 30 million cubic feet per day (MMcfd) net to Western in December 2004 from six development areas, and an additional 12 pilot areas are currently dewatering.

Western Gas is also the largest gatherer and transporter of CBM gas in the Powder River Basin. Our integrated approach separates us from many of our peers, provides us with an incremental profit center and allows us to control the timely hookup of our wells and the optimum placement of compression equipment. We also provide our efficient midstream services to our co-developer and other third-party producers, which provide additional cash flow to the Company.

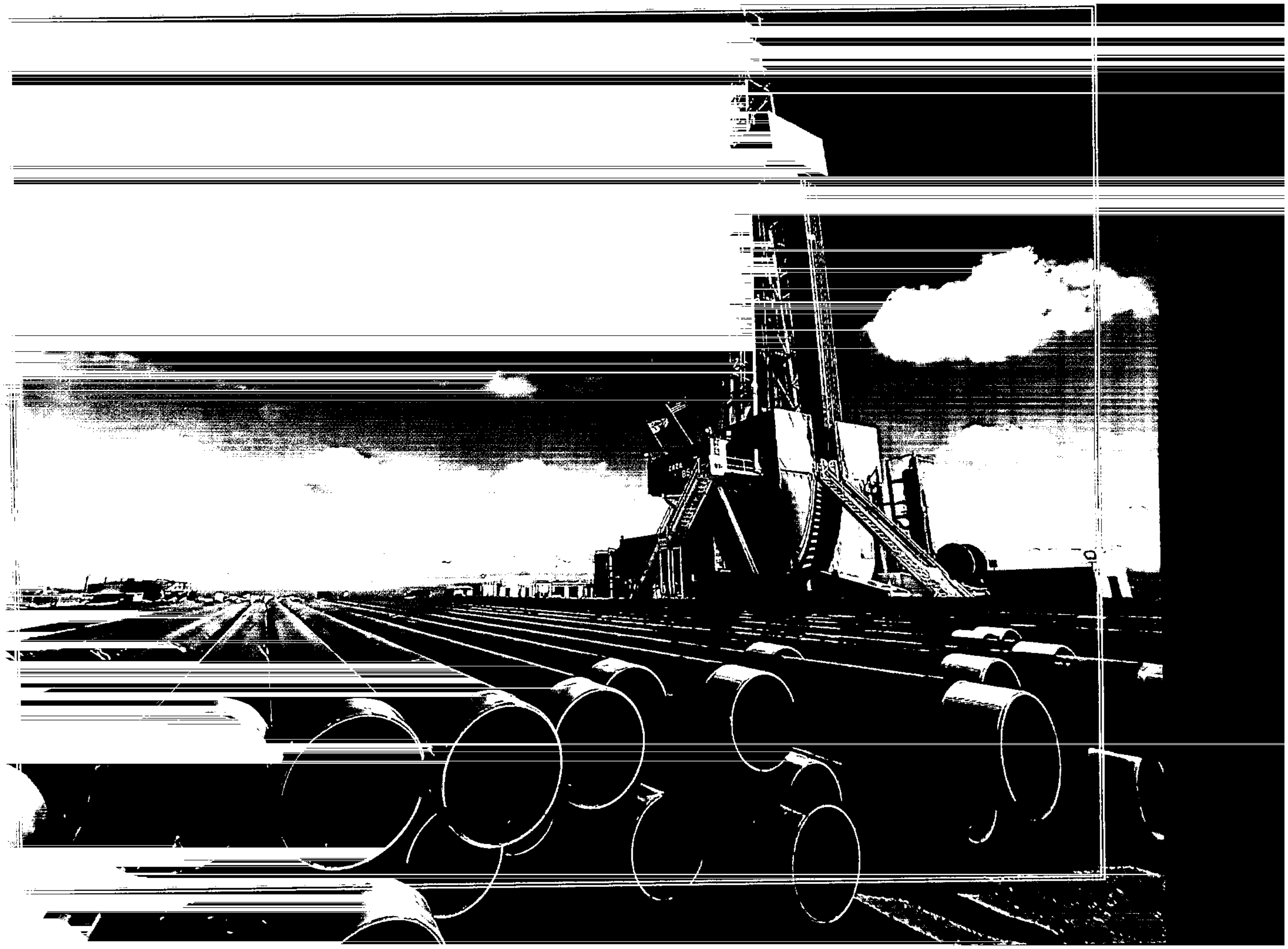
CBM gathering volumes, including our equity and third-party gas, were 396 MMcfd in 2004. We completed construction of two large diameter gathering lines into new Big George development areas and are constructing a third line, which will allow for growth from the expanding Big George fairway production. Approximately 350 MMcfd of the total volumes gathered were also transported on our wholly owned MIGC pipeline to a major interstate pipeline connection or moved on our 13-percent owned and operated Fort Union gathering system. In total, Fort Union handled 432 MMcfd of CBM volumes, including third-party volumes.

The Powder River Basin CBM development represents a meaningful and important supply of gas for America. Our existing leasehold of 533,000 net acres should provide many years of new drilling and production as we develop our significant leasehold of unconventional natural gas reserves.

Greater Green River Basin

Western's position in the prolific Pinedale Anticline and Jonah Field continues to outperform expectations and provides upstream and midstream growth opportunities.

Western participated in 80 gross wells on the Pinedale Anticline in 2004 with a 99 percent success rate. A portion of the Pinedale Anticline has been downspaced to 20 acres, which should ultimately provide another 1,300 potential gross drilling locations.



Net Production

Gas Volumes Gathered

(MMcfd)

The Greater Green River Basin is one of the largest onshore gas provinces in the United States and is home to the Pinedale Anticline and Jonah Field, two of the most prolific gas discoveries in the last 10 years. These two fields host tight gas sands, a significant unconventional natural gas resource. Estimated ultimate recovery (EUR) by industry for both fields is anticipated to exceed 30 Tcfe. Western established a core presence in the basin over 10 years ago and has continued to expand its fully integrated operations in the area.

On the exploration and production side, Western has an approximate 10 percent interest across a majority of the Pinedale Anticline and in three sections of the Jonah Field. The Company has approximately 1,400 possible undrilled locations based on recent 10-acre downspacing in the Jonah Field and assuming the Pinedale Anticline is fully developed on 20-acre spacing. In total, the Company has approximately 193,000 net acres in the Greater Green River Basin, including approximately 28,000 net acres related to new exploration activities in the Red Desert and Washakie Basins on the eastern portion of the Greater Green River Basin.

At year-end 2004, we had 476 Bcfe of net proved reserves, a 33 percent increase from year-end 2003. Net production grew 43 percent in 2004 to 12.7 Bcfe as we experienced a 98 percent success rate on 86 gross wells. We plan to drill 97 gross wells in the area during 2005, including 80 wells on the Pinedale Anticline, eight wells in the Sand Wash Basin area and nine wells in our new exploratory area in the eastern Greater Green River Basin.

There are several catalysts for growth in this area. One of the operators recently received approval for year round drilling and 20-acre downspacing on the northern portion of the Pinedale Anticline. A majority of the remainder of the Anticline could be downspaced to 20 acres during 2005. Additionally, an exploratory well will test deeper horizons on the Anticline. The estimated gas-in-place numbers are being reviewed in the Pinedale Anticline, which could increase recoverable reserves. Finally, the recent downspacing of the Jonah Field to 10 acres and previous downspacing to 20 acres resulted in 125 new potential drilling locations on our three sections in this area. Results of drilling on 10-acre spacing in Jonah Field will have operators reviewing the same possibility for the Pinedale Anticline in the years ahead.

We continued to expand our growing gathering and processing business in the area. We began operation of a newly constructed 200 MMcfd straddle plant in late 2004 near our Granger complex, which provides service to a nearby pipeline for a structured fee. The Company also owns and operates 325 MMcfd of processing capacity in the Granger area. During 2004, we increased gas throughput in all of our southwest Wyoming systems to a total of 434 MMcfd and installed 5,000 new horsepower to handle these growing volumes.

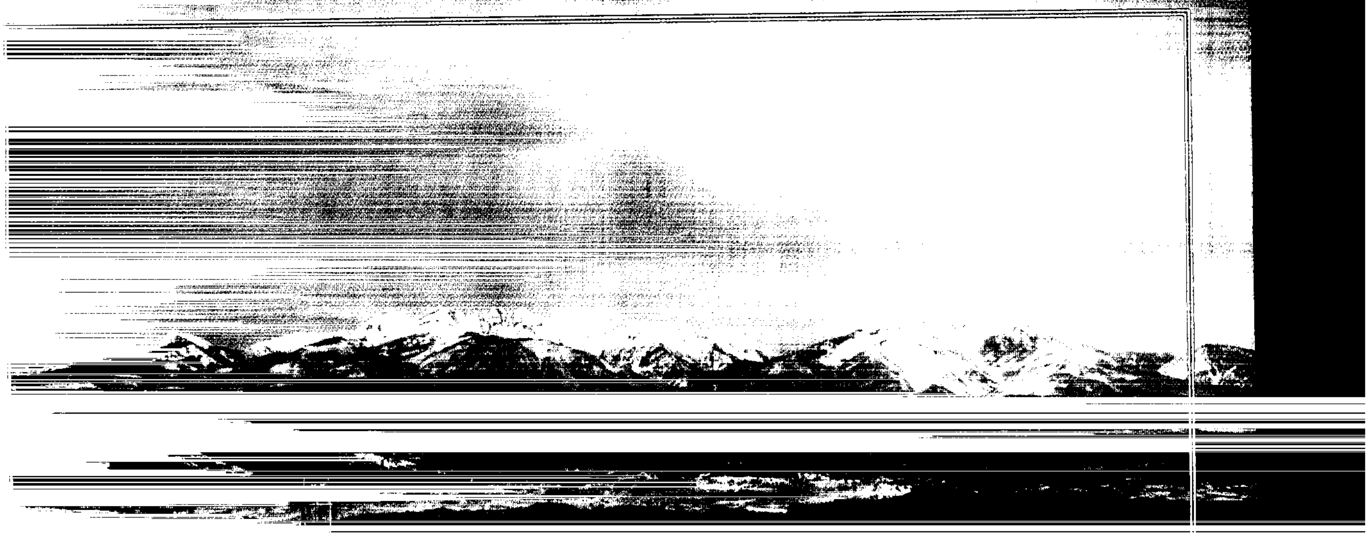
In February 2005, we completed the acquisition of the Patrick Draw processing facility and related gathering systems for $28 million, adding 150 MMcfd of processing capacity and 140 miles of related gathering systems. Patrick Draw will be integrated with our Red Desert processing facility and several gathering systems acquired in early 2003. Patrick Draw increases processing capacity substantially in the eastern Greater Green River Basin to 192 MMcfd, providing for much growth potential in actual throughput volumes.

The Greater Green River Basin represents a significant area of development and expansion for the Company as we further our strategy of being a premier producer, gatherer and processor of unconventional natural gas resources, primarily in the Rocky Mountain region.

Unconventional Gas Resource Exploration

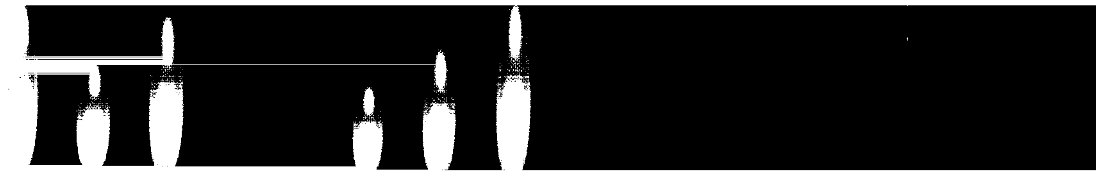
Leveraging off our core competencies, we are pursuing unconventional natural gas projects in the U.S. Rocky Mountain basins, Western Canadian Sedimentary Basin and other select U.S. basins.

The San Juan Basin is becoming a new fully integrated core area for Western. We plan an active drilling program in the area in 2005 and are looking for additional grassroots and acquisition opportunities.



Wells Drilled

Net Acreage Position



Western is leveraging its expertise in unconventional resources and fully integrated business model to new growth opportunities within the gas-rich Rockies, western Canada and select basins elsewhere in the United States. In 2004, Western advanced several exploration projects and we are actively seeking new company-building growth projects through grassroots exploration, joint ventures and niche acquisitions.

In northeast Colorado and western Nebraska, we are targeting the Niobrara formation, an unconventional biogenic gas reservoir. Biogenic activity by microbes generates "bio"genic gas found in some shallow reservoirs that were not buried deep enough to form gas by thermal heat or "thermo"genic activity. We have amassed a 340,000-acre net leasehold position and tested initial rates of gas. We drilled six wells and began a new six-well program in March 2005. A new twelve-mile gathering line we constructed will hook up the wells in the second quarter. The Company has identified 50 to 65 additional prospective drilling locations on 59 square miles of 3-D seismic. We also have acquired a new 27-square mile 3-D seismic program to identify additional drilling prospects. If this play proves successful, we expect to have an active development program for many years.

In 2004, we acquired production, reserves, approximately 24,000 net acres of leasehold and 130 miles of related gathering and a pipeline in the San Juan Basin of New Mexico. In December 2004, net production was 10 million cubic feet equivalent per day (MMcfed) from 122 CBM wells. Much of the production will be connected to Western's adjacent San Juan River processing plant. The Company plans to drill 64 wells and conduct numerous workovers on existing wells in 2005. Proved reserves at year-end were 26.4 Bcfe and we estimate total potential reserves could be three to four times the proved reserves based on anticipated results from our plan to workover and develop additional coals. Western is also actively working to identify additional coal bed methane and low-permeability sand prospects to add leasehold to this emerging core area.

Since early 2004, the Company has acquired approximately 490,000 net acres in a new unconventional gas play in the Rockies. Low-permeability rock comprise the prospective reservoirs, while biogenic activity in organic-rich shales generates the methane gas in this wildcat exploration prospect. We plan to drill several wells to test this play in 2005 and 2006 while continuing to add acreage. If the high-risk exploratory tests succeed commercially, the potential exists for a multi-year, low-risk development project of company-building scale.

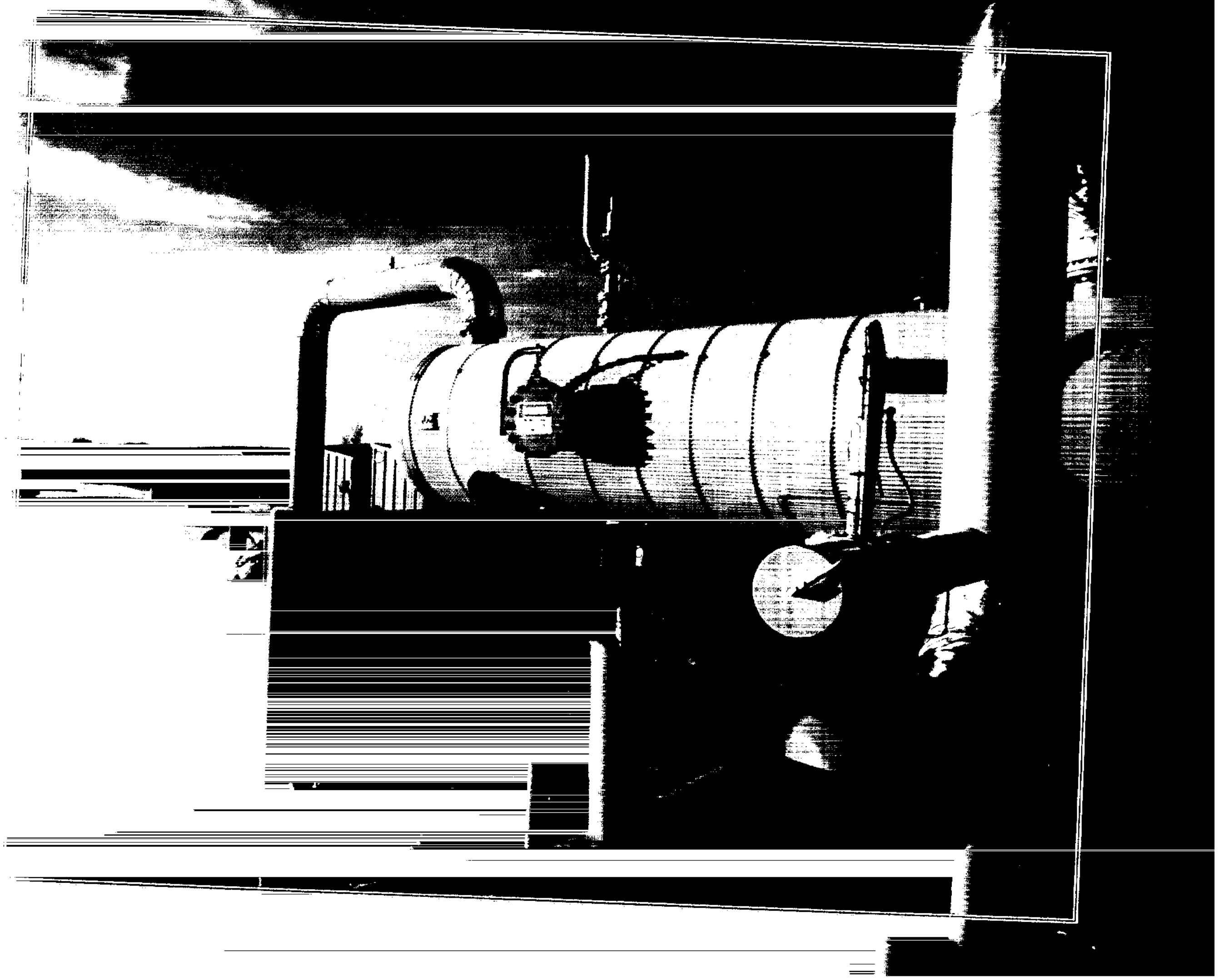
At the start of 2005, we opened an office in Calgary to pursue unconventional gas projects in western Canada. The office will be staffed with geologists and engineers with years of specific experience in exploring and developing gas from coal seams, tight sandstones and shales. The timing for Western's entry into Canada relates to favorable momentum in our United States Rockies exploration program over the last two years and the reduced risk of early Canadian CBM exploration now that such production exceeds 100 MMcfd. Between the abundant resource potential and Western's expertise in unconventional gas, we are excited about the prospects of new fully integrated opportunities in Canada.

Many opportunities exist to explore for and develop new unconventional natural gas resources in the western United States and Canada. We are committed to finding and participating in new profitable growth projects that leverage our fully integrated core competencies and strong balance sheet to new unconventional gas projects.

Midstream & Marketing Operations

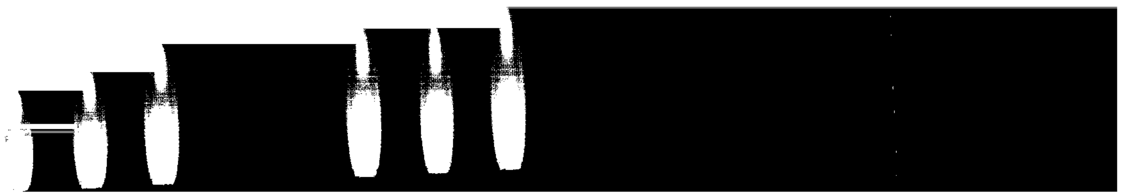
Our high-quality asset base, expertise and low operating costs make us a leader in the midstream business. Our maintenance capital was less than 10 percent of operating profit in 2004 resulting in significant free cash flow.

Western's new compressor stations use state-of-the-art design to maximize efficiency by lowering fuel consumption, minimizing emissions and increasing safety.



Midstream Segments Operating Profit*
(in millions)

Low Operating Costs
($/Mcf of gas volumes gathered)



*Includes Gas Gathering and Processing, Transportation and Marketing segments

Western's cost-efficient midstream and marketing operations provide us with a strategic competitive advantage and significant cash flow to grow our exploration, production and midstream activities. Our midstream assets are located in some of the most actively drilled gas and oil basins in the Rocky Mountain and southwest regions of the United States Our ability to provide midstream services to ourselves and other third parties through our extensive gathering and processing operations is key in our role as a premier developer of unconventional gas reserves.

The midstream business unit experienced a record year in 2004. Strong prices, increased drilling activity and a low-cost structure generated segment-operating profit of $204 million for our gas gathering and processing, transportation and marketing operations. Proven reserves connected to our gathering and processing assets were estimated to be 4.3 Tcf at year-end 2004. New well connections and acquisitions increased gas throughput volumes to approximately 1.4 Bcf per day. In 2005, we plan to expand gathering and processing systems in most of our operating areas to accommodate another strong year of expected drilling by producers dedicated to our facilities.

Western's integrated natural gas structure is meeting with continued success and has provided new opportunities to expand our operations. Since January 2004, through grassroots projects and acquisitions, we increased gathering and processing capacity by 413 MMcfd, added 642 miles of gathering lines and installed or acquired more than 68,060 horsepower of plant and gathering compression to our systems. Our successful efforts to achieve maximum efficiency as a low-cost operator is demonstrated by our outstanding per unit operating cost of $0.19 per Mcf, consistently among the lowest in the industry.

Strong drilling activity and operational efficiencies in our core midstream operations in Oklahoma and West Texas provided additional returns in gathering, processing and sales volumes in 2004. In Oklahoma, we set new records for well connections and new compression for the second year in a row. Gathering throughput volumes increased 12 percent in 2004 to 183 MMcfd and natural gas liquids (NGLs) production remained relatively flat at 308 thousand gallons per day (MGald) compared to 2003. We expect continued throughput growth in the Oklahoma area in 2005 as strong drilling activity is projected by producers dedicated to our gathering systems. At our Midkiff-Benedum complex, recent measurement and compression optimization programs have significantly enhanced Western's competitive advantage in the area. Gas gathering throughput volumes at Midkiff-Benedum remained strong, increasing to 139 MMcfd in 2004. NGL production increased four percent to 830 MGald. Gas gathering throughput volumes in 2005 are expected to increase slightly compared to 2004 as drilling activity remains steady.

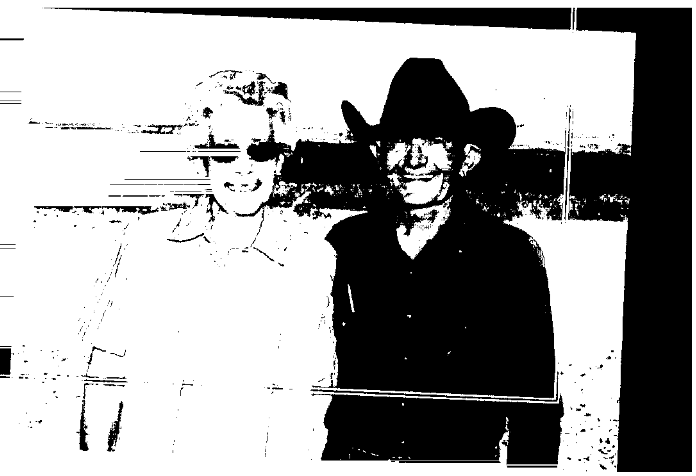
The exceptional performance and leadership shown by our Operations team in 2004 was further enhanced by the implementation of leading-edge communication and information programs. These programs utilize new technology and should contribute to lower operating costs and increased efficiency through automated operations in the areas of compliance, asset management, preventative maintenance, equipment performance and training and development.

Marketing plays a key role in both our upstream and midstream businesses. Their goal is to secure stable markets for our equity and third-party gas and NGLs and utilize firm transportation agreements and gas storage positions to maximize the value received for our natural gas volumes. The marketing team demonstrated strong performance in 2004 with segment-operating profit of approximately $25 million. Through their expertise and solid performance, we have the flexibility to sell gas and NGLs into various markets to optimize the value received for our natural gas and NGL products.

Environmental Stewardship

Western has continually increased energy efficiency while reducing fuel usage, costs and emissions over the last few years, particularly in our midstream operations. Our Energy and Emissions Savings Program and conservation efforts continue to expand our environmental stewardship.

Water produced from CBM wells yields beneficial results to ranchers like the Floyds. Working together, we implemented a leading-edge water treating system, increasing their hay production 490 percent.



Western Gas Resources

Providing Clean Burning Natural Gas for America

Western continues to develop and process clean burning natural gas in an environmentally responsible manner while doing our part to address the domestic energy needs of America.

We are an active partner with the Environmental Protection Agency in the Natural Gas STAR partnership. In 2004, Don Anderson, Western's Compliance Coordinator, received the Natural Gas STAR Implementation Manager of the Year Award in recognition of the combined efforts of many Western employees. Mr. Anderson worked with the EPA on strategies and technologies that enable companies to reduce methane emissions and increase energy efficiencies. This followed 2003 when Western received the Processing Partner of the Year Award by having the greatest methane emissions reductions among all of its processing partners.

Western has always been respectful of its surroundings and proactively incorporates new "best practices" into its activities. We are a leader in water treating and handling in the Powder River Basin. Beginning in 2003, we built two water treating and handling facilities that lower the sodium content in the water so that it may be used for irrigation. Together, Western and a nearby landowner, Fred Floyd, implemented a cutting-edge water treating system, which allowed the water to be used for irrigating his hay crops. The Floyds began using the water to replenish their crops and experienced a 490 percent increase in their hay production. The Floyd family and Western are both very pleased with our association and with the environmental and economic benefits.

Western is also a leader in performing weed mitigation, pest control and air quality protection measures. We have developed control measures to reduce the threat of the West Nile virus in areas where we operate. Our efforts include a spraying program and educating landowners about the most effective techniques to minimize the mosquito population.

Starting in early 2005, Western began a program that represents a company-wide effort to further save and conserve energy. The President's Energy and Emissions Savings Program will focus on further reducing the Company's use of electricity, natural gas, diesel fuel, gasoline, oil, lubricants and paper. The program will explore ways to further reduce the emissions of greenhouse gases including methane, carbon dioxide, nitrous oxide and sulfur dioxide as well as reducing levels of any other natural gas liquid or byproduct. As we acquire and upgrade older plants, we have reduced over 1,500 tons of greenhouse gases in the last year and over 7,500 tons in the last four years. Western has also reduced methane emissions in the last four years through the addition of flares, changing instrument gas to instrument air and installing hot taps in place of pipeline venting.

Recycling programs are in place throughout the Company and conservation is encouraged. Many Western employees volunteer their own time for such efforts as Volunteers for Outdoor Colorado, a non-profit organization that performs trail building, tree planting and reclamation. We take energy and land conservation seriously and will continue to strive toward a cleaner environment.

Safety is also a very important core value for the Company. Western promotes a safe work environment through the newly developed SafeStart program. The behavioral program is designed around safety awareness that educates employees to recognize an unsafe situation before an accident occurs. Since we implemented this program, we have seen a 43 percent reduction in lost time due to accidents on the job.

Of course, perhaps the greatest single contribution to a healthy environment is our focus on natural gas. Since gas produces no solid waste and nearly no sulfur dioxide or particulates, it is far cleaner than other conventional fuels. What is good for Western's shareholders is also good for a healthy environment.

Officers & Directors

★ ★ ★ ★ ★ ★

Western's Officer Team (left to right): Burt Jones, Jeff Jones, John Chandler, John Walter, Peter Dea, Brian Jeffries, Bill Krysiak, Dave Keanini, Ed Aabak and Vance Blalock.

Officers

PETER DEA, 51
President & Chief Executive Officer

JOHN CHANDLER, 48
Executive Vice President &
Chief Operating Officer

BILL KRYSIAK, 44
Executive Vice President &
Chief Financial Officer

JOHN WALTER, 59
Executive Vice President &
General Counsel

ED AABAK, 53
Executive Vice President, Midstream

VANCE BLALOCK, 51
Vice President & Treasurer

BRIAN JEFFRIES, 47
Vice President, Marketing

BURT JONES, 45
Vice President, Business Development

JEFF JONES, 51
Vice President, Production

DAVE KEANINI, 44
Vice President, Engineering,
Environmental & Safety

Directors

JAMES SENTY, 69 A, C, N
Chairman of the Board
Chairman, The Park Bank

WALTER STONEHOCKER, 80 E
Vice Chairman
Retired Senior Vice President

PETER DEA, 51
Chief Executive Officer & President

DEAN PHILLIPS, 73 A, C, N
President of Heetco, Inc.

JOSEPH REID, 74 E, A, C, N
Independent Oil & Gas Consultant
Retired Chief Executive Officer &
President of Meridian Oil Company

RICHARD ROBINSON, 56
Partner of Robinson & Diss, P.C.

BILL SANDERSON, 75 E, A, C, N
Retired President & Chief Operating Officer

WARD SAUVAGE, 79
President of Sauvage Gas Company

BRION WISE, 59 E
Former Chairman and
Chief Executive Officer

E Member Executive Committee
A Member Audit Committee
C Member Compensation Committee
N Member Nominating & Governance Committee

Financial Review

Western delivered record net income of $119 million and cash flow before working capital adjustments of $279 million in 2004. High gas and NGL prices, increased production and steady throughput volumes, a low-cost structure and a high level of commitment from our team contributed to the strong results.

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

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT 0F 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004 OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM ____ TO ______________

Commission file number 1-10389

WESTERN GAS RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Delaware	84-1127613
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1099 18th Street, Suite 1200, Denver, Colorado	80202
(Address of principal executive offices)	(Zip Code)

(303) 452-5603
Registrant's telephone number, including area code

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

Title of each class	Name of exchange on which registered
Common Stock, $0.10 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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 _X_ 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. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes _X_ No______

The aggregate market value of voting common stock held by non-affiliates of the registrant on June 30, 2004 was $1,972,814,219.

The number of shares outstanding of the only class of the registrant's common stock, as of March 3, 2005, was 74,183,197.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III of this Report (Items 10, 11, 12 and 13) is incorporated by reference from the registrant's proxy statement to be filed pursuant to Regulation 14A with respect to the annual meeting of stockholders to be held on May 6, 2005.

Western Gas Resources, Inc.
Form 10-K
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PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

The terms Western, we, us and our as used in this Form 10-K refer to Western Gas Resources, Inc. and its subsidiaries as a consolidated entity, except where it is clear that these terms mean only Western Gas Resources, Inc.

General

Western explores for, develops and produces, gathers, processes and treats, transports and markets natural gas and natural gas liquids, or NGLs. In our upstream operations, we explore for, develop and produce natural gas reserves primarily in the Rocky Mountain region. In our midstream operations, which are comprised of three segments, we design, construct, own and operate natural gas gathering, processing and treating facilities; we own and operate regulated transportation facilities; and we offer marketing services in order to provide our customers with a broad range of services from the wellhead to the sales delivery point. Our midstream operations are conducted in major gas-producing basins in the Rocky Mountain, Mid-Continent and West Texas regions of the United States.

Our operations are conducted through the following four business segments:

- ***Upstream***—We explore for, develop and produce natural gas reserves independently and to enhance and support our existing gathering and processing operations. We sell the natural gas that we produce to third parties. Our producing properties are primarily located in the Powder River and Greater Green River Basins of Wyoming, and the Sand Wash Basin in Colorado. In addition, in October 2004, we acquired properties in the San Juan Basin of New Mexico. Our strategy is to seek new gas prospects in the Rocky Mountain region by utilizing our expertise in exploration and low-risk development of unconventional gas reservoirs including tight-gas sands, coal bed methane, biogenic, and shale gas plays to evaluate acquisitions of either additional leaseholds, proven and undeveloped reserves or companies with operations primarily focused in the Rockies. The development or acquisition of new gas prospects may provide additional opportunities for our other business segments. In January 2005, we opened an office in Calgary, Alberta to evaluate acquisitions of additional leaseholds, proven and undeveloped reserves or companies with operations in the Western Canadian Sedimentary Basin.

- ***Gathering, Processing and Treating***—Our core operations are in well-established areas such as the Permian, Anadarko, Powder River, Greater Green River, and San Juan Basins. We connect natural gas from gas and oil wells to our gathering systems for delivery to our processing or treating plants. At our plants we process natural gas to extract NGLs and we treat natural gas in order to meet pipeline specifications. We provide these services to major oil and gas companies, to independent producers of various sizes and for our own production.

- ***Transportation***— In the Powder River Basin, we own one interstate pipeline and one intrastate pipeline that transport natural gas for producers and energy marketers under fee schedules regulated by state or federal agencies.

- ***Marketing***—Our gas marketing segment is an outgrowth of our upstream and gathering, processing and treating activities. One of the primary goals of our gas marketing operations is the preservation and enhancement of the value received for our equity volumes of natural gas. This goal is achieved through the use of hedges on the production of our equity natural gas and NGLs and through the use of firm transportation capacity. We also buy and sell natural gas and NGLs in the wholesale market in the United States and in Canada. These third-party sales, our firm transportation capacity on interstate pipelines and our gas storage capacity, combined with the stable supply of gas from our facilities and production, enable us to respond quickly to changing market conditions and to take advantage of seasonal price variations and peak demand periods.

Historically, we have derived approximately 97% of our revenues from the sale of gas and NGLs. Our revenues by type of operation are as follows (dollars in thousands):

	Year Ended December 31,					
	2004	%	2003	%	2002	%
Sale of gas	$ 2,518,081	82.0	$ 2,463,451	85.7	$ 2,118,748	85.1
Sale of natural gas liquids	450,761	14.7	346,108	12.0	309,513	12.4
Gathering, processing and transportation revenue	90,874	3.0	83,672	2.9	65,601	2.6
Price risk management activities	6,796	0.2	(21,820)	(0.7)	(8,884)	(0.3)
Other	3,201	0.1	2,599	0.1	4,720	0.2
	$ 3,069,713	100.0	$ 2,874,010	100.0	$ 2,489,698	100.0

Business Strategy

Maximizing the value of our existing core assets and locating new growth projects in the Rocky Mountain region are the focal points of our business strategy. Our core assets are our fully integrated upstream and midstream properties in the Powder River, Greater Green River and San Juan Basins and our midstream operations in west Texas and Oklahoma. Since 2001, our long-term business plan has been to increase stockholder value by: (i) doubling proven reserves and equity production of natural gas from the level at December 31, 2001 over a five-year period; (ii) meeting or exceeding throughput projections in our midstream operations; and (iii) optimizing annual returns.

Double Proven Natural Gas Reserves and Equity Production of Natural Gas from the level at December 31, 2001 over a five-year period. In order to achieve this goal, we will focus on continued development of our leasehold positions in the Powder River Basin coal bed methane play, or CBM, and development in the Greater Green River and San Juan Basins, and actively seek to add other core natural gas development projects. Overall, at February 15, 2005, we hold drilling rights on approximately 1.6 million net acres in these and other Rocky Mountain basins. At December 31, 2004, we had proved developed and undeveloped reserves of approximately 812 billion cubic feet equivalent, or Bcfe, of which 40% are proved developed producing and proved developed non-producing reserves. In total, we have increased our proved developed and undeveloped reserves by approximately 71% from December 31, 2001. During 2004, our production of natural gas as compared to 2003 increased by 5% to 55.5 Bcfe. In total, this represents an increase of approximately 55% in our average equity production of natural gas from 2001 levels. We currently anticipate a 10% to 15% growth in our equity production of natural gas in 2005. In the Powder River Basin, our future growth lies in over 10,000 potential well locations in the Big George, Wyodak and related coals if the play is fully successful. In the Greater Green River Basin, our reserve potential is in the development of 40-acre and 20-acre locations on our leasehold on the Pinedale Anticline, which target sandstone reservoirs in the Lance and Mesa Verde formations and on 20-acre and 10-acre locations on our leasehold in the Jonah Field.

