RANGE RESOURCES CORP
Form 8-K
June 19, 2007

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

FORM 8-K
CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934
Date of report (Date of earliest event reported):
June 19, 2007
RANGE RESOURCES CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**001-12209**	**34-1312571**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)
100 Throckmorton Street, Suite 1200 Ft. Worth, Texas		**76102**
(Address of principal executive offices)		(Zip Code)

Registrant s telephone number, including area code: (817) 870-2601
(Former name or former address, if changed since last report): Not applicable

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligations of the registrant under any of the following provisions (see General Instruction A.2. below):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

ITEM 8.01. OTHER EVENTS.

As of March 30, 2007, we sold our interests in our Gulf of Mexico properties for proceeds of $155.0 million. We reported our operations with respect to these properties as discontinued operations in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007.

This Current Report on Form 8-K was prepared to provide revised financial information that presents these properties as discontinued operations for all periods presented in our Annual Report on Form 10-K for the year ended December 31, 2006, filed on February 26, 2007 (2006 Form 10-K). It should be noted that our net income (loss) was not impacted by the reclassification of our operations with respect to these properties to discontinued operations.

Please note, we have not otherwise updated our financial information or business discussion for activities or events occurring after the date this information was presented in our 2006 Form 10-K. You should read our Quarterly Report on Form 10-Q for the period ended March 31, 2007 and our Current Reports on Form 8-K and any amendments thereto, for updated information.

This filing includes updated information for the following items included in our 2006 Form 10-K:

ITEM 6. SELECTED FINANCIAL DATA

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Unaffected items of our 2006 Form 10-K have not been repeated in this Form 8-K.

Cross-references that are included in the above items and that refer to information included on page numbers that are preceded by an F refer to the corresponding page included in this filing. Other cross-references are to pages in our 2006 Form 10-K.

ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial information for the five years ended December 31, 2006. Significant producing property acquisitions in 2006 and 2004 affect the comparability of year-to-year financial and operating data. All weighted average shares and per share data have been adjusted for the three-for-two stock split effected December 2, 2005. This information should be read in conjunction with Item 7 of this report Management s Discussion and Analysis of Financial Condition and Results of Operations, and our consolidated financial statements and related notes included elsewhere in this report (in thousands, except per share data).

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Balance Sheet Data:					
Current assets [(a)]	$ 388,925	$ 207,977	$ 136,336	$ 66,092	$ 50,619
Current liabilities [(b)]	251,685	321,760	177,162	106,964	67,206
Oil and gas properties, net	2,608,088	1,679,593	1,340,077	658,798	474,800
Total assets	3,187,674	2,018,985	1,595,406	830,091	658,484
Bank debt	452,000	269,200	423,900	178,200	115,800
Subordinated debt	596,782	346,948	196,656	109,980	90,901
Stockholders equity [(c)]	1,256,161	696,923	566,340	274,066	206,109
Weighted average dilutive shares outstanding	138,711	129,126	97,998	86,775	81,627
Cash dividends declared per common share	0.09	.0599	.0267	.0067	
Cash Flow Data:					
Net cash provided from operating activities	479,875	325,745	209,249	124,680	114,472
Net cash used in investing activities	911,659	432,377	624,301	186,838	103,950
Net cash provided from (used in) financing activities	429,416	93,000	432,803	61,455	(12,568)

(a) 2005, 2004 and 2003 include deferred tax assets of $61.7 million, $26.3 million and $19.9 million, respectively. 2006 includes a $93.6 million hedging asset.

(b) 2006, 2005, 2004, 2003 and 2002 include hedging liabilities of $4.6 million,

$160.1 million, $61.0 million, $54.3 million and $26.0 million, respectively.

(c) Stockholders equity includes other comprehensive income (loss) of $36.5 million, ($147.1 million), ($43.3 million), ($42.9 million) and ($21.2 million) in 2006, 2005, 2004, 2003 and 2002, respectively.

Statement of Operations Data:

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Revenues					
Oil and gas sales	$ 649,078	$ 498,376	$ 278,903	$ 179,074	$ 148,310
Transportation and gathering	2,422	2,306	2,002	3,248	3,216
Gain (loss) on retirement of securities			(39)	18,256	3,098
Mark-to-market on oil and gas derivatives	86,491	10,868			
Other	6,821	(2,447)	2,202	(1,877)	(5,958)
Total revenue	744,812	509,103	283,068	198,701	148,666
Costs and expenses					
Direct operating	81,261	57,866	39,419	28,110	23,052
Production and ad valorem taxes	36,415	30,822	19,845	12,059	7,967
Exploration	44,088	29,529	12,619	12,530	11,233
General and administrative	49,886	33,444	20,634	17,818	16,217
Deferred compensation plan	6,873	29,474	19,176	6,559	1,023
Interest expense and dividends on trust preferred	55,849	37,619	22,437	21,507	22,451
Depletion, depreciation and amortization	154,739	114,364	80,628	62,687	57,249
Total costs and expenses	429,111	333,118	214,758	161,270	139,192
Income from continuing operations before income taxes and accounting change	315,701	175,985	68,310	37,431	9,474
Income tax provision (benefit)					
Current	1,912	1,071	(245)	170	(4)
Deferred	119,840	64,809	25,327	14,125	(7,881)
	121,752	65,880	25,082	14,295	(7,885)
Income from continuing operations	193,949	110,105	43,228	23,136	17,359
Income (loss) from discontinued operations	(35,247)	906	(997)	7,788	8,407
Income before cumulative effect of changes in accounting principles	158,702	111,011	42,231	30,924	25,766
				4,491	

Cumulative effect of changes in accounting principles, net of taxes					
Net income	158,702	111,011	42,231	35,415	25,766
Preferred dividends			(5,163)	(803)	
Net income available to common stockholders	$ 158,702	$ 111,011	$ 37,068	$ 34,612	$ 25,766
Earnings per common share:					
Basic - income from continuing operations	$ 1.45	$ 0.89	$ 0.41	$ 0.27	$ 0.22
- income (loss) from discontinued operations	(0.26)		(0.01)	0.10	0.10
- cumulative effect of changes in accounting principles				0.05	
- Net income	$ 1.19	$ 0.89	$ 0.40	$ 0.42	$ 0.32
Diluted - income from continuing operations	$ 1.39	$ 0.85	$ 0.39	$ 0.27	$ 0.22
- income (loss) from discontinued operations	(0.25)	0.01	(0.01)	0.09	0.10
- cumulative effect of changes in accounting principles				0.05	
- Net income	$ 1.14	$ 0.86	$ 0.38	$ 0.41	$ 0.32

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with Item 6, Selected Financial Data and our consolidated financial statements and the accompanying notes included elsewhere in this Form 10-K.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See Disclosures Regarding Forward-Looking Statements at the beginning of this Annual Report and Risk Factors in Item 1A. for additional discussion of some of these factors and risks.

Overview of Our Business

We are an independent natural gas and oil company engaged in the exploration, development and acquisition of oil and gas properties, primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We operate in one segment. We have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our strategy is to increase reserves and production through internally generated drilling projects coupled with complementary acquisitions. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. We use the successful efforts method of accounting for our oil and gas activities.

Industry Environment

We operate entirely within the United States, a mature region for the exploration and production of oil and gas. As a mature region, while new discoveries of oil and gas occur in the United States, the size and frequency of these discoveries is declining, while finding and development costs are increasing. We believe that there remain areas of the United States, such as the Appalachian basin and certain areas in our Southwest and Gulf Coast Divisions, which are underexplored or have not been fully explored and developed with the benefit of newly available exploration, production and reserve enhancement technology. Examples of such technology include advanced 3-D seismic processing, hydraulic reservoir fracture stimulation, advances in well logging and analysis, horizontal drilling and completion techniques, secondary and tertiary recovery practices, and automated remote well monitoring and control devices.

Another characteristic of a mature region is the historical exit of larger independent producers and major oil companies from such regions. These companies, searching for ever larger new discoveries, have ventured increasingly overseas and offshore, de-emphasizing their onshore United States assets. This movement out of mature basins by larger companies has provided acquisition opportunities for companies like ours that maintain well-equipped technical teams capable of generating additional value from these assets. In other situations, to increase cash flow without increasing capital spending, larger independent producers and major integrated oil companies have allowed smaller companies the opportunity to explore and develop reserves on their undeveloped acreage through joint ventures and farm-in arrangements.

We believe the acquisition market for natural gas properties has become extremely competitive as producers vie for additional production and expanded drilling opportunities. Acquisition values have reached historic highs and we expect these values to remain high in 2007. In addition, we expect drilling and service costs to remain at a high level in 2007 and for lease operating expenses to continue to rise as producers are forced to make operational enhancements to maintain aging fields.

Natural gas is a commodity. The price that we receive for the natural gas we produce is largely a function of market supply and demand. Demand for natural gas in the United States has increased dramatically over the last ten years. Demand is impacted by general economic conditions, estimates of gas in storage, weather and other seasonal condition, including hurricanes and tropical storms. Market conditions involving over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. A substantial or extended decline in oil and gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and our ability to access capital markets.

Source of Our Revenues

We derive our revenues from the sale of natural gas and oil that is produced from our properties. Revenues are a function of the volume produced and the prevailing market price at the time of sale. The price of oil and natural gas is the primary factor affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a significant portion of our natural gas and oil production. During 2006, 2005 and 2004 the use of derivative instruments prevented us from realizing the full benefit of upward price movements and may continue to do so in future periods. Discontinued operations includes our Gulf of Mexico properties which were sold in March 2007 and our Austin Chalk properties which were presented as Assets Held for Sale at December 31, 2006 and were sold in February 2007. Unless otherwise indicated, the information included herein relates to our continuing operations.

Principal Components of Our Cost Structure

Direct Operating Expenses. These are day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. Such costs also include workovers and repairs to our oil and gas properties not covered by insurance. These costs are expected to remain high in 2007 as the demand for these services continues to increase. Direct operating expenses includes stock-based compensation expense (non-cash) associated with the adoption of SFAS123(R), amortization of restricted stock grants and mark-to-market of SARs as part of employee compensation.

Production and Ad Valorem Taxes. These costs are primarily paid based on a percentage of market prices and not on hedged prices of production or at fixed rates established by federal, state or local taxing authorities.

Exploration Expense. Geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful exploratory wells or dry holes. Exploration expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS123(R), amortization of restricted stock grants and mark-to-market of SARs as part of employee compensation.

General and Administrative Expense. Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, audit and other professional fees and legal compliance are included in general and administrative expense. General and administrative expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS123(R), amortization of restricted stock grants and mark-to-market of SARs as part of employee compensation.

Interest. We typically finance a portion of our working capital requirements and acquisitions with borrowings under our bank credit facility and with our longer term public traded debt securities. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We may continue to incur significant interest expense as we continue to grow. We expect our 2007 capital budget to be funded with internal cash flow and asset sales.

Depreciation, Depletion and Amortization. The systematic expensing of the capital costs incurred to acquire, explore and develop natural gas and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.

Income Taxes. We are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs (IDC). We do pay some state income taxes where our IDC deductions do not exceed our taxable income or where state income taxes are determined on another basis. Currently, all of our federal taxes are deferred; however, at some point, we will utilize all of our net operating loss carryforwards and we will recognize current income tax expense and continue to recognize current tax expense as long as we are generating taxable income.

Management s Discussion and Analysis of Income and Operations

Volumes and Price Data

	2006	2005	2004
Production:			
Crude oil (bbls)	3,039,150	2,929,013	2,385,375
NGLs (bbls)	1,091,785	1,011,692	988,192
Natural gas (mcf)	70,712,770	57,608,816	43,051,485
Total (mcfe) [a]	95,498,380	81,253,046	63,292,887
Average daily production:			
Crude oil (bbls)	8,326	8,025	6,517
NGLs (bbls)	2,991	2,772	2,700
Natural gas (mcf)	193,734	157,832	117,627
Total (mcfe) [a]	261,639	222,611	172,931
Average sales prices (excluding hedging):			
Crude oil (per bbl)	$ 62.36	$ 53.30	$ 39.20
NGLs (per bbl)	33.62	31.52	23.73
Natural gas (per mcf)	6.59	8.00	5.80
Total (per mcfe) [a]	7.25	7.99	5.79
Average sales prices (including hedging):			
Crude oil (per bbl)	$ 47.46	$ 38.63	$ 27.98
NGLs (per bbl)	33.62	27.27	19.76
Natural gas (per mcf)	6.62	6.21	4.47
Total (per mcfe) [a]	6.80	6.13	4.41
Average NYMEX prices [b]			
Oil (per bbl)	$ 66.22	$ 56.56	$ 41.42
Natural gas (per mcf)	7.26	8.55	6.09

[a] Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcfe.

[b] Based on average of bid week prompt month prices.

Overview of 2006 Results

During 2006, we achieved the following results:

- 15% production growth and 25% reserve growth (including Gulf of Mexico);
- Drilled over 700 net wells (including Gulf of Mexico);
- Continued expansion of drilling inventory and emerging plays;
- Record financial results and continued balance sheet improvement; and
- Completed an acquisition of properties containing 171 Bcfe of proved reserves, of which 49 Bcfe were held for sale at December 31, 2006 and included in discontinued operations.

Our 2006 performance reflects another year of successfully executing our strategy of growth through drilling and complementary acquisitions. The business of exploring for, developing, and acquiring oil and gas is highly competitive and capital intensive. As in any commodity business, the costs associated with finding, acquiring, extracting, and financing the operation are critical to profitability and long-term value creation for stockholders. Generating meaningful growth while containing costs represents an ongoing challenge for management. During periods of historically high oil and gas prices, such as 2005 and 2006, drilling service and operating cost increases are more prevalent due to increased competition for goods and services. We faced other challenges in 2006 including attracting and retaining qualified personnel, consummating and integrating acquisitions, and accessing the capital markets to fund our growth and capital simplification process on sufficiently favorable terms. We have continued to expand and improve the technical staff through the hiring of additional experienced professionals. Our inventory of exploration and development prospects continues to build, providing new growth opportunities, greater diversification of technical risk and better efficiency.

Total revenues increased 46% in 2006 over the same period of 2005. This increase is due to higher production and realized oil and gas prices. Our 2006 production growth is due to acquisitions completed in 2006 and to the continued success of our drilling program. Realized prices were higher by 11% in 2006 reflecting the expiration of lower priced oil and gas hedges. As discussed in Item 1A of this report, significant changes in oil and gas prices can have a significant impact on our balance sheet and our results of operations, particularly on the fair value of our derivatives.