We continue to seek to add additional upstream core projects that are focused on Rocky Mountain natural gas. We will utilize our expertise in exploration and low-risk development of unconventional gas reservoirs including tight-gas sands, coal bed methane, biogenic, and shale gas plays to evaluate acquisitions of either additional leaseholds, proven and undeveloped reserves or companies with operations primarily focused in the Rockies. We may also evaluate unconventional gas reservoirs in areas outside the Rockies, including western Canada, where we can leverage our related exploration, production and gathering expertise.

Meet or Exceed Throughput Projections in our Midstream Operations. To achieve this goal, we must continue our efforts to add to natural gas throughput levels through new well connections, expansion or acquisition of gathering or processing systems and the consolidation of existing facilities. We also seek growth opportunities for gathering and processing through our development of new gas reserves. Our midstream operations provide us with steady throughput volumes and significant cash flow that we can in turn reinvest in new growth opportunities in this or other segments of our operations. In 2004, the throughput volume at our gathering and processing facilities averaged 1.4 billion cubic feet, or Bcf, per day and operating profit contributed by these facilities was $168.9 million. We currently anticipate an 8% to 10% growth in our throughput volumes at our gathering and processing facilities in 2005.

Our gathering and processing operations are located in some of the most actively drilled oil and gas producing basins in the United States. We enter into agreements under which we gather, process or treat natural gas produced on acreage dedicated by third parties to us or acreage which we are developing. We contract for production from newly developed acreage in order to replace declines in existing reserves or increase reserves that are dedicated for gathering, processing or treating at our facilities. Although some of our plants have experienced natural declines in dedicated reserves, overall we have been successful in connecting additional reserves to more than offset these declines. At December 31, 2004, the estimated future natural gas production connected to our gathering, processing and treating facilities totaled approximately 4.3 trillion cubic feet, or Tcf. This is based on an internal review of historical facility throughput gas volume, our interpretation of expected declines from existing connections, and assumes that there are no new well connections to our facilities. We will also evaluate investments in expansions or acquisitions of assets that complement and extend our core natural gas gathering, processing, treating and marketing businesses and new growth projects in the Rocky Mountain region. For example, in November 2004, we signed a purchase and sale agreement to acquire certain natural gas gathering and processing assets located in the Greater Green River Basin, for a total purchase price of approximately $28.0 million, before adjustments. This acquisition closed in February 2005. These systems are comprised of processing capacity of 150 million cubic feet, or MMcf per day, and a total of 140 miles of gathering lines, which, during January 2005, were gathering a total of 31 MMcf, per day.

Optimize Annual Returns. To optimize our annual returns, we will focus our efforts in our primary operating areas in the Powder River and Greater Green River Basins, the Anadarko Basin in Oklahoma, the Permian Basin in west Texas, and the San Juan Basin. We review the economic performance and growth opportunities of each of our assets to ensure that a satisfactory rate of return is achievable. If an asset is not generating targeted returns or is outside our core operating areas, we explore various options, such as integration with other Western-owned facilities or consolidation with third-party-owned facilities, dismantlement, asset trades or sale. Consolidations and joint ventures allow us to increase the throughput of one facility while reducing the capital invested in, and the operating costs of, the consolidated assets. We routinely evaluate our business for methods to reduce our operating and administrative costs, including the implementation of automation and the use of information technology.

Western Gas Resources, Inc. was incorporated in Delaware in 1989. Our principal offices are located at 1099 18th Street, Suite 1200, Denver, Colorado 80202. Our telephone number is (303) 452-5603.

Our website address is http://www.westerngas.com. We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission, or SEC, at http://www.sec.gov . Additionally, our Code of Business Conduct and Ethics, Code of Ethics for Senior Financial Management, Corporate Governance Guidelines and the charters of our Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee are posted on our website and are available in print free of charge to any stockholder who requests them.

2005 Capital Budget

In order to maintain a strong balance sheet, our general goal is to limit our capital expenditures, excluding acquisitions, in any single year to 110% of the projected cash flow generated by our operations for that year. In some years, however, we expect that we will exceed this limitation based on the growth opportunities available to us. In 2005, we anticipate capital expenditures of approximately $338.8 million. We expect that the Rocky Mountain region will utilize approximately 87% or $295.6 million of the 2005 capital budget. The 2005 capital budget is presented in the following table (dollars in thousands).

Type of Capital Expenditure	2005 Capital Budget
Gathering, processing, treating and pipeline assets	$ 112.8
February 2005 acquisition of gathering and processing assets in the Green River Basin	28.0
Exploration and production and lease acquisition activities	186.7
Information technology and other items	3.0
Capitalized interest and overhead	8.3
Total	$ 338.8

The majority of our capital expenditures are expected to be in the Powder River Basin CBM development and in the Greater Green River Basin. In the Powder River Basin CBM development, we plan to invest $118.4 million, or 35% of our total capital program. Of this amount, $81.2 million is planned to be spent on our share of drilling 850 gross wells and for production equipment and undeveloped acreage and $37.2 million is planned to be spent for gathering lines and installation of additional compression units.

In the Greater Green River Basin we expect to invest $126.5 million, or 37% of the total 2005 capital expenditure program. We plan to spend $59.0 million to participate in 85 gross wells, 68 of which are in the rapidly developing Pinedale Anticline area, and $67.5 million to expand gathering and compression services.

The remaining $93.9 million of our 2005 capital spending program is expected to be spent as follows: $55.3 million for well connections, expansions, exploration, maintenance and upgrade projects in our other operating areas, $27.3 for exploration activities including lease acquisition and exploratory drilling, $8.3 million for capitalized interest and overhead and $3.0 million for information technology and other items. Overall, we expect to spend $13.7 million on maintenance and upgrade projects for existing midstream facilities. Due to drilling, regulatory, commodity pricing and other uncertainties that are beyond our control, we can make no assurance that our capital budget for 2005 will not change or that we will actually incur this level of capital expenditure.

Upstream Operations

A vital aspect of our long-term business plan is to double proven natural gas reserves and equity production of natural gas from the level at December 31, 2001 over a five-year period. In order to achieve this goal, we will focus on continued development of our leasehold positions in the Powder River Basin CBM development, the Greater Green River Basin, and the San Juan Basin. Each of our existing upstream projects is fully integrated with our midstream operations. In other words, in each of these areas, we provide the gathering, compression, processing, marketing or transportation services for both our own production and for third-party operators. Additionally, we are actively pursuing new exploration, development and producing property acquisition opportunities.

Our principal upstream operations are summarized in the following table:

Production Area	Gross Acres Under Lease at December 31, 2004	Net Acres Under Lease at December 31, 2004	Proven Reserves at December 31, 2004 (Bcfe)	Average Net Production for the Year Ended December 31, 2004* (MMcfe/day)	Gross Productive Gas Wells at December 31, 2004	Net Productive Gas Wells at December 31, 2004
Powder River Basin CBM	1,045,000	533,000	310	114	4,219	1,999
Jonah/Pinedale Field	161,000	28,000	446	29	240	26
San Juan Basin	34,000	26,000	26	3	124	117
Sand Wash Basin	151,000	137,000	29	6	19	19
Denver-Julesburg Basin	395,000	340,000	-	-	-	-
Other	473,000	385,000	1	1	12	3
Total	2,259,000	1,449,000	812	153	4,614	2,164

* Represents net production sold.

Powder River Basin Coal Bed Methane. We continue to develop our Powder River Basin CBM reserves and expand the associated gathering system in northeast Wyoming. Our net production sold from the Powder River Basin CBM averaged 114 MMcf per day in 2004.

At December 31, 2004, we had established proven developed and undeveloped reserves totaling 310 Bcfe, net, on a portion of this acreage, 50% of which are proven and developed. Overall, this represented a 5% decrease in proven reserves as compared to December 31, 2003. Reserves in total increased by a net 34 Bcfe before production of 42 Bcfe and sales of reserves in place of 9 Bcfe. We did experience additions to reserves from drilling new wells and added new proved undeveloped locations as a result of drilling, which were partially offset by downward revisions in reserve estimates in certain areas in the basin. The downward revisions were mainly in the Wyodak coal and were the result of further pressure draw down in the Hoe Creek area and in the multiple coal area to the north where coals are generally thinner and split into several seams. Our model for reserves conservatively assumes that each well is completed in only one coal seam, and based on the cost to drill and complete a well, these locations were uneconomic and removed from the reserve base. As we proceed with our development, some of the revisions to the thin coals may be recaptured in multiple coal seam completions, which are more economic than historic single zone completions in the thinner coals.

Proved reserves at December 31, 2004 included 179 Bcf from the Big George and related coals, a 25% increase from year-end 2003. Our production from the Big George coal continues to increase and averaged 73 MMcf per day gross, or 30 MMcf per day net, in December 2004 from the All Night Creek Unit, Pleasantville, SG Palo, Bullwhacker, Schoonover and Kingsbury Unit areas. In these development areas and our areas of exploration, as of January 31, 2005, we had 583 Big George wells dewatering and producing gas, 248 Big George wells dewatering and 335 Big George wells drilled and in various stages of completion and hook-up in preparation for dewatering and production.

In 2005, we plan to participate in the drilling of 730 gross wells, or 365 net wells, in the Big George and related coals and an additional 120 gross wells, or 60 net wells, in the Wyodak and related coals. An estimated 640 wells of the 850-well program will be on federal leaseholds and require drilling permits from the Bureau of Land Management, or BLM. The remaining 210 well locations are on fee or state leaseholds. Together with our co-developer, we have drilling permits approved for 120 of the federal wells planned for 2005. Federal drilling permit applications for another 812 locations were submitted to the BLM in 2004. Timely receipt of these permits would allow us to complete our planned 2005-drilling program, and a portion of our 2006-drilling program, on federal leaseholds.

Drilling in the Powder River Basin is dependent on the receipt of various regulatory permits, including BLM drilling permits, Wyoming Department of Environmental Quality, or DEQ, water discharge permits, and the Wyoming State Engineer's Office reservoir permits. Most of our undeveloped prospects from the Big George formation are located in the Powder River drainage area. Water management techniques utilized by us, and approved by the DEQ on a site- specific basis, have included containment or treating. In order to facilitate the processing of our water discharge permit applications on the west side of the basin, and in advance of the final requirements of the DEQ, we have installed and tested various types of water treatment facilities and are treating the water produced in some areas of the basin and, with the approval of the DEQ, discharging into the Powder River. We believe many of the future developments in the Big George coal will likely require water treatment facilities. These treating operations have added and will add to the cost of development and operations in these areas. We continue to evaluate several options for water treatment and are working with the governmental agencies to identify the most effective and cost efficient methods.

Approximately 300 gross wells in our 2005-drilling program will require permits to treat produced water. The remainder of the wells to be drilled in 2005 will require more conventional types of water discharge permits, such as reservoir containment or surface discharge. To date, we, together with our co-developer in this area, have received water discharge permits from the DEQ for approximately 34% of the wells we plan to drill in 2005. We anticipate that all remaining permits necessary to complete our 2005-drilling program will be submitted by the end of the first quarter of 2005. Historically, the DEQ permit process has required approximately 120 to 150 days from initial submittal to final approval. There is, however, no assurance as to the future timing of the receipt of drilling and water discharge permits, the success of our drilling program, or the dewatering time as our development progresses into the western and northern parts of the Powder River Basin.

On April 30, 2003, the BLM issued the final Record of Decision, or ROD, for the Powder River Basin Oil & Gas Environmental Impact Statement, or EIS. The ROD requires additional surveys for plant and animal species, cultural surveys and noxious weed mitigation prior to the BLM granting a drilling permit. A number of cases have been filed by environmental groups against the BLM in Wyoming disputing the validity of the environmental impact statement and ROD. Due to our interests in developing federal leases in the Powder River Basin, we are an intervenor defendant in each of the foregoing cases. In the event of an adverse ruling, the BLM may be required to perform further environmental analysis and, in addition, could be ordered to cease issuing drilling permits until it has completed such further analysis. Consequently, our ability to receive permits and develop our leases may be delayed or restricted by the outcome of these cases.

On August 10, 2004, the Tenth Circuit Court of Appeals issued its decision in Pennaco Energy, Inc. v. United States Department of the Interior. The court upheld a decision by the Interior Board of Land Appeals, or IBLA, that the BLM had not complied with the National Environmental Policy Act in issuing three federal leases to Pennaco Energy, Inc. in the Powder River Basin for coal bed methane development. We are not a party to the case, and the IBLA and Tenth Circuit decisions do not directly address any federal leases held by us. However, we hold approximately 70,000 net acres of federal leasehold in the Powder River Basin, which may potentially be affected by the response to the Pennaco case. In order to resolve the issues raised in the Pennaco decision and related issues, the BLM filed for and received public comment on two proposed environmental assessments. After completion of the environmental assessments, the BLM believes the issues raised in the Pennaco decision will be resolved. We cannot predict what other actions the Department of Interior or third parties might take in response to this matter, or how the decision and actions taken by the BLM in response to the decision may affect the pace of federal leasing or permitting and development in the Powder River Basin.

During 2004, we expended approximately $75.5 million in the Powder River Basin coal bed project for drilling costs, production equipment and lease acquisitions. Our 2005 capital budget for the Powder River Basin coal bed project is estimated at $81.2 million; however, due to regulatory uncertainties, which are beyond our control, we can make no assurance that we will incur this level of capital expenditure during 2005.

Jonah/Pinedale Fields. Our exploration and production assets in the Green River Basin of southwest Wyoming are located in the Pinedale Anticline and Jonah Field areas. During 2004, we participated in the drilling of 80 gross wells, or approximately eight net wells, on the Pinedale Anticline and experienced a success rate of 100%. During 2004, we expended a total of $33.7 million for drilling costs and production equipment. During 2005, we expect to participate in the drilling of 80 gross wells, or approximately nine net wells, on the Pinedale Anticline. Our capital budget for 2005 in the Pinedale Anticline area provides for expenditures of approximately $40.6 million for drilling costs and production equipment. Due to drilling and regulatory uncertainties, which are beyond our control, there can be no assurance that we will incur this level of capital expenditure during 2005.

At December 31, 2004, we had established proven developed and undeveloped reserves totaling 446 Bcfe, net, 43% of which are proved developed producing and proved developed non-producing reserves. This represented an overall 35% increase in proven reserves as compared to December 31, 2003. In total, as a result of our drilling, proved undeveloped locations resulting from drilling, and the increased drilling density discussed below, our proven reserves increased by a net 127 Bcfe in this play in 2004. Partially offsetting this increase was production of 11Bcfe during the year. There can be no assurance, however, as to the ultimate recovery of these reserves.

Historically, drilling on the Pinedale Anticline has been allowed on one well per 40-acre tract. In the third quarter of 2004, the State of Wyoming approved the drilling of two wells per 40-acre tract on approximately half of the Pinedale Anticline. If this spacing were approved along the expanse of the Pinedale Anticline and proves successful, we would significantly increase our number of drilling locations. The timing of the drilling of these additional locations would be subject to the completion of any required regulatory and environmental reviews. In 2004, the state of Wyoming approved 10-acre spacing that significantly increases our number of drilling locations in the Jonah Field.

San Juan Basin. In October 2004, we acquired oil and gas assets in the San Juan Basin of New Mexico for approximately $82.2 million, plus assumed liabilities. The purchase included 32,000 gross acres, or 24,000 net acres, with production of approximately 15 MMcf per day gross, or 11 MMcf per day, net, of coal bed methane. Proved developed and undeveloped reserves as of December 31, 2004 totaled approximately 26 Bcfe. The purchase also included approximately 130 miles of related gathering systems, which are currently connected to our existing San Juan River plant. Our 2005 capital budget in this area provides for expenditures of approximately $21.0 million for our participation in the drilling of 64 gross and net development wells and workovers of the previously drilled wells.

Sand Wash Basin. We continue to explore and develop our acreage position in the Sand Wash Basin in northwest Colorado, located in the Greater Green River Basin. During 2004, we produced and sold 6 MMcfe per day from this acreage. At December 31, 2004, we had established proven developed and undeveloped reserves totaling 29 Bcfe on a portion of this acreage.

At December 31, 2004, we owned approximately 137,000 net oil and gas leasehold acres in this basin. The majority of this acreage is in the exploration phase and will be evaluated in future years. In 2004, approximately $8.2 million was spent in this area. Our 2005 capital budget in this area provides for expenditures of approximately $9.2 million for our participation in the drilling of seven gross and net development wells and one exploratory well.

Exploration. We continue to seek to add additional upstream core projects that are focused on Rocky Mountain natural gas. We will utilize our expertise in exploration and low-risk development of unconventional gas reservoirs including tight-gas sands and coal bed methane to evaluate acquisitions of additional leaseholds, proven and undeveloped reserves, or companies with operations primarily focused in the Rockies. We may also evaluate unconventional gas reservoirs in areas outside the Rockies, including Canada, where we can leverage our related exploration, production and gathering expertise. Through February 15, 2005, we have acquired the drilling rights on approximately 874,000 net acres in other Rocky Mountain basins and continue to expand our leasehold positions.

Denver-Julesburg Basin. This Niobrara gas play is located in the northeastern area of the Denver-Julesburg Basin in northeast Colorado and southwest Nebraska. In this play, as of January 31, 2005, we have acquired the drilling rights on approximately 395,000 gross acres, or approximately 340,000 net acres. We are currently constructing a 12-mile gathering line and expect production from our initial six wells to commence in the second quarter of 2005. We have identified 50 to 65 additional prospective drilling locations on our existing 59 square miles of 3-D seismic data, which will be contingent on the extended production results of the initial wells.

Washakie and Red Desert Basins. The Washakie and Red Desert Basins are located in the eastern portion of the Greater Green River Basin. In these areas, as of February 15, 2005, we have acquired the drilling rights on approximately 41,000 gross acres, or approximately 28,000 net acres. We have drilled two wells through December 31, 2004 in these areas and plan to drill nine exploration wells in these areas in 2005.

During 2004, our capital expenditures in the exploration areas totaled $11.3 million. Our capital expenditure budget for 2005 in the exploration areas totals $32.3 million, primarily for our participation in drilling activities, seismic surveys and leasehold acquisition.

Drilling Results. The following table sets forth the number of wells we drilled during each of the last three years in each of our major producing areas. This information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are defined as those that produce commercial quantities of hydrocarbons whether or not they produce a reasonable rate of return.

	Year Ended December 31,					
Productive Area	2004		2003		2002	
Powder River Basin CBM	Gross	Net	Gross	Net	Gross	Net
Productive wells drilled:	745	377	536	257	909	436
Dry development wells drilled:	3	1	0	0	0	0
Dry exploratory wells drilled:	4	2	0	0	0	0
Jonah/Pinedale Field						
Productive wells drilled:	79	8	53	5	26	4
Dry exploratory wells drilled:	1	0	0	0	0	0
San Juan Basin						
Productive wells drilled:	4	4	0	0	0	0
Dry development wells drilled:	1	1	0	0	0	0
Sand Wash Basin						
Productive wells drilled:	1	1	7	7	2	2
Exploratory productive wells drilled:	1	1	0	0	0	0
Dry exploratory wells drilled:	1	0	1	1	0	0
Other						
Exploratory productive wells drilled:	7	6	4	3	0	0

Production Information. Revenues derived from our producing properties comprised approximately 9%, 7% and 6% of consolidated revenues for the years ended December 31, 2004, 2003 and 2002, respectively. The operating profit (revenues and equity earnings from equity investments less product purchases and operating expenses) derived from our producing properties comprised approximately 43%, 40% and 33% of consolidated operating profit for the years ended December 31, 2004, 2003 and 2002, respectively. We expect both the revenues and operating profit derived from our producing properties to continue to increase commensurately with our production growth.

The following table provides a summary of our net annual production volumes:

	Year Ended December 31,					
	2004		2003		2002	
State/Basin	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)
Colorado – Sand Wash Basin	2,153	9	1,340	6	900	6
Texas (1)	22	3	16	1	20	2
Wyoming:						
Powder River Basin	41,715	-	43,748	-	42,314	-
Greater Green River Basin	10,075	85	7,118	68	4,167	45
New Mexico	927	-	-	-	-	-
Total	54,892	97	52,222	75	47,401	53

(1) Represents a small non-operating working interest in several wells in the Austin Chalk area.

The following table provides a summary of our proved developed and proved undeveloped net reserves as of the end of the last three years:

	Year Ended December 31,					
	2004		2003		2002	
State/Basin	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)
Colorado-Sand Wash Basin	28,293	111	28,011	114	12,624	53
New Mexico-San Juan Basin	25,750	112	-	-	-	-
Wyoming:						
Powder River Basin	309,597	-	325,966	-	414,143	-
Greater Green River Basin	426,796	3,418	314,747	2,539	153,897	1,160
Total	790,436	3,641	668,724	2,653	580,664	1,213

Netherland, Sewell & Associates, Inc, or NSAI prepared the reports for proved reserves for 2004 and 2003. The report for proved reserves in the Powder River Basin and other Wyoming assets for 2002 was prepared by us and audited by NSAI.

Reserve estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves, the projection of future rates of production and the timing of development expenditures. The accuracy of these estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserve estimates are imprecise and should be expected to change as additional information becomes available. Estimates of economically recoverable reserves and of future discounted net cash flows prepared by different engineers or by the same engineers at different times may vary substantially. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of those reserves are based upon assumptions about production levels, prices and costs, which may not be correct. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based. Actual results may differ materially from the results estimated.

Midstream Operations

Our midstream operations consist of our gathering, processing, treating, marketing and transportation operations. An important element of our long-term business plan is to meet or exceed throughput projections in these areas and to optimize their profitability. To achieve this goal, we must continue our efforts to add to natural gas throughput levels through new well connections and through the expansion or acquisition of gathering or processing systems. We also seek to increase the efficiency of our operations by modernization of equipment and the consolidation of existing facilities.

Gas Gathering, Processing and Treating. At December 31, 2004, we operated a variety of gathering, processing and treating facilities, or plant operations, with approximately 10,800 miles of gathering lines, as presented on the Principal Gathering and Processing Facilities Table set forth below. These facilities are primarily located in five states and at December 31, 2004, had a combined throughput capacity of approximately 3.1 Bcf per day of natural gas. Our operations are located in some of the most actively drilled oil and gas producing basins in the United States. Five of our processing plants can further separate, or fractionate, the mixed NGL stream into ethane, propane, normal butane and natural gasoline to obtain a higher value for the NGLs, and three of our plants are capable of processing and treating natural gas containing hydrogen sulfide or other impurities that require removal prior to delivery to market pipelines. In addition to our integrated upstream and midstream operations in the Powder River, Greater Green River, and San Juan Basins, our core assets include our plant operations located in west Texas and Oklahoma. We believe that our core assets have stable production rates, provide a significant operating cash flow and continue to provide us with strategic growth opportunities.

We contract with producers to gather raw natural gas from individual wells located near our plants or gathering systems. Once we have executed a contract, we connect wells to gathering lines through which the natural gas is delivered to a processing plant or treating facility. At a processing plant, we compress the natural gas, extract raw NGLs and treat the remaining dry gas to meet pipeline quality specifications.

We acquire dedicated acreage and natural gas supplies in an effort to maintain or increase throughput levels to offset natural production declines of connected wells. We obtain these natural gas supplies by connecting additional wells, purchasing existing systems from third parties and through internally developed projects or joint ventures. Historically, while individual plants have experienced declines in dedicated reserves, overall we have been successful in connecting additional reserves to more than offset the natural declines. However, the level of future drilling will depend upon, among other factors, the prices for gas and oil, the drilling budgets of third-party producers, energy and environmental policy and regulation of governmental agencies and the availability of foreign oil and gas, none of which is within our control. At December 31, 2004, the estimated future natural gas production connected to our gathering, processing and treating facilities totaled approximately 4.3 Tcf. This is based on an internal review of historical facility throughput gas volume, our interpretation of expected declines from existing connections, and assumes that there are no new well connections to our facilities.

Substantially all gas flowing through our gathering, processing and treating facilities is supplied under three types of contracts providing for the purchase, treating or processing of natural gas for periods ranging from one month to twenty years or in some cases for the life of the oil and gas lease. Approximately 70% of our plant facilities' gross margin, or revenues at the plant less product purchases, for the month of December 2004 was under percentage-of-proceeds agreements where we are typically responsible for the marketing of the gas and NGLs. Under these agreements, we pay producers a specified percentage of the net proceeds received from the sale of the gas and the NGLs.

Approximately 20% of our plant facilities' gross margin for the month of December 2004 was under contracts that are primarily fee-based from which we receive a set fee for each Mcf of gas gathered and/or processed. This type of contract provides us with a steady revenue stream that is not dependent on commodity prices, except to the extent that low prices may cause a producer to delay drilling or shut in production.

Approximately 10% of our plant facilities' gross margin for the month of December 2004 was under contracts with "keepwhole" arrangements or wellhead purchase contracts. We retain the NGLs recovered by the processing facility and keep the producers whole by returning to the producers at the tailgate of the plant an amount of residue gas equal on a Btu basis to the natural gas received at the plant inlet. The "keepwhole" component of the contracts permits us to benefit when the value of the NGLs is greater as a liquid than as a portion of the residue gas stream. However, we are adversely affected when the value of the NGLs is lower as a liquid than as a portion of the residue gas stream.

Midstream Operating Areas

Powder River Basin. Our midstream operations in the Powder River Basin are fully integrated with our upstream operations as we provide the gathering, compression and processing services for our own production. Additionally we provide the same types of services for third parties. As of December 31, 2004, our assets in the Powder River Basin were primarily comprised of our coal bed methane gathering system with a capacity of 548 Mcf per day, several gas processing facilities with a combined capacity of 146 MMcf per day, and our 13% equity interest in Fort Union Gas Gathering, L.L.C., or Fort Union. We averaged 396 MMcf per day of CBM gathering volumes, including third-party gas, during the fourth quarter of 2004. Of that volume, approximately 96 MMcf per day was transported through our MIGC pipeline.

We are the construction manager and field operator of the Fort Union gathering system and header. The Fort Union system delivers coal bed methane gas to its treating facility near Glenrock, Wyoming and accesses interstate pipelines serving gas markets in the Rocky Mountain and Midwest regions of the United States. The gathering pipeline has a capacity of 635 MMcf per day. We have a long-term gathering agreement with Fort Union for 83 MMcf per day of this capacity at $0.14 per Mcf.

We spent approximately $32.2 million in the Powder River Basin for midstream activities during 2004. Our capital budget in the Powder River Basin for midstream activities provides for expenditures of $37.2 million during 2005. Depending upon our future drilling success, we may need to make additional capital expenditures or leasing commitments to continue expansion in this basin. Due to drilling, regulatory, commodity pricing and other uncertainties, which are beyond our control, there can be no assurance that we will incur this level of capital expenditure during 2005.

Greater Green River Basin. Our midstream operations in the Greater Green River Basin of southwest Wyoming are also fully integrated with our upstream operations in this area. Our midstream assets in this basin are comprised of the Granger and Lincoln Road facilities, or collectively the Granger complex, our 50% equity interest in Rendezvous Gas Services, L.L.C., or Rendezvous, our Red Desert facility and our Table Rock, Wamsutter and Desert Springs gathering systems. These facilities have a combined gathering capacity of 664 MMcf per day, and in the year ended December 31, 2004, these facilities averaged throughput of 547 MMcf per day. Additionally, these systems have a combined processing capacity of 370 MMcf per day and in the year ended December 31, 2004, processed an average of 278 MMcf per day. These capacity and processing volumes do not include volumes committed to our straddle facility described below.

In December 2004, a new 200 MMcf per day processing facility adjacent to the Granger Complex was placed into service. This facility straddles a third-party regulated pipeline and processes its gas to meet pipeline specifications. The facility's capacity is contractually committed to this service, and the contract for processing this gas requires a monthly demand charge to be paid by the pipeline regardless of the amount of gas processed. These demand fees total approximately $2.2 million per year and the contract has a term of ten years.

In November 2004, we signed a purchase and sale agreement to purchase certain natural gas gathering and processing assets in the eastern Greater Green River Basin for approximately $28.0 million, before adjustments. This acquisition closed in February 2005. The acquisition included the Patrick Draw processing plant with 150 MMcf per day of capacity and approximately 140 miles of related gathering systems. At December 31, 2004, Patrick Draw was processing approximately 35 MMcf per day of gas. Patrick Draw will be integrated into our existing Red Desert facility and our Table Rock, Wamsutter and Desert Springs gathering systems.

During 2004, we spent approximately $22.7 million in capital expenditures for midstream activities in this basin. Our 2005 capital budget for midstream activities in this basin provides for expenditures of $67.5 million. This capital budget includes $37.3 million for gathering lines and installation of compression to expand the capacity of our Granger Complex, our Wamsutter gathering system and our Red Desert facility, $28.0 million for the acquisition of several gathering and processing assets and $2.2 million for additional contributions to Rendezvous for the expansion of its systems. Due to drilling, commodity pricing and regulatory uncertainties, which are beyond our control, there can be no assurance that we will incur this level of capital expenditure during 2005.

In 2001, we, together with an unrelated third-party, formed Rendezvous. Rendezvous gathers gas along the Pinedale Anticline for blending or processing at either our Granger Complex or at the third-party owned and operated Blacks Fork processing facility. We own a 50% interest in Rendezvous, and we serve as field operator of its systems. At December 31, 2004, the capacity of Rendezvous was 275 MMcf per day and the facility gathered an average of 253 MMcf per day in 2004. During 2004, we implemented an upgrade of our 100 MMcf per day refrigeration unit at our Granger plant at a cost of approximately $3.0 million, in part to process gas delivered off the Rendezvous system.

West Texas. Our primary assets in west Texas are the Midkiff/Benedum complex and the Gomez and Mitchell Puckett treating facilities. These facilities process gas produced by third parties in the Permian Basin, have a combined operational capacity of 565 MMcf per day and processed an average of 280 MMcf per day in the year ended December 31, 2004. Also for this period, these facilities produced an average of 206 MMcf per day of natural gas for delivery to sales markets and produced an average of 831 MGal per day of NGLs. In 2004, our capital expenditures in this area totaled approximately $9.6 million. Our capital budget in this area provides for expenditures of approximately $11.1 million during 2005. This budget includes approximately $7.7 million for additions to the gathering systems and plant facilities and approximately $3.4 million for replacing and upgrading field and plant equipment.

Oklahoma. Our primary assets in Oklahoma are the Chaney Dell and Westana systems. These facilities gather and process gas produced by third parties in the Anadarko Basin and have a combined operational capacity of 175 MMcf per day. During the year ended December 31, 2004, these facilities gathered an average of 182 MMcf per day, produced an average of 159 MMcf per day of natural gas for delivery to sales markets and produced an average of 308 MGal per day of NGLs. During 2004, our capital expenditures in this area totaled $14.9 million. Our capital budget in this area provides for expenditures of approximately $20.8 million during 2005. This budget includes approximately $17.5 million for additions to the gathering systems and plant facilities and approximately $3.3 million for replacing and upgrading field and plant equipment.

San Juan. Our assets in the San Juan Basin of New Mexico are the San Juan River processing facility and the Four Corners Gathering system. These facilities gather and process gas produced by us and third parties in the San Juan and Paradox Basins and have a combined operational capacity of 75 MMcf per day. In 2004, these facilities gathered and processed an average of 29 MMcf per day, produced an average of 23 MMcf per day of natural gas for delivery to sales markets and produced 51 MGal per day of NGLs. During 2004, our capital expenditures in this area totaled $13.6 million, including $11.8 million for the acquisition of approximately 130 miles of related gathering systems in October 2004. Our capital budget in this area provides for expenditures of $2.4 million during 2005. This budget includes $2.0 million for additions to the gathering systems and plant facilities and $400,000 for replacing and upgrading field and plant equipment.

Principal Gathering and Processing Facilities Table. The following table provides information concerning our principal gathering, processing and treating facilities at December 31, 2004.

Facilities [1]	Year Placed in Service	Gas Gathering System Miles	Gas Throughput Capacity (MMcf/D)[2]	Average for the Year Ended December 31, 2004 Gas Throughput (MMcf/D) [3]	Gas Production (MMcf/D)[4]	NGL Production (MGal/D) [4]
Texas						
Gomez Treating [5]	1971	389	280	95	86	-
Midkiff/Benedum	1949	2,332	165	139	91	830
Mitchell Puckett Treating [5]	1972	126	120	46	29	1
Wyoming						
Coal Bed Methane Gathering	1990	1,369	548	396	367	-
Desert Springs Gathering	1979	65	10	6	6	23
Fort Union Gas Gathering[12]	1999	167	635	449	449	-
Granger Complex [6][7][8]	1987	714	325	265	215	340
Hilight Complex [6]	1969	657	124	19	14	63
Kitty/Amos Draw [6]	1969	321	17	6	4	26
Newcastle [6]	1981	146	5	3	2	22
Red Desert [6]	1979	125	42	41	29	53
Rendezvous [10]	2001	238	275	253	253	-
Reno Junction [7]	1991	-	-	-	-	125
Table Rock Gathering	1979	100	20	13	13	-
Wamsutter Gathering [11]	1979	242	50	43	39	21
Wind River Gathering	1979	137	80	52	51	-
Granger Straddle Plant[13]	2004	-	200	5	-	-
Oklahoma						
Chaney Dell/Westana	1966	3,307	175	182	159	308
New Mexico						
San Juan River [5][9]	1955	277	60	27	21	40
Utah						
Four Corners Gathering	1988	104	15	2	2	11
Total		10,816	3,146	2,042	1,830	1,863

(1) Our interest in all facilities is 100% except for Midkiff/Benedum (73%); Newcastle (50%); Fort Union (13%) and Rendezvous (50%). We operate all facilities, and all data include our interests and the interests of other joint interest owners and producers of gas volumes dedicated to the facility. Unless otherwise indicated, all facilities shown in the table are gathering, processing or treating facilities.

(2) Gas throughput capacity is as of December 31, 2004 and represents capacity in accordance with design specifications unless other constraints exist, including permitting or field compression limits.

(3) Aggregate natural gas volumes delivered into our gathering systems.

(4) Volumes of gas and NGLs are allocated to a facility when a well is connected to that facility; volumes exclude NGLs fractionated for third parties.

(5) Sour gas facility (capable of processing or treating gas containing hydrogen sulfide and/or carbon dioxide).

(6) Processing facility that includes fractionation (capable of fractionating raw NGLs into end-use products).

(7) NGL production includes conversion of third-party feedstock to iso-butane.

(8) The Granger Complex includes the Lincoln Road facility. As of January 1, 2004, the volume information for this facility is reported with the volume information for Granger.

(9) Includes the acquisition of gathering assets, which closed on October 1, 2004.

(10) The majority of the gas gathered by the Rendezvous gas gathering system is delivered to our Granger facility and is included with the volume information reported for Granger.

(11) A portion of the gas gathered by the Wamsutter gas gathering system is delivered to our Red Desert facility and is included with the volume information reported for Red Desert.

(12) A portion of the gas gathered by Fort Union is also reported under Coal Bed Methane Gathering.

(13) This facility was placed in service in December 2004.

We routinely review the economic performance of each of our operating facilities to ensure that a satisfactory rate of return is achieved. If an operating facility is not generating targeted returns we will explore various options, such as consolidation with other Western-owned or third-party-owned facilities, dismantlement, asset trades or sale. A description of the significant midstream acquisitions and dispositions since January 1, 2000, involving assets other than those that were previously discussed are:

Acquisition and Disposition of Various Wyoming Gathering Systems. Effective February 1, 2003, we acquired several gathering systems in Wyoming, primarily located in the Greater Green River Basin with smaller operations in the Powder River and Wind River Basins, for a total of $37.1 million. Several of the systems located in the Powder River and Wind River basins did not integrate directly into our existing systems, and accordingly we sold these systems in the third and fourth quarters of 2003.

Toca Processing Facility. In 2002, we sold our Toca processing facility in Louisiana. The sale price was $32.2 million, and resulted in a pre-tax loss of approximately $230,000. The sale included a natural gas processing plant with a capacity of 160 MMcf per day and a fractionator that could separate 14,200 barrels per day of mixed natural gas liquids into propane, normal butane, iso-butane and natural gasoline. The sale also included NGL storage as well as truck, rail and barge loading facilities, which support the complex.

Bethel Treating Facility. In December 2000, we signed an agreement for the sale of all the outstanding stock of our then wholly owned subsidiary, Pinnacle Gas Treating, Inc., or Pinnacle, for $38.0 million. The only asset of this subsidiary was a 300 MMcf per day treating facility and 86 miles of associated gathering assets located in east Texas. The sale closed in January 2001 and resulted in a net pre-tax gain for financial reporting purposes of $12.1 million in the first quarter of 2001.

Arkoma. In August 2001, we sold our Arkoma Gathering System in Oklahoma for gross proceeds of $10.5 million. This sale resulted in a pre-tax gain of $3.9 million.

Westana. In February 2001, we acquired the remaining 50% interest in the Westana Gathering Company for a net purchase price of $9.8 million.

Western Gas Resources-California, Inc. In January 2001, we sold all the outstanding stock of our then wholly owned subsidiary, Western Gas Resources-California, Inc., or WGR-California, for $14.9 million. The only asset of this subsidiary was a 162-mile pipeline in the Sacramento Basin of California. WGR-California acquired the pipeline through the exercise of a purchase option in a transaction that closed immediately prior to the sale by us of WGR-California. We recognized a pre-tax gain on the sale of approximately $5.4 million in 2001.

Transportation Operations

We own and operate MIGC, Inc., an interstate pipeline located in the Powder River Basin, and MGTC, Inc., an intrastate pipeline located in northeast Wyoming. MIGC charges a Federal Energy Regulatory Commission, or FERC, approved tariff and is connected to pipelines owned by Colorado Interstate Gas Company, Williston Basin Interstate Pipeline Company, Kinder Morgan Interstate Pipeline Co., Wyoming Interstate Company, Ltd. and MGTC. MIGC earns fees on a monthly basis from firm capacity contracts under which the shipper pays for transport capacity whether or not the capacity is used and from interruptible contracts where a fee is charged based upon volumes received into the pipeline. Contracts with third parties for capacity on MIGC range in duration from one month to five years and the fees charged averaged $0.35 per Mcf in 2004. MGTC, a public utility, provides transportation and gas sales to various cities in Wyoming at rates that are subject to the approval of the Wyoming Public Service Commission.

The following table provides information concerning our principal transportation assets at December 31, 2004.

			Average for the Year Ended December 31, 2004	
Transportation Facilities (1)	Year Placed In Service	Transportation Miles	Pipeline Capacity (MMcf/D) (2)	Gas Throughput (MMcf/D) (3)
MIGC	1970	263	130	147
MGTC	1963	251	18	8
Total		514	148	155

(1) Our interest in both facilities is 100%, and we operate both facilities.
(2) Pipeline capacity represents certificated capacity at the Powder River junction only and does not include interruptible capacity or capacity at other delivery points.
(3) Aggregate volumes transported by a pipeline.

Marketing

Gas. We market gas produced at our wells and at our plants and gas purchased from third-parties to end-users, local distribution companies, or LDCs, pipelines and other marketing companies throughout the United States and Canada. In addition to our offices in Denver, we have marketing offices in Houston, Texas and Calgary, Alberta. Third-party sales, firm transportation capacity on interstate pipelines and our gas storage positions, combined with the stable supply of gas from our facilities and production, enable us to respond quickly to changing market conditions and to take advantage of seasonal price variations and peak demand periods.

One of the primary goals of our gas marketing operations continues to be the preservation and enhancement of the value received for our equity volumes of natural gas. This goal is achieved through the use of hedges on the production of our equity natural gas and through the use of firm transportation capacity. Historically, the gas produced in the Rocky Mountain region has traded at a substantial discount to the Mid-Continent and West Coast areas as a result of limited pipeline capacity from the region. We have historically used our firm pipeline transportation capacity to access higher priced Mid-Continent markets for both our equity production and for gas purchased from third parties in the Rocky Mountain region. During 2003, additional pipeline capacity out of the Rocky Mountain region went into service. This pipeline expansion contributed to a reduction in the price difference between the Rocky Mountain region and Mid-Continent market center. The additional pipeline capacity from the Rocky Mountain region to the Mid-Continent producing region of the country along with increased exploration and production in the Mid-Continent region may increase overall utilization of the pipeline systems that are used to move gas out of the Mid-Continent region to consuming areas in the upper Midwest. Increased throughput on those systems may cause the market price for natural gas within the Mid-Continent to be reduced relative to other markets. Consistent with our goal to preserve and enhance the value of equity volumes of natural gas, in 2004, we have acquired approximately 101,000 MMBtu per day of additional firm transportation capacity out of the Mid-Continent region to market areas in the upper Midwest and the Mississippi River Valley.

For the year ended December 31, 2004, our total gas sales volumes averaged 1.2 Bcf per day, of which 344 MMcf per day was produced at our plants or from our producing properties. We do not expect our average daily sales volume to increase in 2005. The marketing of gas purchased from third parties typically results in low profit margins relative to the sales price. We sell gas under agreements with varying terms and conditions in order to match seasonal and other changes in demand. As of December 31, 2004, the weighted average duration of our sales contracts was 12 months. During the year ended December 31, 2004, we sold gas to approximately 252 end-users, pipelines, LDCs and other customers. No single customer accounted for more than approximately 9% of our consolidated revenues from the sale of gas, or 7% of total consolidated revenue, for the year ended December 31, 2004. We continually monitor and review the credit exposure to our gas marketing counterparties.

NGLs. We market NGLs, or ethane, propane, iso-butane, normal butane, natural gasoline and condensate, produced at our plants and purchased from third-parties, in the Rocky Mountain, Mid-Continent and Southwestern regions of the United States. A majority of our production of NGLs moves to the Gulf Coast area, which is the largest NGL market in the United States. Through the development of end-use markets and distribution capabilities, we seek to ensure that products from our plants move on a reliable basis, avoiding curtailment of production. For the year ended December 31, 2004, NGL sales averaged 1,641 MGal per day, of which 1,386 MGal per day was produced at our plants.

Consumers of NGLs are primarily the petrochemical industry, the petroleum refining industry and the retail and industrial fuel markets. As an example, the petrochemical industry uses ethane, propane, normal butane and natural gasoline as feedstocks in the production of ethylene, which is used in the production of various plastics products. Further, consumers use propane for home heating, transportation and agricultural applications. Price, seasonality and the economy primarily affect the demand for NGLs.

We sell NGLs under agreements with varying terms and conditions in order to match seasonal and other changes in demand. At December 31, 2004, the terms of our sales contracts range from one month to three years. The marketing of NGLs purchased from third parties typically results in low profit margins relative to the sales price. As in the case of natural gas, we continually monitor and review the credit exposure to our NGL marketing counterparties.

In 2004, one customer accounted for approximately 51% of the Company's consolidated revenues from the sale of NGLs, or 7% of total consolidated revenue. This customer is a large integrated energy company. We also derive revenues from contractual marketing fees charged to some producers for NGL marketing services. For the year ended December 31, 2004, these fees were less than 2% of our total consolidated revenue.

Environmental

The construction and operation of our gathering systems, plants and other facilities used for the gathering, processing, treating or transporting of gas and NGLs are subject to federal, state and local environmental laws and regulations, including those that can impose obligations to clean up hazardous substances at our facilities or at facilities to which we send wastes for disposal. In most instances, the applicable regulatory requirements relate to water and air pollution control or waste management. We employ specialists in environmental engineering, safety and regulatory compliance to monitor environmental and safety compliance at our facilities. In addition, our environmental engineers and safety specialists perform in-house audits of our existing facilities to ensure on-going compliance. Similarly, prior to consummating any major acquisition, our environmental engineers perform audits on the facilities to be acquired. We believe that we are in substantial compliance with applicable material environmental laws and regulations. Environmental regulation can increase the cost of planning, designing, constructing and operating our facilities. We anticipate that the trend in environmental legislation and regulation will continue to be toward stricter standards. The costs for compliance with current environmental laws and regulations have not had and, we believe, will not have a material adverse effect on our financial position or results of operations. We however cannot predict the extent or timing of future regulations or legislation and whether any such regulations or legislation will have a material adverse effect on the financial results of our operations, financial position or cash flows.

Prior to consummating any major acquisition, our environmental engineers perform audits on the facilities to be acquired. In conducting this audit on the acquisition of the gathering and processing facilities acquired in February 2005, we performed phase one environmental assessments and, where conditions indicated, performed phase two assessments. These assessments enabled us to satisfy ourselves that the disclosures by the seller were materially accurate and also to form our own risk assessment of potential environmental issues. In relation to the assets purchased in the February 2005 acquisition, one of the sites was the subject of an Administrative Order between the former owner, the State of Wyoming and a third party who has contracted to remediate the site in accordance with the Administrative Order. As a result of the acquisition, we also became a party to the Administrative Order. Both that site and another site are insured under an insurance policy that was put in place by the seller for the costs of all remediation activities. The obligation to perform and complete those remediation activities has been assigned contractually to a third party environmental specialist whose costs will be reimbursed by the insurance policy.

We are in the process of voluntarily cleaning up substances at several of the facilities that we operate. Our expenditures for environmental evaluation and remediation at existing facilities have not been significant in relation to our results of operations and totaled approximately $2.1 million for the year ended December 31, 2004. In addition, in 2004, we paid approximately $467,000 in air emissions fees to the states in which we operate.

Competition

We compete with other companies in the gathering, processing, treating and marketing businesses both for supplies of natural gas and for customers for our natural gas and NGLs, and in our exploration and production business for the acquisition of leaseholds and other assets or services. Competition for natural gas supplies is primarily based on the efficiency and reliability of our services, the availability of transportation and the ability to obtain a satisfactory price for natural gas and NGLs. Our competitors for obtaining additional gas supplies, for gathering and processing gas and for marketing gas and NGLs include national and local gas gatherers and processors, brokers, marketers and distributors of various sizes and experience. The majority of these competitors have greater financial resources than do we. For customers that have the capability of using alternative fuels, such as oil and coal, we also compete for their business based on the price and availability of such alternative fuels. Our competitors for obtaining leaseholds include major and large independent oil companies as well as smaller independent oil companies and brokers. Competition for oil field services, including drilling rigs, could affect future drilling plans and costs. Competition for sales customers is primarily based upon reliability and price of deliverable natural gas and NGLs. Suppliers in our gas marketing transactions may request additional financial security such as letters of credit that are not required of some of our competitors.

Regulation

Our purchase and sale of natural gas and NGLs and the fees we receive for gathering and processing have generally not been subject to regulation. However, some aspects of our business are subject to federal, state and local laws and regulations that have a significant impact upon our overall operations. See additional discussion of regulatory issues and requirements in Upstream Operations.

As a producer, processor and marketer of natural gas, we depend on the transportation and storage services offered by various interstate and intrastate pipeline companies for the delivery and sale of our own gas supplies as well as those we process and/or market for others. Both the interstate pipelines' performance of transportation and storage services, and the rates charged for such services, are subject to the jurisdiction of the FERC, under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. At times, other system users can pre-empt the availability of interstate transportation and storage services necessary to enable us to make deliveries and/or sales of gas in accordance with FERC-approved methods for allocating the system capacity of open access pipelines. Moreover, the rates the pipelines charge for such services are often subject to negotiation between shippers and the pipelines within FERC-established parameters and will periodically vary depending upon individual system usage and other factors. An inability to obtain transportation and/or storage services at competitive rates can hinder our processing and marketing operations and/or adversely affect our sales margins.

Generally, neither the FERC nor any state agency regulates gathering and processing prices. The Oklahoma Corporation Commission has limited authority in some circumstances, after the filing of a complaint by a producer, to compel a gas gatherer to provide open access gathering and to set aside unduly discriminatory gathering fees. From time to time, state legislatures have considered, and may do so in the future, adopting legislation that would expand the authority of the relevant state administrative body to compel a gas gatherer to publish rates, terms and conditions of its service and under some circumstances, to justify those charges. We cannot predict what additional legislation or regulations the states may adopt regarding gas gathering.

The construction of additional gathering, processing and treating facilities and the development of natural gas reserves require permits from several federal, state and local agencies. In the past we have been successful in receiving all permits necessary to conduct our operations. There can be no assurance, however, that permits in the future will be obtainable or issued timely or that the terms of any permits will be compatible with our business plans.

Employees

At December 31, 2004, we employed 729 full-time employees, of which 434 were employed at field locations. None of our employees is a union member. We consider relations with employees to be excellent.

ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 8 of our Consolidated Financial Statements in Item 8 of this Form 10-K.

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, 2004.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of March 3, 2005, there were 74,183,197 shares of common stock outstanding held by 181 holders of record. The common stock is traded on the New York Stock Exchange, or NYSE, under the symbol "WGR". The following table sets forth quarterly high and low per share sales prices as reported by the NYSE Composite Tape for the quarterly periods indicated.

	HIGH	LOW
2004		
Fourth Quarter	$ 31.50	$ 26.38
Third Quarter	35.25	27.50
Second Quarter	32.78	24.97
First Quarter	25.75	22.75
2003		
Fourth Quarter	$ 23.75	$ 19.20
Third Quarter	20.03	18.20
Second Quarter	20.83	15.96
First Quarter	18.75	15.28

We paid dividends on our common stock aggregating $0.05 per share during each of the second, third and fourth quarters of 2004 and $0.025 per share during the first quarter of 2004 and in each quarter during 2003. Our board of directors has declared a dividend of $0.05 per share of common stock for the quarter ending March 31, 2005 to holders of record as of that date. Declarations of dividends on our common stock are within the discretion of the board of directors. In addition, our ability to pay dividends on our common stock is restricted by covenants in our financing facilities.

Equity Compensation Plan Information

The following table summarizes our equity compensation plans under which securities may be issued as of December 31, 2004. The only types of equity compensation plans that we have are plans that authorize the granting of options to purchase shares of our common stock.

Plan Category	Number of securities to be issued upon exercise of outstanding options (a)	Weighted-average per share exercise price of outstanding options (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	3,151,055	$ 21.60	996,044*
Equity compensation plans not approved by security holders	606,600	$ 12.40	-
Total	3,757,655	$ 20.12	996,044

* Includes options covering 745,204 shares that are available to be granted under our 1997 stock option plan. Our board of directors has determined that no further options will be granted under this plan.

A description of the equity compensation plans that were not approved by the security holders is as follows.

1999 Non-Employee Directors Stock Option Plan. Effective March 1999, our board of directors adopted a stock option plan that authorized the granting of options to purchase 30,000 shares of our common stock to non-employee directors. During 1999, the board of directors approved grants of options covering a total of 30,000 shares of our common stock to several board members. The exercise price of the stock underlying each option was the average closing price for the ten days prior to the grant. Under this plan, options covering up to 33 1/3% of the underlying shares are exercisable on each anniversary from the date of grant and the director must exercise the option within five years of the date each option vests. This plan terminates on the earlier of March 12, 2009 or the date on which all options granted under the plan have been exercised in full.

Chief Executive Officer and President's Plan. Pursuant to the employment agreement, dated October 15, 2001, and the stock option agreement, dated as of November 1, 2001, between Western and Peter A. Dea, our CEO and President, we granted non-qualified stock options to Mr. Dea for the purchase of 600,000 shares of our common stock. The exercise price of the options was equal to $2.50 below the closing price per share on the effective date of his employment agreement. The stock options are subject to the conditions of the agreements and vest equally over four years and must be exercised within five years of the date on which they vest. The difference between the closing price on the effective date and the exercise price is being amortized over four years as compensation expense. This option plan will terminate on the earlier of October 15, 2010 or the date on which all options granted under the plan have been exercised in full.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated historical financial and operating data for Western. Certain prior year amounts have been reclassified to conform to the presentation used in 2004. The data for the three years ended December 31, 2004, 2003 and 2002 should be read in conjunction with our Consolidated Financial Statements and the Notes thereto included elsewhere in this Form 10-K. The selected consolidated financial data for the years ended December 31, 2001 and 2000 are derived from our audited historical Consolidated Financial Statements. See also Item 7 – "Management's Discussion and Analysis of Financial Condition and Results of Operations." Amounts in thousands, except per share amounts and operating data.

	Year ended December 31,				
	2004	2003	2002	2001	2000
Statement of Operations:					
Revenues	$ 3,069,713	$ 2,874,010	$ 2,489,698	$ 3,353,162	$ 3,280,091
Gross profit (a)	267,026	210,430	144,430	200,780	149,155
Income before income taxes	183,268	144,536	80,703	152,126	88,673
Provision for income taxes	68,767	53,593	30,114	56,489	32,565
Income before cumulative effect of change in accounting principle	114,501	90,943	50,589	95,637	56,108
Cumulative effect of change in accounting principle, net of tax	4,714(c)	(6,724)(b)	-	-	-
Net income	119,215	84,219	50,589	95,637	56,108
Earnings per share of common stock before cumulative effect of change in accounting principle	1.56	1.27	0.63	1.30	0.71
Earnings per share of common stock	1.63	1.17	0.63	1.30	0.71
Earnings per share of common stock - assuming dilution	1.61	1.13	0.62	1.24	0.70
Other Financial Data:					
Net cash provided by operating activities	$ 209,448	$ 244,222	$ 124,401	$ 170,881	$ 99,637
Net cash (used in) investing activities	(302,744)	(197,085)	(105,772)	(131,657)	(82,039)
Net cash provided by (used in) financing activities	67,570	(28,333)	(21,349)	(42,119)	(18,733)
Capital expenditures	306,555	203,068	140,637	169,751	108,536
Balance Sheet Data (at year end):					
Total assets	$ 1,840,112	$ 1,460,524	$ 1,302,144	$ 1,267,942	$ 1,431,422
Long-term debt	382,000	339,000	359,933	366,667	358,700
Stockholders' equity	682,028	562,509	483,068	473,352	391,534
Dividends on preferred stock	835	6,841	9,198	11,167	10,416
Dividends on common stock	12,847	6,684	6,603	6,524	6,448
Dividends per share of common stock	0.18	0.10	0.10	0.10	0.10
Operating Data:					
Average gas sales (MMcf/D)	1,225	1,361	1,988	1,961	1,835
Average NGL sales (Mgal/D)	1,641	1,634	2,010	2,347	3,085
Average gas volumes gathered (MMcf/D)	1,361	1,343	1,163	1,161	1,248
Facility capacity (MMcf/D)	3,146	2,883	2,581	2,574	2,374
Net annual production volume (Mmcfe)	55,474	52,672	47,719	35,784	28,187
Average gas prices ($/Mcf)	$ 5.59	$ 4.94	$ 2.92	$ 3.97	$ 3.90
Average NGL prices ($/Gal)	$ 0.75	$ 0.58	$ 0.42	$ 0.49	$ 0.52

(a) Excludes selling and administrative, interest expense, income tax expense, (gains) or losses on sales of assets, cumulative effect of changes in accounting principles and any loss for the early extinguishment of debt. See further discussion in note (b).

(b) We recognized an after-tax loss on the adoption of SFAS No. 143,"Accounting for Asset Retirement Obligations."

(c) We recognized an after-tax gain upon a change in the method of depreciation and depletion of our exploration and production assets.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis relates to factors that have affected our consolidated financial condition and results of operations for the three years ended December 31, 2004, 2003 and 2002. This information should be read in conjunction with our Consolidated Financial Statements and related Notes thereto and the Selected Financial Data included Item 8. of the Form 10-K. Herein we make forward-looking statements that involve risks, uncertainties, and assumptions. Actual results may differ materially from those anticipated in these forward-looking statements as a result of various factors, including, but not limited to, those presented under "Cautionary Statement Regarding Forward-Looking Information" on page 34.

Company Overview

Business Strategy. Maximizing the value of our existing core assets is the focal point of our business strategy. Our core assets are our fully integrated upstream and midstream assets in the Powder River and Greater Green River Basins in Wyoming, the San Juan Basin in New Mexico, the Sand Wash Basin in Colorado and our midstream operations in west Texas and Oklahoma. Our long-term business plan is to increase stockholder value by: (i) doubling proven natural gas reserves and equity production of natural gas from the levels achieved in 2001 over a five year period; (ii) meeting or exceeding throughput projections in our midstream operations; and (iii) optimizing annual returns.

Industry and Company Overview. In North America, our industry has experienced several consecutive years of declining natural gas production. Most of the major gas producing areas, such as the Gulf of Mexico, are mature and are in production decline. We are concentrating our efforts in the Rocky Mountain gas producing basins where there are estimated to be large quantities of undeveloped gas. The U.S. government largely retains the mineral rights to these undeveloped reserves; accordingly, the development and production of these reserves require permits from several governmental agencies including the BLM. We are well positioned for future production growth with a large inventory of undeveloped drilling locations in the Powder River, the Greater Green River and San Juan Basins to meet the growing demand for clean burning natural gas. In addition, our experience and technical expertise position us to acquire new opportunities to develop natural gas in the Rocky Mountain region. Our challenges will be to accomplish these goals with the difficulties encountered by the industry in obtaining the necessary permits from the BLM, and state agencies such as the Wyoming DEQ. We believe that our technical expertise in developing environmentally responsible solutions to the problems encountered in the development of gas reserves will be a competitive advantage in overcoming these challenges.

Our operations are conducted through the following four business segments:

Exploration and Production. We explore for, develop and produce natural gas reserves independently and to enhance and support our existing gathering and processing operations. Our producing properties are primarily located in the Powder River and Greater Green River Basins, and the Sand Wash Basin. These plays are relatively low-risk, multi-year development projects. These provide us with the opportunity to steadily increase our production volume over time at reasonable operating and low finding and development costs. In 2004 our average production sold was 153 MMcfe per day, which is a 2% increase over the average production volume sold in 2003.

We continue to seek to add additional upstream core projects that are focused on Rocky Mountain natural gas. We will utilize our expertise in exploration and low-risk development of unconventional gas reservoirs including tight-gas sands, coal bed methane, biogenic, and shale gas plays to evaluate acquisitions of either additional leaseholds, proven and undeveloped reserves or companies with operations primarily focused in the Rockies. We may also evaluate unconventional gas reservoirs in areas outside the Rockies where we can leverage our related exploration, production and gathering expertise. In January 2005, we opened an exploration office in Calgary, Alberta, Canada to evaluate opportunities in the Western Canadian Sedimentary Basin. Through December 31, 2004, we have acquired the drilling rights on approximately 874,000 net acres in other Rocky Mountain basins and continue to expand our leasehold positions.

Gathering, Processing and Treating. Our core operations are in well-established areas such as the Permian, Anadarko, Powder River, Greater Green River, and San Juan Basins. We connect natural gas from gas and oil wells to our gathering systems for delivery to our processing or treating plants under long-term contracts. At our plants we process natural gas to extract NGLs and treat natural gas in order to meet pipeline specifications. We provide these services to major oil and gas companies, to independent producers of various sizes and for our own production. We believe that our low cost of operations, our high on-line time and our safety records are key elements in our ability to compete effectively and provide service to our customers. Our expertise in gathering, processing and treating operations can enhance the economics of developing new upstream projects.

This segment of our operations has provided a stream of operating profit that is available for reinvestment into other projects or other segments of our business. Overall throughput in our facilities during 2004 remained relatively constant as compared to 2003 and averaged a total of 1.4 Bcf per day.

Transportation. In the Powder River Basin, we own one interstate pipeline, MIGC, Inc., and one intrastate pipeline, MGTC, Inc., which transport natural gas for producers and energy marketers under fee schedules regulated by state or federal agencies.

Marketing. Our gas marketing segment is an outgrowth of our gas processing and upstream activities. One of the primary goals of our gas marketing operations is the preservation and enhancement of the value received for our equity volumes of natural gas. This goal is achieved through the use of hedges on the production of our equity natural gas and NGLs and through the use of firm transportation capacity. We also buy and sell natural gas and NGLs in the wholesale market in the United States and in Canada. These third-party sales, our firm transportation capacity on interstate pipelines and our gas storage positions, combined with the stable supply of gas from our facilities and production, enable us to respond quickly to changing market conditions and to take advantage of seasonal price variations and peak demand periods.

Results of Operations

Year ended December 31, 2004 compared to year ended December 31, 2003
(amounts in thousands, except per share amounts and operating data)

	Year Ended December 31,		Percent
	2004	2003	Change
Financial results:			
Revenues	$ 3,069,713	$ 2,874,010	7
Gross profit	267,026	210,430	27
Net income	119,215	84,219	42
Earnings per share of common stock	1.63	1.17	39
Earnings per share of common stock - diluted	1.61	1.13	42
Net cash provided by operating activities	209,448	244,222	(14)
Net cash used in investing activities	(302,744)	(197,085)	54
Net cash provided by (used in) financing activities	67,570	(28,333)	338
Operating data:			
Average gas sales (MMcf/D)	1,225	1,361	(10)
Average NGL sales (MGal/D)	1,641	1,634	-
Average gas prices ($/Mcf)	$ 5.59	$ 4.94	13
Average NGL prices ($/Gal)	$ 0.75	$ 0.58	29

Net income increased $35.0 million for the year ended December 31, 2004 compared to 2003. This increase was primarily attributable to higher product prices. The price increases were somewhat offset by reduced operating profit from the marketing segment and after-tax charges associated with a settlement with the Commodity Futures Trading Commission, or CFTC, of $7.0 million and the early extinguishment of long-term debt of $6.7 million. Additionally, the 2004 results included a change in accounting principle that resulted in a cumulative reduction of depreciation and depletion for periods prior to 2004 of $4.7 million, net of tax, and the 2003 results included a $6.7 million after-tax loss from the Cumulative effect of a change in accounting principle from the adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations" on January 1, 2003.

Revenues from the sale of gas increased $54.6 million to $2,518.1 million for the year ended December 31, 2004 compared to the year ended December 31, 2003. This increase was primarily due to an increase in product prices, which more than offset a decrease in sales volume in 2004. Average gas prices realized by us increased $0.65 per Mcf to $5.59 per Mcf for the year ended December 31, 2004 compared to 2003. Included in the realized gas price were approximately $7.4 million of gains recognized in 2004 related to futures positions on equity gas volumes. We have entered into additional futures positions for a portion of our equity gas for 2005. See further discussion in "Item 7A. Quantitative and Qualitative Disclosures About Market

Risk." Average gas sales volumes decreased to 1,225 MMcf per day in 2004 from 1,361 MMcf per day in 2003. This decrease was the result of our reduction in third party sales volume due to the increase in product prices and related credit exposure.

Revenues from the sale of NGLs increased $104.7 million to $450.8 million for the year ended December 31, 2004 compared to 2003. This is primarily due to a significant increase in product prices as sales volumes were relatively constant. Average NGL prices realized by us increased $0.17 per gallon to $0.75 per gallon in 2004 compared to 2003. Included in the realized NGL price were $16.3 million of losses recognized in 2004 related to futures positions on equity NGL volumes. We have entered into additional futures positions for a portion of our equity NGL production for 2005. See further discussion in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk." Average NGL sales volumes remained relatively constant in 2004 compared to 2003.

Product purchases increased by $84.4 million for the year ended December 31, 2004 compared to 2003. The increase in product purchases in 2004 compared to 2003 was the result of an increase in product prices that more than offset the reduction in third party sales volume. Overall, combined product purchases as a percentage of sales of all products decreased to approximately 86% in 2004 from 87% in 2003. The reduction in this percentage is primarily the result of a decrease in the sale of third party product.

Plant and transportation operating expense increased by $7.5 million for the year ended December 31, 2004 compared to 2003. The increase was primarily due to a $4.2 million increase in property tax expense, including approximately $1.8 million for prior year property taxes in the state of Oklahoma. Also contributing to the increase was increased fuel costs and compression rental expenses.

Oil and gas exploration and production expenses increased by $25.4 million in the year ended December 31, 2004 compared to 2003. The increase was substantially due to increased lease operating expenses, or LOE, in the Powder River Basin coal bed development. Overall, LOE averaged $0.68 per Mcf in 2004 compared to $0.46 per Mcf in 2003. The increase in LOE is substantially due to higher water handling charges, contract labor, and fuel and operating costs of wellhead blowers in the Powder River Basin. We expect the trend of increasing LOE per Mcf costs to continue in 2005 as water-handling costs are being incurred on dewatering wells in several new pilot areas that have no offsetting gas production as yet.

Depreciation, depletion and amortization, or DD&A increased by $21.6 million in the year ended December 31, 2004 compared to 2003. The increase is the result of additional capital expenditures and depreciation and depletion on our oil and gas assets. In total, we had an $8.0 million increase in DD&A in our midstream operations primarily due to our expanding CBM gathering system in the Powder River Basin. We also had $13.6 million increase in DD&A in our upstream operations primarily due to our continued development in the Powder River Basin, downward revisions to reserves in the Powder River Basin, and our October 2004 acquisition of producing properties in the San Juan Basin. Also contributing to the increase in DD&A in our upstream operations was a change in our method of calculating DD&A. Effective January 1, 2004, we redefined the asset groupings for the calculation of depreciation and depletion on our oil and gas properties from a well-by-well basis to a field wide basis for each of the Jonah, Pinedale and Sand Wash fields and to a grouping of all wells drilled into related coal seams for the Powder River Basin. This change resulted in an increase in DD&A of $4.9 million in 2004.

The change in the depreciation and depletion methodology is treated as a change in accounting principle. Accordingly, the Accumulated depreciation, depletion and amortization for these assets has been recalculated under the new methodology. The cumulative effect of the change in depreciation and depletion methodology is a benefit of $4.7 million, net of tax, and is presented in the Consolidated Statement of Operations under the caption Cumulative effect of change in accounting principle, net of tax.

Selling and administrative expenses increased by $11.8 million in the year ended December 31, 2004 compared to 2003. The increase in selling and administrative expenses included a $7.0 million settlement with the CFTC in July 2004 associated with reporting price information to industry publications, and increased salary and benefit costs.

The Total provision for income taxes, as a percentage of Income before income taxes was approximately 37.6% during the year ended December 31, 2004 as compared to 37.1% in 2003. This increase is due to the settlement paid to the CFTC, which was non-deductible for tax purposes.

Cash Flow Information

Cash flows from operating activities decreased by $34.8 million in the year ended December 31, 2004 compared to 2003.

This decrease was primarily due to the timing of cash receipts and payables and an increase in our inventory of products held for future resale.

Cash flows used in investing activities increased by $105.7 million in 2004 compared to 2003. This increase was due to an increase in capital expenditures and acquisitions in 2004.

Cash flows provided by financing activities increased by $95.9 million in 2004 compared to 2003. This increase was due to additional borrowings to fund our capital expenditure program.

Equity Transactions

Preferred Stock Conversion/Redemption. In December 2003, we issued a notice of redemption for a total of 800,000 shares of our $2.625 cumulative convertible preferred stock. The holders of these shares had the right to convert them into shares of our common stock in lieu of receiving the redemption price in cash. In January 2004, we issued an additional 1,979,244 shares of common stock to holders who elected to convert their shares and paid $672,000 in cash proceeds to complete this redemption. In March 2004, we issued an additional notice of redemption for the remaining 1,260,000 shares of our $2.625 cumulative convertible preferred stock. In April 2004, we issued an additional 3,113,582 shares of common stock to holders who elected to convert their shares and paid $391,000 in cash proceeds to complete this redemption. After these redemptions, the $2.625 cumulative convertible preferred stock was delisted from trading on the New York Stock Exchange and was deregistered by the SEC.

Common Stock Split. On June 18, 2004, we completed a two-for-one split of our common stock, which was distributed in the form of a stock dividend. Shareholders of our common stock received one additional share for every share of common stock held on the record date of June 4, 2004. Upon completion of the stock split, we had approximately 73.6 million shares of common stock outstanding. After the stock split, each share of common stock outstanding or thereafter issued includes or will include one-half of a Series A Junior Participating Preferred Stock purchase right. We have restated our financial information to reflect this split for all periods presented.

Other Information

Price Reporting to Gas Trade Publications. In 2003, we learned that several employees in our marketing department furnished inaccurate information regarding natural gas transactions to energy publications, which compile and report energy index prices. We discovered the inaccuracies during a review of our marketing activities, which was being conducted in response to a subpoena issued by the CFTC. These employees identified inaccuracies associated with reporting of natural gas transactions primarily related to points in Texas. We have discontinued the practice of reporting pricing information to industry publications. In conjunction with our investigation into this matter, we have taken appropriate disciplinary actions including the release of one manager in our marketing department. In July 2004, we reached a settlement of this matter with the CFTC. In conjunction with this settlement, we paid a civil penalty of $7.0 million.

Acquisition of San Juan Properties. In October 2004, we acquired oil and gas assets in the San Juan Basin of New Mexico for approximately $82.2 million, plus assumed liabilities. The purchase included 32,000 gross acres, or 24,000 net acres, with approximately 100 wells that were producing an average of 15 MMcf per day, gross, or 11 MMcf per day, net, of coal bed methane. The purchase also includes approximately 130 miles of related gathering systems, which are currently connected to our existing San Juan River plant.