Comparison of 2006 to 2005

Oil and gas revenue for the years ended December 31, 2006 and 2005 (in thousands) is summarized in the following table:

	2006	2005	Change	%
Revenues:				
Oil wellhead	$ 189,516	$ 156,102	$ 33,414	21%
Oil hedges	(45,265)	(42,948)	(2,317)	5%
Total oil revenue	$ 144,251	$ 113,154	$ 31,097	28%
Gas wellhead	$ 466,099	$ 461,132	$ 4,967	1%
Gas hedges	2,023	(103,498)	105,521	102%
Total gas revenue	$ 468,122	$ 357,634	$ 110,488	31%
NGL	$ 36,705	$ 31,890	$ 4,815	15%
NGL hedges		(4,302)	4,302	100%

Total NGL revenue	$ 36,705	$ 27,588	$ 9,117	33%
Combined wellhead	$ 692,320	$ 649,124	$ 43,196	7%
Combined hedges	(43,242)	(150,748)	107,506	71%
Total oil and gas revenue	$ 649,078	$ 498,376	$ 150,702	30%

Average realized price received for oil and gas during 2006 was $6.80 per mcfe, up 11% or $0.67 per mcfe from 2005. Oil and gas revenues for 2006 reached a record $649.1 million and were 30% higher than 2005 due to higher realized oil and gas prices and an 18% increase in production. The average price received increased 23% to $47.46 per barrel for oil and increased 7% to $6.62 per mcf for gas from 2005. The effect of our hedging program decreased realized prices $0.45 per mcfe in 2006 versus a decrease of $1.86 in 2005.

Production volumes increased 18% from 2005 due to continued drilling success and additions from acquisitions consummated in 2006. Production increased 14.2 Bcfe from 2005. Our production volumes increased 10% in our Appalachia Division, increased 29% in our Southwest Division and declined 36% in our Gulf Coast Division.

Mark-to-market on oil and gas derivatives includes a gain of $86.5 million in 2006. In the fourth quarter of 2005, certain of our gas hedges no longer qualified for hedge accounting due to the effect of gas price volatility on the correlation between realized prices and hedge reference prices.

Other revenue increased in 2006 to a gain of $6.8 million from a loss of $2.4 million in 2005. The 2006 period includes $6.0 million of ineffective hedging gains and income from equity method investments of $548,000. The 2005 period includes ineffective hedging losses of $3.4 million.

Our operating expenses have increased as we continue to grow. We believe most of our operating expense fluctuations should be analyzed on a unit-of-production, or per mcfe basis. The following table presents information about our operating expenses on an mcfe basis for 2006 and 2005:

Operating expenses per mcfe	2006	2005	Change	%
Direct operating expense (excluding $0.01 per mcfe stock-based compensation in 2006 and 2005)	$0.84	$0.71	$0.13	18%
Production and ad valorem tax expense	0.38	0.38		
General and administrative expense (excluding stock-based compensation of $0.15 per mcfe in 2006 and $0.06 per mcfe in 2005)	0.37	0.35	0.02	6%
Interest expense	0.58	0.46	0.12	26%
Depletion, depreciation and amortization expense	1.62	1.41	0.21	15%

Direct operating expense (excluding stock-based compensation) increased $22.5 million to $79.9 million due to higher oilfield service costs, higher volumes and the integration of our recent acquisitions. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $3.5 million of expenses associated with workovers in 2006 versus $2.5 million in 2005. On a per mcfe basis, direct operating expenses (excluding stock-based compensation) were $0.84 per mcfe and increased $0.13 per mcfe from 2005 with the increase consisting primarily of higher utilities ($0.02 per mcfe) and higher water disposal and equipment costs ($0.06 per mcfe).

Production and ad valorem taxes are paid based on market prices and not hedged prices. These taxes increased $5.6 million, or 18%, from the same period of the prior year. On a per mcfe basis, production and ad valorem taxes remained the same when compared to 2005.

General and administrative expense (excluding stock-based compensation) for 2006 increased 25%, or $7.0 million, due to higher salaries and benefits ($6.0 million) and higher office rent and general office expense ($1.0 million). On a per mcfe basis, general and administration expense (excluding stock-based compensation) increased from $0.35 per mcfe in 2005 to $0.37 per mcfe in 2006.

Interest expense for 2006 increased $18.2 million, or 48%, to $55.8 million with higher average interest rates, higher average debt balances and the refinancing of certain debt from short-term floating to longer-term fixed rates. In 2006, we issued $250.0 million of 7.5% senior subordinated notes which added $9.7 million of interest costs. The proceeds from this issuance were used to retire shorter term bank debt. In 2006, the average debt outstanding on the bank credit facility was $347.8 million with an average interest rate of 6.4% compared to an average debt outstanding in 2005 of $314.8 million with an average interest rates of 4.5%. The 2006 period includes $3.2 million of interest expense allocated to discontinued operations versus $1.2 million in 2005.

Depletion, depreciation and amortization, (DD&A), increased $40.4 million, or 35%, due to higher production and higher depletion rates. DD&A increased from $1.41 per mcfe in 2005 to $1.62 per mcfe in 2006. In the fourth quarter of 2006, we lowered our salvage value estimates on our Appalachia wells which increased DD&A expense by $4.6 million. For 2007, based on our current reserve base, we expect our DD&A rate to average approximately $1.85 per mcfe. The increase in DD&A per mcfe is related to our Stroud acquisition, increasing drilling costs and the mix of our production.

Operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, exploration expense and deferred compensation plan expense. In 2006, stock-based compensation is a component of direct operating expense ($1.4 million), exploration expense ($3.1 million), general and administrative expense ($14.3 million) and a $320,000 reduction of gas transportation revenues for a total of $19.1 million. In 2005, stock-based compensation is equal to $480,000 included in direct operating, $1.2 million included in exploration expense, $4.9 million included in general and administrative expense and a reduction of $117,000 of gas transportation revenues for a total of $6.7 million. This expense represents the amortization of restricted stock grants in 2006 and 2005, expenses related to the adoption of SFAS No. 123(R) in 2006 and in 2005, the mark-to-market of SARs granted to employees. The increase in stock-based compensation in 2006 is the result of adopting SFAS No. 123(R) which requires expensing of stock options.

Exploration expense increased 49% to $44.1 million due to higher seismic costs ($2.0 million), higher dry hole costs ($8.5 million) and higher personnel costs. The following table details our exploration-related expenses (in thousands):

Exploration expenses	2006	2005	Change	%
Dry hole expense	$ 15,084	$ 6,560	$ 8,524	130%
Seismic	15,277	13,292	1,985	15%
Personnel expense	6,917	5,872	1,045	18%
Stock-based compensation expense	3,079	1,250	1,829	146%
Other	3,731	2,555	1,176	46%
Total exploration expense	$ 44,088	$ 29,529	$ 14,559	49%

Deferred compensation plan expense decreased 77%, or $22.6 million from 2005. This non-cash expense relates to the increase or decrease in value of our common stock and other investments held in our deferred compensation plans. Our common stock price increased from $13.64 per share at the end of 2004 to $26.34 per share at the end of 2005 to $27.46 per share at the end of 2006.

Income tax expense for 2006 increased $55.9 million, or 85%, over 2005 due to a 79% increase in income from continuing operations before taxes. Our effective tax rate was 39% for 2006 and was 37% for 2005. The twelve months ended December 31, 2006 includes a $2.8 million adjustment for changes in state tax rates. Given our available net operating loss carryforward, we do not expect to pay significant federal income taxes. We paid $1.8 million of state income taxes in 2006.

Discontinued operations includes the operating results and impairment losses on the Austin Chalk properties which were acquired as part of our Stroud transaction. See also Note 4 to our consolidated financial statements. Due to significant price declines subsequent to the purchase of these properties and volumes produced since the acquisition, we recognized impairment charges of $74.9 million. These properties were sold on February 13, 2007 for proceeds of $80.4 million. Discontinued operations also includes the operations results of our Gulf of Mexico properties which were sold in March 2007 for proceeds of $155.0 million.

Comparison of 2005 to 2004

Oil and gas revenue for the years ended December 31, 2005 and 2004 (in thousands) is summarized in the following table:

	2005	2004	Change	%
Revenues				
Oil wellhead	$ 156,102	$ 93,513	$ 62,589	67%
Oil hedges	(42,948)	(26,782)	(16,166)	60%
Total oil revenue	$ 113,154	$ 66,731	$ 46,423	70%
Gas wellhead	$ 461,132	$ 249,557	$ 211,575	85%
Gas hedges	(103,498)	(56,910)	(46,588)	82%
Total gas revenue	$ 357,634	$ 192,647	$ 164,987	86%
NGL	$ 31,890	$ 23,445	$ 8,445	36%
NGL hedges	(4,302)	(3,920)	(382)	10%
Total NGL revenue	$ 27,588	$ 19,525	$ 8,063	41%
Combined wellhead	$ 649,124	$ 366,515	$ 282,609	77%
Combined hedges	(150,748)	(87,612)	(63,136)	72%
Total oil and gas revenue	$ 498,376	$ 278,903	$ 219,473	79%

Average realized price received for oil and gas during 2005 was $6.13 per mcfe, up 39% or $1.72 per mcfe from 2004. Oil and gas revenues for 2005 reached a record $498.4 million and were 79% higher than 2004 due to higher oil and gas prices and a 28% increase in production. The average price received in 2005 increased 38% to $38.63 per barrel for oil and increased 39% to $6.21 per mcf for gas. The effect of our hedging program decreased realized prices $1.86 per mcfe in 2005 versus a decrease of $1.38 in 2004.

Production volumes increased 28% from 2004 due to our drilling program and additions from acquisitions consummated in 2004, primarily our purchase of the 50% of Great Lakes that we did not own and Pine Mountain. Production increased 18.0 Bcfe from 2004. Our production volumes increased 69% in our Appalachia Division, increased 14% in our Southwest Division and declined 22% in our Gulf Coast Division.

Transportation and gathering revenue of $2.3 million increased $304,000 from 2004. This increase is primarily due to higher gas prices and additional throughput volumes offset by lower oil marketing revenue.

Mark-to-market on oil and gas derivatives includes a gain of $10.9 million in 2005. In the fourth quarter of 2005, certain of our gas hedges no longer qualify for hedge accounting due to the effect of volatility of gas prices on the correlation between realized prices and hedge reference prices.

Other revenue declined in 2005 to a loss of $2.4 million from a gain of $2.2 million in 2004. The 2005 period includes ineffective hedging losses due to widening basis differentials of $3.4 million. The 2004 period includes a gain on the sale of properties of $5.0 million and $712,000 of ineffective hedging gains offset by $2.0 million write-down of an insurance claim receivable.

The following table presents information about our operating expenses that generally trend with changes in production for 2005 and 2004:

Operating expenses per mcfe	2005	2004	Change	%
Direct operating expense (excluding $0.01 per mcfe stock-based compensation in 2005)	$0.71	$0.62	$0.09	15%
Production and ad valorem tax expense	0.38	0.31	0.07	23%
General and administration expense (excluding stock-based compensation of $0.06 per mcfe in 2005)	0.35	0.32	0.03	9%
Interest expense	0.46	0.35	0.11	31%
Depletion, depreciation and amortization expense	1.41	1.27	0.14	11%

Direct operating expense (excluding stock-based compensation) increased $18.0 million to $57.4 million due to increased costs from acquisitions, higher oilfield service costs and higher workover costs primarily in our Gulf Coast Division. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $2.5 million of expenses associated with workovers in 2005 versus $1.2 million in 2004. On a per mcfe basis, direct operating expenses (excluding stock-based compensation) were $0.71 per mcfe and increased 15% or $0.09 per mcfe from 2004 consisting primarily of higher field level costs ($0.04 per mcfe).

Production and ad valorem taxes are paid based on market prices and not hedged prices. These taxes increased $11.0 million, or 55%, from the same period of the prior year. On a per mcfe basis, production and ad valorem taxes increased from $0.31 per mcfe to $0.38 per mcfe due to higher market prices.

General and administrative expense (excluding stock-based compensation) for 2005 increased 42%, or $8.5 million, from 2004 with additional personnel costs due to the Great Lakes and Pine Mountain acquisitions ($1.8 million), higher salaries and benefits ($3.5 million), higher legal expenses ($1.3 million) and a $725,000 legal settlement accrual. On a per mcfe basis, general and administration expense (excluding stock-based compensation) increased 9% from $0.32 per mcfe in 2004 to $0.35 per mcfe in 2005.

Interest expense for 2005 increased $15.2 million, or 68%, to $37.6 million with higher average interest rates, higher average debt balances and the refinancing of certain debt from short-term floating to longer-term fixed rates. In March 2005, we issued $150.0 million of 6.375% senior subordinated notes which added $7.8 million of interest costs. The proceeds from this issuance were used to retire lower interest bank debt. Average debt outstanding on the bank credit facility was $314.8 million and $296.6 million for 2005 and 2004, respectively, and the average interest rates were 4.3% and 3.5%, respectively. The 2005 period includes $1.2 million of interest expense allocated to discontinued operations versus $700,000 in 2004.

Depletion, depreciation and amortization (DD&A) increased $33.7 million, or 42%, due to higher production and higher depletion rates. DD&A increased from $1.27 per mcfe in 2004 to $1.41 per mcfe in 2005.

Operating expenses also include stock-based compensation, exploration expense and non-cash compensation expense that generally do not trend with production. In 2005, stock-based compensation expense is a component of direct operating expense ($480,000), exploration expense ($1.2 million) and general and administrative expense ($4.9 million). This expense represents the amortization of restricted stock grants and the market-to-market of SARs granted to employees. In 2004, stock-based compensation is a component of exploration expense ($24,000) and general and administrative expense ($541,000).

Exploration expense increased 134% to $29.5 million due to higher seismic costs ($10.1 million), higher personnel costs, higher stock-based compensation expense ($1.2 million) and higher dry hole costs ($2.9 million).

Exploration expenses	2005	2004	Change	%
Dry hole expense	$ 6,560	$ 3,703	$ 2,857	77%
Seismic	13,292	3,155	10,137	321%
Personnel expense	5,872	4,427	1,445	33%
Stock-based compensation expense	1,250	24	1,226	5,108%
Other	2,555	1,310	1,245	95%
Total exploration expense	$ 29,529	$ 12,619	$ 16,910	134%

Deferred compensation plan expense increased 54%, or $10.3 million, from 2004. This non-cash expense relates to the increase in value of our common stock and other investments held in our deferred compensation plans. Our common stock price increased from $13.64 per share at the end of 2004 to $26.34 per share at the end of 2005.

Tax expense for 2005 increased $40.8 million, or 163%, over 2004 due to a 158% increase in income from continuing operations before taxes. Our effective tax rate for 2005 and 2004 was 37%. Given our available net operating loss carryforward, we do not expect to pay significant federal income taxes.

Management s Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

During 2006, our cash provided from continuing operations was $442.4 million, and we spent $888.8 million on capital expenditures (including acquisitions). During this period, financing activities provided net cash of $429.4 million. Our financing activities included the sale of $250.0 million of 7.5% senior subordinated notes and additional borrowings under our bank credit agreement. At December 31, 2006 we had $2.4 million in cash, total assets of $3.2 billion and a debt-to-capitalization ratio of 45.5%. Long-term debt at December 31, 2006 totaled $1.0 billion, including $452.0 million of bank debt and $596.8 million of senior subordinated notes. Available borrowing capacity under the bank credit facility at December 31, 2006 was $348.0 million.

Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves which is typical in the oil and gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We believe that net cash generated from operating activities and unused committed borrowing capacity under the bank credit facility combined with our oil and gas price hedges currently in place will be adequate to satisfy near term financial obligations and liquidity needs. However, long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. A material drop in oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proved reserves.