Acquisition and Disposition of Gathering Systems. Effective February 1, 2003, we acquired several gathering systems in Wyoming, primarily located in the Greater Green River Basin with smaller operations in the Powder River and Wind River Basins, for a total of $37.1 million. Several of the systems located in the Powder River and Wind River did not integrate directly into our existing systems, and accordingly these systems were sold. During the year ended December 31, 2003, the income, if any, generated by the assets sold was immaterial.

Acquisition of Sand Wash Properties. In August 2003, through the acquisition of the stock of a private corporation for $12.9 million, we acquired additional reserves, production and acreage in the Sand Wash area of the Greater Green River Basin. The assets of this private entity consisted primarily of the remaining interests in various Sand Wash properties that we operate. This acquisition included approximately 11 Bcfe of proved reserves, 2.1 MMcfe per day of production and approximately 11,000 net acres under lease.

Segment Information

Gas Gathering, Processing and Treating. The Gas Gathering, Processing and Treating segment realized segment-operating profit of $168.9 million for the year ended December 31, 2004 compared to $127.3 million in 2003. The increase in operating profit in this segment in 2004 is primarily due to higher realized prices and improved contractual terms on gas gathered in the Powder River Basin.

	Year Ended December 31,		
	2004	2003	2002
Gross Margin ($/Mcf)	$ 0.54	$ 0.44	$ 0.39
Operating Expense ($/Mcf)	0.19	0.17	0.17
Net Margin ($/Mcf)	$ 0.35	$ 0.27	$ 0.22

Exploration and Production. The Exploration and Production segment realized segment-operating profit of $156.1 million in 2004 compared to $114.2 million in 2003. The increase is due to an improvement in realized prices and an increase in the production of natural gas. During 2004, our production of natural gas as compared to 2003 increased by 5% to 55.5 Bcfe. The following table sets forth the average sales price received for our oil and gas products in the years ended December 31, 2004, 2003 and 2002.

	Year Ended December 31,		
	2004	2003	2002
Average sales price: (1)			
Oil ($/Bbl), excluding the effect of hedging positions	$ 37.86	$ 29.21	$ 23.53
Oil ($/Bbl), including the effect of hedging positions	37.86	29.21	23.53
Gas ($/Mcf), excluding the effect of hedging positions	4.68	4.14	2.33
Gas ($/Mcf), including the effect of hedging positions	4.80	3.74	2.84
Production and other costs:			
Lease operating expense ($/Mcfe)	0.68	0.46	0.42
Production tax expense ($/Mcfe)	0.50	0.39	0.23
Gathering and transportation expense ($/Mcfe)	0.72	0.69	0.67
Other expenses ($/Mcfe)	0.01	0.01	0.01
Total costs ($/Mcfe)	$ 1.91	$ 1.55	$ 1.33

(1) The prices received for NGLs are included in the price received for gas.

Marketing. The Marketing segment realized segment-operating profit of $24.6 million in the year ended December 31, 2004 compared to $30.7 million in 2003. The decrease in the marketing profit is primarily due to lower profitability in transactions associated with our firm transportation capacity from the Rocky Mountain region to the Mid-Continent.

Transportation. The Transportation segment realized segment-operating profit of $11.0 million in the year ended December 31, 2004 compared to $11.6 million in 2003. The transportation segment includes the results from the MIGC and MGTC pipelines in the Powder River Basin. The decrease in profit in this segment is due to lower interruptible transportation volume in 2004 as more gas was transported out of the basin through other pipelines.

Year ended December 31, 2003 compared to year ended December 31, 2002
(amounts in thousands, except per share amounts and operating data)

	Year Ended December 31,		Percent
	2003	2002	Change
Financial results:			
Revenues	$ 2,874,010	$ 2,489,698	15
Gross profit	210,430	144,430	46
Net income	84,219	50,589	66

Earnings per share of common stock		1.17		0.63	86
Earnings per share of common stock - diluted		1.13		0.62	82
Net cash provided by operating activities		244,222		124,401	96
Net cash (used in) investing activities		(197,085)		(105,772)	86
Net cash (used in) financing activities		(28,333)		(21,349)	33
Operating data:					
Average gas sales (MMcf/D)		1,361		1,988	(31)
Average NGL sales (MGal/D)		1,634		2,010	(19)
Average gas prices ($/Mcf)	$	4.94	$	2.92	69
Average NGL prices ($/Gal)	$	0.58	$	0.42	38

Net income increased $33.6 million for the year ended December 31, 2003 compared to 2002. The increase in net income was primarily attributable to a significant increase in gas and NGL prices in 2003 compared to 2002. This increase in prices was supplemented by increased equity production from the Powder River Basin CBM project and the Greater Green River Basin. Partially offsetting the increase in net income in the year ended December 31, 2003 was a $6.7 million after-tax loss from the cumulative effect of a change in accounting principle from the adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations" on January 1, 2003.

Revenues from the sale of gas increased $344.7 million to $2,463.5 million for the year ended December 31, 2003 compared to 2002. This increase was primarily due to an increase in product prices, which more than offset a decrease in sales volume in 2003. Average gas prices realized by us increased $2.02 per Mcf to $4.94 per Mcf for the year ended December 31, 2003 compared to 2002. Included in the calculation of the realized gas price were approximately $23.9 million of losses recognized in the year ended December 31, 2003 related to futures positions on equity gas volumes. Average gas sales volumes decreased 627 MMcf per day to 1,361 MMcf per day for the year ended December 31, 2003 compared to 2002. This decrease was due to a reduction in third party sales volume resulting from the increase in product prices and an intentional effort to reduce related credit exposure.

Revenues from the sale of NGLs increased approximately $36.6 million to $346.1 million for the year ended December 31, 2003 compared to 2002. This increase is primarily due to a significant increase in product prices, which was partially offset by a reduction in third-party sales volumes. Average NGL prices realized by us increased $0.16 per gallon to $0.58 per gallon for the year ended December 31, 2003 compared to 2002. Included in the calculation of the realized NGL price were approximately $11.4 million of losses recognized in the year ended December 31, 2003 related to futures positions on equity NGL volumes. Average NGL sales volumes decreased 376 MGal per day to 1,634 MGal per day for the year ended December 31, 2003 compared to 2002.

Product purchases increased by $299.3 million for the year ended December 31, 2003 compared to 2002 as a result of the significant increase in commodity prices. Overall, combined product purchases as a percentage of sales of all products remained relatively constant at approximately 89% for both 2003 and 2002.

Plant and transportation operating expense increased by $6.8 million for the year ended December 31, 2003 compared to 2002. The increase was primarily due to increased throughput at our facilities, the acquisition of several gathering systems in the first quarter of 2003 and additional leased compression in the Powder River Basin coal bed development. Also contributing to this increase were the fees paid to other companies, primarily Rendezvous, for gas gathering services. Rendezvous is a 50% owned entity that delivers gas to our Granger Complex. Rendezvous is accounted for under the equity method, and our share of its gathering revenues is reflected in Earnings from equity investments.

Oil and gas exploration and production expenses increased by $18.2 million in the year ended December 31, 2003 compared to 2002. In our operating areas, the significant increase in residue gas prices in 2003 resulted in substantially higher severance tax expenses. Overall, lease-operating expense, or LOE, for the year ended December 31, 2003 increased by approximately $0.04 per Mcfe compared to 2002 and averaged $0.46 per Mcfe. The increase in lease-operating expense per Mcfe was primarily due to unsuccessful well expenses of $1.8 million in 2003.

Depreciation, depletion and amortization decreased by $3.1 million for the year ended December 31, 2003 as compared to 2002. This decrease was the result of revisions to the operating lives, and salvage values, of our operating assets partially offset by increased production in the Powder River Basin and additional depreciation in 2003 from new projects. The revisions to the operating lives and salvage values of our operating assets were the result of analysis performed in connection with the adoption of SFAS No. 143 on January 1, 2003 and were treated as a revision of an estimate and are accounted for on a prospective basis.

Selling and administrative expenses increased by approximately $4.6 million in the year ended December 31, 2003 as compared to 2002. This increase was the result of higher compensation expenses due to an increased employee count in 2003 resulting from our growing exploration and production operations, and a modification in 2003 to our incentive compensation plan to pay this compensation on a current basis as opposed to a vesting schedule used in prior years. Also contributing to the increase were higher professional fees resulting from litigation concluded in 2003 and our ongoing research associated with the CFTC investigation of our price reporting to trade publications. Partially offsetting these increases were fewer charges for doubtful accounts in 2003 as compared to 2002.

In 2003, in order to properly align our hedged volumes of natural gas to our forecasted equity production, we discontinued hedge treatment on financial instruments for 10 MMcf per day of natural gas and 50,000 Barrels per month of ethane. As a result, a pre-tax loss of $2.8 million was reclassified into earnings from Accumulated other comprehensive income.

Cash Flow Information

Cash flows from operating activities increased by $119.8 million in 2003 compared to 2002. This increase was primarily due to an increase in net income in 2003 compared to the prior year and the timing of cash receipts and payables.

Cash flows used in investing activities increased by $91.3 million in 2003 compared to 2002. This increase was primarily due to a higher level of capital expenditures.

Cash flows used in financing activities increased by $7.0 million in 2003 compared to 2002. This increase was due to increased cash flows from operating activities, which was used to reduce our long-term debt.

Other Information

Acquisition and Disposition of Gathering Systems. Effective February 1, 2003, we acquired several gathering systems in Wyoming, primarily located in the Greater Green River Basin with smaller operations in the Powder River and Wind River Basins, for a total of $37.1 million. Several of the systems located in the Powder River and Wind River Basins did not integrate directly into our existing systems, and accordingly these systems were sold. During the year ended December 31, 2003, the income, if any, generated by the assets sold was immaterial.

Acquisition of Sand Wash Properties. In August 2003, through the acquisition of the stock of a private corporation for $12.9 million, we acquired additional reserves, production and acreage in this area. The assets of this private entity consisted primarily of the remaining interests in various Sand Wash properties that we operate.

Segment Information

Gas Gathering, Processing and Treating. The Gas Gathering, Processing and Treating segment realized segment-operating profit of $127.3 million for the year ended December 31, 2003 as compared to $93.6 million in 2002. The increase in operating profit in this segment in 2003 was primarily due to higher commodity prices, increased gathering volumes and the acquisition of several gathering systems in February 2003.

Exploration and Production. The Exploration and Production segment realized segment-operating profit of $114.2 million for the year ended December 31, 2003 compared to $74.1 million in 2002. The increase in operating profit in this segment in 2003 was primarily due to substantially higher natural gas prices and production volume growth from the Powder River Basin CBM area and the Pinedale Anticline.

Marketing. The Marketing segment realized segment-operating profit of $30.7 million for the year ended December 31, 2003 compared to $36.4 million in 2002.

The decrease in the marketing margin is primarily due to transactions associated with our firm transportation capacity from the Rocky Mountain region to the Mid-Continent. Our firm transportation allows us to purchase gas in the Rocky Mountain region for resale in the higher priced Mid-Continent markets. In the second quarter of 2003, additional transportation capacity out of the Rocky Mountain region became operational, which reduced the price difference between the two regions. There is no assurance that the margins we realized on the sale of gas in 2003 will continue in the future, or that we will continue to originate the same amount of transactions in future years.

Transportation. The Transportation segment realized segment-operating profit of $11.6 million for the year ended December 31, 2003 compared to $16.3 million in 2002. The transportation segment includes the results from the MIGC and MGTC pipelines in the Powder River Basin. The decrease in profit in this segment was due to lower interruptible transportation volume in 2003 as more gas was transported out the basin through other pipelines.

Critical Accounting Estimates

The application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an interpretation and implementation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. For further details on our accounting policies, and the estimates, assumptions and judgments we use in applying these policies and a discussion of new accounting rules, see Note 2 of the Notes to Consolidated Financial Statements.

Use of Estimates. The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the amounts reported for assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the amounts reported for revenues and expenses during the reporting period. These estimates are evaluated on an ongoing basis, utilizing historical experience, consultation with experts and other methods considered reasonable in the particular circumstances. However, actual results may differ significantly from the estimates used. Any effects on our business, financial position or results of operations resulting from revisions to these estimates will be recorded in the period in which the facts that necessitate a revision become known. Although there are a number of areas where we use estimates, what we believe to be the most significant ones are discussed below.

Property and Equipment. Depreciation on our property and equipment is provided using the straight-line method based on the estimated useful life of each facility, which ranges from three to 35 years. Useful lives are determined based on the shorter of our estimate of the life of the equipment or our estimate of the reserves serviced by the equipment. Among other factors, the estimates consider our experience with similar assets and technical analysis of the reserves. The cost of acquired gas purchase contracts is amortized using the straight-line method or units of production. If the actual lives of the equipment or the reserves serviced by the equipment were less than we originally estimated, we may be required to record a loss upon retirement of a specific asset.

Oil and Gas Reserves, Properties and Equipment. We follow the successful efforts method of accounting for oil and gas exploration and production activities. Developed and undeveloped leaseholds with proved reserves are depleted by the units-of-production method based on estimated proved reserves. Development costs and related equipment are depleted and depreciated by the units-of-production method based on estimated proved developed reserves. The units of production method is sensitive to the determination of proved reserves. To the extent the reserves are modified, the depletion determined under the units of production method will be increased or decreased on a prospective basis.

Our reserve estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves, the projection of future rates of production and the timing of development expenditures. The accuracy of these estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserve estimates are imprecise and should be expected to change as additional information becomes available. Estimates of economically recoverable reserves and of future net cash flows prepared by different engineers or by the same engineers at different times may vary substantially. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. Overall, during 2004, 2003 and 2002, we experienced downward revisions. In addition, the estimates of future net revenues from our proved reserves and the present value of those reserves are based upon certain assumptions about production levels, prices and costs, which may not be correct. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based. Actual results may differ materially from the results estimated. We estimate that a 5% change in our reserves either upward or downward would decrease or increase, respectively, our depreciation and depletion on our oil and gas assets by approximately $2.3 million.

Asset Retirement Obligations. We use significant judgment in estimating our future liability for asset retirement. We evaluate each asset and in some cases individual components of assets to determine and estimate the future cost and timing of retiring those assets. The estimate of the future cost is then discounted back to the present and recorded as a liability. This liability will vary based upon the probability, timing and the extent of remediation necessary to reclaim those facilities, the discount factor used in those determinations and the projected costs of the remediation. We evaluate these estimates on an ongoing basis and modify our assumptions as appropriate.

Impairment of Long-Lived Assets. If changes in the expected performance of an asset occur, or if overall economic conditions warrant, we will review our assets to determine their economic viability. In accordance with SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets", assets are to be evaluated at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets. Accordingly, our review is completed at the plant facility, the related group of plant facilities or the oil and gas producing field or producing coal seam level. In order to determine whether an impairment exists, we compare the net book value of the asset to the estimated fair market value or the undiscounted expected future net cash flows, determined by applying future prices estimated by management over the shorter of the lives of the facilities or the associated reserves. If an impairment exists, write-downs of assets are based upon expected future net cash flows discounted using an interest rate commensurate with the risk associated with the underlying asset. This analysis is sensitive to, among other things; management's expectation of commodity prices, operating costs, drilling plans, production rates and the evaluation in determining asset groupings for which cash flows are largely independent of the cash flows of other assets. During 2004, 2003 and 2002, we had no impairments of long-lived assets.

Identification of Derivatives and Mark to Market Valuations. The determination of which contractual instruments meet the definition of a derivative under accounting rules is subject to differing interpretations as is the valuation of those derivatives. Management uses its judgment to analyze all contracts to determine whether or not they qualify as derivatives and to determine their value. A specific area in which management's judgment is required includes identifying contracts meeting the criteria for exclusion from derivatives treatment, market liquidity, and market valuation. This analysis is dependent upon commodity prices, outside market factors and management's intent upon entering into these contracts. An analysis of the impact of the change in market prices on the value of our derivatives is included in "Item 7A. Quantitative and Qualitative Disclosures on Market Risk."

Recently Issued Accounting Pronouncements. We continually monitor and revise our accounting policies as new rules are issued. At this time, there are several new accounting pronouncements that have recently been issued, but not yet adopted, which will have an impact on our accounting when they become effective in 2005. The following pronouncements have been issued but not yet adopted.

SFAS No. 123(R). SFAS No. 123(R), *"Share Based Payment"* was issued in December 2004 and must be adopted no later than periods beginning after June 15, 2005. This pronouncement requires companies to expense the fair value of employee stock options and other forms of stock based compensation. We intend to adopt this pronouncement in the third quarter of 2005. Currently, we are complying with the pro forma disclosure requirements of SFAS No. 123, *"Accounting for Stock Based Compensation"* which are included in Note 2 – Summary of Significant Accounting Policies to Consolidated Financial Statements. We estimate that if we had adopted SFAS No. 123(R) for the year ended December 31, 2004, Earnings per share of common stock - assuming dilution would have been approximately $1.54 per share of common stock or a reduction of approximately $0.07 per share of common stock from the actual results for 2004.

SFAS No. 151. SFAS No. 151, *"Inventory Costs, an amendment of ARB No. 43, Chapter 4"* was issued in November 2004 and is effective for us for inventory costs incurred in fiscal years beginning after June 15, 2005, and will be applied prospectively. SFAS No. 151 amends APB Opinion No. 43, Chapter 4, "Inventory Pricing" to clarify the accounting for abnormal amounts of costs and the allocation of fixed production overheads. We believe that the adoption of SFAS No. 153 will not affect our earnings, financial position or cash flows.

SFAS No. 153. SFAS No. 153, *"Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29"* was issued in December 2004 and is effective for us for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005, and will be applied prospectively. SFAS No. 153 amends APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. The guidance in APB Opinion No. 29 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged but includes certain exceptions to that principle. SFAS No. 153 amends APB Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. We will adopt SFAS No. 153 as required.

EITF No. 04-13. At its November 2004 meeting, the Emerging Issues Task Force of the FASB began discussion of Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." This Issue addresses the question of when it is appropriate to measure purchases and sales of inventory at fair value and record them in cost of sales and revenues and when they should be recorded as an exchange measured at the book value of the item sold. The EITF did not reach a consensus on this issue, but requested the FASB staff to further explore the alternative views. We record natural gas, and NGL purchases and sales of inventory entered into contemporaneously with the same counterparty as cost of sales and revenues. These transactions occur under contractual arrangements that establish the agreement terms either jointly, in a single contract, or separately, in individual contracts. Should the EITF reach a consensus on this issue requiring these transactions to be recorded as exchanges measured at book value, Total revenues and Product purchases on the Consolidated Statement of Operations would be lower by equal amounts with no impact on net income. We have not yet determined the amount of any adjustment to Total revenues and Product purchases under the EITF.

FSP FAS 19-a. In February 2005, the FASB Staff posted its proposed staff position FSP FAS 19-a, "Accounting for Suspended Well Costs." At issue is the current requirement of SFAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," to capitalize the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. The capitalized costs become part of the entity's wells, equipment, and facilities if the well successfully located proved reserves. However, if the well has not found proved reserves, the capitalized costs of drilling the well are expensed, net of any salvage value. Questions have arisen as to whether there are circumstances that would permit the continued capitalization of exploratory-well costs beyond the one-year limit specified in SFAS 19 other than when additional exploration wells are necessary to justify major capital expenditures and those wells are underway or firmly planned for the near future. In its proposal, the FASB Staff states that exploratory well costs could be capitalized beyond a one-year limit if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making progress assessing reserves and the economic and operational viability of the project. Comments on the proposed FASB Staff position were due March 7, 2005. This FSP will be effective in the first quarter after it is approved. We do not believe that this FSP will have a material impact on our results of operations, financial position or cash flows.

American Jobs Creation Act of 2004. During October 2004, H.R. 4520, the "American Jobs Creation Act of 2004," (the "Act") was enacted. It provides for certain additional tax deductions from qualified taxable income beginning in 2005, subject to certain limitations. Although we expect that the Act may result in a reduction in our effective tax rate, we have not yet determined the full impact of this law.

Liquidity and Capital Resources

Our sources of liquidity and capital resources historically have been net cash provided by operating activities, funds available under our financing facilities and proceeds from offerings of debt and equity securities. In the past, these sources have been sufficient to meet our needs and finance the growth of our business. We can give no assurance that the historical sources of liquidity and capital resources will be available for future development and acquisition projects, and we may be required to seek additional or alternative financing sources. Product prices, hedges of equity production, sales of inventory, the volume of natural gas processed by our facilities, the volume of natural gas produced from our producing properties, the margin on third-party product purchased for resale, as well as the timely collection of our receivables are all expected to have significant influences on our future net cash provided by operating activities. Additionally, our future growth will be dependent upon obtaining additions to dedicated plant reserves, acquisitions, new project development, marketing results, efficient operation of our facilities and our ability to obtain financing at favorable terms.

During the past several years, we have been successful in developing additional reserves of natural gas and increasing our equity natural gas production. However, the overall level of drilling and production associated with our producing properties will depend upon, among other factors, the price for gas, availability of transportation capacity to market centers, the energy and environmental policy and regulation by governmental agencies, the issuance of drilling and water disposal permits, and the length of time for wells in the Powder River Basin to be dewatered, none of which is within our control. Any reduction in the levels of exploration, development and production by us or a significant reduction in natural gas prices could have a material adverse effect on our financial condition, results of operations and cash flows.

Although some of our plants have experienced natural declines in dedicated reserves, overall we have been successful in connecting additional reserves to more than offset these declines. However, the overall level of drilling associated with our plant facilities will depend upon, among other factors, the prices for oil and gas, the drilling budgets of third-party producers, availability of transportation capacity to market centers, the energy and environmental policy and regulation by governmental agencies, the pace at which drilling permits are received, and the availability of foreign oil and gas, none of which is within our control. There is no assurance that we will continue to be successful in replacing the dedicated reserves processed at our facilities. Any prolonged reduction in prices for natural gas and NGLs may depress the levels of exploration, development and production by third parties. Lower levels of these activities could result in a corresponding decline in the demand for our gathering, processing and treating services. A reduction in any of these activities could have a material adverse effect on our financial condition, results of operations and cash flows.

We believe that the amounts available to be borrowed under our financing facilities, together with net cash provided by operating activities, will provide us with sufficient funds to connect new reserves, maintain our existing facilities and complete our current capital expenditure program. Depending on the timing and the amount of our future projects, we may be required to seek additional sources of capital. Our ability to secure such capital is restricted by our financing facilities, although we may request additional borrowing capacity from our lenders, seek waivers from our lenders to permit us to borrow funds from third-parties, seek replacement financing facilities from other lenders, use stock as a currency for acquisitions, sell existing assets or use a combination of alternatives. While we believe that we would be able to secure additional financing, if required, we can provide no assurance that we will be able to do so or as to the terms of any additional financing.

We utilized amounts available under the revolving credit facility together with an additional $100.0 million borrowing under the master shelf agreement to redeem our $155.0 million, 10% senior subordinated notes in June 2004, to pay a $7.8 million prepayment penalty on this redemption, and to meet scheduled principal repayments during 2004 of $35.0 million under the master shelf agreement. We believe that amounts available under the revolving credit facility will be sufficient to meet scheduled principal repayments during 2005 of $10.0 million under the master shelf agreement.

We have effective shelf registration statements filed with the SEC for an aggregate of $200.0 million of debt securities and preferred stock, along with the shares of common stock, if any, into which those securities are convertible, and $62.0 million of debt securities, preferred stock or common stock. These shelf registrations allow us to access the debt and equity markets, subject to market conditions.

Sources and Uses of Funds. Our sources and uses of funds for the year ended December 31, 2004 are summarized as follows (dollars in thousands):

Sources of funds:	
Borrowings under the revolving credit facility	$ 2,654,230
Borrowings under the master shelf agreement	100,000
Proceeds from the dispositions of property and equipment	1,501
Net cash provided by operating activities	209,448
Change in balance of outstanding checks	31,581
Distributions from equity investments	2,310
Proceeds from exercise of common stock options	9,993
Total sources of funds	$ 3,009,063
Uses of funds:	
Payments related to long-term debt (including debt issue costs)	$ 2,713,316
Capital expenditures	306,555
Redemption of $2.625 cumulative convertible preferred stock	1,930
Preferred dividends paid	757
Common dividends paid	12,231
Total uses of funds	$ 3,034,789

Capital Investment Program. We currently anticipate capital expenditures in 2005 of approximately $338.8 million. The 2005 capital budget is an 11% increase over the amount expended in 2004. This increase is the result of an expected increase in drilling activity in each of our upstream areas and additional drilling activity by third party producers whose acreage is dedicated to our midstream facilities. Overall, capital expenditures in the Powder River Basin CBM development and in the Greater Green River Basin operations represent 38% and 34%, respectively, of the total 2005 budget. Due to drilling and regulatory uncertainties that are beyond our control, we can make no assurance that our capital budget for 2005 will not change or that we will actually incur this level of capital expenditures. This budget may be increased to provide for acquisitions if approved by our board of directors.

The 2005 capital budget and our capital expenditures during the year ended December 31, 2004 are presented in the following table (dollars in thousands).

Type of Capital Expenditure	2005 Capital Budget	Capital Expenditures During the Year Ended December 31, 2004
Gathering, processing, treating and pipeline assets	$ 112.8*	$ 83.0*
Exploration and production and lease acquisition activities	186.7	132.7
Acquisition of San Juan Basin oil and gas properties	-	82.2
Acquisition of Greater Green River Basin midstream assets	28.0	-
Information technology and other items	3.0	2.3
Capitalized interest and overhead	8.3	6.4
Total Capital Expenditures	$ 338.8	$ 306.6

* Includes $13.7 million budgeted in 2005 and $9.0 million expended in 2004 for maintaining existing facilities.

Contractual Commitments and Obligations

Contractual Cash Obligations. A summary of our contractual cash obligations as of December 31, 2004 is as follows (dollars in thousands):

		Payments by Period			
Type of Obligation	Total Obligations	Due in 2005	Due in 2006 – 2007	Due in 2008 – 2009	Due Thereafter
Guarantee of Fort Union Project Financing	$ 4,743	$ 866	$ 1,931	$ 1,946	$ -
Operating Leases	82,321	16,607	31,978	23,472	10,264
Firm Transportation Capacity Agreements	251,223	38,883	72,130	59,281	80,929
Firm Storage Capacity Agreements	29,091	7,044	8,311	4,815	8,921
Long-term Debt	382,000	35,000	20,000	227,000	100,000
Interest on Long-Term Debt *	80,679	16,504	30,577	24,743	8,856
Total Contractual Cash Obligations	$ 830,057	$ 114,904	$ 164,927	$ 341,257	$ 208,970

* The interest rate assumed on the revolving credit facility is the rate at December 31, 2004 of 3.8%.

Guarantee of Fort Union Project Financing. We own a 13% equity interest in Fort Union Gas Gathering, L.L.C., or Fort Union, and are the construction manager and field operator. Fort Union gathers and treats natural gas in the Powder River Basin in northeast Wyoming. Initial construction and any expansions of the gathering header and treating system have been project financed by Fort Union. This debt is amortizing on an annual basis and is scheduled to be fully paid in 2009. Our requirement to fund under this guarantee would be reduced by the value of assets held by Fort Union. This guarantee is not reflected on our Consolidated Balance Sheet.

Operating Leases. In the ordinary course of our business operations, we enter into operating leases for office space, and for office, communication, transportation and compression equipment. Payments made on these leases are a component of operating expenses and are reflected on the Consolidated Statement of Operations and, as operating leases, are not reflected on our Consolidated Balance Sheet. These leases have terms ranging from one month to ten years and the majority of the leases have return or fair market purchase options available at various times during the lease. If we were to exercise the purchase options on all the leased compression equipment, these purchase options would require the capital expenditure of approximately $41.5 million between 2007 and 2013.

Firm Transportation Capacity and Gathering Agreements. Access to firm transportation is also a significant element of our business strategy. Firm transportation ensures that our equity production has access to downstream markets and allows us to capture incremental profit when pricing differentials between physical locations occur. Firm transportation agreements generally require the payment of fixed monthly fees regardless of the quantity of gas that flows under a particular agreement. These agreements are not reflected on our Consolidated Balance Sheet.

The fixed fees associated with our existing contracts for firm transportation capacity during 2005 will average approximately $0.16 per Mcf. The associated contract periods range from one month to thirteen years. Under firm transportation contracts, we are required to pay the fees associated with these contracts whether or not the transportation is used.

Firm Storage Capacity Agreements. We customarily store gas in underground storage facilities to ensure an adequate supply for long-term sales contracts and to capture seasonal price differentials. As of December 31, 2004, we had contracts in place for approximately 17.1 Bcf of storage capacity at various third-party facilities. Firm storage agreements generally require the payment of fixed monthly fees regardless of the quantity of gas that is in storage under a particular agreement. Of the total storage capacity under contract, approximately 6.5 Bcf is under contract to our Canadian subsidiary, WGR Canada, Inc., and Western guarantees the subsidiary's performance under these contracts. This subsidiary is wholly owned by us and fully consolidated in our financial statements.

The fees associated with these contracts in 2005 will average $0.56 per Mcf of annual capacity. The associated contract periods at December 31, 2004 had an average term of 34 months. At December 31, 2004, we held gas in our contracted storage facilities and in imbalances of approximately 16.3 Bcf at an average cost of $5.61 per Mcf compared to 12.7 Bcf at an average cost of $4.64 per Mcf at December 31, 2003. These positions are for storage withdrawals within the next 15 months. At the time we place product into storage, we contract for the sale of that product, physically or financially, and do not speculate on the future value of the product. These agreements for storage capacity are not reflected on our Consolidated Balance Sheet.

From time to time, we lease NGL storage space at major trading locations to facilitate the distribution of products. At December 31, 2004, we held NGLs in storage at various third-party facilities of 2,745 MGal, consisting primarily of propane and ethane, at an average cost of $0.30 per gallon compared to 2,989 MGal at an average cost of $0.30 per gallon at December 31, 2003.

Long-term Debt

Revolving Credit Facility. The revolving credit facility matures in June 2009. In December 2004, the size of the commitment under the revolver was increased from $400 million to $500 million. At January 31, 2005, $199.0 million was outstanding under this facility. Loans made under this facility are secured by a pledge of the capital stock of our significant subsidiaries. These subsidiaries also guarantee the borrowings under the facility.

The borrowings under the credit facility bear interest at Eurodollar rates or a base rate, as requested by us, plus an applicable percentage based on our debt to capitalization ratio. The base rate is the agent's published prime rate. We also pay a quarterly commitment fee ranging between 0.20% and 0.375%, depending on our debt to capitalization ratio. This fee is paid on unused amounts of the commitment. At December 31, 2004, the interest rate payable on borrowings under this facility was approximately 3.8%. Under the credit facility, we are subject to a number of covenants, including: maintaining a total debt to capitalization ratio of not more than 55% and maintaining a ratio of EBITDA, as defined in the credit facility, to interest over the last four quarters in excess of 3.0 to 1.0. The credit facility ranks equally with borrowings under our master shelf agreement with The Prudential Insurance Company. This facility has been rated Ba1 by Moody's and is not yet rated by S&P.

Master Shelf Agreement. Amounts outstanding under the master shelf agreement at January 31, 2005 are as indicated in the following table (dollars in thousands):

Issue Date	Amount	Interest Rate	Final Maturity	Principal Repayment Schedule
July 28, 1995	$ 30,000	7.61%	July 28, 2007	$10,000 on each of July 28, 2005 through 2007
June 30, 2004	100,000	5.92%	June 30, 2011	Single payment at maturity
January 18, 2005	25,000	5.57%	January 18, 2015	Single payment at maturity
Total	$ 155,000			

Our borrowings under the master shelf agreement are secured by a pledge of the capital stock of our significant subsidiaries. These subsidiaries also guaranty the borrowings under the facility. All of the borrowings under the master shelf agreement can be prepaid prior to their final maturity by paying a yield-maintenance fee. Under our master shelf agreement, we are subject to a number of covenants, including: maintaining a total debt to capitalization ratio of not more than 55% and maintaining a quarterly test of EBITDA, as defined in the master shelf agreement, to interest for the last four quarters in excess of 3.0 to 1.0.

In December 2004, we gave notice to Prudential of our intention to prepay the $25 million note due January 17, 2008. This note bore interest at 6.36% per annum and was prepaid at par on January 18, 2005. To fund the prepayment, we issued a new $25 million note to Prudential, due January 2015 and bearing interest at 5.57% per annum. During 2005, we will make scheduled payments totaling $10.0 million on this facility. We intend to fund these repayments with funds available under the revolving credit facility.

Senior Subordinated Notes. In 1999, we sold $155.0 million of senior subordinated notes in a private placement with a final maturity of 2009 due in a single payment which were subsequently exchanged for registered publicly tradable notes under the same terms and conditions. The subordinated notes bore interest at 10% per annum. We incurred approximately $5.0 million in offering commissions and expenses, which were capitalized and were being amortized over the term of the notes. We redeemed the senior subordinated notes in June 2004 using amounts available under the revolving credit facility and an additional borrowing under the master shelf agreement. In connection with this redemption, we paid a prepayment penalty of $7.75 million and expensed approximately $2.9 million of unamortized offering commissions and expenses.

Covenant Compliance. We were in compliance with all covenants in our debt agreements at December 31, 2004.

Environmental

The construction and operation of our gathering systems, plants and other facilities used for the gathering, processing, treating or transporting of gas and NGLs are subject to federal, state and local environmental laws and regulations, including those that can impose obligations to clean up hazardous substances at our facilities or at facilities to which we send wastes for disposal. In most instances, the applicable regulatory requirements relate to water and air pollution control or waste management. We employ specialists in environmental engineering, safety and regulatory compliance to monitor environmental and safety compliance at our facilities. In addition, our environmental engineers and safety specialists perform in-house audits of our existing facilities to ensure on-going compliance. Similarly, prior to consummating any major acquisition, our environmental engineers perform audits on the facilities to be acquired. We believe that we are in substantial compliance with applicable material environmental laws and regulations. Environmental regulation can increase the cost of planning, designing, constructing and operating our facilities. We anticipate that the trend in environmental legislation and regulation will continue to be toward stricter standards. The costs for compliance with current environmental laws and regulations have not had and, we believe, will not have a material adverse effect on our financial position or results of operations. We however cannot predict the extent or timing of future regulations or legislation and whether any such regulations or legislation will have a material adverse effect on the financial results of our operations, financial position or cash flows.

Prior to consummating any major acquisition, our environmental engineers perform audits on the facilities to be acquired. In conducting this audit on the acquisition of the gathering and processing facilities acquired in February 2005, we performed phase one environmental assessments and, where conditions indicated, performed phase two assessments. These assessments enabled us to satisfy ourselves that the disclosures by the seller were materially accurate and also to form our own risk assessment of potential environmental issues. In relation to the assets purchased in the February 2005 acquisition, one of the sites was the subject of an Administrative Order between the former owner, the State of Wyoming and a third party who has contracted to remediate the site in accordance with the Administrative Order. As a result of the acquisition, we also became a party to the Administrative Order. Both that site and another site are insured under an insurance policy that was put in place by the seller for the costs of all remediation activities. The obligation to perform and complete those remediation activities has been assigned contractually to a third party environmental specialist whose costs will be reimbursed by the insurance policy.

We are in the process of voluntarily cleaning up substances at several of the facilities that we operate. Our expenditures for environmental evaluation and remediation at existing facilities have not been significant in relation to our results of operations and totaled approximately $2.1 million for the year ended December 31, 2004. In 2004, we also paid approximately $467,000 in air emissions fees to the states in which we operate.

Cautionary Statement Regarding Forward-Looking Information

The Private Securities Litigation Reform Act of 1995 ("the Act") provides a safe harbor for forward-looking information made on our behalf. All statements, other than statements of historical facts, which address activities or actions that we expect or anticipate will or may occur in the future, and growth of our operations and other such matters are forward-looking terminology, such as "may," "intend," "will," "should," "expect," "anticipate," "estimate," "plan," "predict" or "continue" or comparable terminology.

This Annual Report contains forward-looking statements relating to, without limitation, our future economic performance, plans and objectives for future operations and forecasts of revenue and other financial items. Forward-looking statements made by us are based on our knowledge of our business and the environment in which we operate, but any one, or a combination, of factors could cause actual results to differ materially from our projections in the Annual Report. These factors, set forth herein and in our other documents on file with the SEC, include our ability to expand our gathering operations, completion our budgeted capital expenditures, the success of our drilling activities, our ability to respond to competitive pressures, the composition of gas to be treated and the drilling schedules and success of producers with acreage dedicated to our facilities, the condition of the capital markets, uncertainties associated with ongoing and future litigation and legal and regulatory programs (including those described under Items1 and 3 of our Annual Report on Form 10-K, in our quarterly reports on Form 10-Q and in our current reports on Form 8-K) and numerous other factors affecting our business generally and in the markets for gas and NGLs in which we participate. The forward-looking statements speak only as to the date when they are made. We assume no obligation to update and supplement forward-looking statements that become untrue because of subsequent events.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our commodity price risk management program has two primary objectives. The first goal is to preserve and enhance the value of our equity volumes of gas and NGLs with regard to the impact of commodity price movements on cash flow and net income in relation to those anticipated by our operating budget. The second goal is to manage price risk related to our marketing activities to protect profit margins. This risk relates to fixed price purchase and sale commitments, the value of storage inventories and exposure to physical market price volatility.

We utilize a combination of fixed price forward contracts, exchange-traded futures and options, as well as fixed index swaps, basis swaps and options traded in the over-the-counter, or OTC, market to accomplish these goals. These instruments allow us to preserve value and protect margins because corresponding losses or gains in the value of the financial instruments offset gains or losses in the physical market.

We also use financial instruments to reduce basis risk. Basis is the difference in price between the physical commodity being hedged and the price of the futures contract used for hedging. Basis risk is the risk that an adverse change in the futures market will not be completely offset by an equal and opposite change in the cash price of the commodity being hedged. Basis risk exists in natural gas primarily due to the geographic price differentials between cash market locations and futures contract delivery locations.

We enter into futures transactions on the New York Mercantile Exchange, or NYMEX, and through OTC swaps and options with various counterparties, consisting primarily of investment banks, financial institutions and other natural gas companies. We conduct credit reviews of all of our OTC counterparties and have agreements with many of these parties that contain collateral requirements. We generally use standardized swap agreements that allow for offset of positive and negative OTC exposures with the same counterparty. OTC exposure is marked-to-market daily for the credit review process. Our exposure to OTC credit risk is reduced by our ability to require a margin deposit from our counterparties based upon the mark-to-market value of their net exposure. We are also subject to margin deposit requirements under these same agreements and under margin deposit requirements for our NYMEX transactions. At December 31, 2004, we had $3.0 million of margin deposits outstanding.

We continually monitor and review the credit exposure to our marketing counterparties. In recent months the prices of natural gas and NGLs, and therefore our credit exposures, have increased significantly. In order to minimize our credit exposures, we have utilized existing netting agreements to reduce our net credit exposure, established new netting agreements with additional customers, terminated several long-term marketing obligations, negotiated accelerated payment terms with several customers, and increased the amount of credit which we make available to substantial companies which meet our credit requirements. Although netting agreements similar to those that we utilize have been upheld by bankruptcy courts in the past, if any of the customers with whom we have netting agreements were to file for bankruptcy, we can provide no assurance that our agreements will not be challenged or as to the outcome of any challenge.

The use of financial instruments may expose us to the risk of financial loss in some circumstances, including instances when (i) our equity volumes are less than expected, (ii) our customers fail to purchase or deliver the contracted quantities of natural gas or NGLs, or (iii) our OTC counterparties fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in these prices.

Risk Policy and Control. We control the extent of risk management and marketing activities through policies and procedures that involve the senior level of management. On a daily basis, our marketing activities are audited and monitored by our independent risk oversight department, or IRO. This department reports to the Chief Financial Officer, thereby providing a separation of duties from the marketing department. Additionally, the IRO reports monthly to the Risk Management Committee, or RMC. This committee is comprised of corporate managers and officers and is responsible for developing the policies and guidelines that control the management and measurement of risk, subject to the approval of the board of directors. The RMC is also responsible for setting risk limits including value-at-risk and dollar stop loss limits, subject to the approval of the board of directors.

Hedge Positions. As of January 31, 2005, we have hedged approximately 49% of our projected 2005 equity natural gas volumes and approximately 51% of our projected 2005 equity production of crude oil, condensate, and NGLs. All these contracts are designated and accounted for as cash flow hedges. As such, gains and losses related to the effective portions of the changes in the fair value of the derivatives are recorded in Accumulated other comprehensive income, a component of

Stockholders' equity. Realized gains or losses on these cash flow hedges are recognized in the Consolidated Statement of Operations through Sale of gas or Sale of natural gas liquids when the hedged transactions occur.

To qualify as cash flow hedges, the hedge instruments must be designated as cash flow hedges and changes in their fair value must be highly correlated with changes in the price of the forecasted transaction being hedged so that our exposure to the risk of commodity price changes is reduced. To meet this requirement, we hedge the price of the commodity and, if applicable, the basis between that derivative's contract delivery location and the cash market location used for the actual sale of the product. This structure attains a high level of effectiveness, ensuring that a change in the price of the forecasted transaction will result in an equal and opposite change in the cash price of the hedged commodity. We utilize crude oil as a surrogate hedge for natural gasoline and condensate. Our hedges are tested for effectiveness at inception and on a quarterly basis thereafter. We use regression analysis based on a five-year period of time for this test.

In the first quarter of 2004, we determined in our quarterly effectiveness testing that our hedges of equity butane production which utilized crude oil puts as a surrogate were no longer effective hedges. Therefore, in the first quarter, we discontinued cash flow hedge accounting treatment on these instruments. The value of these financial instruments remained in Accumulated other comprehensive income and was reclassified to our results of operations during 2004 as the underlying transactions occurred. Gains or losses from the ineffective portions of changes in the fair value of cash flow hedges are recognized currently in earnings through Price risk management activities. During 2004, we recognized a loss of $159,000 from the ineffective portions of our hedges.

Outstanding Equity Hedge Positions and the Associated Basis for 2005. The following table details our hedge positions as of January 31, 2005. In order to determine the hedged price to the particular operating region, deduct the basis differential from the NYMEX price. The prices for NGLs do not include the cost of the hedges of approximately $572,000 as of January 31, 2005. There is no associated cost for the natural gas hedges.

Product	Year	Quantity and Settle Price	Hedge of Basis Differential
Natural gas	2005	80,000 MMBtu per day with an average minimum price of $4.75 per MMBtu and an average maximum price of $8.88 per MMBtu.	Mid-Continent – 60,000 MMBtu per day with an average basis price of $0.42 per MMBtu. Permian – 5,000 MMBtu per day with an average basis price of $0.48 per MMBtu. Rocky Mountain – 15,000 MMBtu per day with an average basis price of $0.72 per MMBtu.
Crude, Condensate, Natural Gasoline	2005	50,000 Barrels per month with an average minimum price of $31.00 per barrel and an average maximum price of $48.01 per barrel.	Not Applicable
Propane	2005	75,000 Barrels per month with an average minimum price of $0.52 per gallon and an average maximum price of $0.88 per gallon.	Not Applicable
Ethane	2005	75,000 Barrels per month. Floor at $0.38 per gallon.	Not Applicable

Account balances related to hedging transactions (designated as hedges under SFAS 133) at December 31, 2004 were $2.9 million in Current assets from price risk management activities, $1.7 million in Current liabilities from price risk management activities, $240,000 in Deferred income taxes payable, net, and a $410,000 after-tax unrealized gain in Accumulated other comprehensive income, a component of Stockholders' equity. The unrealized gain in Accumulated other comprehensive income will be reclassified to earnings in 2005.

Value at Risk. We measure market risk in our natural gas and liquid marketing portfolios using value-at-risk, or VaR. We define VaR as a measure of the maximum expected loss over a given horizon under normal market conditions. VaR does not explicitly indicate potential realized losses. VaR does, however, implicitly indicate a firm's potential realized loss if market conditions were to remain constant or if the portfolio is liquidated within the specified time period. Our calculations are derived from Financial Engineering Association's VaR Works using the variance/co-variance method. We assume a one-day holding period with a 95% confidence level. There is a 95% (19 out of 20 business days) chance that the portfolio loss will be less than a specified amount if the entire portfolio were liquidated the next day. As of December 31, 2004, our VaR position for natural gas and liquid marketing portfolios was $542,000 and the average for all of 2004 was $447,000. This figure includes the risk related to our entire marketing portfolio of natural gas and NGL financial instruments and the related underlying physical transactions. We also measure market risk by sensitivity valuations. As of December 31, 2004, an increase in natural gas prices of $1.00 per MMbtu would lead to an increase in the fair value of our marketing portfolio of $1.6 million and an increase in crude oil prices of $5.00 per barrel would lead to an increase in the fair value of our marketing portfolio of $900,000. To the extent that a transaction is not fully hedged or there is any hedge ineffectiveness, additional gains or losses associated with the transaction may be reported in future periods.

Summary of Derivative Positions. A summary of the change in our derivative position from December 31, 2003 to December 31, 2004 is as follows (dollars in thousands):

Fair value of contracts outstanding at December 31, 2003	$ 6,707
Decrease in value due to change in price	(6,847)
Increase in value due to new contracts entered into during the period	19,677
Gains realized during the period from existing and new contracts	(8,196)
Changes in fair value attributable to changes in valuation techniques	-
Fair value of contracts outstanding at December 31, 2004	$ 11,341

A summary of our outstanding derivative positions at December 31, 2004 is as follows (dollars in thousands):

	Fair Value of Contracts at December 31, 2004				
Source of Fair Value	Total Fair Value	Maturing In 2005	Maturing In 2006-2007	Maturing In 2008-2009	Maturing Thereafter
Exchange published prices	$ 11,434	$ 11,392	$ 42	-	-
Other actively quoted prices (1)	(243)	(403)	160	-	-
Other valuation methods (2)	150	150	-	-	-
Total fair value	$ 11,341	$ 11,139	$ 202	-	-

(1) Other actively quoted prices are derived from broker quotations, trade publications, and industry indices.
(2) Other valuation methods are the Black-Scholes option-pricing model utilizing prices and volatility obtained from broker quotations, trade publications, and industry indices.

Foreign Currency Derivative Market Risk. As a normal part of our business, we enter into physical gas transactions which are payable in Canadian dollars. We enter into forward purchases and sales of Canadian dollars from time to time to fix the cost of our future Canadian dollar denominated natural gas purchase, sale, storage, and transportation obligations. This is done to protect marketing margins from adverse changes in the U.S. and Canadian dollar exchange rate between the time the commitment for the payment obligation is made and the actual payment date of such obligation. As of December 31, 2004, we had sold forward contracts for $31.3 million in Canadian dollars in exchange for $24.0 million in U.S. dollars, and the fair market value of these contracts was a loss of $2.1 million in U.S. dollars.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

Western Gas Resources, Inc.'s Consolidated Financial Statements as of December 31, 2004 and 2003 and for each of the three years in the period ended December 31, 2004:

Supplementary Data

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Our management does not expect that our internal control over financial reporting will prevent all error and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control systems' objectives will be met. The design of any system of controls is based in part on certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with policies or procedures.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2004. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework.* Based on our assessment and those criteria, management concluded that, as of December 31, 2004, our internal controls over financial reporting are effective.

PricewaterhouseCoopers, LLP, the registered public accounting firm that audited the financial statements included in this annual report, has issued its report on management's assessment of our internal control over financial reporting.

Scope of Management's Report on Internal Control Over Financial Reporting

We conduct a portion of our oil and gas operations through joint operating agreements with other companies. Under a portion of these joint operating agreements, the other company is the operator of the well and charges us a proportional share of the cost of the well and the on-going well operations. Under the agreements, we have the contractual right to audit the charges billed to us, but we do not have the contractual right or ability to dictate or modify the internal controls of these entities and do not have the ability, in practice, to assess those controls. These oil and gas operations are accounted for under the proportionate consolidation method. The total assets of approximately $210 million at December 31, 2004 and the total revenues of approximately $148 million for the year ended December 31, 2004 represent 11% and 5%, respectively, of our consolidated financial statement amounts, and 45% and 56%, respectively, of the assets and revenues in the Exploration and Production Segment.

/s/ PETER A. DEA
Peter A. Dea
Chief Executive Officer and President

/s/ WILLIAM J. KRYSIAK
William J. Krysiak
Executive Vice President – Chief Financial Officer
(Principal Financial and Accounting Officer)

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of Western Gas Resources, Inc.:

We have completed an integrated audit of Western Gas Resources, Inc.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Western Gas Resources, Inc. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, the Company changed its method of computing depletion for oil and gas properties effective January 1, 2004, its method of accounting for asset retirement obligations effective January 1, 2003, and its method of testing long-lived assets for impairment in 2003.

Internal control over financial reporting

Also, in our opinion, management's assessment, included under "Management's Report on Internal Control Over Financial Reporting" appearing in Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in "Scope of Management's Report on Internal Control Over Financial Reporting", management has excluded its oil and gas operations managed by other joint interest operators from its assessment of internal control over financial reporting as of December 31, 2004 because the Company does not have the ability to dictate or modify the controls of these entities and does not have the ability, in practice, to assess those controls. These oil and gas operations are owned through undivided interests and proportionately consolidated in the Company's consolidated financial statements. These properties had total assets and total revenues of $210 million and $148 million, respectively, representing 11% and 5% of the related consolidated financial statement amounts, as of and for the year ended December 31, 2004.

PricewaterhouseCoopers LLP
Denver, Colorado
March 11, 2005

WESTERN GAS RESOURCES, INC.
CONSOLIDATED BALANCE SHEET
(000s, except share data)

	December 31, 2004	December 31, 2003
ASSETS		
Current assets:		
Cash and cash equivalents	$ 390	$ 26,116
Trade accounts receivable, net	393,750	262,509
Inventory	94,604	70,304
Assets from price risk management activities	22,238	17,149
Other	12,494	11,225
Total current assets	523,476	387,303
Property and equipment:		
Gas gathering, processing and transportation	1,150,904	1,028,176
Oil and gas properties and equipment (successful efforts method)	495,314	329,555
Construction in progress	150,273	134,751
	1,796,491	1,492,482
Less: Accumulated depreciation, depletion and amortization	(570,582)	(495,721)
Total property and equipment, net	1,225,909	996,761
Other assets:		
Gas purchase contracts (net of accumulated amortization of $40,652 and $38,937, respectively)	27,704	29,219
Assets from price risk management activities	618	1,466
Investments in joint ventures	35,729	39,289
Other	26,676	6,486
Total other assets	90,727	76,460
TOTAL ASSETS	$ 1,840,112	$ 1,460,524
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 400,672	$ 303,186
Accrued expenses	60,472	42,136
Liabilities from price risk management activities	11,099	10,603
Dividends payable	3,704	3,056
Total current liabilities	475,947	358,981
Long-term debt	382,000	339,000
Liabilities from price risk management activities	417	1,304
Other long-term liabilities	51,827	22,057
Deferred income taxes payable, net	247,893	176,673
Total liabilities	1,158,084	898,015
Stockholders' equity:		
Preferred Stock; 10,000,000 shares authorized:		
$2.625 cumulative convertible preferred stock, par value $.10; none and 2,060,000 outstanding, respectively	-	206
Common stock, par value $.10; 100,000,000 shares authorized; 74,078,733 and 68,271,802 shares issued, respectively	7,430	6,876
Treasury stock, at cost; 50,032 common shares in treasury	(788)	(788)
Additional paid-in capital	392,437	381,581
Retained earnings	278,687	173,076
Accumulated other comprehensive income	4,262	1,558
Total stockholders' equity	682,028	562,509
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,840,112	$ 1,460,524

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

WESTERN GAS RESOURCES, INC.
CONSOLIDATED STATEMENT OF CASH FLOWS
(000s)

	Year Ended December 31,		
	2004	2003	2002
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 119,215	$ 84,219	$ 50,589
Add income items that do not affect operating cash flows:			
Depreciation, depletion and amortization	95,536	73,906	77,005
Deferred income taxes	66,289	49,326	19,614
Distributions more than or (less than) equity income, net	127	1,076	(2,906)
(Gain) loss on the sale of property and equipment	1,288	(156)	948
Non-cash change in fair value of derivatives	(1,572)	(1,235)	13,788
Compensation expense from re-priced stock options	646	376	224
Cumulative effect of change in accounting principle	(4,714)	6,724	-
Other non-cash items, net	2,112	1,430	1,809
Adjustments to working capital to arrive at net cash provided by operating activities:			
(Increase) in trade accounts receivable	(126,883)	(7,720)	(35,216)
(Increase) decrease in product inventory	(22,215)	(25,136)	7,164
Decrease (increase) in other current assets	1,553	8,869	(13,329)
(Increase) decrease in other assets and liabilities, net	(5,019)	(359)	348
Increase (decrease) in accounts payable	65,905	55,689	(23,129)
Increase (decrease) in accrued expenses	17,180	(2,787)	27,492
Net cash provided by operating activities	209,448	244,222	124,401
Cash flows from investing activities:			
Purchases of property and equipment, including acquisitions	(306,555)	(188,318)	(125,600)
Proceeds from the disposition of property and equipment	1,501	5,983	34,865
Distributions from (contributions to) equity investees	2,310	(14,750)	(15,037)
Net cash used in investing activities	(302,744)	(197,085)	(105,772)
Cash flows from financing activities:			
Net proceeds from exercise of common stock options	9,993	5,027	6,489
Change in outstanding checks	31,581	4,510	6,735
Payments for the redemption of preferred stock	(1,930)	(1,201)	(12,607)
Borrowings under long-term debt	100,000	25,000	-
Payments on long-term debt	(190,000)	(43,333)	(8,333)
Borrowings under revolving credit facility	2,654,230	1,022,300	994,545
Payments on revolving credit facility	(2,521,230)	(1,024,900)	(992,945)
Debt issue costs paid	(2,086)	(1,861)	(126)
Dividends paid	(12,988)	(13,875)	(15,107)
Net cash provided by (used in) financing activities	67,570	(28,333)	(21,349)
Net (decrease) increase in cash and cash equivalents	(25,726)	18,804	(2,720)
Cash and cash equivalents at beginning of year	26,116	7,312	10,032
Cash and cash equivalents at end of year	$ 390	$ 26,116	$ 7,312

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

WESTERN GAS RESOURCES, INC.
CONSOLIDATED STATEMENT OF OPERATIONS
(000s, except share and per share amounts)

	Year Ended December 31,		
	2004	2003	2002
Revenues:			
Sale of gas	$ 2,518,081	$ 2,463,451	$ 2,118,748
Sale of natural gas liquids	450,761	346,108	309,513
Gathering, processing and transportation	90,874	83,672	65,601
Price risk management activities	6,796	(21,820)	(8,884)
Other	3,201	2,599	4,720
Total revenues	3,069,713	2,874,010	2,489,698
Costs and expenses:			
Product purchases	2,540,799	2,456,441	2,157,179
Plant and transportation operating expense	95,868	88,344	81,530
Oil and gas exploration and production costs	77,608	52,245	34,007
Depreciation, depletion and amortization	95,536	73,906	77,005
Selling and administrative expense	52,246	40,423	35,828
(Gain) loss on sale of assets	1,288	(156)	948
Loss from early extinguishment of debt	10,662	-	-
Earnings from equity investments	(7,124)	(7,356)	(4,453)
Interest expense	19,562	25,627	26,951
Total costs and expenses	2,886,445	2,729,474	2,408,995
Income before income taxes	183,268	144,536	80,703
Provision for income taxes:			
Current	2,478	4,267	10,500
Deferred	66,289	49,326	19,614
Total provision for income taxes	68,767	53,593	30,114
Income before cumulative effect of change in accounting principle	114,501	90,943	50,589
Cumulative effect of change in accounting principle, net of tax (expense) or benefit of ($2,710) and $3,967, respectively	4,714	(6,724)	-
Net income	$ 119,215	$ 84,219	$ 50,589
Preferred stock requirements	(835)	(6,841)	(9,198)
Income attributable to common stock	$ 118,380	$ 77,378	$ 41,391
Earnings per share of common stock before cumulative effect of change in accounting principle	$ 1.56	$ 1.27	$ 0.63
Cumulative effect of change in accounting principle per share of common stock, net of tax	$ 0.07	$ (0.10)	$ -
Earnings per share of common stock	$ 1.63	$ 1.17	$ 0.63
Weighted average shares of common stock outstanding	72,419,980	66,412,228	65,905,086
Income attributable to common stock - assuming dilution	$ 118,380	$ 84,219	$ 41,391
Earnings per share of common stock - assuming dilution	$ 1.61	$ 1.13	$ 0.62
Weighted average shares of common stock outstanding - assuming dilution	73,494,747	74,694,420	67,215,120

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

WESTERN GAS RESOURCES, INC.
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(000s, except share amounts)

	Shares of $2.28 Cumulative Preferred Stock	$2.625 Cumulative Convertible Preferred Stock	Shares of Common Stock	Shares of Common Stock in Treasury	Shares of $2.28 Cumulative Preferred Stock in Treasury	$2.28 Cumulative Preferred Stock	$2.625 Cumulative Convertible Preferred Stock	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained (Deficit) Earnings	Accumulated Other Comprehensive Income (Loss) Net of Tax	Notes Receivable from Key Employees	Total Stock-holders' Equity
Balance at December 31, 2001	591,136	2,760,000	65,378,018	50,032	44,290	$ 59	$ 276	$ 3,293	$ (1,907)	$387,505	$ 66,128	$ 18,882	$ (884)	$473,352
Comprehensive income:														
Net income, 2002	-	-	-	-	-	-	-	-	-	-	50,589	-	-	50,589
Other comprehensive income from equity investees	-	-	-	-	-	-	-	-	-	-	-	556	-	556
Translation adjustments	-	-	-	-	-	-	-	-	-	-	-	283	-	283
Reclassification adjustment for settled contracts	-	-	-	-	-	-	-	-	-	-	-	(17,142)	-	(17,142)
Changes in fair value of outstanding hedge positions	-	-	-	-	-	-	-	-	-	-	-	(119)	-	(119)
Fair value of new hedge positions	-	-	-	-	-	-	-	-	-	-	-	(5,272)	-	(5,272)
Change in accumulated derivative comprehensive income	-	-	-	-	-	-	-	-	-	-	-	(22,533)	-	(22,533)
Total comprehensive income, net of tax	-	-	-	-	-	-	-	-	-	-	-	-	-	28,895
Stock options exercised	-	-	777,204	-	-	-	-	36	-	5,975	-	-	-	6,011
Effect of re-priced options	-	-	-	-	-	-	-	-	-	478	-	-	-	478
Officer loans forgiven	-	-	-	-	-	-	-	-	-	-	-	-	589	589
Tax benefit related to stock options exercised	-	-	-	-	-	-	-	-	-	1,154	-	-	-	1,154
Dividends declared on common stock	-	-	-	-	-	-	-	-	-	-	(6,603)	-	-	(6,603)
Dividends declared on $2.28 cumulative preferred stock	-	-	-	-	-	-	-	-	-	-	(957)	-	-	(957)
Dividends declared on $2.625 cumulative convertible preferred stock	-	-	-	-	-	-	-	-	-	-	(7,244)	-	-	(7,244)
Redemption of $2.28 cumulative preferred stock	(591,136)	-	-	-	(44,290)	(59)	-	-	1,119	(14,046)	379	-	-	(12,607)
Balance at December 31, 2002	-	2,760,000	66,155,222	50,032	-	$ -	$ 276	$ 3,329	$ (788)	$381,066	$ 102,292	$ (2,812)	$ (295)	$ 483,068
Comprehensive income:														
Net income, 2003	-	-	-	-	-	-	-	-	-	-	84,219	-	-	84,219
Translation adjustments	-	-	-	-	-	-	-	-	-	-	-	1,237	-	1,237
Reclassification adjustment for settled contracts	-	-	-	-	-	-	-	-	-	-	-	5,272	-	5,272
Changes in fair value of outstanding hedge positions	-	-	-	-	-	-	-	-	-	-	-	127	-	127
Fair value of new hedge positions	-	-	-	-	-	-	-	-	-	-	-	(2,266)	-	(2,266)
Change in accumulated derivative comprehensive income	-	-	-	-	-	-	-	-	-	-	-	3,133	-	3,133
Total comprehensive income, net of tax	-	-	-	-	-	-	-	-	-	-	-	-	-	88,589
Stock options exercised	-	-	415,180	-	-	-	-	24	-	3,570	-	-	-	3,594
Effect of re-priced options	-	-	-	-	-	-	-	-	-	904	-	-	-	904
Officer loans forgiven	-	-	-	-	-	-	-	-	-	-	-	-	295	295
Tax benefit related to stock options exercised	-	-	-	-	-	-	-	-	-	727	-	-	-	727
Dividends declared on common stock	-	-	-	-	-	-	-	-	-	-	(6,684)	-	-	(6,684)
Dividends declared on $2.625 cumulative convertible preferred stock	-	-	-	-	-	-	-	-	-	-	(6,783)	-	-	(6,783)
Conversion of $2.625 cumulative convertible preferred stock	-	(676,344)	1,701,400	-	-	-	(68)	85	-	(17)	-	-	-	-
Redemption of $2.625 cumulative convertible preferred stock	-	(23,656)	-	-	-	-	(2)	-	-	(1,231)	32	-	-	(1,201)

Balance at December 31, 2003	-	2,060,000	68,271,802	50,032	-	$ -	$ 206	$ 3,438	$ (788)	$385,019	$ 173,076	$ 1,558	$ -	$ 562,509
Comprehensive income:														
Net income, 2004	-	-	-	-	-	-	-	-	-	-	119,215	-	-	119,215
Translation adjustments	-	-	-	-	-	-	-	-	-	-	-	816	-	816
Other comprehensive income from equity affiliates	-	-	-	-	-	-	-	-	-	-	-	(780)	-	(780)
Reclassification adjustment for settled contracts	-	-	-	-	-	-	-	-	-	-	-	2,266	-	2,266
Changes in fair value of outstanding hedge positions	-	-	-	-	-	-	-	-	-	-	-	16	-	16
Reduction due to estimated ineffectiveness	-	-	-	-	-	-	-	-	-	-	-	(8)	-	(8)
Fair value of new hedge positions	-	-	-	-	-	-	-	-	-	-	-	394	-	394
Change in accumulated derivative comprehensive income	-	-	-	-	-	-	-	-	-	-	-	2,668	-	2,668
Total comprehensive income, net of tax	-	-	-	-	-	-	-	-	-	-	-	-	-	121,919
Stock options exercised	-	-	681,703	-	-	-	-	54	-	9,939	-	-	-	9,993
Effect of re-priced options	-	-	-	-	-	-	-	-	-	646	-	-	-	646
Tax benefit related to stock options exercised	-	-	-	-	-	-	-	-	-	2,527	-	-	-	2,527
Dividends declared on common stock	-	-	-	-	-	-	-	-	-	-	(12,847)	-	-	(12,847)
Dividends declared on $2.625 cumulative convertible preferred stock	-	-	-	-	-	-	-	-	-	-	(789)	-	-	(789)
Conversion of $2.625 cumulative convertible preferred stock	-	(2,024,404)	5,125,228	-	-	-	(204)	255	-	(93)	-	-	-	(42)
Redemption of $2.625 cumulative convertible *preferred stock*	-	(35,596)	-	-	-	-	(2)	-	-	(1,918)	32	-	-	(1,888)
Two for one common stock split	-	-	-	-	-	-	-	3,683	-	(3,683)	-	-	-	-
Balance at December 31, 2004	-	-	74,078,733	50,032	-	$ -	$ -	$ 7,430	$ (788)	$392,437	$ 278,687	$ 4,262	$ -	$ 682,028

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

NOTE 1 - NATURE OF ORGANIZATION

Western Gas Resources, Inc. (the "Company") explores for, develops and produces, gathers, processes and treats, transports and markets natural gas and natural gas liquids ("NGLs"). In its upstream operations, the Company explores for, develops and produces natural gas reserves primarily in the Rocky Mountain region. In its midstream operations the Company designs, constructs, owns and operates natural gas gathering, processing and treating facilities and owns and operates regulated transportation facilities, and offers marketing services in order to provide its customers with a broad range of services from the wellhead to the sales delivery point. The Company's midstream operations are conducted in major gas-producing basins in the Rocky Mountain, Mid-Continent and Southwestern regions of the United States.

In 2002, the Company adopted a Stockholder Rights Plan under which Series A Junior Participating Preferred Stock Purchase Rights were distributed as a dividend at the rate of one-half of one right for each share of its common stock held by stockholders of record as of the close of business on April 9, 2002. Each right initially will entitle stockholders to buy one unit consisting of 1/100th of a share of a new series of preferred stock for $180 per unit. The right generally will be exercisable only if a person or group acquires beneficial ownership of 15% or more of the Company's then outstanding common stock or commences a tender or exchange offer upon consummation of which a person or group would beneficially own 15% or more of its then outstanding common stock. The rights will expire on March 22, 2011.

In June 2004, the Company completed a two-for-one split of its common stock, which was distributed in the form of a stock dividend. Stockholders of the Company's common stock received one additional share for every share of common stock held on the record date of June 4, 2004. After the stock split, each share of common stock outstanding or thereafter issued includes or will include one-half of a Series A Junior Participating Preferred Stock purchase right. The Company has restated its financial information to reflect this split for all periods presented.

In November 1992, the Company issued 1,400,000 shares of $2.28 Cumulative Preferred Stock with a liquidation preference of $25 per share, at a public offering price of $25 per share, redeemable at the Company's option on or after November 15, 1997. In 2000, the Company re-purchased 39,190 of the $2.28 Cumulative Preferred Stock for a total consideration of approximately $1.0 million. In 2001, the Company purchased in open market transactions an additional 5,100 shares of this preferred stock for a total cost, including broker commissions, of approximately $129,000, or an average of $25.29 per share of this preferred stock. In December 2001, the Company redeemed 808,864 shares of this preferred stock at the liquidation preference for total proceeds of $20.6 million including accrued and unpaid dividends. In December 2002, the Company redeemed the remaining 546,846 shares of this preferred stock at the liquidation preference for total proceeds of $14.0 million including accrued and unpaid dividends.

In February 1994, the Company issued 2,760,000 shares of $2.625 Cumulative Convertible Preferred Stock with a liquidation preference of $50 per share, at a public offering price of $50 per share, redeemable at the Company's option on or after February 16, 1997 and convertible at the option of the holder into Common Stock at a per share conversion price of $19.88. In November 2003 and in December 2003, the Company issued notices of redemption for approximately 700,000 and 800,000 shares, respectively, of its $2.625 cumulative convertible preferred stock at the liquidation preference plus 0.525% premium. In relation to the notice of redemption issued in November 2003, in December 2003 a total of 1,701,400 common shares were issued and $1.2 million was paid in cash to complete the redemption. In relation to the notice of redemption issued in December 2003, in January 2004 a total of 1,979,244 common shares were issued and $672,000 was paid in cash. In March 2004, the Company issued an additional notice of redemption for the remaining 1,260,000 shares of its $2.625 cumulative convertible preferred stock. In April 2004, the Company issued an additional 3,113,582 shares of common stock to holders who elected to convert their shares and paid $391,000 in cash proceeds to complete this redemption. After these redemptions, the $2.625 cumulative convertible preferred stock was delisted from trading on the New York Stock Exchange and application was made to the SEC to deregister such stock.

Significant Projects and Asset Divestitures

Acquisition of San Juan Properties. In October 2004, the Company acquired oil and gas assets in the San Juan Basin of New Mexico for approximately $82.2 million, plus assumed liabilities. The purchase also included related gathering systems, which are connected to the Company's San Juan River plant. In connection with this acquisition, the Company increased Oil and gas properties and equipment by $72.6 million and increased Gas gathering, processing and transportation by $13.3 million.

Acquisition and Disposition of Gathering Systems. Effective February 1, 2003, the Company acquired several gathering systems in Wyoming, primarily located in the Greater Green River Basin with smaller operations in the Powder River and Wind River Basins, for a total of $37.1 million. Several of the systems located in the Powder River did not integrate directly into the Company's existing systems, and accordingly these systems were sold in 2003. During the year ended December 31, 2003, the income generated by the assets sold was immaterial.

Acquisition of Sand Wash Properties. In August 2003, through the acquisition of the stock of a private corporation for $12.9 million, the Company acquired additional reserves, production and acreage in the Sand Wash Basin. The assets of this private entity consisted primarily of the remaining interests in various Sand Wash properties operated by the Company.

Toca Processing Facility. In September 2002, the Company sold its Toca processing facility in Louisiana. The sale price was $32.2 million and resulted in a pre-tax loss of approximately $230,000. During the year ended December 31, 2002, this facility generated net after-tax earnings of approximately $683,000, or $.01 per share of common stock, respectively. The Company believes the results from this facility are immaterial for separate presentation as a discontinued operation. Approximately $15.0 million of the proceeds received from this asset sale were initially used to reduce amounts outstanding on the Company's revolving credit facility. At December 31, 2002, the remaining amount of $17.2 million was on deposit with a trustee in anticipation of the completion of a like-kind exchange transaction and was reflected on the Consolidated Balance Sheet under the caption Other current assets. These funds, along with additional amounts drawn on the Company's revolving credit facility, were used in a February 2003 acquisition of several gathering systems described above.