Bank Debt

We maintain an $800.0 million revolving credit facility, which we refer to as our bank debt or our bank credit facility. The bank credit facility is secured by substantially all of our assets and matures on October 25, 2011. Availability under the bank credit facility is subject to a borrowing base set by the banks semi-annually with an option to set more often in certain circumstances. The borrowing base is dependent on a number of factors, primarily the lenders assessment of future cash flows. Redeterminations of the borrowing base require approval of 75% of the lenders; increases require unanimous approval. At February 22, 2007, the bank credit facility had a $1.2 billion borrowing base and an $800.0 million facility amount. Credit availability is equal to the lesser of the facility amount or the borrowing base resulting in credit availability of $287.0 million on February 20, 2007. The facility amount can be increased to the borrowing base with twenty days notice.

Limitations on the payment of dividends and other restricted payments as defined are imposed under our bank debt and our subordinated notes. Under the bank credit facility, common and preferred dividends are permitted. The terms of each of our subordinated notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings and equity issuances since the original issuances of the notes. At December 31, 2006, approximately $496.2 million was available under the restricted payment baskets for each of our subordinated notes. The bank credit facility provides for a restricted payment basket of $20.0 million plus 66-2/3% of net cash proceeds from common stock issuances and 50% of net income. Approximately $446.4 million was available under the bank credit facility restricted payment basket as of December 31, 2006. The debt agreements contain customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2006.

Cash Flow

Our principal sources of cash are operating cash flow, bank borrowings and at times, issuance of debt and equity securities. Our operating cash flow is highly dependent on oil and gas prices. As of December 31, 2006, we had entered into hedging agreements covering 84.9 Bcfe and 71.7 Bcfe for 2007 and 2008. The $528.7 million of cash capital expenditures for 2006, excluding acquisitions, was funded with internal cash flow and borrowing under the bank credit facility. The $698.0 million capital budget for 2007, which excludes acquisitions, is expected to increase production and to expand the reserve base. Based on current projections, oil and gas futures prices and our hedge position, the 2007 capital program is expected to be funded with internal cash flow and asset sales.

Net cash provided from continuing operations in 2006 was $442.4 million, compared with $288.6 million in 2005 and $167.0 million in 2004. In 2006, cash flow from continuing operations increased due to higher production volumes and higher realized prices partially offset by increasing operating costs. In 2005, cash flow from operations increased due to higher production volumes and prices partially offset by increasing operating, exploration and interest expenses. In 2004, cash flow from operations increased due to higher volumes and prices partially offset by increasing operating costs.

Net cash used in investing activities in 2006 was $911.7 million, compared with $432.4 million in 2005 and $624.3 million in 2004. In 2006, we spent $493.2 million in additions to oil and gas properties and $360.1 million on acquisitions. The 2005 period included $266.4 million in additions to oil and gas properties and $153.6 million of acquisitions. The 2004 period included $154.6 million in additions to oil and gas properties and $485.6 million of acquisitions.

Net cash provided from financing activities in 2006 was $429.4 million compared with $93.0 million in 2005 and $432.8 million in 2004. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. During 2006, we received proceeds of $249.5 million from the issuance of our 7.5% Notes. During 2005, we received proceeds of $150.0 million and $109.2 million from the issuance of our 6.375% Notes and a common stock offering. During 2005, the outstanding balance under our bank credit facility declined $154.7 million primarily due to the proceeds received from the 6.375% Notes being applied to our bank debt. During 2004, we received proceeds of $98.1 million and $246.1 million from the issuance of additional 7.375% Notes and two common stock offerings, respectively. During 2004, the outstanding balance under our bank credit facility increased $245.7 million with $70.0 million related to the Great Lakes acquisition and the remaining increase the result of funding other acquisitions. Also in 2004, we redeemed the remaining outstanding 6% Debentures for $11.6 million.

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of oil and gas properties, repayment of principal and interest on outstanding debt and payment of dividends. During 2006, $493.2 million of capital was expended on drilling projects. Also in 2006, $360.1 million was expended on acquisitions primarily to purchase producing properties. The capital program, excluding acquisitions, was funded by net cash flow from operations and borrowings under our credit facility and our acquisitions were funded primarily with proceeds received from the issuance of our 7.5% Notes and borrowings under our credit facility. The 2007 capital budget of $698.0 million, excluding acquisitions, is expected to be funded by cash flow from operations and asset sales. In February 2007, we sold the Austin Chalk properties for proceeds of $80.4 million. Development and exploration activities are highly discretionary, and, for the foreseeable future, we expect such activities to be maintained at levels equal to internal cash flow and asset sales. To the extent capital requirements exceed internal cash flow and proceeds from asset sales, debt or equity may be issued to fund these requirements. The Stroud acquisition included the issuance of 6.5 million shares and the assumption of $106.7 million of debt. We currently believe we have sufficient liquidity and cash flow to meet our obligations for the next twelve months; however, a drop in oil and gas prices or a reduction in production or reserves could adversely affect our ability to fund capital expenditures and meet our financial obligations. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

Cash Dividend Payments

The amount of future dividends is subject to declaration by the board of directors and depends on earnings, capital expenditures and various other factors, such as restrictions under our bank debt and our subordinated notes. In 2006, we paid $12.2 million in dividends to our common shareholders ($0.03 per share in the fourth quarter and $0.02 per share in the third, second and first quarters). In 2005, we paid $7.6 million in dividends to our common stockholders ($0.02 per share in the fourth quarter and $0.0133 per share in the third, second and first quarters). In 2004, we paid $3.2 million in dividends to our common stockholders ($0.0067 per share in the second and third quarters and $0.0133 per share in the fourth quarter). Also in 2005 and 2004, we paid $2.2 million and $2.9 million in preferred stock dividends.

Future Commitments

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. As of December 31, 2006, we do not have any capital leases nor have we entered into any material long-term contracts for equipment. As of December 31, 2006, we do not have any off-balance sheet debt or other such unrecorded obligations and we have not guaranteed the debt of any other party. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2006. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2006 reflects accrued interest payable on our bank debt of $925,000 which is payable in January 2007. We expect to make annual interest payments of $14.8 million per year on our 7.375% Notes, $18.8 million per year on our 7.5% Notes and payments of $9.6 million per year on our 6.375% Notes.

The following summarizes our contractual financial obligations at December 31, 2006 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under the bank credit facility and proceeds from asset sales proceeds.

	Payment due by period				
	2007	2008 and 2009	2010 and 2011	Thereafter	Total
	(in thousands)				
Bank debt due 2011	$	$	$ 452,000(a)	$	$ 452,000
7.375% senior subordinated notes due 2013				200,000	200,000
6.375% senior subordinated notes due 2015				150,000	150,000
7.5% senior subordinated notes due 2016				250,000	250,000
Operating leases	5,010	10,236	6,431	9,610	31,287
Drilling contracts	12,830	2,160			14,990
Service contracts	1,794	3,705	2,754		8,253
Derivative obligations (b)	4,621	266			4,887
Asset retirement obligation liability	4,216	8,651	8,423	74,298	95,588
Total contractual obligations (c)	$ 28,471	$ 25,018	$ 469,608	$ 683,908	$ 1,207,005

(a) Due at termination date of our bank credit facility, which we expect to renew, but there is no assurance that can be accomplished. Interest paid on our bank credit facility would be approximately $28.9 million each year assuming no change in the interest rate or outstanding balance.

(b) Derivative obligations

represent net open derivative contracts valued as of December 31, 2006.

(c) This table does not include the liability for the deferred compensation plans since these obligations will be funded with existing plan assets.

Hedging Oil and Gas Prices

We enter into derivative agreements to reduce the impact of oil and gas price volatility on our operations. At December 31, 2006, swaps were in place covering 73.6 Bcf of gas at prices averaging $9.29 per mcf. We also had collars covering 56.1 Bcf of gas at weighted average floor and cap prices of $7.42 to $10.49 and 4.5 million barrels of oil at weighted average floor and cap prices of $55.72 to $70.11. The derivative fair value, represented by the estimated amount that would be realized or payable on termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a pretax gain of $149.8 million at December 31, 2006. The contracts expire monthly through December 2008. Transaction gains and losses are determined monthly and are included as increases or decreases on oil and gas revenue in the period the hedged production is sold. Realized hedging losses of $46.5 million were recognized in 2006 compared to losses of $171.1 million in 2005 and losses of $100.1 million in 2004. Changes in the value of the ineffective portion of all open hedges are recognized in earnings quarterly in other revenue. Unrealized effective gains and losses on hedging positions are recorded at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX, on our consolidated balance sheet as other comprehensive income (OCI) a component of stockholders equity. As of the fourth quarter of 2005, certain of our gas hedges no longer qualify for hedge accounting due to the effect of volatility of gas prices in the fourth quarter of 2005 and on the correlation between realized prices and hedge reference prices. These derivatives were marked-to-market in the amount of a gain of $10.9 million in the fourth quarter of 2005 and as a gain of $86.5 million in the year December 31, 2006.

At December 31, 2006, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2007	Swaps	96,336 Mmbtu/day	$ 9.13
2007	Collars	98,500 Mmbtu/day	$ 7.13 - $9.99
2008	Swaps	105,000 Mmbtu/day	$ 9.42
2008	Collars	55,000 Mmbtu/day	$ 7.93 - $11.39
Crude Oil			
2007	Collars	6,300 bbl/day	$ 53.46 - $65.33
2008	Collars	6,000 bbl/day	$ 58.09 - $75.11

Interest Rates

At December 31, 2006, we had $1.0 billion of debt outstanding. Of this amount, $600.0 million bears interest at fixed rates averaging 7.2%. Bank debt totaling $452.0 million bears interest at floating rates, which averaged 6.4% at year-end 2006. The 30-day LIBOR rate on December 31, 2006 was 5.3%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2006 would cost us approximately $4.5 million in additional annual interest.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance liquidity and capital resource position, or for any other purpose.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and accelerated during 2005 and 2006, commodity prices for oil and gas increased significantly. The higher prices have led to increased activity in the industry and, consequently, rising costs. These costs trends have put pressure not only on our operating costs but also on our capital costs. We expect further increases in these costs for 2007.

The following table indicates the average oil and gas prices received over the last five years and quarterly for 2006, 2005 and 2004. Average price calculations exclude hedging gains and losses. Oil is converted to natural gas equivalent at the rate of one barrel equals six mcfe.

	Average Prices (Excluding Hedging)			Average NYMEX Prices [(a)]	
	Oil (Per bbl)	Natural Gas (Per mcf)	Equivalent Mcf (Per mcfe)	Oil (Per bbl)	Natural Gas (Per mcf)
Annual					
2006	$62.36	$ 6.59	$ 7.25	$ 66.22	$ 7.26
2005	53.30	8.00	7.99	56.56	8.55
2004	39.20	5.80	5.79	41.42	6.09
2003	28.23	5.03	4.85	31.04	5.44
2002	23.16	3.02	3.16	26.08	3.25
Quarterly					
2006					
First	$59.74	$ 8.33	$ 8.41	$ 63.48	$ 9.07
Second	65.36	6.28	7.17	70.70	6.82
Third	64.53	6.12	7.00	70.48	6.53
Fourth	59.80	5.91	6.58	60.21	6.62
2005					
First	$47.01	$ 5.98	$ 6.25	$ 49.84	$ 6.32
Second	48.72	6.41	6.65	53.17	6.80
Third	59.94	7.88	8.16	63.19	8.25
Fourth	56.38	11.30	10.54	60.02	12.85
2004					
First	$31.95	$ 5.20	$ 5.06	$ 35.15	$ 5.69
Second	35.76	5.51	5.43	38.32	5.97
Third	41.01	5.60	5.72	43.88	5.84
Fourth	45.76	6.66	6.71	48.23	6.87

(a) Based on average of bid week prompt month prices.

Management s Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

Oil and Gas Properties

Proved reserves are defined by the SEC as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in the depletion rates utilized by us. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Vice President of Reservoir Engineering who reports directly to our Chief Operating Officer. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to review our estimates of proved reserves. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%.

The following table sets forth a summary of the percent of reserves which were reviewed by independent petroleum consultants for each of the years ended 2006, 2005 and 2004.

	Audited [a]	
2006	2005	2004
87%	84%	88%

(a) Audited reserves are those reserves estimated by our employees and reviewed by an independent petroleum consultant.

We utilize the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration drilling costs are expensed and can have a significant effect on reported operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and gas reserves as estimated by our engineers and reviewed by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Otherwise, well costs are expensed if a determination as to whether proved reserves were found cannot be made within one year following completion of drilling and these criteria are not met. Proven property leasehold costs are charged to expense using the units of production method based on total proved reserves. Unproved properties are assessed periodically (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

We adhere to the Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated (at least annually) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider a combination of time, geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $226.3 million in 2006 compared to $28.6 million in 2005 and $14.8 million in 2004.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. Estimated reserves are used as the basis for calculating the expected future cash flows from a property, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to oil and gas producing activities and reserve quantities in Note 19, Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities to our consolidated financial statements. Changes in the estimated reserves are considered in estimates for accounting purposes and are reflected on a prospective basis.

We monitor our long-lived assets recorded in property, plant and equipment in our consolidated balance sheet to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustment to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts, environmental regulations or tax laws. All of these factors must be considered when testing a property s carrying value for impairment. We cannot predict whether impairment charges may be required in the future.

We are required to develop estimates of fair value to allocate purchase prices paid to acquire businesses to the assets acquired and liabilities assumed under the purchase method of accounting. The purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. We use all available information to make these fair value determinations. See Note 3 to the consolidated financial statements for information on these acquisitions.

Derivatives

We use commodity derivative contracts to manage our exposure to oil and gas price volatility. We account for our commodity derivatives in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. For derivative contracts designated as hedges, earnings are affected by the ineffective portion of a hedge contract (changes in realized prices that do not match the changes in the hedge price). Ineffective gains or losses are recorded in other revenue while the hedge contract is open and may increase or reverse until settlement of the contract. This may result in significant volatility to current period income. For derivatives qualifying as hedges, the effective portion of any changes in fair value is recognized in stockholders equity as other comprehensive income (OCI), and then reclassified to earnings, in oil and gas revenue, when the hedged transaction is consummated. This may result in significant volatility in stockholders equity. The fair value of open hedging contracts is an estimated amount that could be realized upon termination. As of the fourth quarter of 2005, certain of our gas hedges no longer qualify for hedge accounting due to the volatility of gas prices and their effect on our basis differentials and are marked-to-market.

The commodity derivatives we use include commodity collars and swaps. While there is a risk that the financial benefit of rising prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation, (ARO), a corresponding adjustment is made to the oil and gas property balance. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in our consolidated statement of operations.

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit which can take years to complete and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized.

In determining deferred tax liabilities, accounting rules require OCI to be considered, even though such income or loss has not yet been earned. At year-end 2005, deferred tax liabilities exceeded deferred tax assets by $113.1 million, with $85.5 million of deferred tax assets related to unrealized deferred hedging losses included in OCI. At year-end 2006, deferred tax liabilities exceeded deferred tax assets by $468.6 million, with $21.3 million of deferred tax liabilities related to unrealized hedging gains included in OCI.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities.