Powder River Basin Coal Bed Methane. The Company continues to develop its Powder River Basin coal bed methane reserves and expand the associated gathering system. During the years ended December 31, 2004, 2003 and 2002, the Company expended approximately $106.9 million, $53.3 million and $71.0 million, respectively, on this project.

Greater Green River Basin. The Company's assets in southwest Wyoming and northwest Colorado include the Granger and Lincoln Road facilities (collectively the "Granger Complex"), the Company's 50% equity interest in Rendezvous Gas Services, L.L.C. ("Rendezvous"), the Red Desert facility, Wamsutter gathering, and production from the Jonah Field, Pinedale Anticline and Sand Wash areas. During the years ended December 31, 2004, 2003 and 2002, the Company expended approximately $63.9 million, $102.5 million and $37.1 million, respectively, in this area.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies followed by the Company and its wholly owned subsidiaries are presented here to assist the reader in evaluating the financial information contained herein. The Company's accounting policies are in accordance with generally accepted accounting principles.

Principles of Consolidation. The consolidated financial statements include the accounts of the Company and the Company's wholly owned subsidiaries. All material inter-company transactions have been eliminated in consolidation. The Company's interest in certain non-controlled investments is accounted for by the equity method.

Inventories. The cost of gas and NGL inventories are determined by the weighted average cost method on a location-by-location basis. Residue and NGL inventory covered by derivative contracts is accounted for on a specific identification basis. Product inventory includes $88.8 million and $67.1 million of gas and $2.0 million and $1.6 million of NGLs at December 31, 2004 and 2003, respectively.

Property and Equipment. Property and equipment is recorded at cost, including capitalized interest. Interest incurred during the construction period of new projects is capitalized and amortized over the life of the associated assets. Repair and maintenance of property and equipment is expensed as incurred.

Depreciation is provided using the straight-line method based on the estimated useful life of each facility, which ranges from three to 35 years. Useful lives are determined based on the shorter of the life of the equipment or the reserves serviced by the equipment. The cost of acquired gas purchase contracts is amortized using the straight-line method or units of production.

In connection with the adoption of SFAS No. 143 on January 1, 2003, a review was completed of the Company's operating assets. As a result of this evaluation, the operating lives and salvage values of the associated equipment was reevaluated, and the Company extended the useful life of many of its operating assets and adjusted the estimated salvage value of its operating equipment. These adjustments resulted in an approximate $10.7 million, or $0.10 per share of common stock - assuming dilution, decrease in depreciation, depletion and amortization in the year ended December 31, 2003, from the expense calculated using the previous useful lives. The adjustments to the salvage value and depreciable lives of the Company's assets are treated as a revision of an estimate and are accounted for on a prospective basis.

In December 2004, the Company placed into service a new 200 MMcf per day processing facility adjacent to its Granger Complex. This facility straddles a third-party regulated pipeline and processes its gas to meet pipeline specifications. The facility's capacity is contractually committed to this service, and the contract for processing this gas requires a monthly charge to be paid by the pipeline regardless of the amount of gas processed. These fees total approximately $2.2 million per year and the contract has a term of ten years. In accordance with EITF 01-08, "Determining Whether an Arrangement Contains a Lease", facilities that are built to provide services to one specific customer should be evaluated for potential treatment as capital leases. The Company has determined that accounting for this contract as a capital lease is appropriate. On the Consolidated Balance Sheet, at December 31, 2004 related to this transaction, the Company had receivables of $22.4 million in Other assets for the fixed portion of the non-current future lease payments plus the unguaranteed residual value at the end of the lease term and $2.2 million in Other Current assets. The Company also had deferred revenue totaling $17.8 million in Other long-term liabilities for the non-current deferred revenue and $2.0 million in Accrued expenses for the current portion.

Oil and Gas Properties and Equipment. The Company follows the successful efforts method of accounting for oil and gas exploration and production activities. Acquisition costs, development costs and successful exploration costs are capitalized. Upon surrender or impairment of undeveloped properties, the original cost is charged against income. Developed and undeveloped leaseholds with proved reserves are depleted by the units-of-production method based on estimated proved reserves. Development costs and related equipment are depleted and depreciated by the units-of-production method based on estimated proved developed reserves.

Exploratory lease rentals and geological and geophysical costs are charged to expense as incurred. Exploratory drilling costs are capitalized when incurred pending the determination of whether a well has found proved reserves. A determination of whether a well has found proved reserves is made shortly after drilling is completed. The determination is based on a process that relies on interpretations of available geological, geophysical, and engineering data. If an exploratory well is determined to be unsuccessful, the capitalized drilling costs will be charged to expense in the period the determination is made. If an exploratory well requires a major capital expenditure before production can begin, the cost of drilling the exploratory well will continue to be carried as an asset pending determination of whether proved reserves have been found only as long as: i) the well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made, and ii) drilling of additional exploratory wells is under way or firmly planned for the near future. If the drilling of additional exploratory wells in the area is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory well is assumed to be impaired, and its costs are charged to expense.

As of December 31, 2004, the Company has included disclosures related to suspended well costs. The Company evaluated all existing capitalized exploratory well costs under the provisions of the pending FSP. The following table reflects the net changes in capitalized exploratory well costs during the years ended December 31, 2004, 2003 and 2002 (000s).

	2004	2003	2002
Beginning balance at January 1,	$ 25,083	$ 18,795	$ 7,239
Additions to capitalized exploratory well costs pending the determination of proved reserves	30,683	12,804	11,830
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(6,900)	(4,655)	(49)
Capitalized exploratory well costs charged to expense	(320)	(1,861)	(225)
Ending balance at December 31,	$ 48,546	$ 25,083	$ 18,795

Substantially all of the Company's exploratory wells that have been capitalized for a period greater than one year are located in the Powder River Basin. In this basin, the Company drills wells into various coal seams. In order to produce gas from the coal seams, a period of dewatering lasting from a few to twenty-four months, or in some cases longer, is required prior to obtaining sufficient gas production to justify capital expenditures for compression and gathering, and to classify the reserves as proven. In order to accelerate the dewatering time, the Company drills additional exploratory wells in these areas.

Effective January 1, 2004, the Company redefined the asset groupings for the calculation of depreciation and depletion on its oil and gas properties from a well-by-well basis to a field wide basis for each of the Jonah, Pinedale and Sand Wash fields and to a grouping of all wells drilled into related coal seams for the Powder River Basin. This change resulted in an increase in Depreciation, depletion and amortization expense of $4.9 million, or $.07 per share of common stock - assuming dilution, in 2004. The change in the depreciation and depletion methodology is treated as a change in accounting principle. Accordingly, the Accumulated depreciation, depletion and amortization for these assets has been recalculated under the new methodology. The cumulative effect of the change in depreciation and depletion methodology for the year ended December 31, 2004 is a benefit of $4.7 million, net of tax, or $0.06 per share of common stock - assuming dilution, and is presented in the Consolidated Statement of Operations under the caption Cumulative effect of change in accounting principle, net of tax.

Income Taxes. Deferred income taxes reflect the impact of temporary differences between amounts of assets and liabilities for financial reporting purposes and such amounts as measured by tax laws. These temporary differences are determined and accounted for in accordance with SFAS No. 109, "Accounting for Income Taxes."

Foreign Currency Adjustments. The Company has a subsidiary in Canada. The functional currency of this subsidiary is the Canadian dollar. The assets and liabilities associated with this subsidiary are translated into U.S. dollars at the exchange rate as of the balance sheet date and revenues and expenses at the weighted-average of exchange rates in effect during each reporting period. The translation gains for the years ended December 31, 2004, 2003 and 2002 were $800,000, $1.2 million and $283,000, respectively, net of tax.

Revenue Recognition. In the Gas Gathering, Processing and Treating segment, the Company recognizes revenue for its services at the time the service is performed. The Company records revenue from its gas and NGL marketing activities, including sales of the Company's equity production, upon transfer of title. In accordance with EITF 03-11, the Company records revenue on its physical gas and NGL marketing activities on a gross basis versus sales net of purchases basis because it obtains title to all the gas and NGLs that it buys including third-party purchases, bear the risk of loss and credit exposure on these transactions, and it is the Company's intention upon entering these contracts to take physical delivery of the product. Gas imbalances on the Company's production are accounted for using the sales method. Gas imbalances on the Company's production at December 31, 2004 and 2003 are immaterial. For its marketing activities the Company utilizes mark-to-market accounting for its derivatives. Under mark-to-market accounting, the expected margin to be realized over the term of the transaction is recorded in the month of origination. To the extent that a transaction is not fully hedged or there is any hedge ineffectiveness, additional gains or losses associated with the transaction may be reported in future periods. In the Transportation segment, the Company realizes revenue on a monthly basis from firm capacity contracts under which the shipper pays for transport capacity whether or not the capacity is used and from interruptible contracts where a fee is charged based upon volumes received into the pipeline. See additional discussion in Note 9 – Business Segments and Related Information.

In order to minimize transportation costs or make product available at a location of our customer's preference, from time to time, the Company will enter into arrangements to buy product from a party at one location and arrange to sell a like quantity of product to this same party at another location. In accordance with EITF 03-11, the Company records revenue on these transactions on a gross basis versus sales net of purchases basis because it obtains title to the product that it buys, bears the risk of loss, credit and performance exposure on these transactions, and the Company takes physical delivery of the product. For the years ended December 31, 2004, 2003 and 2002, the Company recorded revenues of $92.6 million, $95.5 million and $39.8 million, respectively, and product purchases of $86.7 million, $84.2 million and $36.3 million, respectively, for transactions which were entered into concurrently and with the intent to buy and sell like quantities with the same counter party at different locations and at market prices at those locations.

Accounting for Derivative Instruments and Hedging Activities. The Company recognizes the change in the market value of all derivatives, including storage contracts and firm transportation contracts to the extent utilized, as either assets or liabilities in the statement of financial position and measures those instruments at fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income depending upon the nature of the underlying transaction.

Comprehensive Income. Accumulated other comprehensive income is reported as a separate component of stockholders' equity. Accumulated other comprehensive income includes cumulative translation adjustments for foreign currency transactions and the change in fair market value of cash flow hedges. The Company's accumulated derivative gains at December 31, 2004 totaled $410,000 and will be reclassified into earnings during 2005. These items are separately reported on the Consolidated Statement of Changes in Stockholders' Equity.

Impairment of Long-Lived Assets. The Company reviews its long-lived assets whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's assets are evaluated at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets. In order to determine whether an impairment exists, the Company compares its net book value of the asset to the undiscounted expected future net cash flows, determined by applying future prices estimated by management over the shorter of the lives of the facilities or the reserves supporting the facilities. If an impairment exists, write-downs of assets are based upon expected future net cash flows discounted using an interest rate commensurate with the risk associated with the underlying asset.

The Company reviews its assets at the plant facility, the related group of plant facilities or the oil and gas producing field or producing coal seam level. Prior to 2003, the Company completed its impairment analysis on its oil and gas producing properties on an individual well-by-well basis. In the fourth quarter of 2003, the Company conducted a review of its oil and gas producing properties, which included an evaluation of the geologic formations and production history for the Company's producing properties. This review indicated that the cash flows from individual wells in its operating areas were not largely independent of the cash flows of other wells producing in the same field or coal seam. As a result of this review, the Company redefined the asset groupings to a field wide analysis for impairment for the Jonah, Pinedale and Sand Wash Basins and a grouping of all wells drilled into related coal seams for the Powder River Basin. These asset groupings were used to determine if any impairment was necessary for the years ended December 31, 2004 and 2003, and it was determined that none of the asset groups were impaired. In addition, as the previous method of asset grouping was not appropriate under generally accepted accounting principles, a reevaluation of the impairment test for the year ended December 31, 2002 was completed utilizing the new asset groups. That revised impairment test also did not result in an impairment of the Company's producing properties for that period, and accordingly, the correction of this error in the method of application of the accounting principle relating to asset grouping for testing the impairment of producing oil and gas properties did not have any financial statement impact for the year ended December 31, 2002.

Cumulative Effect of a Change in Accounting Principle. In June 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 was effective for fiscal years beginning after June 15, 2002. SFAS No. 143 establishes accounting standards for recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. The Company adopted SFAS No. 143 on January 1, 2003 and recorded an $11.5 million increase to Property and equipment, a $4.4 million increase to Accumulated depreciation, depletion and amortization, a $17.8 million increase to Other long-term liabilities and a $6.7 million non-cash, after-tax loss from the Cumulative effect of a change in accounting principle.

The following is a reconciliation of the asset retirement obligation for the years ended December 31, 2004 and 2003 (000's):

	2004	2003
Asset retirement obligation as of January 1	$ 20,644	$ 17,801
Liability accrued upon capital expenditures	3,562	1,994
Changes due to revisions of estimated retirement costs	7,262	-
Liability settled	(139)	(306)
Accretion of discount expense	1,335	1,155
Asset retirement obligation as of December 31	$ 32,664	$ 20,644

Exclusive of assets disposed of during 2002, if the Company had adopted SFAS No. 143 as of January 1, 2002, it estimates that the asset retirement obligation at that date would have been $15.7 million, based on the same assumptions used in its calculation of the obligation at January 1, 2003. The estimated 2002 pro forma effect of a hypothetical January 1, 2002 adoption of SFAS No. 143 on net income and earnings per share, for annual and interim periods, is not material.

Earnings Per Share of Common Stock. Earnings per share of common stock are computed by dividing income attributable to common stock by the weighted average shares of common stock outstanding. In addition, earnings per share of common stock - assuming dilution is computed by dividing income attributable to common stock by the weighted average shares of common stock outstanding as adjusted for potential common shares. Income attributable to common stock is net income less preferred stock dividends. The following table presents the dividends declared by the Company for each class of its outstanding equity securities (000's, except per share amounts):

	Year Ended December 31,		
	2004	2003	2002
Common Stock	$ 12,847	$ 6,684	$ 6,603
Preferred Stock	835	6,783	8,201
Total Dividends Declared	$ 13,682	$ 13,467	$ 14,804
Dividends Declared Per Share:			
Common Stock	$ 0.18	$ 0.10	$ 0.10
Preferred Stock	$ 0.81	$ 2.82	$ 2.68

Common stock options and, until the final conversion or redemption in April 2004, the Company's $2.625 cumulative convertible preferred stock are potential common shares. The following is a reconciliation of the weighted average shares of common stock outstanding to the weighted average common shares outstanding – assuming dilution. The share information presented reflects the two-for-one common stock split completed in 2004.

	Year Ended December 31,		
	2004	2003	2002
Weighted average shares of common stock outstanding	72,419,980	66,412,228	65,905,086
Potential common shares from:			
Common stock options	1,074,767	1,413,354	1,310,034
$2.625 Cumulative Convertible Preferred Stock	-	6,868,838	-
Weighted average shares of common stock outstanding - assuming dilution	73,494,747	74,694,420	67,215,120

The numerators and the denominators for the prior periods were adjusted to reflect these potential common shares and any related preferred dividends in calculating fully diluted earnings per share.

Concentration of Credit Risk. Financial instruments that potentially subject the Company to concentrations of credit risk consist principally of trade accounts receivable and OTC swaps and options. The risk is limited due to the large number of entities comprising the Company's customer base and their dispersion across geographic locations. The Company records its trade accounts receivable at the invoiced amount, which does not include interest.

The Company continually monitors and reviews the credit exposure to its marketing counter parties. This review has resulted in a reduction in sales volumes with various counter parties in order to maintain acceptable credit exposures. During 2002, the Company reserved approximately $1.6 million for doubtful accounts through a charge to Selling and administrative expense. During 2004 and 2003, the Company did not increase its allowance for doubtful accounts. The Company records an allowance for doubtful accounts on a specific identification basis, and the balance in the reserve for doubtful accounts was $648,000 and $2.3 million, respectively, at December 31, 2004 and 2003.

Cash and Cash Equivalents. Cash and cash equivalents includes all cash balances and highly liquid investments with an original maturity of three months or less. At December 31, 2004 and 2003, the Company had outstanding disbursements to vendors and producers totaling $72.0 million and $40.4 million, respectively, which were reclassified to Accounts payable. The change in outstanding disbursements to vendors and producers is presented as a component of Cash flows from financing activities in the Statement of Cash Flows.

Supplementary Cash Flow Information. Interest paid was $22.3 million, $28.0 million, and $28.1million, respectively, for the years ended December 31, 2004, 2003 and 2002. Capitalized interest associated with construction of new projects was $2.5 million, $1.8 million and $1.7 million, respectively, for the years ended December 31, 2004, 2003 and 2002. Income taxes paid were $9.4 million, $11.1 million and $1.5 million, respectively, for the years ended December 31, 2004, 2003 and 2002. A lease receivable of $24.6 million and an unearned revenue liability of $19.8 million were recorded for the year ending December 31, 2004 for the lease of the Granger 200MMcf per day straddle plant. Asset retirement obligation assets of $10.7 million were recorded for capitalized assets and asset retirement obligation liabilities of $12.1 million were recorded for the year ending December 31, 2004.

Stock Compensation. As permitted under SFAS No. 123, "Accounting for Stock-Based Compensation", the Company has elected to continue to measure compensation costs for stock-based employee compensation plans as prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." The Company has complied with the pro forma disclosure requirements of SFAS No. 123 as required under the pronouncement. The Company realizes an income tax benefit for any amount the employee declares as ordinary income. The tax benefit related to the amount of ordinary income that exceeds the amount recognized by the Company totals $2.5 million and was credited to additional paid-in capital.

The Company had options covering 27,000, 49,438 and 119,000 common shares outstanding at December 31, 2004, 2003 and 2002, respectively, which were treated as re-priced options. The Company is required to record compensation expense (if not previously accrued) equal to the number of unexercised re-priced options multiplied by the amount by which its stock price at the end of any quarter exceeds $10.5021 per share. Based on the Company's per share stock price at December 31, 2004, 2003 and 2002 of $29.25, $23.63 and $18.43, respectively; expense of $310,000, $529,000 and $224,000 was recorded in the years ended December 31, 2004, 2003 and 2002, respectively.

SFAS No. 123 encourages companies to record compensation expense for stock-based compensation plans at fair value. As permitted under SFAS No. 123, the Company has elected to continue to measure compensation costs for such plans as prescribed by APB No. 25. Such information was only calculated for the options granted under the 1999 Stock Option Plan, the 2002 Stock Option Plan and the 2002 Directors' Plan, as there were no grants under any other plans.

The following is a summary of the options to purchase the Company's common stock granted during the years ended December 31, 2004, 2003 and 2002, respectively.

	Year Ended December 31,		
	2004	2003	2002
1999 Stock Option Plan	140,876	-	340,000
2002 Stock Option Plan	956,841	1,129,900	375,994
2002 Directors' Plan	32,000	36,000	36,000
Total options granted	1,129,717	1,165,900	751,994

The following is a summary of the weighted average fair value per share of the options granted during the years ended December 31, 2004, 2003 and 2002, respectively.

	Year Ended December 31,		
	2004	2003	2002
1999 Stock Option Plan	$ 13.12	-	$ 8.68
2002 Stock Option Plan	$ 13.09	$ 9.77	$ 8.72
2002 Directors' Plan	$ 12.13	$ 10.70	$ 11.25

These values were estimated using the Black-Scholes option-pricing model with the following assumptions:

	1999 Stock Option Plan			2002 Stock Option Plan			2002 Directors' Plan		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
Risk-free interest rate	3.74%	-	3.40%	3.77%	3.47%	3.41%	4.46%	2.59%	3.40%
Expected life (in years)	7	-	7	7	7	7	7	7	7
Expected volatility	39%	-	55%	39%	53%	55%	40%	54%	56%
Expected dividends (quarterly)	$0.05	-	$0.025	$0.05	$0.025	$0.025	$0.05	$0.025	$0.025

Had compensation expense for the Company's 2004, 2003 and 2002 grants for stock-based compensation plans been determined consistent with the fair value method under SFAS No. 123, the Company's net income, income attributable to common stock, earnings per share of common stock and earnings per share of common stock - assuming dilution would approximate the pro forma amounts below (000s, except per share amounts):

	2004		2003		2002	
	As Reported	Pro forma	As Reported	Pro forma	As Reported	Pro forma
Net income	$ 119,215	$ 114,057	$ 84,219	$ 80,779	$ 50,589	$ 47,978
Net income attributable to common stock	118,380	113,222	77,378	73,938	41,391	38,780
Earnings per share of common stock	1.63	1.56	1.17	1.12	0.63	0.59
Earnings per share of common stock - assuming dilution	1.61	1.54	1.13	1.08	0.62	0.58
Stock-based employee compensation cost, net of related tax effects, included in net income	$ 428	N/A	$ 576	N/A	$ 375	N/A
Stock-based employee compensation cost, net of related tax effects, includable in net income if the fair value based method had been applied	N/A	$ 5,586	N/A	$ 4,016	N/A	$ 2,987

The fair market value of the options at grant date is amortized over the appropriate vesting period for purposes of calculating compensation expense.

Use of Estimates and Significant Risks. The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported for assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the amounts reported for revenues and expenses, including depletion, during the reporting period. Therefore, the reported amounts of the Company's assets and liabilities, revenues and expenses and associated disclosures with respect to contingent assets and obligations are necessarily affected by these estimates. These estimates are evaluated on an ongoing basis, utilizing historical experience, consultation with experts and other methods considered reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the estimates used. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

The Company is subject to a number of risks inherent in the industry in which it operates, including price volatility, counterparty credit risk, the success of its drilling programs and other gas supply. The Company's financial condition, results of operations and cash flows will depend significantly upon the prices received for gas and NGLs. These prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond the control of the Company. In addition, the Company must continually connect new wells to its gathering systems in order to maintain or increase throughput levels to offset natural declines in dedicated volumes. The number of new wells drilled by the Company and other producers will depend upon, among other factors, prices for gas and oil, the drilling budgets of third-party producers, the energy and tax policies of the federal and state governments, the pace at which permits required for drilling and production operations are obtained, and the availability of foreign oil and gas, none of which are within the Company's control.

Revised classifications. In 2004, the Company revised its classification in its Statement of Cash Flows for the years ended December 31, 2003 and 2002, of the Change in the balance of outstanding checks from a component of Net cash provided by operating activities to a component of Cash flows from financing activities. This change in classification had the effect of decreasing previously reported cash provided by operating activities by $4,510 and $6,735 for the years ended December 31, 2003 and 2002, respectively, with corresponding increases in the respective periods in cash flows used in financing activities.

Recently Issued Accounting Pronouncements

SFAS No. 123(R). SFAS No. 123(R), "*Share Based Payment*" was issued in December 2004 and must be adopted no later than periods beginning after June 15, 2005. This pronouncement requires companies to expense the fair value of employee stock options and other forms of stock based compensation. The Company intends to adopt this pronouncement in the third quarter of 2005. Currently, the Company is complying with the pro forma disclosure requirements of SFAS No. 123, *"Accounting for Stock Based Compensation*" which are included in Note 2 – Summary of Significant Accounting Policies to Consolidated Financial Statements. If the Company had adopted SFAS No. 123(R) for the year ended December 31, 2004, Earnings per share of common stock - assuming dilution would have been $1.54 per share of common stock or a reduction of approximately $0.07 per share of common stock from the actual results for 2004.

SFAS No. 151. SFAS No. 151, "*Inventory Costs, an amendment of ARB No. 43, Chapter 4*" was issued in November 2004 and is effective for the Company for inventory costs incurred in fiscal years beginning after June 15, 2005, and will be applied prospectively. SFAS No. 151 amends APB Opinion No. 43, Chapter 4, "Inventory Pricing" to clarify the accounting for abnormal amounts of costs and the allocation of fixed production overheads. The Company believes that the adoption of SFAS No. 153 will not affect its earnings, financial position or cash flows.

SFAS No. 153. SFAS No. 153, "*Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29*" was issued in December 2004 and is effective for the Company for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005, and will be applied prospectively. SFAS No. 153 amends APB Opinion No. 29, *Accounting for Nonmonetary Transactions*. The guidance in APB Opinion No. 29 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged but included certain exceptions to that principle. SFAS No. 153 amends APB Opinion No. 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The Company will adopt SFAS No. 153 as required.

EITF No. 04-13. At its November 2004 meeting, the Emerging Issues Task Force of the FASB began discussion of Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." This Issue addresses the question of when it is appropriate to measure non-monetary purchases and sales of inventory at fair value and record them in cost of sales and revenues and when they should be recorded as an exchange measured at the book value of the item sold. The EITF did not reach a consensus on this issue, but requested the FASB staff to further explore the alternative views. The implementation of this EITF, if approved, may reduce revenues and related costs but will not have a significant impact on its net income, financial position or cash flows.

FSP FAS 19-a. In February 2005, the FASB Staff posted its proposed staff position FSP FAS 19-a, "Accounting for Suspended Well Costs." At issue is the current requirement of SFAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," to capitalize the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. The capitalized costs become part of the entity's wells, equipment, and facilities if the well successfully located proved reserves. However, if the well has not found proved reserves, the capitalized costs of drilling the well are expensed, net of any salvage value. Questions have arisen as to whether there are circumstances that would permit the continued capitalization of exploratory-well costs beyond the one-year limit specified in SFAS 19 other than when additional exploration wells are necessary to justify major capital expenditures and those wells are underway or firmly planned for the near future. In its proposal, the FASB Staff states that exploratory well costs could be capitalized beyond a one-year limit if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making progress assessing reserves and the economic and operational viability of the project. Comments on the proposed FASB Staff position were due March 7, 2005. This FSP will be effective in the first quarter after it is approved. The Company does not believe that this FSP will have a material impact on our results of operations, financial position or cash flows.

American Jobs Creation Act of 2004. During October 2004, H.R. 4520, the "American Jobs Creation Act of 2004," was enacted. The Act provides for certain additional tax deductions from qualified taxable income beginning in 2005, subject to certain limitations. Although the Company expects that the Act may result in a reduction in the Company's effective tax rate, the Company has not yet determined the full impact of this law.

NOTE 3 - RELATED PARTIES

From time to time, the Company enters into joint ventures and partnerships in order to reduce risk, create strategic alliances and to establish itself in oil and gas producing basins in the United States. It is our policy that all transactions entered into by the Company with its related parties were consummated in the ordinary course of business and on terms that would be comparable to those obtained from third parties.

Fort Union. Fort Union Gas Gathering, L.L.C. ("Fort Union"), owns a gathering pipeline and treater in the Powder River Basin. At December 31, 2004 and 2003, the Company owned an approximate 13% interest in Fort Union and is the construction manager and field operator. The Company accounts for its investment in this entity under the equity method of accounting. Construction and expansions of the gathering header and treating system were project financed by Fort Union. At December 31, 2004, Fort Union had total project financing debt outstanding of $35.7 million. This debt is amortizing on an annual basis and is scheduled to be fully paid in 2009. All participants in Fort Union have guaranteed Fort Union's payment of the project financing on a proportional basis, resulting in the Company's guarantee of $4.7 million of the debt of Fort Union. This guarantee is not reflected on the Consolidated Balance Sheet.

The Company has entered into long-term agreements for firm gathering services on 83 MMcf per day of capacity for $0.14 per Mcf on Fort Union. The Company acts as field operator of Fort Union and charges a monthly overhead fee to cover such services. In 2004, 2003 and 2002, the Company received overhead fees from Fort Union totaling $43,000, $(2,000) and $25,000, respectively, and the Company paid to Fort Union a total of $5.0 million, $6.4 million and $5.3 million for gathering services, respectively. At December 31, 2004 and 2003, the Company had a net amount due to Fort Union of $7,000 and $71,000, respectively. At December 31, 2004, the Company's investment in Fort Union totaled $2.6 million and is included in Investments in joint ventures on the Consolidated Balance Sheet.

Rendezvous. At December 31, 2004 and 2003, the Company owned a 50% interest in Rendezvous Gas Services, L.L.C., ("Rendezvous") and the Company serves as field operator of its systems. Rendezvous was formed in 2001 to gather gas for the Company and other third parties along the Pinedale Anticline for blending or processing at either the Company's Granger Complex or at a third-party owned processing facility. The Granger Complex utilizes Rendezvous to deliver significant volumes of gas contractually dedicated to the Granger Complex for processing or blending. In December 2004, approximately 77% of the gas processed or blended at the Granger Complex was delivered to the facility by Rendezvous. The other 50% owner in Rendezvous is a large utility with oil and gas production and gathering and processing assets in the same area. Rendezvous was expanded during 2004 and 2003, and at December 31, 2004, the Company had a total of $33.2 million invested in this venture. The investment is included in Investments in joint ventures on the Consolidated Balance Sheet. The Company accounts for its investment in this entity under the equity method of accounting. The Company charges a monthly overhead fee to act as field operator of Rendezvous and an overhead charge for capital projects it constructs on behalf of the venture. In 2004 and 2003, the Company received overhead fees as field operator from Rendezvous totaling $100,000 for both years and overhead fees on capital projects totaling $42,800 and $825,000, respectively. In 2004 and 2003, the Company paid to Rendezvous a total of $3.9 million and $2.2 million, respectively, for gathering services. At December 31, 2004 and 2003, the Company had a net amount due to Rendezvous of $1.2 million and $382,000, respectively.

Officer Transactions. In prior years, the Company had entered into agreements committing the Company to loan to certain key employees an amount sufficient to exercise their options as each portion of their options vests under the Key Employees' Incentive Stock Option Plan. The loan and accrued interest were to be forgiven if the employee was continually employed by the Company and upon a resolution of the board of directors. In 2002, the Company forgave loans related to 125,000 shares of Common Stock totaling $703,000. Pursuant to the terms of an agreement entered into in 2001, the remaining loan was forgiven in May 2003. As of December 31, 2003, there were no loans outstanding under these programs and the program is no longer in effect. At December 31, 2002, loans related to 55,000 shares of Common Stock totaling $295,000 were outstanding under these programs. In prior years, the Company had accrued for the forgiveness of these loans. In October 2001, the Company's former Chief Executive Officer and President retired. The Company had entered into a consulting agreement with this executive providing for payments of $167,000 in May 2002 and $175,000 in May 2003.

NOTE 4 - COMMODITY RISK MANAGEMENT

Risk Management Activities. The Company's commodity price risk management program has two primary objectives. The first goal is to preserve and enhance the value of the Company's equity volumes of gas and NGLs with regard to the impact of commodity price movements on cash flow, net income and earnings per share in relation to those anticipated by the Company's operating budget. The second goal is to manage price risk related to the Company's physical gas, crude oil and NGL marketing activities to protect profit margins. This risk relates to fixed price purchase and sale commitments, the value of storage inventories and exposure to physical market price volatility.

The Company utilizes a combination of fixed price forward contracts, exchange-traded futures and options, as well as fixed index swaps, basis swaps and options traded in the OTC to accomplish these objectives. These instruments allow the Company to preserve value and protect margins because corresponding losses or gains in the value of the financial instruments offset gains or losses in the physical market.

The Company also uses financial instruments to reduce basis risk. Basis is the difference in price between the physical commodity being hedged and the price of the futures contract used for hedging. Basis risk is the risk that an adverse change in the futures market will not be completely offset by an equal and opposite change in the cash price of the commodity being hedged. Basis risk exists in natural gas primarily due to the geographic price differentials between cash market locations and futures contract delivery locations.

The Company enters into futures transactions on the New York Mercantile Exchange ("NYMEX") and through OTC swaps and options with various counter parties, consisting primarily of financial institutions and other natural gas companies. The Company conducts a credit review of OTC counter parties and has agreements with many of these parties that contain collateral requirements. The Company generally uses standardized swap agreements that allow for offset of positive and negative OTC exposures. OTC exposure is marked-to-market daily for the credit review process. The Company's exposure to OTC credit risk is reduced by its ability to require a margin deposit from its counterparties based upon the mark-to-market value of their net exposure. The Company is also subject to margin deposit requirements under these same agreements and under margin deposit requirements for its NYMEX transactions. At December 31, 2004 and 2003, the Company had posted margin deposits totaling $3.0 million and $5.7 million, respectively, with various counterparties.

The use of financial instruments may expose the Company to the risk of financial loss in certain circumstances, including instances when (i) the Company's equity volumes are less than expected, (ii) the Company's customers fail to purchase or deliver the contracted quantities of natural gas or NGLs, or (iii) the Company's OTC counter parties fail to perform. To the extent that the Company engages in hedging activities, it may be prevented from realizing the benefits of favorable price changes in the physical market. However, it is similarly insulated against decreases in such prices.

All equity-hedging contracts are designated and accounted for as cash flow hedges. As such, gains and losses related to the effective portions of the changes in the fair value of the derivatives are recorded in Accumulated other comprehensive income, a component of Stockholders' equity. Realized gains or losses on these cash flow hedges are recognized in the Consolidated Statement of Operations through Sale of gas or Sale of natural gas liquids when the hedged transactions occur. Realized and unrealized gains or losses represented by the periodic or final cash settlements from economic hedges are included in Price risk management activities on the Consolidated Statement of Operations. Economic hedges are financially settled derivatives that either were not designated or did not qualify as hedges under SFAS No. 133. These are marked-to-market through earnings.

To qualify as cash flow hedges, the hedge instruments must be designated as cash flow hedges and changes in their fair value must be highly correlated with changes in the price of the forecasted transaction being hedged so that the Company's exposure to the risk of commodity price changes is reduced. To meet this requirement, the Company hedges the price of the commodity, and if applicable, the basis between that derivative's contract delivery location and the cash market location used for the actual sale of the product. This structure attains a high level of effectiveness, insuring that a change in the price of the forecasted transaction will result in an equal and opposite change in the cash price of the hedged commodity. In 2004, 2003 and 2002, the Company utilized crude oil as a surrogate hedge for natural gasoline, butane and condensate. These hedges were tested for effectiveness at inception and on a quarterly basis thereafter. Regression analysis based on a five-year period of time was used for these tests. In the first quarter of 2004, the Company determined in its quarterly effectiveness testing that its hedges of equity butane production which utilized crude oil puts as a surrogate were no longer effective hedges. Therefore, in the first quarter, the Company discontinued cash flow hedge accounting treatment on these instruments. The value of these financial instruments remained in Accumulated other comprehensive income and was reclassified to the Company's results of operations in 2004 as the underlying transactions occurred. Gains or losses from the ineffective portions of changes in the fair value of cash flow hedges are recognized currently in earnings through Price risk management activities. During the year ended December 31, 2004, 2003 and 2002, the Company recognized losses of $159,000, $110,000 and $154,000, respectively, from the ineffective portions of its hedges.