Accounting Standards Not Yet Adopted

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. For Range, SFAS No. 157 will be effective January 1, 2008, with early application permitted. We are currently evaluating the provisions of this statement.

In July 2006, FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109 was issued. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods and disclosure. For Range, the provisions of FIN 48 are effective January 1, 2007. The cumulative effect of adopting FIN 48 will be recorded in retained earnings. Range is currently evaluating the provisions of FIN 48 to determine the impact on its consolidated financial statements but we do not expect a material impact on our financial position or results of operations.

RANGE RESOURCES CORPORATION
INDEX TO FINANCIAL STATEMENTS

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our financial statements and financial statement schedules are set forth at pages F-2 through F-37 inclusive.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Range Resources Corporation:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity, comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits 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 consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Range Resources Corporation at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, in 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), Share-Based Payment.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2007 expressed an unqualified opinion thereon.

Ernst & Young LLP
Fort Worth, Texas
February 26, 2007, except for Note 4 and 17 as to
which the date is June 18, 2007

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except per share data)

	December 31, 2006	December 31, 2005
Assets		
Current assets:		
Cash and equivalents	$ 2,382	$ 4,750
Accounts receivable, less allowance for doubtful accounts of $746 and $624	125,421	123,875
Assets held for sale	79,304	
Assets of discontinued operation	78,161	5,670
Unrealized derivative gain	93,588	425
Deferred tax asset		61,677
Inventory and other	10,069	11,580
Total current assets	388,925	207,977
Unrealized derivative gain	61,068	
Equity method investment	13,618	
Oil and gas properties, successful efforts method	3,359,093	2,284,313
Accumulated depletion and depreciation	(751,005)	(604,720)
	2,608,088	1,679,593
Transportation and field assets	80,066	65,210
Accumulated depreciation and amortization	(32,923)	(25,966)
	47,143	39,244
Assets of discontinued operation		61,589
Other assets	68,832	30,582
Total assets	$ 3,187,674	$ 2,018,985
Liabilities		
Current liabilities:		
Accounts payable	$ 171,914	$ 113,503
Asset retirement obligations	3,853	3,121
Accrued liabilities	30,026	26,043
Liabilities of discontinued operation	28,333	8,778
Accrued interest	12,938	10,214
Unrealized derivative loss	4,621	160,101
Total current liabilities	251,685	321,760

Bank debt	452,000	269,200
Subordinated notes	596,782	346,948
Deferred tax, net	468,643	174,817
Unrealized derivative loss	266	70,948
Deferred compensation liability	90,094	73,492
Asset retirement obligations	72,043	53,443
Liabilities of discontinued operation		11,454
Commitments and contingencies		
Stockholders Equity		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par, 250,000,000 shares authorized, 138,931,565 issued at December 31, 2006 and 129,913,046 issued at December 31, 2005	1,389	1,299
Common stock held in treasury 5,826 shares at December 31, 2005		(81)
Additional paid-in capital	1,079,994	845,519
Retained earnings	160,313	13,800
Common stock held by employee benefit trust, 1,853,279 and 1,971,605 shares, respectively, at cost	(22,056)	(11,852)
Deferred compensation		(4,635)
Accumulated other comprehensive income (loss)	36,521	(147,127)
Total stockholders equity	1,256,161	696,923
Total liabilities and stockholders equity	$ 3,187,674	$ 2,018,985

See accompanying notes.

F-3

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31, 2006	2005	2004
Revenues			
Oil and gas sales	$ 649,078	$ 498,376	$ 278,903
Transportation and gathering	2,422	2,306	2,002
Mark-to-market on oil and gas derivatives	86,491	10,868	
Other	6,821	(2,447)	2,163
Total revenue	744,812	509,103	283,068
Costs and expenses			
Direct operating	81,261	57,866	39,419
Production and ad valorem taxes	36,415	30,822	19,845
Exploration	44,088	29,529	12,619
General and administrative	49,886	33,444	20,634
Deferred compensation plan	6,873	29,474	19,176
Interest expense	55,849	37,619	22,437
Depletion, depreciation and amortization	154,739	114,364	80,628
Total costs and expenses	429,111	333,118	214,758
Income from continuing operations before income taxes	315,701	175,985	68,310
Income tax provision (benefit)			
Current	1,912	1,071	(245)
Deferred	119,840	64,809	25,327
	121,752	65,880	25,082
Income from continuing operations	193,949	110,105	43,228
Income (loss) from discontinued operations, net of taxes	(35,247)	906	(997)
Net income	158,702	111,011	42,231
Preferred dividends			(5,163)
Net income available to common stockholders	$ 158,702	$ 111,011	$ 37,068
Earnings per common share:			
Basic income from continuing operations	$ 1.45	$ 0.89	$ 0.41

discontinued operations		(0.26)				(0.01)
net income	$	1.19	$	0.89	$	0.40
Diluted income from continuing operations	$	1.39	$	0.85	$	0.39
discontinued operations		(0.25)		0.01		(0.01)
net income	$	1.14	$	0.86	$	0.38

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2006	**2005**	**2004**
Operating activities:			
Net income	$ 158,702	$ 111,011	$ 42,231
Adjustments to reconcile net cash provided from operating activities:			
(Income) loss from discontinued operations	35,247	(906)	997
Gain from equity method investment	(548)		
Deferred income tax expense	119,840	64,809	25,327
Depletion, depreciation and amortization	154,738	114,364	80,627
Exploration dry hole costs	15,085	6,559	1,100
Mark-to-market on oil and gas derivatives gains	(86,491)	(10,868)	
Unrealized derivative (gains) losses	(5,654)	3,505	(1,793)
Allowance for bad debts	80	675	1,762
Amortization of deferred financing costs and discount	1,827	1,662	1,071
Non-cash compensation	27,455	37,391	20,667
(Gain) loss on sale of assets and other	940	(512)	(3,109)
Changes in working capital, net of amounts from business acquisitions:			
Accounts receivable	30,286	(64,333)	(38,741)
Inventory and other	(1,157)	(3,452)	(6,080)
Accounts payable	(5,049)	27,472	34,746
Accrued liabilities and other	(2,949)	1,219	8,162
Net cash provided from continuing operations	442,352	288,596	166,967
Net cash provided from discontinued operations	37,523	37,149	42,282
Net cash provided from operating activities	479,875	325,745	209,249
Investing activities:			
Additions to oil and gas properties	(493,236)	(266,396)	(154,612)
Additions to field service assets	(14,449)	(11,310)	(4,237)
Acquisitions, net of cash acquired	(360,149)	(153,600)	(485,564)
Investing activities of discontinued operations	(23,204)	(10,511)	(11,948)
Investment in equity method affiliate and other assets	(21,009)		
Proceeds from disposal of assets and other repayments	388	9,440	32,060
Net cash used in investing activities	(911,659)	(432,377)	(624,301)
Financing activities:			
Borrowings on credit facilities	802,500	299,000	634,578
Repayments on credit facilities	(619,700)	(453,700)	(528,878)
Issuance of subordinated notes	249,500	150,000	98,125

Treasury stock purchases		(2,808)	
Dividends paid common stock	(12,189)	(7,614)	(3,219)
preferred stock		(2,213)	(2,950)
Debt issuance costs	(6,960)	(4,119)	(3,630)
Issuance of common stock	16,265	114,470	250,460
Other debt repayments		(16)	(11,683)
Net cash provided from financing activities	429,416	93,000	432,803
Net increase (decrease) in cash and equivalents	(2,368)	(13,632)	17,751
Cash and equivalents at beginning of year	4,750	18,382	631
Cash and equivalents at end of year	$ 2,382	$ 4,750	$ 18,382

See accompanying notes.

F-5

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In thousands)

	Preferred stock		Common stock		Treasury	Additional	Retained	Stock held by	Deferred	Accumulate other
	Shares	Par Value	Shares	Par Value	common stock	paid-in capital	earnings (deficit)	employee benefit trust	compensatio	omprehens (loss)/gain
mber 31, 2003	1,000	$ 50,000	84,616	$ 846	$	$ 399,380	$ (124,011)	$ (8,441)	$ (856)	$ (42,852
ends ($5.16 per share)							(5,163)			
mmon stock			28,390	284		258,171		255	(401)	
ends ($0.0267 per share)							(2,654)			
securities	(1,000)	(50,000)	8,823	88		49,912				
ensive loss										(449
							42,231			
mber 31, 2004			121,829	1,218		707,463	(89,597)	(8,186)	(1,257)	(43,301
mmon stock			8,084	81		138,056		(3,666)	(3,378)	
ends ($0.0599 per share)							(7,614)			
purchases					(2,808)					
issuances					2,727					
ensive loss										(103,826
							111,011			
mber 31, 2005			129,913	1,299	(81)	845,519	13,800	(11,852)	(4,635)	(147,127
mmon stock			9,018	90		234,475		(10,204)	4,635	
ends ($0.09 per share)							(12,189)			
issuances					81					

ensive gain										183,648
						158,702				
mber 31, 2006	**$**	**138,931**	**$ 1,389**	**$**	**$ 1,079,994**	**$ 160,313**	**$ (22,056)**	**$**	**$**	**36,521**

See accompanying notes.

F-6

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	Year Ended December 31,		
	2006	**2005**	**2004**
Net income	$ 158,702	$ 111,011	$ 42,231
Net deferred hedging gains (losses), net of tax:			
Contract settlements reclassified to income	29,302	101,209	63,633
Change in unrealized deferred hedging gains (losses)	152,294	(206,348)	(64,477)
Change in unrealized gains on securities held by deferred compensation plan, net of taxes	2,052	1,313	395
Comprehensive income	$ 342,350	$ 7,185	$ 41,782

See accompanying notes

RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation (Range, we, us, or our) is engaged in the exploration, development and acquisitio of oil and gas properties primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We seek to increase our reserves and production primarily through drilling and complementary acquisitions. Prior to June 2004, we held our Appalachian oil and gas assets through a 50% owned joint venture, Great Lakes Energy Partners L.L.C. or Great Lakes. In June 2004, we purchased the 50% of Great Lakes that we did not own. Range is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of all of our subsidiaries. The statement of operations for the year ended December 31, 2004 includes 50% of the revenues and expenses of Great Lakes up to June 23, 2004 and 100% thereafter. Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting and are carried at our share of net assets plus loans and advances. Income from equity method investments represents our proportionate share of income generated by equity method investees and is included in other revenues on our consolidated statement of operations. All material intercompany balances and transactions have been eliminated.

In accordance with the provisions related to discontinued operations within SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the accompanying consolidated financial statements and notes reflect the results of operations, financial position and cash flows of the following components as discontinued operations. See also Note 3 and 4.

Austin Chalk properties

Gulf of Mexico properties

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. Actual results could differ from the estimates and assumptions used.

Income per Common Share

Basic net income per share is calculated based on the weighted average number of common shares outstanding. Diluted net income per share assumes issuance of stock compensation awards and conversion of convertible debt and preferred securities, provided the effect is not antidilutive. All common stock shares and per share amounts in the accompanying financial statements have been adjusted for the three-for-two stock split effected on December 2, 2005.

Business Segment Information

The Financial Accounting Standards Board (FASB), Statement of Financial Accounting Standards (SFAS) No. 131, Disclosure About Segments of an Enterprise and Related Information, establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance.

Segment reporting is not applicable to us as we have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we allocate capital resources on a project-by-project basis, across our entire asset base to maximize profitability without regard to individual areas or segments.

Revenue Recognition and Gas Imbalances

Oil, gas and natural gas liquids revenues are recognized when the products are sold and delivery to the purchaser has occurred. Although receivables are concentrated in the oil and gas industry, we do not view this as unusual credit risk. We provide for an allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit. We have allowances for doubtful accounts relating to exploration and production receivables of $745,900 at December 31, 2006 compared to $623,800 at December 31, 2005.

We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of the gas produced. A liability is recognized when the imbalance exceeds the estimate of remaining reserves. Gas imbalances at December 31, 2006 and December 31, 2005 were not significant. At December 31, 2006, we had recorded a net liability of $441,200 for those wells where it was determined that there was insufficient reserves to recover the imbalance situation.

Cash and Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less.

Marketable Securities

Holdings of equity securities qualify as available-for-sale or trading and are recorded at fair value.

Inventories

Inventories consist primarily of tubular goods used in our operations and are stated at the lower of specific cost of each inventory item or market value.

Oil and Gas Properties

We follow the successful efforts method of accounting for oil and gas producing activities. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Well costs are expensed if a determination as to whether proved reserves were found cannot be made within one year. The status of suspended well costs is monitored continuously and reviewed not less than quarterly. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Oil and NGLs are converted to gas equivalent basis or mcfe at the rate one barrel equals 6 mcf. The depletion, depreciation and amortization (DD&A) rates were $1.62 per mcfe in 2006 compared to $1.41 per mcfe in 2005 and $1.27 per mcfe in 2004. Depletion is provided on the units of production method. Unproved properties had a net book value of $226.3 million at December 31, 2006 compared to $28.6 million at December 31, 2005 and $14.8 million at December 31, 2004. The increase in unproved properties in 2006 is primarily related to our Stroud acquisition completed in 2006. Unproved properties are reviewed quarterly for impairment and impaired if conditions indicate we will not explore the acreage prior to expiration or the carrying value is above fair value.

Our long-lived assets are reviewed for impairment periodically for events or changes in circumstances that indicate that the carrying amount of an asset may not be recoverable. Long-lived assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop proved reserves. Expected future cash inflow from the sale of production of reserves is calculated based on estimated future prices. We estimate prices based upon market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value, (as determined by discounted future net cash flows) and the carrying value of the asset. In the third quarter of 2006, we recorded in discontinued operations a $2.4 million impairment on an offshore property due to declining oil and gas prices. In the fourth quarter of 2006, we lowered our salvage value estimates on our Appalachia wells which increased DD&A expense by $4.6 million.

Proceeds from the disposal of miscellaneous properties are credited to the net book value of their amortization group with no immediate effect on income. However, gain or loss is recognized from the sale of less than an entire amortization group if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

Transportation and Field Assets

Our gas transportation and gathering systems are generally located in proximity to certain of our principal fields. Depreciation on these systems is provided on the straight-line method based on estimated useful lives of 10 to 15 years. We receive third-party income for providing certain transportation and field services which is recognized as earned. Depreciation on the associated assets is calculated on the straight-line method based on estimated useful lives ranging from five to seven years. Buildings are depreciated over 10 to 15 years. Depreciation expense was $7.5 million in 2006 compared to $6.4 million in 2005 and $4.7 million in 2004.

Other Assets

The expenses of issuing debt are capitalized and included in other assets on our consolidated balance sheet. These costs are amortized over the expected life of the related instruments. When a security is retired prior to maturity or modifications significantly change the cash flows, related unamortized costs are expensed. Other assets at December 31, 2006 include $13.4 million of unamortized debt issuance costs, $44.2 million of marketable securities held in our deferred compensation plans and $9.0 million of other investments.