In 2003, in order to properly align the Company's hedged volumes of natural gas to its forecasted equity production, the Company discontinued hedge treatment on financial instruments for 10 MMcf per day of natural gas and 50,000 barrels per month of ethane. As a result, a pre-tax loss of $2.8 million was reclassified into earnings from Accumulated other comprehensive income. In 2002, in order to properly align the Company's hedged volumes of natural gas to its forecasted equity production for 2003, the Company discontinued hedge treatment on financial instruments for 6 MMcf per day. As a result, a pre-tax gain of $790,000 was reclassified into earnings in 2002 from Accumulated other comprehensive income. There were no gains or losses reclassified into earnings as a result of the discontinuance of cash flow hedges in 2004.

Account balances related to equity hedging transactions at December 31, 2004 were $2.9 million in Current Assets from price risk management activities, $1.7 million in Current Liabilities from price risk management activities, $240,000 in Deferred income taxes payable, net, and a $410,000 after-tax unrealized gain in Accumulated other comprehensive income, a component of Stockholders' Equity. Based on the commodity prices as of December 31, 2004, the after-tax gain will be reclassified from Accumulated other comprehensive income to Sale of gas or Sale of natural gas liquids during 2005.

Natural Gas Derivative Market Risk. As of December 31, 2004, the Company held a notional quantity of approximately 342 Bcf of natural gas futures, swaps and options extending from January 2005 to October 2006 with a weighted average duration of approximately five months. This was comprised of approximately 151 Bcf of long positions and 191 Bcf of short positions in these instruments. As of December 31, 2003, the Company held a notional quantity of approximately 268 Bcf of natural gas futures, swaps and options extending from January 2004 to October 2006 with a weighted average duration of approximately five months. This was comprised of approximately 107 Bcf of long positions and 161 Bcf of short positions in these instruments.

Crude Oil and NGL Derivative Market Risk. As of December 31, 2004, the Company held a notional quantity of approximately 163,800 MGal of NGL futures, swaps and options extending from January 2005 to December 2005 with a weighted average duration of approximately six months. This was comprised of approximately 100,800 MGal of long positions and 63,000 MGal of short positions in these instruments. As of December 31, 2003, the Company held a notional quantity of approximately 191,520 MGal of NGL futures, swaps and options extending from January 2004 to December 2004 with a weighted average duration of approximately six months. This was comprised of approximately 120,960 MGal of long positions and 70,560 MGal of short positions in these instruments.

Foreign Currency Derivative Market Risk. As a normal part of its business, the Company enters into physical gas transactions which are payable in Canadian dollars. The Company enters into forward purchases and sales of Canadian dollars from time to time to fix the cost of its future Canadian dollar denominated natural gas purchase, sale, storage and transportation obligations. This is done to protect marketing margins from adverse changes in the U.S. and Canadian dollar exchange rate between the time the commitment for the payment obligation is made and the actual payment date of such obligation. As of December 31, 2004, the Company had sold forward contracts for $31.3 million in Canadian dollars in exchange for $24.0 million in U.S. dollars, and the fair market value of these contracts was a loss of $2.1 million in U.S. dollars. As of December 31, 2003, the net notional value of such contracts was approximately $24.3 million in Canadian dollars, which approximated its fair market value.

NOTE 5 - DEBT

The following summarizes the Company's consolidated debt at the dates indicated (000s):

	December 31,	
	2004	2003
Variable Rate Revolving Credit Facility	$ 227,000	$ 94,000
Master Shelf and Subordinated Notes	155,000	245,000
Total long-term debt	$ 382,000	$ 339,000

Variable Rate Revolving Credit Facility. The revolving credit facility matures in June 2009. In December 2004, the size of the commitment under the revolver was increased from $400 million to $500 million. At December 31, 2004, $227.0 million was outstanding under this facility. Loans made under this facility are secured by a pledge of the capital stock of the Company's significant subsidiaries. These subsidiaries also guarantee the borrowings under the facility.

The borrowings under the revolving credit facility bear interest at Eurodollar rates or a base rate, as requested by the Company, plus an applicable percentage based on the Company's debt to capitalization ratio. The base rate is the agent's published prime rate. The Company also pays a quarterly commitment fee ranging between 0.20% and 0.375%, depending on its debt to capitalization ratio. This fee is paid on unused amounts of the commitment. At December 31, 2004, the interest rate payable on borrowings under this facility was approximately 3.8%. Under the revolving credit facility, the Company is subject to a number of covenants, including: maintaining a total debt to capitalization ratio of not more than 55% and maintaining a ratio of EBITDA, as defined in the revolving credit facility, to interest over the last four quarters in excess of 3.0 to 1.0. The revolving credit facility ranks equally with borrowings under the Company's master shelf agreement with The Prudential Insurance Company. This facility has been rated Ba1 by Moody's and is in the process of being rated by S&P.

Master Shelf Agreement. Amounts outstanding under the master shelf agreement at December 31, 2004 are as indicated in the following table (000s):

Issue Date	Amount	Interest Rate	Final Maturity	Principal Repayment Schedule
July 28, 1995	$ 30,000	7.61%	July 28, 2007	$10,000 on each of July 28, 2005 through 2007
January 17, 2003	25,000	6.36%	January 17, 2008	Single payment at maturity
June 30, 2004	100,000	5.92%	June 30, 2011	Single payment at maturity
Total	$ 155,000			

The Company's borrowings under the master shelf agreement are secured by a pledge of the capital stock of its significant subsidiaries. These subsidiaries also guarantee the borrowings under the facility. All of the borrowings under the master shelf agreement can be prepaid prior to their final maturity by paying a yield-maintenance fee. Under the master shelf agreement, the Company is subject to a number of covenants, including: maintaining a total debt to capitalization ratio of not more than 55% and maintaining a quarterly test of EBITDA, as defined in the master shelf agreement, to interest for the last four quarters in excess of 3.0 to 1.0.

In December 2004, the Company notified Prudential of its intention to prepay the $25 million note due January 17, 2008. This note bore interest at 6.36% per annum and was prepaid at par on January 18, 2005. To fund the prepayment, the Company issued a new $25 million note to Prudential, due January 2015 that bears interest at 5.57% per annum. During 2005, the Company will make scheduled payments totaling $10.0 million on the master shelf. The Company intends to fund these repayments with funds available under the revolving credit facility.

Senior Subordinated Notes. In 1999, the Company sold $155.0 million of senior subordinated notes in a private placement with a final maturity of 2009 due in a single payment which were subsequently exchanged for registered publicly tradable notes under the same terms and conditions. The subordinated notes bore interest at 10% per annum. The Company incurred approximately $5.0 million in offering commissions and expenses, which were capitalized and were being amortized over the term of the notes. The Company redeemed the senior subordinated notes in June 2004 using amounts available under the revolving credit facility and an additional borrowing under the master shelf agreement. In connection with this redemption, a prepayment penalty of $7.75 million was paid and expensed and approximately $2.9 million of unamortized offering commissions were expensed.

Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2004 (000s):

2005	$ 35,000
2006	10,000
2007	10,000
2008	-
2009	227,000
Thereafter	100,000
Total	$ 382,000

NOTE 6 - FINANCIAL INSTRUMENTS

The Company, using available market information and valuation methodologies, has determined the estimated fair values of the Company's financial instruments. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided herein are not necessarily indicative of the amount that the Company could realize upon the sale or refinancing of such financial instruments.

	December 31, 2004		December 31, 2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(000s)		(000s)	
Cash and cash equivalents	$ 390	$ 390	$ 26,116	$ 26,116
Trade accounts receivable	393,750	393,750	262,509	262,509
Accounts payable	400,672	400,672	303,186	303,186
Long-term debt	382,000	384,544	339,000	371,553
Derivative contracts	$ 11,340	$ 11,340	$ 6,707	$ 6,707

The Company in estimating the fair value of its financial instruments used the following methods and assumptions:

Cash and cash equivalents, trade accounts receivable and accounts payable. Due to the short-term nature of these instruments, the carrying value approximates the fair value.

Long-term debt. The Company's long-term debt was comprised of fixed and floating rate facilities. The fair market value for the fixed rate debt was estimated using discounted cash flows based upon the Company's current borrowing rates for debt with similar maturities. The floating rate portion of the long-term debt was borrowed on a revolving basis, which accrues interest at current rates; as a result, carrying value approximates fair value of this outstanding debt.

Derivative contracts. Fair value represents the amount at which the instrument could be exchanged in a current arms-length transaction.

NOTE 7 - INCOME TAXES

The provision for income taxes for the years ended December 31, 2004, 2003 and 2002 is comprised of (000s):

	2004	2003	2002
Current:			
Federal	$ 820	$ 4,002	$ 9,404
State	1,658	265	1,096
Total Current	2,478	4,267	10,500
Deferred:			
Federal	64,305	47,612	18,967
State	1,984	1,714	647
Total Deferred	66,289	49,326	19,614
Total tax provision	$ 68,767	$ 53,593	$ 30,114

Not included above is the tax (expense) and benefit, respectively, allocated to the cumulative effect of a change in accounting principle of approximately ($2.7) million and $4.0 million for the years ended December 31, 2004 and 2003. There were no such items in 2002.

Temporary differences and carry-forwards which give rise to the deferred tax liabilities (assets) at December 31, 2004 and 2003, net of the tax effect of the cumulative change in accounting principle, are as follows (000s):

	2004	2003
Property and equipment	$ 280,565	$ 222,884
Differences between the book and tax basis of acquired assets	10,505	11,341
Hedging derivatives	235	(1,298)
Total deferred income tax liabilities	291,305	232,927
Alternative Minimum Tax ("AMT") credit carry-forwards	(43,412)	(50,220)

Net Operating Loss ("NOL") carry-forwards	-	(6,034)
Total deferred income tax assets	(43,412)	(56,254)
Net deferred income taxes payable	$ 247,893	$ 176,673

The change in the net deferred income taxes in 2004 and 2003 includes a $2.5 million and $700,000 tax benefit, respectively, associated with the exercise of incentive stock options, which is included in Additional paid in capital.

The differences between the provision for income taxes at the statutory rate and the actual provision for income taxes, before the tax effect of the change in accounting principle, for the years ended December 31, 2004, 2003 and 2002 are summarized as follows (000s):

	2004	%	2003	%	2002	%
Income tax before effect of change in accounting principle at statutory rate	$ 64,144	35.0	$ 50,588	35.0	$ 28,246	35.0
State income taxes, net of federal benefit	1,979	1.1	2,021	1.4	968	1.2
Federal and state effect of non-deductibility of CFTC settlement	2,518	1.4				
Canada income taxes, effect of disallowed loss on sale of stock and other miscellaneous items	126	0.1	984	0.7	900	1.1
Total	$ 68,767	37.6	$ 53,593	37.1	$ 30,114	37.3

At December 31, 2004, the Company had AMT credit carry-forwards for federal income tax purposes of approximately $43.4 million, respectively. These carry-forwards have no expiration.

The Company believes that the AMT credit carry-forwards will be realized because they are substantially offset by existing taxable temporary differences reversing or are expected to be realized by achieving future profitable operations based on the Company's dedicated and owned reserves, past earnings history and projections of future earnings.

NOTE 8 - COMMITMENTS AND CONTINGENT LIABILITIES

Litigation

Gracey et al. v. Western Gas Resources, Inc. et al., United States District Court, Southern District of New York, Case No. 03-CV-6186 (vm) (S.D.N.Y.). On September 17, 2004, the plaintiffs, traders of natural gas futures contracts on the NYMEX filed this action on behalf of themselves and a putative class of others similarly situated. In the complaint, the plaintiffs claim that the Company manipulated the prices of natural gas futures on the NYMEX in violation of the Commodity Exchange Act, or CEA, by reporting allegedly "inaccurate, misleading and false trading information" to trade publications that compile and publish indices of natural gas spot prices. In addition, the complaint asserts that the Company aided and abetted the alleged CEA violations of others. The plaintiffs seek to recover actual damages on behalf of themselves and a class of natural gas futures traders, and their costs of litigation including attorney's fees. The Company believes that the claims are without merit and intends to vigorously contest the allegations in this case.

United States of America and ex rel. Jack J. Grynberg v. Western Gas Resources, Inc., et al., United States District Court, District of Colorado, Civil Action No. 97-D-1427. The Company, along with over 300 other natural gas companies, are defendants in litigation filed on September 30, 1997, in 72 separate actions filed by Mr. Grynberg on behalf of the federal government. The allegations made by Mr. Grynberg are that established gas measurement and royalty calculation practices improperly deprived the federal government of appropriate natural gas royalties and violate 31 U. S. C. 3729 (a) (7) of the False Claims Act. The cases have been consolidated to the United States District Court for the District of Wyoming. Discovery on the jurisdictional issues is being completed to determine if this matter qualifies as a qui tam action (an action on behalf of the individual plaintiff and the government). The Company believes that Mr. Grynberg's claims are baseless and without merit and intends to vigorously contest the allegations in this case.

Price, et al. v. Gas Pipelines, Western Gas Resources, Inc., et al., District Court, Stevens County, Kansas, Case No. 99-C-30. Western is a defendant in litigation filed on September 23, 1999, along with numerous other natural gas companies, in which Mr. Price is claiming an under measurement of gas and Btu volumes throughout the country. The Company along with other natural gas companies filed a motion to dismiss for failure to state a claim. The court denied these motions to dismiss. The court denied plaintiff's motion for certification as a class and, in the third quarter of 2003, the plaintiff amended and refiled for certification as a class. On May 12, 2003, Mr. Price filed a further claim, *Will Price et al v. Western*

Gas Resources, Inc. et al., District Court, Stevens County, Kansas, Case No. 03C23, relating to certain matters previously removed from the foregoing action. The Company believes that Mr. Price's claims are without merit and intends to vigorously contest the allegations in this case.

Other Litigation. The Company is involved in various other litigation and administrative proceedings arising in the normal course of business. In the opinion of the Company's management, any liabilities that may result from these claims will not, individually or in the aggregate, have a material adverse effect on its financial position, results of operations or cash flow.

Retirement Plan. The Company provides a Retirement Plan for its present and past employees, or participants. The purpose of the Retirement Plan is to provide a method for participants to save toward their retirement. Beginning in January 1989, participants were given the option to invest their contributions in the Western Gas Fund. The Western Gas Fund is comprised of shares of the Company's common stock, purchased in the open market by the trustee, Fidelity Management Trust Company, and short-term investments. A participant's ownership in the Western Gas Fund is measured in Units rather than in shares of common stock. To effectuate participant investment elections and therefore purchases and sales of Units, the trustee purchases and sells the common stock in the open market at market prices.

The Company is required to register the shares of its common stock purchased by the trustee of the Retirement Plan under the Securities Act. Although all the purchases by the trustee were made in the open market and in a manner consistent with the Retirement Plan and the investment elections of the participants, the Company determined that approximately 934,000 shares of its common stock purchased by the trustee beginning August 14, 2001 and ending August 14, 2002 (the "Rescission Period") may not have been properly registered in accordance with the Securities Act. As a result of this determination, the Company filed a registration statement on Form S-3 with the SEC providing for a rescission offer to certain of the plan participants. The SEC declared this registration statement effective in December 2004. The Company issued a rescission notice to the affected parties in December 2004. The notice period ended on January 10, 2005. In connection with the rescission offer, the Company has not re-acquired any of its common stock and has paid total damages, including interest, to the eligible plan participants of approximately $39,000.

Price Reporting to Gas Trade Publications. In 2003, the Company learned that several employees in its marketing department furnished inaccurate information regarding natural gas transactions to energy publications, which compile and report energy index prices. The Company discovered the inaccuracies during a review of its marketing activities, which was being conducted in response to a subpoena issued by the Commodity Futures Trading Commission ("CFTC"). These employees identified inaccuracies associated with reporting of natural gas transactions primarily related to points in Texas. The Company has discontinued the practice of reporting pricing information to industry publications. In conjunction with its investigation into this matter, the Company has taken appropriate disciplinary actions including the release of one manager in its marketing department. In the second quarter of 2004, the Company reached a settlement of this matter with the CFTC. In conjunction with this settlement, the Company paid a civil penalty of $7.0 million that is included in Selling and administrative expense.

Commitments

Lease Commitments. As a normal course of the Company's business operations, the Company enters into operating leases for office space and office, communication and transportation equipment. In addition, primarily to support its growing development in the Powder River Basin coal bed development, the Company has entered into operating leases for compression equipment. These leases are classified as operating leases and have terms ranging from one month to ten years. The majority of the leases for compression have purchase options at various times throughout the primary terms of the agreements and have renewal provisions. Rental payments under operating leases have totaled $15.3 million, $13.8 million and $10.8 million in 2004, 2003 and 2002, respectively. Future operating lease payments by year under these leases are as follows (000s):

2005	$ 16,607
2006	16,422
2007	15,556
2008	13,982
2009	9,490
Thereafter	10,264
Total	$ 82,321

Firm Transportation Capacity. The Company enters into firm transportation agreements with interstate pipeline companies as a part of its marketing operations and to ensure that its equity production has access to downstream markets. To the extent that these contracts are in support of its marketing operations, the agreements are classified as derivatives in accordance with SFAS No. 133 and the difference between fair value and cost is included in income. At December 31, 2004, these agreements have terms ranging from one month to thirteen years. Payments under these agreements have totaled \$29.3 million, \$26.4 million and \$29.2 million in 2004, 2003 and 2002, respectively. Future payments by year under these agreements are as follows (000s):

2005	\$ 38,883
2006	36,473
2007	35,657
2008	32,594
2009	26,687
Thereafter	80,929
Total	\$ 251,223

Storage Capacity. The Company enters into storage agreements with various third parties primarily as part of its marketing operations. To the extent that these contracts are in support of its marketing operations, the agreements are classified as derivatives in accordance with SFAS No. 133 and the difference between fair value and cost is included in income. Payments under these agreements totaled \$6.2 million, \$5.2 million and \$5.1 million in 2004, 2003 and 2002, respectively. As of December 31, 2004, the Company had contracts in place for approximately 17.1 Bcf of storage capacity at various third-party facilities. The associated contract periods have an average term of 34 months. Future payments by year under these agreements are as follows (000s):

2005	\$ 7,044
2006	5,127
2007	3,184
2008	2,715
2009	2,100
Thereafter	8,921
Total	\$ 29,091

Post Retirement Benefits. In July 2004, the Company's board of directors authorized the development of an amendment to the board's existing health care plan to provide for health care benefits for qualifying members, and their spouses, after their retirement from the Company's board of directors. At December 31, 2004, the terms of the plan had not yet been finalized and, accordingly, no accrual for the future cost of this benefit had yet been made.

NOTE 9 - BUSINESS SEGMENTS AND RELATED INFORMATION

The Company operates in four principal business segments, as follows: Gathering, Processing and Treating; Exploration and Production; Marketing; and Transportation. Management separately monitors these segments for performance against its internal forecast and these segments are consistent with the Company's internal financial reporting package. These segments have been identified based upon the differing products and services, regulatory environment and the expertise required for these operations.

Gathering, Processing and Treating. In the Gathering, Processing and Treating segment, collectively with the Marketing and Transportation segments referred to as the midstream operations, the Company connects producers' wells (including those of the Company's Exploration and Production segment) to its gathering systems for delivery to its processing or treating plants, process the natural gas to extract NGLs and treat the natural gas in order to meet pipeline specifications. In some areas, where no processing is required, the Company gathers and compresses producers' gas and delivers it to pipelines for further delivery to market. Except for volumes taken in kind by the Company's producers, the Marketing segment sells the gas and NGLs extracted at most of its facilities.

In this segment, the Company recognizes revenue for its services at the time the service is performed. Included in this segment is the Company's Powder River coal bed methane gathering operation, which gathers gas from producers, including the Company's Exploration and Production segment. In 2003, this service for the Exploration and Production segment was performed under a percentage-of-proceeds contract and in 2004, this service was performed under a fee-based contract. The change of contract type had no effect on the Operating profit of either the Gathering, Processing and Treating segment or the Exploration and Production segment.

Substantially all gas flowing through the Company's gathering, processing and treating facilities is supplied under three types of contracts providing for the purchase, treating or processing of natural gas for periods ranging from one month to twenty years or in some cases for the life of the oil and gas lease. Approximately 70% of the Company's plant facilities' gross margin, or revenues at the plant less product purchases, for the month of December 2004 was under percentage-of-proceeds agreements in which the Company is typically responsible for the marketing of the gas and NGLs. Under these agreements, the Company pays producers a specified percentage of the net proceeds received from the sale of the gas and the NGLs. Revenue is recognized when the gas or NGLs are sold and the related product purchases are recorded as a percentage of the sale of the product.

Approximately 20% of the Company's plant facilities' gross margin for the month of December 2004 was under contracts that are primarily fee-based from which the Company receives a set fee for each Mcf of gas gathered and/or processed. This type of contract provides the Company with a steady revenue stream that is not dependent on commodity prices, except to the extent that low prices may cause a producer to delay drilling or shut in production. Revenue is recognized under these contracts when the related services are rendered.

Approximately 10% of the Company's plant facilities' gross margin for the month of December 2004 was under contracts with "keepwhole" arrangements or wellhead purchase contracts. Under these contracts, the Company retains the NGLs recovered by the processing facility and keeps the producers whole by returning to the producers at the tailgate of the plant an amount of gas equal on a Btu basis to the natural gas received at the plant inlet. The "keepwhole" component of the contracts permits the Company to benefit when the value of the NGLs is greater as a liquid than as a portion of the residue gas stream. However, the Company is adversely affected when the value of the NGLs is lower as a liquid than as a portion of the residue gas stream. Revenue is recognized when the product is sold.

Exploration and Production. The activities of the Exploration and Production segment, also referred to as upstream operations, include the exploration and development of gas properties in the Rocky Mountain area, including those where the Company's gathering and/or processing facilities are located. The Marketing segment sells the majority of the production from these properties and remits to the Exploration and Production segment all of the proceeds from the sales of gas and its proportional share of transportation charges.

Marketing. The Company's Marketing segment markets gas and NGLs extracted at its gathering, processing and treating facilities and produced from its exploration and production assets and buys and sells gas and NGLs in the United States and Canada from and to a variety of customers. In this segment, revenues for sales of product are recognized at the time the gas or NGLs are delivered to the customer and title passes. Revenues in this segment are sensitive to changes in the market prices of the underlying commodities. The marketing of products purchased from third parties typically results in low operating margins relative to the sales price. The Company sells its products under agreements with varying terms and conditions in order to match seasonal and other changes in demand. Also included in this segment are the Company's Canadian marketing operations, which are conducted through its wholly owned subsidiary WGR Canada, Inc. and which are immaterial for separate presentation.

During the years ended December 31, 2004, 2003 and 2002, the Company sold gas to a variety of customers including end-users, pipelines, energy merchants, local distribution companies and others. In 2004, no single customer accounted for more than approximately 9% of the Company's consolidated revenues from the sale of gas, or 7% of total consolidated revenue. In 2003, no single customer accounted for more than 6% of the Company's consolidated revenues from the sale of gas, or 5% of total consolidated revenue. In 2002, two customers accounted for approximately 10% of the Company's consolidated revenues from the sale of gas, or 9% of total consolidated revenue. One of these customers is an energy merchant and the other customer is an electric utility.

During the years ended December 31, 2004, 2003 and 2002, the Company sold NGLs to a variety of customers including end-users, fractionators, chemical companies, energy merchants and other customers. In 2004, one customer accounted for approximately 51% of the Company's consolidated revenues from the sale of NGLs, or 7% of total consolidated revenue. This customer is a large integrated energy company. In 2003, two customers accounted for approximately 49% of the Company's consolidated revenues from the sale of NGLs, or 6% of total consolidated revenue. One of these customers is a large integrated energy company and the other is a large petrochemical company. In 2002, three customers accounted for approximately 38% of the Company's consolidated revenues from the sale of NGLs, or 5% of total consolidated revenue. One of these customers is a large integrated energy company, another is a large petrochemical company and the third is an energy merchant.

Transportation. The Transportation segment reflects the operations of the Company's MIGC, Inc. and MGTC, Inc. pipelines. The revenue presented in this segment is derived from transportation of gas for the Company's Marketing segment and other third parties. In this segment, the Company realizes revenue on a monthly basis from firm capacity contracts under which the shipper pays for transport capacity whether or not the capacity is used and from interruptible contracts where a fee is charged based upon volumes received into the pipeline. The Transportation segment's capacity contracts range in duration from one month to five years.

Segment Information. The following table sets forth the Company's segment information as of and for the three years ended December 31, 2004, 2003 and 2002 (000s). Due to the Company's integrated operations, the use of allocations in the determination of business segment information is necessary. Inter-segment revenues are valued at prices comparable to those of unaffiliated customers. Prior period amounts in the segment information have been reclassified to conform to the presentation used in 2004.

Year Ended December 31, 2004:

	Gas Gathering and Processing	Exploration and Production	Marketing	Trans-portation	Corporate	Eliminating Entries	Total
Revenues from unaffiliated customers:							
Sale of gas	$ 3,666	$ 9,554	$2,495,713	$ 1,779	$ -	$ -	$ 2,510,712
Sale of natural gas liquids	5	-	467,081	-	-	-	467,086
Equity hedges:							
Gas	649	6,720	-	-	-	-	7,369
Liquids	(16,325)	-	-	-	-	-	(16,325)
Gathering, processing and transportation revenue	84,148	-	-	6,726	-	-	90,874
Total revenues from unaffiliated customers	72,143	16,274	2,962,794	8,505	-	-	3,059,716
Inter-segment revenues	1,051,981	252,797	54,321	14,128	-	(1,373,227)	-
Price risk management activities	(12)	-	6,808	-	-	-	6,796
Interest income	-	4	-	1	20,181	(20,186)	-
Other, net	1,210	12	(43)	49	1,973	-	3,201
Total revenues	1,125,322	269,087	3,023,880	22,683	22,154	(1,393,413)	3,069,713
Product purchases	871,426	2,450	2,999,426	4,559	-	(1,337,062)	2,540,799
Plant operating and transportation expense	92,143	23	(167)	7,150	-	(3,281)	95,868
Oil and gas exploration and production expense	-	110,473	-	-	-	(32,865)	77,608
Earnings from equity investments	(7,124)	-	-	-	-	-	(7,124)
Segment operating profit	168,877	156,141	24,621	10,974	22,154	(20,205)	362,562
Depreciation, depletion and amortization	38,585	47,911	123	1,655	7,262	-	95,536
Selling and administrative expense	-	-	-	-	52,292	(46)	52,246
(Gain) loss from sale of assets	224	(520)	-	(15)	300	1,299	1,288
Loss from early extinguishment of debt	-	-	-	-	10,662	-	10,662
Interest expense	-	42	295	(328)	39,739	(20,186)	19,562
Income before income taxes	$ 130,068	$ 108,708	$ 24,203	$ 9,662	$ (88,101)	$ (1,272)	$ 183,268
Identifiable assets:							
Other allocated assets	$ 32,042	$ 7,160	$ 148,962	$ 47,457	$ 419,139	$ (76,286)	$ 578,474
Equity investment	35,729	-	-	2,559	570,638	(573,197)	35,729
Property and equipment	674,011	463,052	17	36,665	52,733	(569)	1,225,909
Total identifiable assets	$ 741,782	$ 470,212	$ 148,979	$ 86,681	$ 1,042,510	$ (650,052)	$ 1,840,112

Year Ended December 31, 2003:

	Gas Gathering and Processing	Exploration and Production	Marketing	Trans-portation	Corporate	Eliminating Entries	Total
Revenues from unaffiliated customers:							
Sale of gas	$ 5,041	$ 4,746	$2,476,429	$ 1,098	$ -	$ -	$ 2,487,314
Sale of natural gas liquids	11	-	357,504	-	-	-	357,515
Equity hedges:							
Gas	(2,358)	(21,505)	-	-	-	-	(23,863)
Liquids	(11,407)	-	-	-	-	-	(11,407)
Gathering, processing and transportation revenue	76,621	-	-	7,051	-	-	83,672
Total revenues from unaffiliated customers	67,908	(16,759)	2,833,933	8,149	-	-	2,893,231
Inter-segment revenues	1,081,358	221,266	38,510	14,093	-	(1,355,227)	-
Price risk management activities	(11)	(866)	(20,943)	-	-	-	(21,820)
Interest income	-	42	-	3	12,490	(12,535)	-
Other, net	1,967	21	4	42	565	-	2,599
Total revenues	1,151,221	203,705	2,851,504	22,287	13,055	(1,367,762)	2,874,010
Product purchases	948,518	2,289	2,820,495	2,982	-	(1,317,843)	2,456,441
Plant operating and transportation expense	82,810	328	318	7,680	-	(2,792)	88,344
Oil and gas exploration and production expense	-	86,856	-	-	-	(34,610)	52,245
Earnings from equity investments	(7,356)	-	-	-	-	-	(7,356)
Segment operating profit	127,249	114,232	30,691	11,625	13,055	(12,517)	284,336
Depreciation, depletion and amortization	30,676	33,321	141	1,689	8,078	-	73,906
Selling and administrative expense	-	-	-	-	40,481	(58)	40,423
(Gain) loss from sale of assets	123	(194)	-	586	53	(724)	(156)
Interest expense	-	24	262	(154)	38,030	(12,535)	25,627
Income before income taxes	$ 96,450	$ 81,081	$ 30,288	$ 9,504	$ (73,587)	$ 800	$ 144,536
Identifiable assets:							
Other allocated assets	$ 4,067	$ 7,001	$ 113,895	$ 40,628	$ 325,591	$ (66,708)	$ 424,474
Equity investment	-	-	-	-	632,622	(593,333)	39,289
Property and equipment	608,623	288,954	1,531	39,010	57,912	731	996,761
Total identifiable assets	$ 612,690	$ 295,955	$ 115,426	$ 79,638	$ 1,016,125	$ (659,310)	$1,460,524

Year Ended December 31, 2002:

	Gas Gathering and Processing	Exploration and Production	Marketing	Trans-portation	Corporate	Eliminating Entries	Total
Revenues from unaffiliated customers:							
Sale of gas	$ 2,156	$ 1,497	$ 2,085,760	$ 1,252	$ -	$ -	$ 2,090,665
Sale of natural gas liquids	17	-	317,743	-	-	-	317,760
Equity hedges:							
Gas	3,238	24,846	-	-	-	-	28,084
Liquids	(8,247)	-	-	-	-	-	(8,247)
Gathering, processing and transportation revenue	56,806	281	-	8,345	169	-	65,601
Total revenues from unaffiliated customers	53,970	26,624	2,403,503	9,597	169	-	2,493,863
Inter-segment revenues	638,807	112,868	22,868	15,794	87	(790,424)	-
Price risk management activities	(233)	589	(9,241)	-	-	-	(8,885)
Interest income	44	43	10	1	8,514	(8,612)	-
Other, net	3,595	19	6	2	(660)	1,758	4,720
Total revenues	696,183	140,143	2,417,146	25,394	8,110	(797,278)	2,489,698
Product purchases	532,963	2,698	2,380,446	935	-	(759,863)	2,157,179
Plant operating and transportation expense	74,119	170	290	8,133	234	(1,416)	81,530
Oil and gas exploration and production expense	-	63,149	-	-	-	(29,142)	34,007
Earnings from equity investments	(4,453)	-	-	-	-	-	(4,453)
Segment operating profit	93,554	74,126	36,410	16,326	7,876	(6,857)	221,435
Depreciation, depletion and amortization	41,959	26,770	158	1,675	6,443	-	77,005
Selling and administrative expense	-	-	-	-	35,882	(54)	35,828
(Gain) loss from sale of assets	877	(323)	-	476	494	(576)	948
Interest expense	-	66	132	(26)	35,391	(8,612)	26,951
Income before income taxes	$ 50,718	$ 47,613	$ 36,120	$ 14,201	$ (70,334)	$ 2,385	$ 80,703
Identifiable assets:							
Other allocated assets	$ 34,021	$ 911	$ 118,854	$ 24,534	$ 285,469	$ (53,907)	$ 409,882
Equity investment	2,839	-	-	-	467,600	(444,823)	25,616
Property and equipment	551,094	225,943	7	42,072	47,523	7	866,646
Total identifiable assets	$ 587,954	$ 226,854	$ 118,861	$ 66,606	$ 800,592	$ (498,723)	$1,302,144

NOTE 10 - EMPLOYEE BENEFIT PLANS

Retirement Plan. A discretionary retirement plan (a defined contribution plan) exists for all Company employees meeting certain service requirements. The Company may make annual discretionary contributions to the plan as determined by the board of directors, and during the three years ended December 31, 2004, the match of employee contributions was a sliding scale of 60% to 100% of the first 5% of employee compensation based upon years of service. Contributions are made to Fidelity Management Trust Company, as trustee. The trustee invests the funds in accordance with the participants' investment elections into mutual funds and a fund to purchase the Company's common stock. The discretionary contributions made by the Company were $3.1 million, $2.2 million and $1.9 million, for the years ended December 31, 2004, 2003 and 2002, respectively. The matching contributions were approximately $1.5 million, $1.4 million and $1.3 million for the years ended December 31, 2004, 2003 and 2002, respectively.

1999 Non-Employee Directors Stock Option Plan. Effective March 1999, the board of directors of the Company adopted a 1999 Non-Employee Directors' Stock Option Plan ("1999 Directors Plan") that authorized the granting of options to purchase 30,000 shares of the Company's common stock. During 1999, the board approved options grants covering 30,000 shares to several board members. Under this plan, each of these options becomes exercisable as to 33 1/3% of the shares covered by it on each anniversary from the date of grant. This plan terminates on the earlier of March 12, 2009 or the date on which all options granted under the plan have been exercised in full.

1993, 1997 and 1999 Stock Option Plans. The 1993 Stock Option Plan ("1993 Plan"), the 1997 Stock Option Plan ("1997 Plan"), and the 1999 Stock Option Plan ("1999 Plan") became effective on March 29, 1993, May 21, 1997, and May 21, 1999, respectively, after approvals by the Company's stockholders. Each plan is intended to be an incentive stock option plan in accordance with the provisions of Section 422 of the Internal Revenue Code of 1986, as amended. The Company reserved 2,000,000 shares of common stock for issuance upon exercise of options under each of the 1993 Plan and the 1997 Plan and 1,500,000 shares of common stock for issuance upon exercise of options under the 1999 Plan. The 1993 Plan terminated on March 29, 2003. The 1997 Plan and the 1999 Plan will terminate on the later of May 21, 2007 and May 21, 2009, respectively, or the date on which all the respective options granted under each of the plans have expired or been exercised in full. Although options covering 745,204 shares are available to be granted under the 1997 Plan, no further options will be granted under this plan. During 2004, options covering 140,876 shares were granted under the 1999 Plan.