Stock-based Compensation

The 2005 Equity Based Compensation Plan (the 2005 Plan) authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights, restricted stock awards, and phantom stock rights to employees. The Non-Employee Director Stock Plan (the Director Plan) allows grants to our non-employee directors of our Board of Directors. The 2005 Plan was approved by shareholders in May 2005 and replaces our 1999 stock option plan. No new grants will be made from the 1999 stock option plan. The number of shares that may be issued under the 2005 Plan is equal to (i) 5.6 million shares (15.0 million less the 2.2 million shares issued under the 1999 Stock Options Plan prior to May 18, 2005, the effective date of the 2005 Plan and less the 7.2 million shares issuable pursuant to awards under the 1999 Stock Option Plan outstanding as of the effective date of the 2005 Plan) plus (ii) the number of shares subject to 1999 Stock Option Plan awards outstanding at May 18, 2005, that subsequently lapse or terminate without the underlying shares being issued. The Director Plan was approved by shareholders in May 2004 and no more than 300,000 shares of common stock may be issued under the Plan.

Stock options represent the right to purchase shares of stock in the future at the fair market value of the stock on the date of grant. Most stock options granted under our stock option plans vest over a three year period and expire five years from the date they are granted. Similar to stock options, stock appreciation rights (SARs), represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the value of the stock on the date of grant. All SARs granted under the 2005 Plan will be settled in shares of stock, vest over a three year period and have a maximum term of five years from the date they are granted. We began issuing SARs in 2005 instead of options to reduce the dilution impact of our equity compensation plans.

The Compensation Committee grants restricted stock to certain employees and to non-employee directors of the Board of Directors as part of their compensation. Compensation expense is recognized over the balance of the vesting period.

Prior to January 1, 2006, we accounted for stock options granted under our stock-based compensation plans under the recognition and measurement provisions of APB Opinion No. 25, Accounting for Stock Issued to Employees and related Interpretations, as permitted by SFAS No. 123, Accounting for Stock-Based Compensation. For our stock options, no stock-based compensation expense was recognized in our statements of operations prior to January 1, 2006, as all stock options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R), Share-Based Payment, using the modified prospective transition method. Under this transition method, compensation cost for stock options and stock appreciation rights recognized in 2006 includes (a) compensation cost ($11.2 million) for all stock-based payments granted prior to, but not yet vested as of December 31, 2005, based on the remaining service period and the grant date fair value estimated in accordance with the original provisions of Statement No. 123 and (b) compensation cost ($3.7 million) for all stock-based payments granted subsequent to December 31, 2005, based on the service period (on a straight line basis) and the grant-date fair value estimated in accordance with SFAS No. 123(R). Pursuant to SFAS No. 123(R), results for prior periods have not been restated. In 2006, stock based compensation has been allocated to direct operating expense ($1.4 million), exploration expense ($2.5 million), general and administrative expense ($10.7 million) and a $303,000 reduction to transportation and gathering revenues to align SFAS No. 123(R) expense with the employee s cash compensation.

We also began granting stock-settled SARs in July 2005 as part of our stock-based compensation plans to reduce the dilutive impact of our equity plans. Prior to January 1, 2006, we accounted for these SARs grants under the recognition and measurement provisions of APB Opinion No. 25, which required expense to be recognized equal to the amount by which the quoted market value exceeded the original grant price on a mark-to-market basis. Therefore, we recognized $5.8 million of compensation cost in the last six months of 2005 related to SARs. In order to present stock-based compensation expense on a consistent basis, the $5.8 million of 2005 SARs related expense has been allocated to direct operating expense ($480,000), exploration expense ($1.2 million), general and administrative expense ($4.0 million) and a $117,000 reduction to transportation and gathering revenues. Beginning January 1, 2006, as required under the provisions of SFAS No. 123(R), those SARs granted prior to, but not yet vested as of December 31, 2005, are being expensed over the service period based on grant date fair value estimated in accordance with the original provisions of SFAS No. 123 and all SARs granted subsequent to December 31, 2005 are being expensed over the service period (on a straight-line basis) based on grant-date fair value estimated in accordance with SFAS No. 123(R).

As a result of adopting SFAS No. 123(R) on January 1, 2006, our income from continuing operations before income taxes and net income for 2006 is $18.2 million and $11.5 million lower, respectively, than if we had continued to account for stock-based compensation under APB Opinion No. 25. Also, as a result of adopting SFAS No. 123(R), our December 31, 2005 unearned deferred compensation and additional paid-in capital related to our restricted stock issuances was eliminated. As of December 31, 2006, there was $12.4 million of unrecognized compensation related to restricted stock awards expected to be recognized over the next 3 years.

The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provisions of SFAS No. 123(R) to options and SARs granted under our stock-based compensation plans in 2005 and 2004. For the purposes of this pro forma disclosure, the value is estimated using a Black-Scholes-Merton option-pricing formula and expensed over the option s vesting periods.

	Year Ended December 31, 2005	2004
	(in thousands, except per share data)	
Net income as reported	$ 111,011	$ 42,231
Add: Total stock-based employee compensation expense included in net income, net of tax	23,556	13,020
Deduct: Total stock-based employee compensation expense determined under fair value based method, net of tax	(29,235)	(17,114)
Pro forma net income	$ 105,332	$ 38,137
Earnings per share:		
Basic as reported	$ 0.89	$ 0.40
Basic pro forma	0.85	0.35
Diluted as reported	0.86	0.38
Diluted pro forma	0.82	0.34

As required, the pro forma disclosures above included options and SARs granted since January 1, 1995. For purposes of pro forma disclosures, the estimated fair value is amortized to expense over the vesting period. For options with graded vesting, expense is recognized on a straight-line basis over the vesting period. The fair value of each option grant on the date of grant for the disclosures is estimated by using the Black-Scholes option pricing model with the following weighted-average assumptions used for 2005 and 2004: fair value of $8.48 and $4.52 per share;

expected dividend per share of $0.08 and $0.04; expected historical volatility factors of 54% and 67%; risk-free interest rates of 4.1% and 3.5%, and an average expected life of 5 years.

Derivative Financial Instruments and Hedging

We use commodity-based derivatives to reduce the volatility of oil and gas prices. For derivatives qualifying as hedges of future cash flows, the effective portion of any changes in fair value is recognized in a component of stockholders equity called other comprehensive income (OCI), and then reclassified to income, as a component of oil and gas revenues, when the underlying anticipated transaction occurs. Any ineffective portion (changes in realized prices that do not match changes in the reference price used to settle the hedge) is recognized in earnings, as a component of other revenues, as it occurs. Ineffective gains or losses are recorded while the hedge contract is open and may increase or reverse until settlement of the contract. Typically, when oil and gas prices increase, OCI decreases. Of the $149.8 million gain recorded in OCI at December 31, 2006, $89.0 million is expected to be reclassified to income in 2007, if prices remain at their December 31, 2006 levels. Actual amounts that will be reclassified will vary as a result of changes in prices. As of the fourth quarter of 2005, certain of our oil and gas derivatives no longer qualify for hedge accounting due to the effect of volatility of gas prices on the correlation between realized prices and hedge reference prices. As a result, we recognized a gain of $10.9 million in the fourth quarter of 2005 and a gain of $86.5 million in the year ended December 31, 2006 related to these oil and gas derivatives that no longer qualify for hedge accounting. We expect these derivative positions will continue to be marked to market going forward. This may result in more volatility in our income in future periods.

Asset Retirement Obligations

The fair values of asset retirement obligations are recognized in the period they are incurred, if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities and include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures. Estimates are based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. The depreciation will generally be determined on a units-of-production basis while accretion to be recognized will escalate over the life of the producing assets. We do not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined.

Deferred Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include our expectation to generate sufficient taxable income including tax credits and operating loss carryforwards.

Accumulated Other Comprehensive Income (Loss)

We follow the provisions of SFAS No. 130, Reporting Comprehensive Income which establishes standards for reporting comprehensive income. Comprehensive income includes net income as well as all changes in equity during the period, except those resulting from investments and distributions to owners. At December 31, 2006, we had a $51.3 million pre-tax gain in OCI relating to unrealized commodity hedges. We also had a pre-tax gain of $6.2 million relating to our marketable securities held in the deferred compensation plan.

The components of accumulated other comprehensive income (loss) and related tax effects for three years ended December 31, 2006, were as follows (in thousands):

	Gross	Tax Effect	Net of Tax
Accumulated other comprehensive loss at December 31, 2003	$ (67,472)	$ 24,620	$ (42,852)
Contract settlements reclassified to income	100,121	(36,488)	63,633
Change in unrealized deferred hedging losses	(102,506)	38,029	(64,477)
Change in unrealized gains (losses) on securities held by deferred compensation plan	626	(231)	395
Accumulated other comprehensive loss at December 31, 2004	(69,231)	25,930	(43,301)
Contract settlements reclassified to income	160,267	(59,058)	101,209
Change in unrealized deferred hedging losses	(327,448)	121,100	(206,348)
Change in unrealized gains (losses) on securities held by deferred compensation plan	2,049	(736)	1,313

Accumulated other comprehensive loss at December 31, 2005	(234,363)	87,236	(147,127)
Contract settlements reclassified to income	46,511	(17,209)	29,302
Change in unrealized deferred hedging gains	242,122	(89,828)	152,294
Change in unrealized gains (losses) on securities held by deferred compensation plan	3,203	(1,151)	2,052
Accumulated other comprehensive income at December 31, 2006	$ 57,473	$ (20,952)	$ 36,521

Reclassifications

Certain reclassifications of prior years data have been made to conform with our current year classification. This includes a reclassification in 2005 of our SARs mark-to-market expense of $5.8 million from deferred compensation plan expense to direct operating expense ($480,000), exploration expense ($1.2 million), general and administrative expense ($4.0 million) and a $117,000 reduction of gas transportation revenues. This reclassification was made to align the expense with employee cash compensation. These reclassifications did not impact our net income, stockholders equity or cash flows.

Accounting Pronouncements Implemented

In December 2004, the FASB issued SFAS No. 123(R) as a revision of SFAS No. 123, Accounting for Stock-Based Compensation. This statement requires entities to measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the grant date. That cost is recognized over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. In addition, awards classified as liabilities are remeasured at fair value each reporting period.

We adopted SFAS No. 123(R) as of January 1, 2006, for all awards granted, modified or cancelled after adoption, and for the unvested portion of awards outstanding at January 1, 2006. At the date of adoption, SFAS No. 123(R) requires that an assumed forfeiture rate be applied to any unvested awards and that awards classified as liabilities be measured at fair value. Prior to adopting SFAS No. 123(R), we recognized forfeitures as they occurred and applied the intrinsic value method to awards classified as liabilities.

SFAS No. 123(R) also requires a company to calculate the pool of excess tax benefits available to absorb tax deficiencies recognized subsequent to adopting the statement. In November 2005, the FASB issued FASB Staff Position No. 123(R)-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards, to provide an alternative transition election (the short-cut method) to account for the tax effects of share-based payment awards to employees. We elected the short-cut method to determine our pool of excess tax benefits as of January 1, 2006.

See Stock-based compensation above and Note 12 to the consolidated financial statements for the disclosures regarding share-based payments required by SFAS No. 123(R).

Effective January 1, 2006, we adopted SFAS No. 154, Accounting Changes and Error Corrections A Replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 requires companies to recognize (1) voluntary changes in accounting principle and (2) changes required by a new accounting pronouncement, when the pronouncement does not include specific transition provisions, retrospectively to prior periods financial statements, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. The adoption had no immediate effect on our financial statements.

In September 2006, the SEC issued SEC Staff Accounting Bulletin (SAB) No. 108, Financial Statements Considering the Effects of Prior-Year Misstatements When Quantifying Misstatements in Current Year Financial Statements. SAB No. 108 addresses how a registrant should quantify the effect of an error in the financial statements for purposes of assessing materiality and requires that the effect be computed using both the current year income statement perspective (rollover) and the year-end balance sheet perspective (iron curtain) methods for fiscal years ending after November 15, 2006. If a change in the method of quantifying errors is required under SAB No. 108, this represents a change in accounting policy; therefore, if the use of both methods results in a larger, material misstatement than the previously applied method, the financial statements must be adjusted. SAB No. 108 allows the cumulative effect of such adjustments to be made to opening retained earnings upon adoption. The adoption of SAB No. 108 did not have a significant effect on our consolidated results of operations, financial position or cash flows.

Accounting Pronouncements Not Yet Adopted

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. For Range, SFAS No. 157 will be effective January 1, 2008, with early application permitted. We are currently evaluating the provisions of this statement.

In July 2006, the FASB issued FASB Interpretation (FIN) 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109. FIN 48 clarifies the accounting for uncertain income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods and disclosure. The cumulative effect of adoption FIN 48 will be recorded in retained earnings. For Range, the provisions of FIN 48 are effective January 1, 2007. We are currently evaluating the provisions of FIN 48 to determine the impact on our consolidated financial statements but we do not expect a material impact on our financial position or results of operations.

In June 2006, the FASB ratified the consensus reached by the EITF regarding Issue No. 06-03, How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation). Included in the scope of this issue are any taxes assessed by a governmental authority that are imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer. The EITF concluded that the presentation of such taxes on a gross basis (included in revenues and costs) or a net basis (excluded from revenues) is an accounting policy decision that should be disclosed pursuant to APB Opinion No. 22. In addition, the amounts of such taxes reported on a gross basis must be disclosed if those tax amounts are significant. For Range, the disclosure prescribed by this consensus is required in our 2007 consolidated financial statements but early application is permitted.

(3) ACQUISITIONS AND DISPOSITIONS

Acquisitions are accounted for as purchases, and accordingly, the results of operations are included in our statement of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets and assumed liabilities based on their estimated fair value at the time of the acquisition. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities. We purchased various properties for consideration of $709.0 million in 2006 compared to $173.5 million in 2005 and $648.2 million in 2004. These purchases included $630.1 million, $152.8 million and $619.0 million for proved oil and gas reserves, respectively; the remainder represents unproved acreage purchases. As part of our acquisitions for 2006, we allocated $140.0 million to the Austin Chalk properties which were classified as Assets Held for Sale at December 31, 2006. As part of our acquisitions for 2004, we allocated $15.5 million to gathering facilities acquired in the transactions. See also Note 19 Costs Incurred for Property Acquisition, Exploration and Development.

Our purchases in 2006 include the acquisition in June of Stroud Energy, Inc. (Stroud), a private oil and gas company with operations in the Barnett Shale in North Texas, the Cotton Valley in East Texas and the Austin Chalk in Central Texas. To acquire Stroud, we paid $171.5 million of cash (including transaction costs) and issued 6.5 million shares of our common stock. The cash portion of the acquisition was funded with borrowings under our bank facility. We also assumed $106.7 million of Stroud s debt which was retired with borrowings under our bank facility. The fair value of consideration issued was based on the average of our stock price for the five day period before and after May 11, 2006, the date the acquisition was announced. See also Note 4 for discussion of assets held for sale.

The following table summarizes the final purchase price allocation of fair values of assets acquired and liabilities assumed at closing (in thousands):

Purchase price:	
Cash paid (including transaction costs)	$ 171,529
6.5 million shares of common stock (at fair value of $27.26 per share)	177,641
Stock options assumed (652,000 options)	9,478
Debt retired	106,700
Total	$ 465,348
Allocation of purchase price:	
Working capital deficit	$ (13,557)
Other long-term assets	55
Oil and gas properties	487,345
Assets held for sale	140,000
Deferred income taxes	(147,062)

Asset retirement obligations	(1,433)
Total	$ 465,348

The following unaudited pro forma data include the results of operations as if the Stroud acquisition had been consummated at the beginning of 2005. The pro forma information for 2005 includes two material non-recurring amounts not directly related to the transaction and expected to reoccur. The year ended December 31, 2005 pro forma information includes an $18.4 million pre-tax stock compensation expense related to restricted and unrestricted shares issued to Stroud management and employees and a pre-tax $6.2 million loss on repurchase of mandatorily redeemable preferred units. The pro forma data is based on historical information and does not necessarily reflect the actual results that would have occurred nor are they necessarily indicative of future results of operations (in thousands, except per share data).

	Year Ended December 31,	
	2006	2005
Revenues	$779,487	$526,491
Income from continuing operations	$193,372	$ 81,753
Net income	$161,998	$ 95,086
Per share data:		
Income from continuing operations-basic	$ 1.41	$ 0.63
Income from continuing operations-diluted	$ 1.36	$ 0.60
Net income basic	$ 1.18	$ 0.73
Net income diluted	$ 1.14	$ 0.70

In 2004, we purchased Appalachian oil and gas properties, through the purchase of Pine Mountain, for $152.4 million cash paid to the seller, $57.2 million cash paid to repay debt and $13.3 million for the retirement of oil and gas commodity hedges. Also in 2004, we purchased the 50% of Great Lakes we did not previously own for $200.0 million cash paid to the seller plus the assumption of $70.0 million of Great Lakes bank debt and the retirement of $27.7 million of oil and gas commodity hedges. The debt assumed was refinanced and consolidated with our existing credit facility as of the purchase date.

The following unaudited pro forma data include the results of operations of the Pine Mountain and Great Lakes acquisitions as if they had been consummated at the beginning of 2004. The pro forma data are based on historical information and do not necessarily reflect the actual results that would have occurred nor are they necessarily indicative of future results of operations (in thousands, except per share amounts).

	2004
Revenues	$339,925
Income from continuing operations	54,382
Net income	53,385
Per share data:	
Income from continuing operations Basic	$ 0.44
Income from continuing operations Diluted	$ 0.43
Net income basic	$ 0.43
Net income diluted	$ 0.42

(4) ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

As part of the Stroud acquisition (see discussion in Note 3), we purchased Austin Chalk properties in Central Texas which were sold in February 2007 for proceeds of $80.4 million. We originally allocated $140.0 million to these properties. However, subsequent to the acquisition natural gas prices started to decline. As a result, we recognized impairment of $74.9 million, and at December 31, 2006 the carrying value is equal to sales proceeds less costs to sell. See also Note 17. We believe we have met the criteria of SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets that allow us to classify these assets as held for sale on our balance sheet and have presented the results of operations as discontinued operations. As of March 30, 2007, we sold our Gulf of Mexico assets for proceeds of $155.0 million. As a result, the results of operations for these properties have been reclassified to discontinued operations. All prior periods reflect this reclassification. The following footnotes have also been revised to reflect this reclassification: Note 2, 3, 5, 6, 9, 11, 17 and 18. Discontinued operations for the years ended December 31, 2006, 2005 and 2004 are summarized as follows (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Revenues:			
Oil and gas sales [3]	$ 54,192	$ 26,698	$ 36,800
Transportation and gathering	85	155	200
Other	(19)	(116)	639
	54,258	26,737	37,639
Costs and expenses:			
Direct operating	12,201	9,246	6,889
Production and ad valorem taxes	1,065	694	659
General, administrative and exploration	2,400	1,075	8,600
Interest expense [1]	3,232	1,178	682
Depletion, impairment and accretion expense [2]	89,863	13,150	22,343
(Loss) income from discontinued operations before income taxes	(54,503)	1,394	(1,534)
Income tax benefit (expense)	19,256	(488)	537
(Loss) income from discontinued operations, net of taxes	$ (35,247)	$ 906	$ (997)
Production:			
Crude oil (bbls)	139	102	127
Natural gas (mcf)	7,928	5,395	7,671
Total (per mcfe)	8,763	6,009	8,433

(1) Interest expense is allocated to discontinued operations for our Austin Chalk properties operations based on the debt incurred at the

time of the acquisition (for Austin Chalk) and based on the ratio of our Gulf of Mexico oil and gas properties to our total oil and gas properties at December 31, 2006 (for Gulf of Mexico).

(2) Impairment expense includes losses in fair value resulting from lower oil and gas prices and volumes produced since the acquisition date.

(3) Hedging gains and losses for the Gulf of Mexico operations have been allocated to discontinued operations based on the designated hedge values for those assets.

(5) INCOME TAXES

Our income tax expense from continuing operations was $121.8 million for the year ended December 31, 2006 compared to $65.9 million in 2005 and $25.1 million in 2004. A reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2006	2005	2004
Federal statutory tax rate	35%	35%	35%
State	4	2	2
Consolidated effective tax rate	39%	37%	37%

Income taxes paid (in thousands)	$ 1,973	$ 615	$ 150

Income tax provision (benefit) attributable to income from continuing operations consists of the following:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Current:			
U.S. federal	$ 150	$	$ (192)
U.S. state and local	1,762	1,071	(53)
	$ 1,912	$ 1,071	$ (245)
Deferred:			
U.S. federal	$ 110,296	$ 61,279	$ 23,987
U.S. state and local	9,544	3,530	1,340
	$ 119,840	$ 64,809	$ 25,327

Significant components of deferred tax assets and liabilities are as follows:

	December 31,	
	2006	2005
	(in thousands)	
Deferred tax assets		
Net operating loss carryover	$ 69,141	$ 76,944
Allowance for doubtful accounts	962	1,166
Net unrealized loss in OCI		85,462
Deferred compensation	38,664	27,721
AMT credits and other	30,641	44,738
Total deferred tax assets	139,408	236,031
Deferred tax liabilities		
Depreciation and depletion	(547,899)	(346,070)
Net unrealized gain in OCI	(21,264)	
Valuation allowance and other	(38,888)	(3,101)
Total deferred tax liabilities	(608,051)	(349,171)
Net deferred tax liability	$ (468,643)	$ (113,140)

At December 31, 2006, deferred tax liabilities exceeded deferred tax assets by $468.6 million, with $21.3 million of deferred tax liabilities related to net deferred hedging gains included in OCI. A portion of our deferred tax assets relate to items which are capital assets, which upon disposition will result in capital losses. Due to the uncertainty related to the utilization of the capital loss, a valuation allowance was recognized in the amount of $3.1 million.

At December 31, 2006, we had regular net operating loss (NOL) carryovers of $229.6 million and alternative minimum tax (AMT) NOL carryovers of $192.4 million that expire between 2012 and 2026. Regular NOLs generally offset taxable income and to such extent, no income tax payments are required. We have $26.9 million of NOLs generated in years prior to 1998 which are subject to yearly limitations due to IRC Section 382. We do not believe the application of the Section 382 limitation hinders our ability to utilize such NOLs and therefore, no valuation allowance has been provided. At December 31, 2006, we have AMT credit carryovers of $700,000 that are not subject to limitation or expiration.

(6) EARNINGS PER COMMON SHARE

The following table sets forth the computation of basic and diluted earnings per common share (in thousands, except per share amounts):

	Year Ended December 31,		
	2006	2005	2004
Numerator:			
Income from continuing operations	$ 193,949	$ 110,105	$ 43,228
Loss from discontinued operations	(35,247)	906	(997)
Preferred stock dividends			(5,163)
Net income	$ 158,702	$ 111,011	$ 37,068
Denominator:			
Weighted average shares outstanding	135,016	126,339	96,050
Stock held in deferred compensation plan and treasury shares	(1,265)	(2,209)	(2,506)
Weighted average shares, basic	133,751	124,130	93,544
Effect of dilutive securities:			
Weighted average shares outstanding	135,016	126,339	96,050
Employee stock options and other	3,696	2,863	1,948
Treasury shares	(1)	(76)	
Dilutive potential common shares for diluted earnings per share	138,711	129,126	97,998
Basic income from continuing operations	$ 1.45	$ 0.89	$ 0.41
discontinued operations	(0.26)		(0.01)
net income	$ $1.19	$ 0.89	$ 0.40
Diluted income from continuing operations	$ 1.39	$ 0.85	$ 0.39
discontinued operations	(0.25)	0.01	(0.01)
net income	$ 1.14	$ 0.86	$ 0.38

Stock appreciation rights for 88,500 shares were outstanding but not included in the computations of diluted net income per share for the year ended December 31, 2006 because the exercise price of the SARs was greater than the average price of the common shares and would be anti-dilutive to the computations. Options to purchase 318,200 shares of common stock were outstanding but not included in the computation of diluted net income per shares for the year ended December 31, 2004 because the exercise prices of the options were greater than the average market price of the common shares and would be anti-dilutive to the computations.

(7) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the year ended December 31, 2006, 2005 and 2004 (in thousands):

	2006	2005	2004
Balance at beginning of period	$ 25,340	$ 7,332	$ 2,043
Additions to capitalized exploratory well costs pending the determination of proved reserves	4,695	26,915	4,767
Additions due to purchase of Great Lakes			2,012
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(16,710)	(8,614)	(784)
Capitalized exploratory well costs charged to expense	(3,341)	(293)	(706)
Balance at end of period	9,984	25,340	7,332
Less exploratory well costs that have been capitalized for a period of one year or less	(4,792)	(21,589)	(6,124)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 5,192	$ 3,751	$ 1,208
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	3	3

As of December 31, 2006, of the $5.2 million of capitalized exploratory well costs that have been capitalized for more than one year, all of the wells have additional exploratory wells in the same prospect area drilling or firmly planned. None of the wells are operated by us. The $10.0 million of capitalized exploratory well costs at December 31, 2006 was incurred in 2006 ($4.7 million), in 2005 ($2.9 million) and in 2004 ($2.4 million).

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at December 31, 2006 is shown parenthetically). No interest was capitalized during 2006, 2005, and 2004 (in thousands):

	December 31,	
	2006	2005
Bank debt (6.4%)	$ 452,000	$ 269,200
Senior Subordinated Notes:		
7.375% Senior Subordinated Notes due 2013, net of $2.7 million and $3.1 million discount, respectively	197,262	196,948
6.375% Senior Subordinated Notes due 2015	150,000	150,000
7.5% Senior Subordinated Notes due 2016, net of $480,000 discount	249,520	
Total debt	$ 1,048,782	$ 616,148

Bank Debt

In October 2006, we entered into an amended and restated $800.0 million revolving bank credit facility, which we refer to as our bank debt or bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of an $800.0 million facility amount or the borrowing base. The borrowing base as of February 22, 2007 was $1.2 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and pursuant to certain unscheduled redeterminations. The facility amount may be increased to the borrowing base amount with twenty days notice. As of December 31, 2006, the outstanding balance under the bank credit facility was $452.0 million and there was $348.0 million of borrowing capacity available. The loan matures on October 25, 2011. Borrowing under the bank credit facility can either be base rate loans or LIBOR loans. On all base rate loans, the rate per annum is equal to the lesser of (i) the maximum rate (the weekly ceiling as defined in Section 303 of the Texas Finance Code or other applicable laws if greater) (the Maximum Rate) or, (ii) the sum of (A) the higher of (1) the prime rate for such date, or (2) the sum of the federal funds effective rate for such date plus one-half of one percent (0.50%) per annum, plus a base rate margin of between 0.0% to 0.5% per annum depending on the total outstanding under the bank credit facility relative to the borrowing base. On all LIBOR loans, we pay a varying rate per annum equal to the lesser of (i) the Maximum Rate, or (ii) the sum of the quotient of (A) the LIBOR base rate, divided by (B) one minus the reserve requirement applicable to such interest period, plus a LIBOR margin of between 1.0% and 1.75% per annum depending on the total outstanding under the bank credit facility relative to the borrowing base. We may elect, from time-to-time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 6.4% and 4.5% for the years ended December 31, 2006 and 2005, respectively. A commitment fee is paid on the undrawn balance based on an annual rate of 0.25% to 0.375%. At December, 31, 2006, the commitment fee was 0.25% and the interest rate margin was 1.0%. At February 22, 2007, the interest rate (including applicable margin) was 6.4%.

Senior Subordinated Notes

In 2003, we issued $100.0 million aggregate principal amount of 7.375% senior subordinated notes due 2013 (7.375% Notes). In 2004, we issued an additional $100.0 million of 7.375% Notes; therefore, $200.0 million of the 7.375% Notes are currently outstanding. The 7.375% Notes were issued at a discount which will be amortized over the life of the 7.375% Notes into interest expense. In 2005, we issued $150.0 million of 6.375% senior subordinated notes due 2015 (6.375% Notes). In May 2006, we issued $150.0 million of the 7.5% Senior Subordinated Notes due 2016 (the 7.5% Notes). In August 2006, we issued an additional $100.0 million of the 7.5% Notes; therefore, $250.0 million of the 7.5% Notes are currently outstanding. Interest on our senior subordinated notes is payable semi-annually and each of the notes are guaranteed by certain of our subsidiaries.

We may redeem the 7.375% Notes, in whole or in part, at any time on or after July 15, 2008, at redemption prices of 103.7% of the principal amount as of July 15, 2008, and declining to 100.0% on July 15, 2011 and thereafter. Prior to July 15, 2006, we may redeem up to 35% of the original aggregate principal amount of the 7.375% Notes at a redemption price of 107.4% of the principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings. We may redeem the 6.375% Notes, in whole or in part, at any time on or after March 15, 2010, at redemption prices from 103.2% of the principal amount as of March 15, 2010 and declining to 100% on March 15, 2013 and thereafter. Prior to March 15, 2008, we may redeem up to 35% of the original aggregate principal amount of the 6.375% Notes at a redemption price of 106.4% of the principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings. We may redeem the 7.5% Notes, in whole or in part, at any time on or after May 15, 2011 at redemption prices from 103.75% of the principal amount as of May 15, 2011 and declining to 100% on May 15, 2014 and thereafter. Prior to May 15, 2009, we may redeem up to 35% of the original aggregate principal amount of the 7.5% Notes at a redemption price of 107.5% of principal amount thereof plus accrued and unpaid interest if any, with the proceeds of certain equity offerings; provided that at least 65% of the original aggregate principal amount of our 7.5% Notes remains outstanding immediately after the occurrence of such redemption and provided that such redemption occurs within 60 days of the date of closing the equity sale.

If we experience a change of control, there may be a requirement to repurchase all or a portion of the senior subordinated notes at 101% of the principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and will be subordinated to future senior debt that we or our subsidiary guarantors are permitted to incur under the bank credit facility and the indentures governing the subordinated notes.

Guarantees

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees of the 7.375% Notes, the 6.375% Notes and the 7.5% Notes are full and unconditional and joint and several; any subsidiaries other than the subsidiary guarantors are minor subsidiaries.