Chief Executive Officer and President's Plan. Pursuant to the Employment Agreement, dated October 15, 2001, and the Stock Option Agreement, dated as of November 1, 2001, between the Company and Peter A. Dea, the Company's Chief Executive Officer and Président, non-qualified stock options were granted for the purchase of 600,000 shares of the Company's common stock. The exercise price of the options was equal to $2.50 below the closing price per share on the effective date of the Employment Agreement. The stock options are subject to the conditions of the Agreements and vest equally over four years. The difference between the closing price on the effective date and the exercise price is being amortized over four years as compensation expense. This option plan will terminate on the earlier of October 15, 2010 or the date on which all options granted under the plan have been exercised in full.

2002 Non-Employee Directors Stock Option Plan. Effective May 2002, the stockholders approved the 2002 Non-Employee Directors' Stock Option Plan ("2002 Directors Plan") that authorized the granting of options to purchase 220,000 shares of the Company's common stock. The 2002 Directors Plan provides for a three-year vesting schedule while the non-employee director serves on the Company's board. Under this plan, a newly elected non-employee director will be granted 10,000 options to acquire common stock as of the date of election. The 2002 Directors Plan also provides for an annual grant on the date of the Company's annual meeting to each non-employee director of 4,000 options to acquire common stock. The purchase price of the stock under each option shall be the fair market value of the stock at the time such option is granted and no options shall be re-priced. The 2002 Directors Plan requires the non-employee director to exercise the option at the earlier of ten years from the date of the plan or within five years of the date each portion vests. The non-employee director's right to exercise options under the 2002 Directors Plan is subject to continuous service since the grant was made. If the non-employee director dies or becomes disabled (within the meaning of the 2002 Directors Plan) or a change of control occurs, then all of the options granted to the non-employee director shall become 100% exercisable. The 2002 Directors Plan will terminate on the later of May 17, 2012 or the date on which all options granted under the plan have expired or been exercised in full. During 2004, 2003 and 2002, a total of 32,000, 32,000 and 36,000 options, respectively, were granted under this plan.

2002 Stock Option Plan. Effective May 2002, the stockholders approved the 2002 Stock Incentive Plan ("2002 Plan") that authorized the granting of options to purchase 2,500,000 shares of the Company's common stock. No employee may be granted more than 250,000 options to acquire common stock in any fiscal year. The 2002 Plan requires the employee to exercise the option at the earlier of ten years from the date of the 2002 Plan or within five years of the date each portion vests. The employee's right to exercise options under the 2002 Plan is subject to continuous employment since the grant was made. If the employee dies, becomes disabled (within the meaning of the 2002 Plan) or a change of control occurs, then all of the options granted to the employee shall become 100% exercisable. The 2002 Plan will terminate on the later of May 17, 2012 or the date on which all options granted under the plan have expired or been exercised in full. During 2004, 2003 and 2002, a total of 956,841, 1,129,900 and 375,994 options, respectively, were granted under this plan.

Under each of the 1997, 1999 and 2002 plans, the board of directors of the Company determines and designates from time to time those employees of the Company to whom options are to be granted. If any option terminates or expires prior to being exercised, the shares relating to such option are released and may be subject to re-issuance pursuant to a new option. The board of directors has the right to, among other things, fix the method by which the price is determined and the terms and conditions for the grant or exercise of any option. The purchase price of the stock under each option shall be the average closing price for the ten days prior to the grant. Under the 1997, 1999 and 2002 Plans, the board of directors has the authority to set the vesting schedule from 20% per year to 33 1/3% per year. Under each of the plans, the employee must exercise the option within five years of the date each portion vests.

The following table summarizes the number of stock options exercisable and available for grant under the Company's benefit plans at December 31, 2004, 2003, 2002:

	Per Share Price Range	1999 Directors Plan	1993 Plan	1997 Plan	1999 Plan	Chief Executive Officer's Plan	2002 Stock Incentive Plan	2002 Non-Employee Director's Plan
Exercisable:								
December 31, 2004	$0.01–5.00	6,600	-	36,536	-	-	-	-
	$5.01–10.00	-	-	11,000	-	-	-	-
	$10.01-15.00	-	-	-	33,672	450,000	-	-
	$15.01-20.00	-	-	-	586,038	-	395,961	32,000
	$20.01-25.00	-	-	-	-	-	5,000	-
	TOTAL	6,600	-	47,536	619,710	450,000	400,961	32,000
December 31, 2003	$0.01–5.00	-	-	109,266	-	-	-	-
	$5.01–10.00	16,700	-	65,320	800	-	-	-
	$10.01-15.00	-	-	-	71,762	300,000	-	-
	$15.01-20.00	-	-	-	575,504	-	84,882	10,666
	TOTAL	16,700	-	174,586	648,066	300,000	84,882	10,666
December 31, 2002	$0.01–5.00	-	-	182,810	-	-	-	-
	$5.01–10.00	16,700	86,560	136,000	34,964	-	-	-
	$10.01-15.00	-	11,632	-	67,284	150,000	-	-
	$15.01-20.00	-	8,578	-	140,482	-	-	-
	TOTAL	16,700	106,770	318,810	242,730	150,000	-	-
Available for Grant:								
December 31, 2004	-	-	-	-	4,500	-	122,340	124,000
December 31, 2003	-	-	-	-	120,876	-	1,006,972	156,000
December 31, 2002	-	-	-	-	-	-	2,124,006	184,000

The following table summarizes the stock option activity under the Company's benefit plans:

	Per Share Price Range	1999 Directors Plan	1993 Plan	1997 Plan	1999 Plan	Chief Executive Officer's Plan	2002 Stock Incentive Plan	2002 Non-Employee Directors Plan
Balance at 12/31/01		23,366	456,380	697,640	1,034,572	600,000	-	-
Granted	$16.48-16.73	-	-	-	340,000	-	375,994	36,000
Exercised	$2.30-17.50	(6,666)	(323,756)	(354,630)	(81,666)	-	-	-
Forfeited or expired	$2.30-18.17	-	(22,570)	(24,200)	(30,140)	-	-	-
Balance at 12/31/02		16,700	110,054	318,810	1,262,766	600,000	375,994	36,000
Granted	$16.18-22.33	-	-	-	-	-	1,129,900	32,000
Exercised	$2.30-18.17	-	(16,028)	(144,224)	(130,402)	-	(36,160)	-
Forfeited or expired	$6.63-18.91	-	(94,026)	-	(668)	-	(12,866)	(4,000)
Balance at 12/31/03		16,700	-	174,586	1,131,696	600,000	1,456,868	64,000
Granted	$23.56-31.06	-	-	-	140,876	-	956,841	32,000
Exercised	$2.30-19.02	(10,100)	-	(127,050)	(375,653)	-	(168,900)	-
Forfeited or expired	$13.32-28.35	-	-	-	(24,500)	-	(72,209)	-
Balance at 12/31/04		6,600	-	47,536	872,419	600,000	2,172,600	96,000
Weighted-average remaining contractual life (years)		1.8	-	2.3	5.0	4.3	6.1	5.4

The following table summarizes the weighted average option exercise price information under the Company's benefit plans:

	1999 Directors Plan	1993 Plan	1997 Plan	1999 Plan	Chief Executive Officer's Plan	2002 Stock Incentive Plan	2002 Non-Employee Directors Plan
Balance at 12/31/01	2.76	9.08	4.04	15.81	12.51	-	-
Granted	-	-	-	16.48	-	16.49	18.91
Exercised	(2.76)	(7.99)	(3.38)	(11.25)	-	-	-
Forfeited or expired	-	(17.50)	(2.96)	(13.23)	-	-	-
Balance at 12/31/02	$ 2.76	$ 9.87	$ 4.87	$ 16.34	$ 12.51	$ 16.49	$ 18.91
Granted	-	-	-	-	-	18.91	19.38
Exercised	-	(9.21)	(5.30)	(11.79)	-	(16.52)	-
Forfeited or expired	-	(14.51)	-	(11.73)	-	(16.48)	(18.91)
Balance at 12/31/03	$ 2.76	$ -	$ 4.52	$ 16.87	$ 12.51	$ 18.37	$ 19.15
Granted	-	-	-	28.35	-	28.45	27.69
Exercised	(2.76)	-	(4.94)	(16.93)	-	(17.86)	-
Forfeited or expired	-	-	-	(15.68)	-	(18.67)	-
Balance at 12/31/04	$ 2.76	$ -	$ 3.37	$ 18.72	$ 12.51	$ 22.83	$ 21.99

NOTE 11 - QUARTERLY RESULTS OF OPERATIONS (UNAUDITED):

The following summarizes certain quarterly results of operations (000s, except per share amounts):

	Operating Revenues	Gross Profit (a)	Income Before Cumulative Effect of Change in Accounting Principle	Earnings Per Share of Common Stock Before Cumulative Effect of Change in Accounting Principle	Net Income	Earnings Per Share of Common Stock	Earnings Per Share of Common Stock – Assuming Dilution
2004 quarter ended:							
March 31	$ 771,216	$ 54,130	$ 24,374	$ 0.34	$ 29,088	$ 0.41	$ 0.40
June 30	726,303	50,836	13,975	0.19	13,975	0.19	0.19
September 30	718,255	69,498	35,118	0.48	35,118	0.48	0.47
December 31	853,939	81,900	41,034	0.55	41,034	0.55	0.55
	$ 3,069,713	$ 256,364	$ 114,501	$ 1.56	$ 119,215	$ 1.63	$ 1.61
2003 quarter ended:							
March 31	$ 888,106	$ 65,490	$ 30,099	$ 0.42	$ 23,375	$ 0.32	$ 0.31
June 30	660,491	48,935	20,900	0.29	20,900	0.29	0.28
September 30	666,800	49,193	20,889	0.29	20,889	0.29	0.28
December 31	658,613	46,812	19,055	0.27	19,055	0.27	0.26
	$ 2,874,010	$ 210,430	$ 90,943	$ 1.27	$ 84,219	$ 1.17	$ 1.13

(a) Excludes selling and administrative, interest and income tax expenses, (gains) or losses on sale of assets and the cumulative effect of the change in accounting principle.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

Costs. The following tables set forth capitalized costs at December 31, 2004, 2003 and 2002 and costs incurred for oil and gas producing activities for the years ended December 31, 2004, 2003 and 2002 (000s):

	2004	2003	2002
Capitalized costs:			
Proved properties	$ 475,448	$ 315,635	$ 239,579
Unproved properties	134,519	83,384	64,451
Total	609,967	399,019	304,030
Less accumulated depreciation and depletion	(149,624)	(111,658)	(79,050)
Net capitalized costs	$ 460,343	$ 287,361	$ 224,980
Costs incurred:			
Acquisition of properties			
Proved	$ 47,775	$ 14,202	$ 426
Unproved	36,776	10,279	2,770
Development costs	95,466	60,479	48,648
Exploration costs	38,098	18,089	22,547
Total costs incurred	$ 218,115	$ 103,049	$ 74,391

Results of Operations. The results of operations for oil and gas producing activities, excluding corporate overhead and interest costs, for the years ended December 31, 2004, 2003 and 2002 are as follows (000s):

	2004	2003	2002
Revenues from sale of oil and gas:			
Sales	$ 10,767	$ 5,905	$ 2,227
Transfers	251,585	220,107	112,137
Total	262,352	226,012	114,364
Production costs	(106,732)	(86,800)	(65,536)
Exploration costs	(7,093)	(6,764)	(3,543)
Depreciation, depletion and amortization	(46,977)	(31,385)	(25,691)
Income tax expense	(68,426)	(57,342)	(7,558)
Results of operations	$ 33,124	$ 43,721	$ 12,036

Reserve Quantity Information. Reserve estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and of future net cash flows expected there from prepared by different engineers or by the same engineers at different times may vary substantially. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in commodity prices and operating costs. Any significant revision of reserve estimates could materially adversely affect the Company's financial condition, results of operations and cash flows.

The following table sets forth information for the years ended December 31, 2004, 2003 and 2002 with respect to changes in the Company's proved (i.e. proved developed and undeveloped) reserves, all of which are in the United States.

	Natural Gas (MMcf)	Crude Oil (MBbls)
December 31, 2001	470,237	661
Revisions of previous estimates	(88,344)	51
Extensions and discoveries	246,704	554
Purchases of reserves in place	(532)	-
Production	(47,401)	(53)
December 31, 2002	580,664	1,213
Revisions of previous estimates	(65,474)	571
Extensions and discoveries	191,751	887
Purchases of reserves in place	14,005	57
Production	(52,222)	(75)
December 31, 2003	668,724	2,653
Revisions of previous estimates	(82,300)	(85)
Extensions and discoveries	241,300	1,058
Purchases of reserves in place	26,676	112
Sales of reserves in place	(9,072)	-
Production	(54,892)	(97)
December 31, 2004	790,436	3,641
Proved developed reserves, included above:		
December 31, 2001	252,266	262
December 31, 2002	265,300	400
December 31, 2003	282,374	823
December 31, 2004	316,563	1,209

Standardized Measures of Discounted Future Net Cash Flows. Estimated discounted future net cash flows and changes therein were determined in accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. The Company believes such information is essential for a proper understanding and assessment of the data presented.

Future cash inflows are computed by applying year-end prices of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves.

The assumptions used to compute estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, or their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Also included in this caption are asset retirement obligations.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the Company's proved oil and gas reserves. Permanent differences in oil and gas related tax credits and allowances are recognized.

An annual discount rate of 10% was used to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

Information with respect to the Company's estimated discounted future cash flows from its oil and gas properties for the years ended December 31, 2004, 2003 and 2002 is as follows (000s):

	2004	2003	2002
Future cash inflows	$ 3,872,043	$ 3,152,573	$1,587,891
Future production costs	(950,891)	(710,999)	(463,471)
Future development costs	(411,257)	(275,302)	(193,255)
Future income tax expense	(838,615)	(740,314)	(305,263)
Future net cash flows	1,671,280	1,425,958	625,902
10% annual discount for estimated timing of cash flows	(872,035)	(740,598)	(265,250)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 799,245	$ 685,360	$ 360,652

Principal changes in the Company's estimated discounted future net cash flows for the years ended December 31, 2004, 2003 and 2002 are as follows (000s):

	2004	2003	2002
As of January 1,	$ 685,360	$ 360,652	$ 171,370
Sales and transfers of oil and gas produced, net of production costs	(155,620)	(139,211)	(50,828)
Net changes in prices and production costs related to future production	(35,978)	578,659	263,448
Development costs incurred during the period	95,466	60,479	40,753
Changes in estimated future development costs	(78,593)	(22,565)	(42,869)
Changes in extensions and discoveries	365,896	272,110	148,114
Revisions of previous quantity estimates	(161,703)	(321,395)	(87,705)
Purchases (sales) of reserves in place	25,643	22,898	(586)
Accretion of discount	104,118	53,655	24,118
Net change in income taxes	(45,344)	(179,922)	(105,163)
As of December 31,	$ 799,245	$ 685,360	$ 360,652

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Under the direction of our Chief Executive Officer and President ("CEO") and the Executive Vice President—Chief Financial Officer ("CFO"), we reviewed and evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended) as of the end of the period covered by this report. Based on such evaluation, our CEO and CFO concluded, as of the date of such evaluation, that our disclosure controls and procedures are effective.

Management's Report on Internal Control Over Financial Reporting

Our management's report on internal control over financial reporting is set forth in Item 8 of this Annual Report on Form 10-K and is incorporated by reference herein.

Changes in Internal Control Over Financial Reporting

There have not been any changes in our internal control over financial reporting during the quarter ended December 31, 2004, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pursuant to instruction G (3) to Form 10-K, Items 10, 11, 12, 13 and 14 are omitted because the Company will file a definitive proxy statement (the "Proxy Statement") pursuant to Regulation 14A under the Securities Exchange Act of 1934 not later than 120 days after the close of the fiscal year. The information required by such Items will be included in the Proxy Statement to be so filed for the Company's annual meeting of stockholders scheduled for May 6, 2005 and is hereby incorporated by reference.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

(1) Financial Statements:

Reference is made to page 38 for a list of all financial statements filed as a part of this report.

(2) Financial Statement Schedules:

None required.

(3) Exhibits:

3.1 Certificate of Incorporation of Western Gas Resources, Inc. (previously filed as Exhibit 3.1 to our Registration Statement on Form S-1, Registration No. 33-31604 and incorporated herein by reference).

3.2 Certificate of Amendment to the Certificate of Incorporation of Western Gas Resources, Inc. (previously filed as Exhibit 3.2 to our Registration Statement on Form S-1, Registration No. 33-31604 and incorporated herein by reference).

3.3 Certificate of Designation, Preferences and Rights of Series A Junior Participating Preferred Stock (previously filed as part of Exhibit 1 to our Form 8-A filed on March 30, 2001 and incorporated herein by reference).

3.4 Certificate of Designation of the $2.625 Cumulative Convertible Preferred Stock of Western Gas Resources, Inc. (previously filed in our Current Report on Form 8-K filed on February 25, 1994 and incorporated herein by reference).

3.5 Amended and Restated Bylaws of Western Gas Resources, Inc., adopted by the Board of Directors on May 7, 2004 (previously filed as Exhibit 99.1 to our Current Report on Form 8-K filed on May 11, 2004 and incorporated herein by reference).

4.1 Rights Agreement, dated as of March 22, 2001 between Western Gas Resources, Inc., and Fleet National Bank as Rights Agent, including exhibits thereto (previously filed as Exhibit 1 to our Form 8-A filed on March 30, 2001 and incorporated herein by reference).

4.2 Indenture between Western Gas Resources, Inc. and Guarantors to Chase Bank of Texas, National Association, Trustee for $225,000,000 Senior Subordinated Notes Due 2009, dated June 15, 1999 (previously filed as Exhibit 28 to our Quarterly Report on Form 10-Q filed on August 13, 1999 and incorporated herein by reference).

4.3 Western Gas Resources, Inc. First Supplemental Indenture to 10% Senior Subordinated Notes due 2009 dated October 19, 1999 (previously filed as Exhibit 4.10 to our Annual Report on Form 10-K filed on March 15, 2001 and incorporated herein by reference).

4.4 Western Gas Resources, Inc. Second Supplemental Indenture to 10% Senior Subordinated Notes due 2009 dated September 29, 2000 (previously filed as Exhibit 4.11 to our Annual Report on Form 10-K filed on March 15, 2001 and incorporated herein by reference).

4.5 Western Gas Resources, Inc. Third Supplemental Indenture to 10% Senior Subordinated Notes due 2009 dated January 3, 2001 (previously filed as Exhibit 4.12 to our Annual Report on Form 10-K filed on March 15, 2001 and incorporated herein by reference).

10.1 Registration Rights Agreement among Western Gas Resources, Inc., WGP, Inc., Heetco, Inc., NV, Dean Phillips, Inc., Sauvage Gas Company and Sauvage Gas Service, Inc. (previously filed as Exhibit 10.14 to our Registration Statement on Form S-4, Registration No. 33-39588 dated March 27, 1991 and incorporated herein by reference).

10.2 Amendment No. 1 to Registration Rights Agreement, dated as of May 1, 1991, between Western Gas Resources, Inc., Bill Sanderson, WGP, Inc., Dean Phillips, Inc., Heetco, Inc. NV, Sauvage Gas Company and Sauvage Gas Service, Inc. (previously filed as Exhibit 4.2 to our Quarterly Report on Form 10-Q filed for the quarter ended June 30, 1991 and incorporated herein by reference).

10.3 Third Amended and Restated Master Shelf Agreement, dated as of December 19, 1991 (effective as of January 13, 2003), by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America, Pruco Life Insurance Company, Prudential Investment Management Company, Inc. and ING Life Insurance & Annuity Company (previously filed as Exhibit 10.29 to our Annual Report on Form 10-K filed on March 24, 2003 and incorporated herein by reference).

10.4 Letter Amendment No. 1 to Third Amended and Restated Master Shelf Agreement, dated as of April 24, 2003, by and among Western Gas Resources, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Prudential Investment Management, Inc. and ING Life Insurance & Annuity Company (previously filed as Exhibit 10.5 to our Quarterly Report on Form 10Q filed on May 13, 2003 and incorporated herein by reference).

10.5 Letter Amendment No. 2 to Third Amended and Restated Master Shelf Agreement, dated as of June 29, 2004, by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America, Pruco Life Insurance Company, Prudential Investment Management, Inc., ING Life Insurance & Annuity Company and each Purchaser listed on the Purchaser Schedule attached Thereto (previously filed as Exhibit 10.6 to our Current Report on Form 8-K filed on July 1, 2004 and incorporated herein by reference).

10.6 Amended and Restated Credit Agreement, dated as of June 29, 2004, among Western Gas Resources, Inc., as Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, BNP Paribas, JPMorgan Chase Bank, The Royal Bank of Scotland plc and Wachovia Bank, National Association, as Co-Syndication Agents, Union Bank of California, N.A., U.S. Bank National Association and Wells Fargo Bank, N.A., as Co-Documentation Agents, and the Other Lenders a Party Thereto (previously filed as Exhibit 10.1 to our Current Report on Form 8-K filed on July 1, 2004 and incorporated herein by reference).

10.7 First Amendment to Amended and Restated Credit Agreement, dated as of December 20, 2004, by and among Western Gas Resources, Inc. and bank of America, N.A., as Agent and the Lenders under the Original Agreement (previously filed as Exhibit 10.1 to our Current Report on Form 8-K filed on December 22, 2004 and incorporated herein by reference).

10.8 Continuing Guaranty, dated as of June 29, 2004, by MIGC, Inc., Western Gas Resources – Texas, Inc., MGTC, Inc., Mountain Gas Resources, Inc. Lance Oil & Gas Company, Inc. and Western Gas Wyoming, L.L.C. in favor of Bank of America, N.A., as Administrative Agent (previously filed as Exhibit 10.2 to our Current Report on Form 8-K filed on July 1, 2004 and incorporated herein by reference).

10.9 Amended and Restated Pledge Agreement, dated as of June 29, 2004, by Western Gas Resources, Inc., in favor of Bank of America, N.A., as Administrative Agent (previously filed as Exhibit 10.3 to our Current Report on Form 8-K filed on July 1, 2004 and incorporated herein by reference).

10.10 Amended and Restated Subsidiary Pledge Agreement, dated as of June 29, 2004, by MIGC, Inc., in favor of Bank of America, N.A., as Administrative Agent (previously filed as Exhibit 10.4 to our Current Report on Form 8-K filed on July 1, 2004 and incorporated herein by reference).

10.11 Amended and Restated Intercreditor Agreement, dated as of June 29, 2004, by and among the Banks, Bank of America, N.A., as Administrative Agent for the Banks and The Prudential Insurance Company of America, Pruco Life Insurance Company, ING Life Insurance & Annuity Company, Prudential Investment Management, Inc., Pruco Life Insurance Company of New Jersey, Gibralter Life Insurance Co., Ltd., RGA Reinsurance Company, American Bankers Life Assurance Company of Florida, Inc., Fortis Benefits Insurance Company and Connecticut General Life Insurance Company, consented to agreed by Western Gas Resources, Inc. and its subsidiaries listed therein (previously filed as Exhibit 10.5 to our Current Report on Form 8-K filed on July 1, 2004 and incorporated herein by reference).

10.12 Credit Agreement, dated as of April 24, 2003, among Western Gas Resources, Inc., as Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, Bank One, NA and Fleet National Bank, as Co-Syndication Agents, The Royal Bank of Scotland plc and Wachovia Bank, National Association, as Co-Documentation Agents, and the Other Lenders Party Thereto (previously filed as Exhibit 10.2 to our Quarterly Report on Form 10-Q filed on May 13, 2003 and incorporated by reference herein).

10.13 Intercreditor Agreement, dated as of April 24, 2003, by and among the banks (as defined therein), Bank of America, N.A., as Administrative Agent for the banks and The Prudential Insurance Company of America, Pruco Life Insurance Company, ING Life Insurance & Annuity Company and Prudential Investment Management, Inc., consented to agreed by Western Gas Resources, Inc. and its subsidiaries listed therein (previously filed as Exhibit 10.3 to Western Gas Resources, Inc., 10-Q dated March 31, 2002 and incorporated herein by reference).

10.14 Restated Retirement Plan of Western Gas Resources, Inc., dated May 1, 2001 (previously filed as Exhibit 4.9 to our Registration Statement on Form S-8 filed on August 14, 2002 and incorporated herein by reference).

10.15 Western Gas Resources, Inc., 1997 Stock Option Plan (previously filed as Exhibit 10.29 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.16 First Amendment to the Western Gas Resources, Inc. 1997 Stock Option Plan (previously filed as Exhibit 10.30 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.17 Second Amendment to the Western Gas Resources, Inc. 1997 Stock Option Plan (previously filed as Exhibit 10.31 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.18 Western Gas Resources, Inc., 1999 Stock Option Plan. (Previously filed as Exhibit 4.7 to our Registration Statement on Form S-8, Registration No. 333-95255, filed on January 24, 2000 and incorporated herein by reference). *

10.19 First Amendment to the Western Gas Resources, Inc. 1999 Stock Option Plan (previously filed as Exhibit 10.33 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.20 Second Amendment to the Western Gas Resources, Inc. 1999 Stock Option Plan (previously filed as Exhibit 10.34 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.21 Western Gas Resources, Inc. 2002 Stock Option Plan (previously filed as Exhibit 10.35 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.22 First Amendment to the Western Gas Resources, Inc. 2002 Stock Option Plan (previously filed as Exhibit 10.36 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.23 Western Gas Resources, Inc. Non-Employee Director's Stock Option Plan (previously filed as part of Exhibit 4.7 to our Registration Statement on Form S-8, Registration No. 333-95259, filed on January 24, 2000 and incorporated herein by reference). *

10.24 Western Gas Resources, Inc. 2002 Non-Employee Director's Stock Option Plan (previously filed as Exhibit 10.38 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.25 Stock Option Agreement, effective November 1, 2001, by and between Western Gas Resources, Inc. and Peter A. Dea (previously filed as Exhibit 99.1 to our Registration Statement on Form S-8 filed on December 21, 2002, and incorporated herein by reference).*

10.26 2001 Employment Agreement, dated June 14, 2001, by and between Western Gas Resources, Inc. and Edward A. Aabak, together with 2001 Indemnification Agreement (previously filed as Exhibit 10.41 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.27 2001 Employment Agreement, dated June 14, 2001, by and between Western Gas Resources, Inc. and John F. Chandler, together with 2001 Indemnification Agreement (previously filed as Exhibit 10.42 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.28 2001 Employment Agreement, dated October 15, 2001, by and between Western Gas Resources, Inc. and William J. Krysiak, together with 2001 Indemnification Agreement (previously filed as Exhibit 10.43 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.29 2001 Employment Agreement, dated June 14, 2001, by and between Western Gas Resources, Inc. and John C. Walter, together with 2001 Indemnification Agreement (previously filed as Exhibit 10.44 to our Annual Report on Form 10-K filed on March 11, 2004 and incorporated herein by reference). *

10.30 Employment Agreement, dated October 15, 2001, by and between Western Gas Resources, Inc. and Peter A. Dea, together with Indemnification Agreement, dated November 1, 2001 (previously filed as exhibits to the Stock Option Plan filed on Registration Statement on Form S-8, Registration Number 333-7573 and incorporated herein by reference). *

11.1 Statement regarding computation of per share earnings.

21.1 List of Subsidiaries of Western Gas Resources, Inc.

23.1 Consent of PricewaterhouseCoopers LLP. †

23.2 Consent of Netherland, Sewell & Associates, Inc. †

31.1 Section 302 Certification of the Chief Executive Officer. †

31.2 Section 302 Certification of the Chief Financial Officer. †

32.1 Section 906 Certification of the Chief Executive Officer and Chief Financial Officer. †

* Management contract or compensating plan or arrangement.
† Indicates exhibits filed with this Form 10-K.

(b) Exhibits required by Item 601 of Regulation S-K. See (a) (3) above.

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, in the City of Denver, State of Colorado on March 11, 2005.

WESTERN GAS RESOURCES, INC.
(Registrant)

By: /s/ PETER A. DEA
Peter A. Dea
Chief Executive Officer, President and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ PETER A. DEA Peter A. Dea	Chief Executive Officer, President and Director (Principal Executive Officer)	March 11, 2005
/s/ WILLIAM J. KRYSIAK William J. Krysiak	Executive Vice President -Chief Financial Officer (Principal Financial and Accounting Officer)	March 11, 2005
/s/ JAMES A. SENTY James A. Senty	Chairman of the Board	March 11, 2005
/s/ WALTER L. STONEHOCKER Walter L. Stonehocker	Vice Chairman of the Board	March 11, 2005
/s/ DEAN PHILLIPS Dean Phillips	Director	March 11, 2005
/s/ JOSEPH E. REID Joseph E. Reid	Director	March 11, 2005
/s/ RICHARD B. ROBINSON Richard B. Robinson	Director	March 11, 2005
/s/ BILL M. SANDERSON Bill M. Sanderson	Director	March 11, 2005
/s/ WARD SAUVAGE Ward Sauvage	Director	March 11, 2005
/s/ BRION G. WISE Brion G. Wise	Director	March 11, 2005

Reconciliation of Net Income to

Cash Flow before Working Capital Adjustments:

(Dollars in thousands)	Year Ended December 31,		
	2004	2003	2002
Net Income	$ 119,215	$ 84,219	$ 50,589
Add income items that do not affect			
cash flows before working capital adjustments:			
Depreciation, depletion and amortization	95,536	73,906	77,005
Deferred income taxes	66,289	49,326	19,614
Distributions less than equity income, net	127	1,076	(2,906)
(Gain) loss on sale of assets	1,288	(156)	948
Non-cash change in fair value of derivatives	(1,572)	(1,235)	13,788
Compensation expense from repriced stock options	646	376	224
Foreign currency translation adjustments	816	1,238	-
Cumulative effect of changes in accounting principles	(4,714)	6,724	-
Other non-cash items	1,296	192	1,809
Cash flow before working capital adjustments	$ 278,927	$ 215,666	$ 161,071

Cash Flow before Working Capital Adjustments is not a measure determined pursuant to generally accepted accounting principles, or GAAP, nor is it an alternative to GAAP income. The Company is presenting this information as it is an important measure of financial performance used by equity analysts.

Glossary of Terms

Connected Reserves – Estimated future economic production associated with the wells currently producing and connected to Western's facilities for terms varying from one month, to their economic life (which in some cases will exceed fifty years). This is based on an internal review of historical facility throughput gas volume, our interpretation of expected declines from existing conditions, and assumes that there are no new well connections to our facilities.

Gas Processing – The separation of the components of natural gas by mechanical, refrigeration or cryogenic methods for the purpose of making salable liquid hydrocarbon products and also for the treating of the residue methane gas to meet required pipeline specifications. Salable gas liquid products include ethane, propane, butanes and natural gasoline.

Gas Throughput – The total gas moving through a pipeline system or processing facility.

Leasehold – The amount of acreage or property on which a company holds contractual drilling and legal rights for minerals such as natural gas and oil.

Natural Gas Liquids (NGLs) – Those hydrocarbons that go from a gaseous state in reservoir conditions to a liquid state at the surface in gas processing plants. Natural gas liquids include ethane, propane, butanes and natural gasoline.

Possible Reserves – Those unproved quantities of natural gas and/or oil which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves.

Probable Reserves – Those unproved quantities of natural gas and/or oil which analysis of geological and engineering data suggests are at least 50 percent likely to be recoverable.

Proved Reserves – Those quantities of natural gas and/or oil, which by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves included Proved Developed Producing ("PDP"), Proved Developed Non-producing ("PDNP") and Proved Undeveloped ("PUD").

Shareholder Return – Calculated as: Ending Share Price – Beginning Share Price + Dividends, divided by Beginning Share Price.

Unconventional Natural Gas – Natural gas reservoirs that occur in coal seams, low permeability or 'tite' gas sands and shales. They typically cover large areas and often lack the apparent traps of conventional reservoirs.

Units of Measure

Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet
Tcf	Trillion cubic feet
MMcfd	Million cubic feet per day
Bcfd	Billion cubic feet per day
MMcfe	Million cubic feet of gas equivalent
Bcfe	Billion cubic feet of gas equivalent
Tcfe	Trillion cubic feet of gas equivalent

Investor Information

★ ★ ★ ★ ★ ★

Corporate Office
1099 18th Street
Suite 1200
Denver, Colorado 80202

Stock Information
New York Stock Exchange
Common Stock: WGR

Annual Meeting
The annual meeting of stockholders is scheduled to be held on May 6, 2005, at 10:00 a.m., at the Embassy Suites Hotel, 1881 Curtis Street, Denver, Colorado, 80202. A formal notice of the meeting and a proxy statement will be distributed on or about April 6, 2005, to stockholders of record at the close of business on March 15, 2005.

Independent Accountants
PricewaterhouseCoopers LLP
Denver, Colorado

Transfer Agent and Registrar
EquiServe Trust Company, N.A.
P.O. Box 43010
Providence, RI 02940-3010
(800) 736-3001
www.equiserve.com

Common Stock Statistics

	High	Low	Last	Dividends Paid
2004				
1st Quarter	25.75	22.75	25.34	0.05
2nd Quarter	32.78	24.97	32.42	0.05
3rd Quarter	35.25	27.50	28.59	0.05
4th Quarter	31.50	26.38	29.25	0.05
2003				
1st Quarter	18.75	15.28	16.07	0.05
2nd Quarter	20.83	15.96	19.60	0.05
3rd Quarter	20.03	18.20	18.86	0.05
4th Quarter	23.75	19.20	23.50	0.05

Direct Deposit of Dividends
The Company offers direct deposit of dividends at no additional cost. To take advantage of this service, contact EquiServe Trust Company, N.A. at (800) 736-3001.

Additional Information
Western's Quarterly Reports on Form 10-Q and Annual Report on Form 10-K are available upon request by calling (800) 933-5603. To access information on-line, visit our Web site at www.westerngas.com.

Investor Contact
Financial analysts and investors may obtain additional information by contacting Ron Wirth, Director of Investor Relations, at (800) 933-5603, (303) 252-6090 (direct), or rwirth@westerngas.com.

Information Regarding Forward-Looking Statements

The statements herein, other than statements of historical facts, which address activities or actions that we expect or anticipate will or may occur in the future, and growth of our operations and other such matters are forward-looking statements. Forward-looking statements can be identified by the use of forward-looking terminology, such as "may," "intend," "will," "should," "expect," "anticipate," "estimate," "plan," "predict" or "continue" or comparable terminology. Numerous factors could cause actual results to differ materially from our projections in this Annual Report. These factors are set forth herein and in our other documents on file with the SEC. See further discussion in Item 7 of Form 10-K—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Cautionary Statement Regarding Forward-Looking Information."

NYSE CEO Certification

On May 11, 2004, Peter Dea, the Chief Executive Officer and President of Western Gas Resources, filed the CEO annual certification in accordance with Section 303A.12(a) of the New York Stock Exchange Listed Company Manual, certifying that, as of such date, he was not aware of any violation of the New York Stock Exchange's corporate governance listing standards.

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