Debt Covenants

The debt agreements contain covenants relating to working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2006. Under the bank credit facility, common and preferred dividends are permitted, subject to the provisions of the restricted payment basket. The bank credit facility provides for a restricted payment basket of $20.0 million plus 50% of net income plus 66-2/3% of net cash proceeds from common stock issuances. Approximately $446.4 million was available under the bank credit facility s restricted payment basket on December 31, 2006. The terms of each of our subordinated notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings and equity issuances since the original issuances of the notes. At December 31, 2006, approximately $496.2 million was available under the restricted payment baskets for each of the subordinated notes.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2006 (in thousands):

	Year Ended December 31
2007	$
2008	
2009	
2010	
2011	452,000
2012	
Thereafter	600,000
	$ 1,052,000

(9) ASSET RETIREMENT OBLIGATION

A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2006 and 2005 is as follows (in thousands):

	2006	2005
Beginning of period	$ 68,063	$ 70,727
Liabilities incurred	4,006	3,694
Acquisitions continuing operations	790	119
Acquisitions discontinued operations	742	
Liabilities settled	(3,057)	(6,126)
Accretion expense continuing operations	4,824	5,072
Accretion expense discontinued operations	37	
Change in estimate	20,183	(5,423)
End of period	95,588	68,063
Less current portion	(4,216)	(3,166)
Long-term portion	$ 91,372	$ 64,897

Accretion expense is recognized as a component of depreciation, depletion and amortization. The significant increase in 2006 as a result of changes in estimates is primarily related to rising abandonment costs and lower gas prices which accelerated the timing of abandonment. December 31, 2006 includes $20.1 million related to discontinued operations ($363,000 as a current portion) versus $11.5 million in December 31, 2005 ($45,000 as a current portion).

(10) CAPITAL STOCK

We have authorized capital stock of 260 million shares which includes 250 million shares of common stock and 10 million shares of preferred stock. All shares have been adjusted for the three-for-two common stock split affected on December 2, 2005. All common stock shares and treasury shares have been retroactively restated to reflect this stock split.

The following is a schedule of changes in the number of outstanding common shares since the beginning of 2005:

	Year Ended December 31,	
	2006	2005
Beginning balance	129,907,220	121,829,027
Public offerings		6,900,000
Shares issued for Stroud acquisition	6,517,498	
Shares issued in lieu of bonuses	20,686	25,590
Stock options/SARs exercised	1,956,164	1,105,549
Restricted stock grants	474,609	
Deferred compensation plan	12,998	20,885
Shares contributed to 401(k) plan	36,564	33,018
Fractional shares		(1,023)
Treasury shares	5,826	(5,826)
Ending balance	138,931,565	129,907,220

In June 2005, we completed a public offering of 6.9 million shares of common stock at $16.51 per share. Net proceeds from the offering of $109.2 million funded our acquisition of certain Permian basin properties.

Treasury Stock

During 2005, we bought in open market purchases, 201,000 shares at an average price of $14.00. As of December 31, 2006, all of these shares had been used for equity compensation. The board of directors has approved up to an additional $10.0 million of repurchases of common stock based on market conditions and opportunities.

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Financial instruments include cash and equivalents, receivables, payables, marketable securities, debt and commodity and interest rate derivatives. The carrying value of cash and equivalents, receivables, payables is considered to be representative of fair value because of their short maturity.

The following table sets forth our other financial instruments fair values at each of these dates (in thousands):

	December 31, 2006		December 31, 2005	
	Book Value	Fair Value	Book Value	Fair Value
Derivatives assets:				
Commodity swaps and collars [a]	$ 154,656	$ 154,656	$	$
Interest rate swaps [a]			425	425
Derivatives liabilities:				
Commodity swaps and collars [a]	(4,887)	(4,887)	(231,049)	(231,049)
Net derivatives asset (liability)	$ 149,769	$ 149,769	$ (230,624)	$ (230,624)
Marketable securities [b]	$ 44,226	$ 44,226	$ 21,769	$ 21,769
Long-term debt [c]	$ 1,048,782	$ 1,058,069	$ (616,148)	$ (619,523)

(a) All derivatives are marked to market and therefore their book value is assumed to be equal to fair value.

(b) Marketable securities held in our deferred compensation plans which are marked to market.

(c) The book value of our bank debt approximates fair value because of their floating rate structure. The fair value of our senior subordinated notes is based on current market quotes.

At December 31, 2006, we had open swap contracts covering 73.6 Bcf of gas at prices averaging $9.29 per mcf. We also had collars covering 56.1 Bcf of gas at weighted average floor and cap prices of $7.42 to $10.49 per mcf and 4.5 million barrels of oil at weighted average floor and cap prices of $55.72 to $70.11 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a net unrealized pre-tax gain of $149.8 million at December 31, 2006. These contracts expire monthly through December 2008. Transaction gains and losses are determined monthly and are included as increases or decreases to oil and gas revenues in the period the hedged production is sold. In 2006, realized losses were $43.2 million relating to our hedges compared with losses of $150.7 million in 2005 and losses of $87.6 million in 2004. In the fourth quarter of 2005, certain of our gas hedges no longer qualified for hedge accounting and were marked to market. This resulted in a gain of $86.5 million in 2006 versus a gain of $10.9 million in 2005. Gains and losses due to commodity hedge ineffectiveness are recognized in earnings in other revenues. The ineffective portion of hedges that qualified for hedge accounting was a gain of $6.0 million in 2006 versus a loss of $3.4 million in 2005 and a gain of $712,000 in 2004.

The following table sets forth the hedging volumes by year as of December 31, 2006:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2007	Swaps	96,336 Mmbtu/day	$9.13
2007	Collars	98,500 Mmbtu/day	$7.13 $ 9.99
2008	Swaps	105,000 Mmbtu/day	$9.42
2008	Collars	55,000 Mmbtu/day	$7.93 $ 11.39
Crude Oil			
2007	Collars	6,300 bbl/day	$53.46 $ 65.33
2008	Collars	6,000 bbl/day	$58.09 $ 75.11

In the past, we have used interest rate swap agreements to manage the risk that interest payments on amounts outstanding under the variable rate bank credit facility may be adversely affected by volatility in market interest rates. Our interest rate swap agreements ended on June 30, 2006.

The combined fair value of net gains on oil and gas derivatives totaling $149.8 million appears as unrealized derivative gains and unrealized derivative losses on our consolidated balance sheet at December 31, 2006. Hedging activities are conducted with major financial or commodities trading institutions which we believe are acceptable credit risk. At times, such risk may be concentrated with certain counterparties. The credit worthiness of these counterparties is subject to continuing review.

(12) EMPLOYEE BENEFIT AND EQUITY PLANS

Stock and Option Plans

We have six equity-based stock plans, of which two are active. Under the active plans, incentive and non-qualified options, stock appreciation rights (SARs), restricted stock awards, phantom stock rights and annual cash incentive awards may be issued to directors and employees pursuant to decisions of the Compensation Committee of the Board of Directors which is made up of outside independent directors. All awards granted under these plans have been issued at the prevailing market price at the time of the grant. Information with respect to stock option and SARs activities is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2003	5,746,703	$ 3.58
Granted	2,514,750	7.74
Exercised	(1,252,905)	3.46
Expired/forfeited	(135,443)	5.14
Outstanding at December 31, 2004	6,873,105	5.09
Granted	3,141,937	16.96
Exercised	(1,105,549)	4.84
Expired/forfeited	(167,188)	9.08
Outstanding at December 31, 2005	8,742,305	9.31
Granted	1,658,160	24.36
Stock options assumed in Stroud acquisition	652,062	19.67
Exercised	(2,051,237)	9.22
Expired/forfeited	(149,164)	18.32
Outstanding at December 31, 2006	8,852,126	$ 12.76

The following table shows information with respect to outstanding stock options and SARs at December 31, 2006:

	Outstanding			Exercisable	
Range of Exercise Prices	Shares	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Shares	Weighted Average Exercise Price
$ 0.59 $4.99	2,570,002	2.85	$ 3.60	2,570,002	$ 3.60

5.00	9.99	1,375,008	2.13		7.01	660,046		7.02
10.00	14.99	368,673	2.85		11.50	196,412		12.13
15.00	19.99	2,821,048	3.78		16.98	844,274		17.58
20.00	24.99	1,554,395	4.26		24.20	97,885		24.04
25.00	30.80	163,000	4.33		26.55	21,150		25.85
	Total	8,852,126	3.31	$	12.76	4,389,769	$	7.74

The weighted average fair value of an option/SAR to purchase one share of common stock during 2006 was $8.51. The fair value of each stock option/SAR granted during 2006 was estimated as of the date of grant using the Black-Scholes-Merton option pricing model based on the following assumptions: risk-free interest rate of 4.8%; dividend yield of 0.3%; expected volatility of 40.9%; and an expected life of 3.5 years.

As of December 31, 2006, the aggregate intrinsic value (the difference in value between exercise and market price) of the awards outstanding was $130.1 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable was $86.5 million and 3.2 years. As of December 31, 2006, the number of fully-vested awards and awards expected to vest was 8.7 million. The weighted average exercise price and weighted average remaining contractual life of these awards were $12.60 and 3.3 years and the aggregate intrinsic value was $128.8 million. As of December 31, 2006, unrecognized compensation cost related to the awards was $16.5 million, which is expected to be recognized over a weighted average period of 0.84 years.

For the year ended December 31, 2006, total stock-based compensation expense due to the adoption of SFAS 123(R) was $14.8 million. The total related tax benefits were $2.3 million. For the year ended December 31, 2006, cash received upon exercise of stock option/SARs awards was $16.3 million. Due to the net operating loss carryover for tax purposes, tax benefits realized for deductions that were in excess of the stock-based compensation were not recognized.

Restricted Stock Grants

In 2006, we issued 499,200 shares of restricted stock grants as compensation to directors and employees, at an average price of $24.43. The restricted grants included 15,000 issued to directors, which vest immediately, and 484,200 to employees with vesting over a three-year period. In 2005, we issued 192,500 shares of restricted stock grants (from treasury stock) as compensation to directors and employees, at an average price of $22.47. The restricted grants included 26,200 issued to directors, which vest immediately, and 166,300 to employees with vesting over a three-to-four year period. In 2004, we issued 121,400 shares of restricted stock grants as compensation to directors and employees, at an average price of $7.93. The restricted grants included 36,000 issued to directors, which vest immediately, and 85,400 to employees with vesting over a three-year period. We recorded compensation expense for restricted stock grants of $4.3 million in the year ended December 31, 2006 compared to $942,000 in 2005 and $567,000 in 2004.

A summary of the status of our unvested restricted stock outstanding at December 31, 2006 and changes during the twelve months then ended, is presented below:

	Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2006	238,107	$ 14.20
Granted	499,161	24.43
Vested	(212,129)	17.70
Forfeited	(23,628)	21.02
Outstanding at December 31, 2006	501,511	$ 22.58

401(k) Plan

We maintain a 401(k) Plan for our employees. The 401(k) Plan permits employees to contribute up to 50% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. Historically, we have made discretionary contributions of our common stock to the 401(k) Plan annually. In 2005, we began matching contributions of up to 3% of salary in cash with the remainder of our contribution in common stock. All our contributions become fully vested after the individual employee has three years of service with us. Great Lakes also maintained a 401(k) plan for its employees which was merged into our plan effective January 1, 2005. In 2006, we contributed $1.9 million to the 401(k) Plan compared to $1.5 million in 2005 and $1.2 million in 2004. We do not require that employees hold the contributed Range stock in their account. Employees have a variety of investment options in the 401(k) Plan. Employees may, at anytime, diversify out of our stock, based on their personal investment strategy.

Stock Purchase Plan

In 1997, stockholders approved a stock purchase plan which authorized the sale of up to 1.75 million shares of common stock to officers, directors, key employees and consultants. Under the stock purchase plan, the right to purchase shares may be granted at prices ranging from 50% to 85% of market value. At December 31, 2006, there were no rights outstanding to purchase shares and there were 373,000 remaining shares authorized to be granted.

Deferred Compensation Plan

In 1996, the Board of Directors adopted a deferred compensation plan (the Plan). The Plan gives directors, certain officers and key employees the ability to defer all or a portion of their salaries and bonuses and invests in Range common stock or makes other investments at the individual s discretion. Great Lakes also had a deferred compensation plan that allowed certain employees to defer all or a portion of their salaries and bonuses and invest such amounts in certain investments at the employee s discretion. In December 2004, we adopted the Range Resources Corporation Deferred Compensation Plan (2005 Deferred Compensation Plan). The 2005 Deferred Compensation Plan is intended to operate in a manner substantially similar to the old plans, subject to new requirements and changes mandated under Section 409A of the Internal Revenue Code. The old plans were frozen and will not receive additional contributions. The assets of all of the plans are held in a rabbi trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated in a manner similar to treasury stock with an offsetting amount reflected as a deferred compensation liability and the carrying value of the deferred compensation plan liability is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense category on our consolidated statement of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at market value in other assets on our consolidated balance sheet. The deferred compensation liability on our consolidated balance sheet reflects the market value of the securities held in the Rabbi Trust. The cost of common stock held in the Rabbi Trust is shown as a reduction to stockholders equity. Changes in the market value of the marketable securities are reflected in OCI, while changes in the fair value of the liability is charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market expenses of $6.9 million in 2006 compared to $29.5 million in 2005 and $19.2 million in 2004. Since we actually issue the common shares to the Rabbi Trust, we do not incur additional cash expense other than the original fair market value of the stock when issued.

(13) SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Net cash provided from operations included:			
Income taxes paid to taxing authorities	$ 1,973	$ 615	$ 150
Interest paid	55,925	34,148	19,216
Non-cash investing and finance activities:			
Common stock issued under benefit plans	$ 2,058	$ 3,180	$ 2,122
6.5 million shares issued for Stroud acquisition	177,641		
Stock options (652,000) issued in Stroud acquisition	9,478		
Preferred stock converted to common stock			(50,000)
Asset retirement costs capitalized, excluding acquisitions [(a)]	25,821	(1,730)	3,994

(a) For information regarding purchase price allocations of businesses acquired see Note 3.

(14) COMMITMENTS AND CONTINGENCIES

Litigation

We are involved in various legal actions and claims arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

Lease Commitments

We lease certain office space and equipment under cancelable and non-cancelable leases. Rent expense under such arrangements totaled $5.0 million, $2.2 million and $1.7 million in 2006, 2005 and 2004, respectively. Future minimum rental commitments under non-cancelable leases having remaining lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations
2007	$ 5,010
2008	5,308
2009	4,928
2010	3,867
2011	2,564
Thereafter	9,610
Sublease rentals	(222)
	$ 31,065

Other Commitments

As of December 31, 2006, we have contracts with various drilling contractors to use two drilling rigs in 2007 with terms of up to 2 years and minimum future commitments of $12.8 million in 2007 and $2.2 million in 2008. Early termination of these contracts at December 31, 2006 would have required us to pay maximum penalties of $11.3 million. We do not expect to pay any early termination penalties related to these contracts.

(15) MAJOR CUSTOMERS

We market our production on a competitive basis. Gas is sold under various types of contracts including month-to-month, and one-to-five-year contracts. Oil purchasers may be changed on 30 days notice. The price for oil is generally equal to a posted price set by major purchasers in the area or is based on NYMEX pricing, adjusted for quality and transportation. We sell to oil and gas purchasers on the basis of price, credit quality and service. For the year ended December 31, 2006, two customers each accounted for 10% or more of total oil and gas revenues and the combined sales to those customers accounted for 25% of total oil and gas revenues. For the year ended December 31, 2005, four customers each accounted for 10% or more of total oil and gas revenues and the combined sales to those four customers accounted for 56% of total oil and gas revenues. For the year ended December 31, 2004, two customers each accounted for 10% or more of total oil and gas revenue and combined sales to those two customers accounted for 25% of total oil and gas revenues. We believe that the loss of any one customer would not have a material adverse effect on our results.

(16) EQUITY METHOD INVESTMENTS

On April 18, 2006, we acquired a 50% interest in Whipstock Natural Gas Services, LLC (Whipstock), an unconsolidated investee in the business of providing oil and gas drilling equipment, well servicing rigs and equipment, and other well services in Appalachia. On the acquisition date, we contributed cash of $11.7 million representing the fair value of 50% of the common stock of Whipstock.

We account for our investment in Whipstock under the equity method of accounting pursuant to Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock. Under this method, we record our proportionate share of Whipstock s net earnings, declared dividends and partnership distributions based on the most recently available financial statements of the investee. There were no dividends or partnership distributions received from Whipstock during the year ended December 31, 2006. Whipstock follows a calendar year basis of financial reporting consistent with Range and our equity in Whipstock s earnings from the acquisition date through December 31, 2006 is included in our results of operations for 2006 in other revenue. In determining our proportionate share of the net earnings of Whipstock, certain adjustments are required to be made to Whipstock s reported results. These adjustments are made to eliminate the profits recognized by Whipstock for services provided to Range. For the year ended December 31, 2006, our equity in the earnings of Whipstock of $548,000 was reduced by $1.1 million in order to eliminate the profit on services provided to Range. Range and Whipstock have entered into an agreement whereby Whipstock will provide Range with the right of first refusal such that Range will have the opportunity to secure services from Whipstock in preference to and in advance of Whipstock entering into additional commitments for services with other customers. All services provided to Range will be at Whipstock s usual and customary terms. We also evaluate our equity method investment for potential impairment whenever events or changes in circumstances indicate that there is an other than temporary decline in value of the investment. Such events may include sustained operating losses by the investee or long-term negative changes in the investee s industry. These indicators were not present, and as a result, we did not recognize any impairment charges related to our investment in Whipstock for the year ended December 31, 2006.

Summarized financial information of investees accounted for under the equity method of accounting is as follows:

	2006 (in thousands)
Balance Sheet	
Current assets	$ 5,871
Non-current assets	30,261
Current liabilities	(5,458)
Non-current liabilities	(4,035)
Members equity	26,639
Income Statement	
Total revenues	$ 23,235
Gross profit	7,653
Income from operations	3,487
Interest expense	(198)
Net income	3,289

Our carrying value of our equity method investment is $300,000 higher than the underlying net assets of the investee. This basis difference is being amortized into earnings over five years.

(17) SUBSEQUENT EVENTS

On February 13, 2007, we sold our Austin Chalk properties for net sales proceeds of $80.4 million. These properties were classified as Assets Held for Sale at December 31, 2006. See also Note 3 and Note 4. On March 30, 2007 we sold our Gulf of Mexico properties for proceeds of $155.0 million. We recorded a pre-tax gain on the sale of our Gulf of Mexico properties of $95.6 million in the first quarter of 2007.

(18) SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years.

	2006				
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 166,555	$ 149,358	$ 163,410	$ 169,755	$ 649,078
Transportation and gathering	(39)	957	1,015	489	2,422
Mark-to-market on oil and gas derivatives	11,281	17,503	54,950	2,757	86,491
Other	1,433	1,572	250	3,566	6,821
Total revenues	179,230	169,390	219,625	176,567	744,812
Costs and expenses					
Direct operating	18,133	16,933	22,336	23,859	81,261
Production and ad valorem taxes	9,551	8,545	9,874	8,445	36,415
Exploration	8,922	7,763	16,508	10,895	44,088
General and administrative	11,330	12,514	12,170	13,872	49,886
Deferred compensation plan	4,479	(2,188)	(2,638)	7,220	6,873
Interest expense	10,234	11,643	16,389	17,583	55,849
Depletion, depreciation and amortization	31,651	33,995	40,606	48,487	154,739
Total costs and expenses	94,300	89,205	115,245	130,361	429,111
Income from continuing operations	84,930	80,185	104,380	46,206	315,701
Income tax					
Current	578	622	615	97	1,912
Deferred	31,150	29,676	38,707	20,307	119,840
	31,728	30,298	39,322	20,404	121,752
Income from continuing operations	53,202	49,887	65,058	25,802	193,949
Discontinued operations, net of taxes	2,473	1,383	(13,728)	(25,375)	(35,247)
Net income	$ 55,675	$ 51,270	$ 51,330	$ 427	$ 158,702
Earnings per common share:					
Basic income from continuing operations	$ 0.41	$ 0.38	$ 0.47	$ 0.19	$ 1.45
discontinued operations	0.02	0.01	(0.10)	(0.19)	(0.26)

net income	$	0.43	$	0.39	$	0.37	$		$	1.19
Diluted income from continuing operations	$	0.40	$	0.37	$	0.46	$	0.18	$	1.39
discontinued operations		0.01		0.01		(0.10)		(0.18)		(0.25)
net income	$	0.41	$	0.38	$	0.36	$		$	1.14

	2005				
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 100,044	$ 109,619	$ 133,892	$ 154,821	$ 498,376
Transportation and gathering	488	590	656	572	2,306
Mark-to-market on oil and gas derivatives				10,868	10,868
Other	9	348	(954)	(1,850)	(2,447)
Total revenues	100,541	110,557	133,594	164,411	509,103
Costs and expenses					
Direct operating	13,377	14,244	14,517	15,728	57,866
Production and ad valorem taxes	5,638	6,924	8,279	9,981	30,822
Exploration	2,715	8,923	7,501	10,390	29,529
General and administrative	6,603	6,241	9,019	11,581	33,444
Deferred compensation plan	4,067	5,276	17,450	2,681	29,474
Interest expense	8,327	9,261	9,613	10,418	37,619
Depletion, depreciation and amortization	26,491	26,685	29,417	31,771	114,364
Total costs and expenses	67,218	77,554	95,796	92,550	333,118
Income from continuing operations before income taxes	33,323	33,003	37,798	71,861	175,985
Income tax					
Current			331	740	1,071
Deferred	12,482	12,384	13,861	26,082	64,809
	12,482	12,384	14,192	26,822	65,880
Income from continuing operations	20,841	20,619	23,606	45,039	110,105
Discontinued operations, net of taxes	1,162	1,042	1,059	(2,357)	906
Net income	$ 22,003	$ 21,661	$ 24,665	$ 42,682	$ 111,011
Earnings per common share:					
Basic income from continuing operations	$ 0.17	$ 0.17	$ 0.19	$ 0.35	$ 0.89
discontinued operations	0.01	0.01		(0.02)	
net income	$ 0.18	$ 0.18	$ 0.19	$ 0.33	$ 0.89

Diluted income from continuing operations	$	0.17	$	0.16	$	0.18	$	0.34	$	0.85
discontinued operations		0.01		0.01		0.01		(0.02)		0.01
net income	$	0.18	$	0.17	$	0.19	$	0.32	$	0.86

(19) SUPPLEMENTAL INFORMATION ON NATURAL GAS AND OIL EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES

The following information concerning our natural gas and oil operations has been provided pursuant to Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities, (SFAS No. 69). Our natural gas and oil producing activities are conducted onshore within the continental United States and offshore in the Gulf of Mexico. The following information includes the activities of our Gulf of Mexico properties which qualify for reporting as discontinued operations in the Consolidated Statement of Operations.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization [(a)]

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Oil and gas properties:			
Properties subject to depletion	$ 3,414,964	$ 2,519,454	$ 2,082,236
Unproved properties	226,263	28,636	14,790
Total	3,641,227	2,548,090	2,097,026
Accumulated depreciation, depletion and amortization	(964,551)	(806,908)	(694,667)
Net capitalized costs	$ 2,676,676	$ 1,741,182	$ 1,402,359

(a) Includes capitalized asset retirement costs and the associated accumulated amortization.

Costs Incurred for Property Acquisition, Exploration and Development [(a)]

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Acquisitions:			
Acreage purchases	$ 79,762	$ 20,674	$ 9,690
Unproved leasehold	132,821		4,043
Proved oil and gas properties	209,262	131,748	522,126
Purchase price adjustment [(b)]	147,062	20,966	79,352
Asset retirement obligations	896	119	17,524
Development	464,586	252,574	144,007
Exploration [(c)]	70,870	59,539	31,830
Gas gathering facilities:			
Acquisitions		8	15,539
Exploratory	3,418		
Development	16,272	11,415	4,778
Subtotal	1,124,949	497,043	828,889
Asset retirement obligations	25,821	(1,730)	3,994
Total costs incurred	$ 1,150,770	$ 495,313	$ 832,883

Austin Chalk (Assets Held for Sale):

Acquisitions	$ 140,110	$	$
Development	$ 15,012	$	$

(a) Includes cost incurred whether capitalized or expensed.

(b) Represents non-cash gross up to account for differences in book and tax basis.

(c) Includes $45,252, $30,604 and $21,219 of exploration costs expensed in 2006, 2005 and 2004, respectively. Exploration expense includes $3,079 and $1,250 of stock-based compensation in 2006 and 2005, respectively.

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

Reserves of crude oil, condensate, natural gas liquids and natural gas are estimated by our engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

The SEC defines proved reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered as a result of additional investments for drilling new wells to offset productive units, recompleting existing wells, and/or installing facilities to collect and transport production.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, and, especially in the case of natural gas, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average realized prices used at December 31, 2006 to estimate reserve information were $57.66 per barrel for oil, $25.98 per barrel for natural gas liquids and $5.24 per mcf for gas, using benchmark prices of $61.05 per barrel and $5.64 per Mmbtu. The average realized prices used at December 31, 2005 to estimate reserve information were $57.80 per barrel for oil, $36.00 per barrel for natural gas liquids and $9.83 per mcf for gas, using benchmark prices of $61.04 per barrel and $10.08 per Mmbtu. The average realized prices used at December 31, 2004 to estimate reserve information were $40.44 per barrel for oil, $25.05 per barrel for natural gas liquids and $6.05 per mcf for gas, using benchmark prices of $43.33 per barrel and $6.18 per Mmbtu.

	Crude Oil and NGLs (Mbbls)	Natural Gas (Mmcf)	Natural Gas Equivalents (Mmcfe)
Proved developed and undeveloped reserves:			
Balance, December 31, 2003	33,023	486,404	684,541
Revisions	(312)	(24,251)	(26,111)
Extensions, discoveries and additions	5,515	122,790	155,875
Purchases	7,062	421,775	464,149
Sales	(3,622)	(9,568)	(31,303)
Production	(3,500)	(50,722)	(71,726)
Balance, December 31, 2004	38,166	946,428	1,175,425
Revisions	2,499	809	15,802
Extensions, discoveries and additions	7,932	169,785	217,377
Purchases	2,343	71,569	85,626
Sales	(5)	(177)	(205)
Production	(4,043)	(63,004)	(87,263)
Balance, December 31, 2005	46,892	1,125,410	1,406,762
Revisions	(42)	(48,609)	(48,863)
Extensions, discoveries and additions	10,871	314,261	379,491
Purchases	242	121,683	123,133
Sales	(4)	(1,500)	(1,522)
Production	(4,252)	(75,267)	(100,775)
Balance, December 31, 2006 [a]	53,707	1,435,978	1,758,226
Proved developed reserves:			
December 31, 2004	27,715	580,006	746,299
December 31, 2005	33,029	724,876	923,050
December 31, 2006	37,750	875,395	1,101,895

[a] The December 31, 2006 balance excludes reserves associated with the Austin Chalk properties that are shown as Assets Held for Sale on our balance sheet. The total proved developed and undeveloped reserves for these assets at December 31, 2006 were 42.3 Bcfe which is comprised of 39.3 Bcfe of gas.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas and oil reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed, as prescribed by SFAS No. 69, is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were prepared by our petroleum engineering staff. Proved reserves are estimated quantities of natural gas and crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.

2. Estimated future cash inflows are calculated by applying current year-end prices of natural gas and oil relating to our proved reserves to the quantities of those reserves produced in each future year.

3. Future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on current year-end economic conditions. Future income tax expenses are based on current year-end statutory tax rates giving effect to the remaining tax basis in the natural gas and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.

4. The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves is as follows and does not include cash flows associated with hedges outstanding at each of the respective reporting dates.

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Future cash inflows	$ 10,192,067	$ 13,520,985	$ 7,109,349
Future costs:			
Production	(2,575,212)	(2,266,828)	(1,472,484)
Development	(1,225,710)	(825,261)	(601,447)
Future net cash flows before income taxes	6,391,145	10,428,896	5,035,418
Future income tax expense	(1,999,934)	(3,496,799)	(1,523,915)
Total future net cash flows before 10% discount	4,391,211	6,932,097	3,511,503
10% annual discount	(2,388,987)	(3,547,787)	(1,762,092)
Standardized measure of discounted future net cash flows	$ 2,002,224	$ 3,384,310	$ 1,749,411

The following table summarizes changes in the standardized measure of discounted future net cash flows.

	As of December 31,		
	2006	2005	2004
		(in thousands)	
Beginning of period	$ 3,384,310	$ 1,749,411	$ 1,002,981
Revisions to previous estimates:			
Changes in prices	(2,390,159)	1,633,812	129,916
Revisions in quantities	(91,793)	59,244	(59,591)
Changes in future development costs	(623,607)	(367,732)	(399,562)
Accretion of discount	488,737	239,636	139,582
Net change in income taxes	733,846	(856,115)	(254,114)
Purchases of reserves in place	231,314	321,022	1,059,294
Additions to proved reserves from extensions, discoveries and improved recovery	712,902	814,973	355,742
Production	(554,788)	(425,902)	(248,891)
Development costs incurred during the period	223,158	143,918	72,144
Sales of natural gas and oil	(2,859)	(769)	(71,441)
Timing and other	(108,837)	72,812	23,351
End of period	$ 2,002,224	$ 3,384,310	$ 1,749,411

ITEM 9.01. FINANCIAL STATEMENTS AND EXHIBITS

(d) Exhibits:

23.1 Consent of Ernest & Young LLP

23.2 Consent of Degolyer and MacNaughton

23.3 Consent of H. J. Gruy and Associates, Inc.

23.4 Consent of Wright & Company, Inc.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

RANGE RESOURCES CORPORATION

By: /s/ Roger S. Manny

Roger S. Manny
Chief Financial Officer

Date: June 18, 2007

EXHIBIT INDEX

Exhibit Number	Description
23.1	Consent of Ernst & Young LLP
23.2	Consent of Degolyer and MacNaughton
23.3	Consent of H. J. Gruy and Associates, Inc.
23.4	Consent of Wright & Company, Inc.